Oregon
Theodore R. Kulongoski, Governor

Public Utility Commission
550 Capitol St NE, Suite 215
Mailing Address: PO Box 2148
Salem, OR 97308-2148
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

June 4, 2010

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **<u>Docket No. UE 215</u>** - In the Matter of PORTLAND GENERAL ELECTRIC COMPANY REQUEST FOR A GENERAL RATE REVISION.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Opening Testimony.

Lois Meerdink
/s/ Lois Meerdink

Lois Meerdink
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-8959
Email: Lois.Meerdink@state.or.us

cc: UE 215 Service List - parties

PUBLIC UTILITY COMMISSION
OF OREGON

UE 215

STAFF OPENING TESTIMONY OF

Judy Johnson
Moshrek Sobhy
Michael Dougherty
Dustin Ball
Ed Durrenberger
Kelcey Brown/Linnea Wittekind
Kenneth R. Zimmerman
Juliet Johnson
Steve Storm
Jorge Ordonez
George R. Compton
Irina Phillips

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision.

<u>REDACTED VERSION</u>
June 4, 2010

CASE: UE 215
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Judy Johnson. I am Program Manager of the Revenue Requirements Section in the Electric and Natural Gas Division at the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am the revenue requirements summary witness for the Commission staff (Staff) in this proceeding. Accordingly, I am generally familiar with the adjustments to Portland General Electric's (PGE or company) filing in this docket sponsored by other Staff analysts.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/102, consisting of 11 pages. This exhibit contains tables summarizing Staff's proposal for PGE's revenue requirement in this docket.

Q. WHAT IS STAFF'S POSITION ON REVENUE REQUIREMENT ISSUES?

A. A partial stipulation between PGE, Staff, Citizens' Utility Board (CUB), and Industrial Customers of Northwest Utilities (ICNU) is currently being prepared and is expected to be signed shortly and filed with the Commission. Joint testimony supporting the partial stipulation is also being prepared.

Q. PLEASE DESCRIBE THE INFORMATION IN EXHIBIT STAFF/102.

A. Exhibit Staff/102 contains three separate elements, which together summarize Staff's revenue requirements for PGE on UE 215.

Pages 1-4 provide a listing of proposed adjustments and indicate whether the adjustments are subject to the partial stipulation.

Pages 5 and 6 are the summary schedules for all the adjustments, both stipulated and contested. Page 5, column (2) shows the composite of the stipulated and Staff-proposed adjustments to the test year data contained in PGE's filing. Column (4) shows Staff's proposed change to PGE's revenue requirement of $59,695 million, or an increase of 6.59 percent from existing rates. Staff believes this revenue change is required for the company to achieve a reasonable rate of return. Page 6 contains the summary income tax calculations for Staff's proposal.

Page 7 shows the Staff's cost of capital calculation.

The revenue, expense, and rate base changes associated with each adjustment are displayed beginning on page 8.

Q. WHY DOES STAFF USE $157.762 MILLION AS PGE'S REVENUE REQUIREMENT INSTEAD OF $125.185 MILLION AS SHOWN IN THE COMPANY'S FILING?

A. This filing is made up of two portions, a general rate case portion and a power cost adjustment portion. The net of these two pieces is $125.185 million. However, the general rate case portion without the power cost adjustment is $157.762 million. Because these two pieces of the filing are being pursued with different time tables and in separate settlement discussions, Staff believes it is much clearer to show the general rate case portion on its own.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER – RATES AND TARIFFS
ADDRESS:	550 CAPITOL ST. N.E., SALEM, OREGON 97310-1380
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

EXPERIENCE:

3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is Program Manager of Rates & Tariffs. I was previously a Senior Analyst for the Revenue Requirements Section.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UE 215
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 4, 2010

NARRATIVE SUMMARY SHEET
ADJUSTMENTS
UE 215
Twelve Months Ending December 31, 2011
($000)

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results (Non-NVPC)	**$157,762**
		Commission Authorized Adjustments	
S-0	SS/JO	**Rate of Return** **NOT SETTLED.** Staff recommends 9.2% ROE vs. the Company's 10.5%. Staff also used a slightly lower Long-term Debt	**($36,213)**
S-1	DB	**Miscellaneous O&M & A&G Adjustments** SETTLED EXCEPT FOR STORM DAMAGE. Adjustment is based on a series of adjustments to Account 901-935 and 560-598	**($14,689)**
S-2	JAJ	**AMI Savings** SETTLED.	**($1,764)**
S-3	MS	**FTE Adjustment** SETTLED AND DELETED	**$0**
S-4	MS	**Wage & Salary Adjustment** NOT SETTLED. Staff's adjustment reconciles the proposed salary level with CPI	**($7,423)**
S-5	ED	**Boardman Fly Ash Adjustment** NOT SETTLED. Staff believes the fly ash disposal costs included in 2011 are not known and measurable. Staff also restored the revenue that represents the value of fly ash as a concrete additive	**($3,213)**
S-6	ED	**Hydro O&M Adjustment**	**($2,698)**

NARRATIVE SUMMARY SHEET
ADJUSTMENTS
UE 215
Twelve Months Ending December 31, 2011
($000)

		NOT SETTLED. Staff does not believe the the FERC requirements are known and measurable for the Clackamas Project	
S-7	ED	**Transmission O&M Adjustment** **SETTLED AND DELETED**	**$0**
S-8	ED	**O&M One Time Event Adjustment** NOT SETTLED. Staff believes that occurances that happen once should not be put into base rates.	**($6,640)**
S-9	MD	**Information Technology Adjustment** O&M SETTLED AND RATE BASE NOT SETTLED. Staff belives that information technology costs have been overstated for 2011	**($5,624)**
S-10	MD	**Various O&M Adjustments**	**($1,327)**

NARRATIVE SUMMARY SHEET
ADJUSTMENTS
UE 215
Twelve Months Ending December 31, 2011
($000)

		SETTLED.	
S-11	MM	**Transmission & Distribution Revenue Adjustment** SETTLED.	**($259)**
S-12	MM	**Other Transmission Revenue Adjustment** SETTLED.	**($310)**
S-13	LW/KB	**Clackamas Hydro Relicensing Project Adjustment** NOT SETTLED. Staff believes that only the costs associated with the relicensing effort are reasonable to include at this time, except for meals and entertainment. Staff's adjustment is primarily due to costs that Staff believes are associated with License measures, not yet imposed by a FERC order.	**($380)**
S-14	MP	**Depreciation & Amortization Expense & Rate Base** SETTLED	**($6,163)**
S-15	KZ	**Capital Projects Adjustment** PARTIALLY SETTLED. Staff believes capital projects is overstated and does not comply with ORS 757.355	**($11,364)**
		Total Adjustments (Base Rates):	(98,067)
		Calculated Revenue Requirement Change (Base Rates):	**$59,695**

Staff Contacts

503-378-5264	SS	Steve Storm
503-378-4629	JO	Jorge Ordonez
503-373-7946	DB	Dustin Ball

NARRATIVE SUMMARY SHEET
ADJUSTMENTS
UE 215
Twelve Months Ending December 31, 2011
($000)

503-378-6636	JAJ	Judy Johnson
503-378-6117	MS	Moshrek Sobhy
503-373-1536	ED	Ed Durrenberger
503-378-3623	MD	Mike Dougherty
503-378-6164	MM	Matt Muldoon
503-378-6116	LW	Linnea Wittekind
503-378-6667	KB	Kelcey Brown
503-378-8714	JSJ	Juliet Johnson
503-373-1123	MP	Ming Peng
503-373-1583	KZ	Ken Zimmerman
503-378-6123	GC	George Compton

Portland General Electric
UE 215
Revenue Requirement Model
Twelve Months Ending December 31, 2011
($000)

	SUMMARY SHEET	Results per Company filing (1)	Staff Proposed Adjustments (2)	2011 Adjusted (3)	Revenue Req without Power Costs 1/1/2011 (4)	Results at Reasonable Return w/out Power Costs (5)
1	**Operating Revenues**					
2	Retail Sales	$906,043	$0	$906,043	59,695	$965,738
3	Wholesale Sales		0	0	0	0
4	Other Revenues	20,961	800	21,761	0	21,761
5	**Total Operating Revenues**	$927,004	$800	$927,804	59,695	$987,499
6	**Operating Expenses**					
7	Net Variable Power Costs	$0	$0	$0	$0	$0
8	Production O&M (excludes Trojan)	123,227	(11,600)	111,627	0	111,627
9	Trojan O&M	90	0	90	0	90
10	Transmission O&M	12,621	(432)	12,189	0	12,189
11	Distribution O&M	84,075	(4,236)	79,839	0	79,839
12	Customer & MBC O&M	60,722	(2,069)	58,653	0	58,653
13	Uncollectibles	9,609	0	9,609	340	9,949
14	OPUC Fees	5,268	0	5,268	187	5,455
15	A&G, Ins/Ben, & Gen Plant	120,548	(18,963)	101,585	0	101,585
16	**Total Operation & Maintenance**	$416,159	($37,300)	$378,859	$527	$379,386
17	Depreciation	216,287	(9,231)	207,056	0	207,056
18	Amortization	16,277	0	16,277	0	16,277
19	Property Tax	41,724	0	41,724	0	41,724
20	Payroll Tax	11,942	(35)	11,907	0	11,907
21	Other Taxes	1,396	0	1,396	0	1,396
22	Franchise Fees	42,432	(326)	42,106	1,492	43,598
23	Utility Income Tax	5,515	20,025	25,540	22,515	48,055
24	**Total Operating Expenses**	$751,732	($26,867)	$724,865	$24,534	$749,399
25	**Net Operating Revenues**	$175,272	$27,667	$202,939	35,891	$238,830
26	**Average Rate Base**					
27	Electric Plant in Service	$6,491,337	($116,583)	$6,374,754	$0	$6,374,754
28	Less: Accumulated Depreciation & Amortization	(3,023,949)	2,970	(3,020,979)	0	(3,020,979)
29	Accumulated Deferred Income Taxes	(353,967)	0	(353,967)	0	(353,967)
30	Accumulated Deferred Inv. Tax Credit	(5)	0	(5)	0	(5)
31	**Net Utility Plant**	$3,113,416	($113,613)	$2,999,803	$0	$2,999,803
32	Plant Held for Future Use	$0	$0	$0	$0	$0
33	Acquisition Adjustments	0	0	0	0	0
34	Working Capital	58,954	(1,046)	57,908	957	58,865
35	Fuel Stock	72,169	0	72,169	0	72,169
36	Materials & Supplies	0	0	0	0	0
37	Customer Advances for Construction	0	0	0	0	0
38	Weatherization Loans	0	0	0	0	0
39	Misc Deferred Credits	(50,196)	0	(50,196)	0	(50,196)
40	Misc. Deferred Debits	47,251	0	47,251	0	47,251
41	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0
42	**Total Average Rate Base**	$3,241,594	($114,659)	$3,126,935	$957	$3,127,892
43	**Rate of Return**	5.41%		6.49%		**7.64%**
44	**Implied Return on Equity**	N/A		6.91%		9.20%

Portland General Electric
UE 215
Income Tax Calculation On Revenue Requirement
Twelve Months Ending December 31, 2011
($000)

	Income Tax Calculations	Per Company Filing (1)	Staff Proposed Adjustments (2)	2011 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$927,004	$800	$927,804	$59,695	$987,499
2	Book Expenses Other than Depreciation	529,930	(37,661)	492,269	2,019	494,288
3	State Tax Depreciation	216,287	(9,231)	207,056	0	207,056
4	Interest	98,496	(3,577)	94,918	29	94,947
5 Less:	Schedule M Differences	148,535	0	148,535	0	148,535
6	State Taxable Income	($66,244)	$51,269	($14,974)	$57,647	$42,673
7	Production Deduction	$0	$0	$0	$0	$0
8	Total State Taxable Income	($66,244)	$51,269	($14,974)	$57,647	$42,673
9	State Income Tax @ 6.617%	($4,135)	$3,202	($933)	$3,598	$2,665
10	State Tax Credits	(3,699)	0	(3,699)	0	(3,699)
11	Net State Income Tax	($7,834)	$3,202	($4,632)	$3,598	($1,034)
12	Additional Tax Depreciation	0	0	0	0	0
13 Plus:	Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	($58,410)	$48,067	($10,342)	$54,049	$43,707
15	Federal Tax @ 35%	($20,443)	$16,823	($3,620)	$18,917	$15,297
16	Federal Tax Credits	(31,137)	0	(31,137)	0	(31,137)
17	Current Federal Tax	($51,580)	$16,823	($34,757)	$18,917	($15,840)
18	ITC Adjustment					
19	Deferral	0	0	0	0	0
20	Restoration	0	0	0	0	0
21	Total ITC Adjustment	$0	$0	$0	$0	$0
22	Provision for Deferred Taxes	$64,930	$0	$64,930	$0	$64,930
23	Total Income Tax	$5,515	$20,025	$25,540	$22,515	$48,055

Portland General Electric
UE 215
Cost of Capital

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00570
Taxes Other - Franchise	0.02499
OPUC Fees	0.00313
- Resource supplier	
State Taxable Income	0.966185
State Income Tax	0.060309
Federal Taxable Income	0.905876
Federal Income Tax @ 35%	0.317057
ITC	
Current FIT	0.317057
Other	
Total Excise Taxes	0.377366
Total Revenue Sensitive Costs	0.411181
Utility Operating Income	0.588819
Net-to-Gross Factor	1.6983140

Cost of Capital

Staff's Case

COST OF CAPITAL	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	6.071%	3.036%
Preferred Stock			0.000%
Common Equity	50.00%	9.200%	4.600%
Total	100.00%		7.636%

Company's Case

COST OF CAPITAL-PGE	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	6.077%	3.039%
Preferred Stock			0.000%
Common Equity	50.00%	10.500%	5.250%
Total	100.00%		8.289%

Portland General Electric
UE 215
Twelve Months Ending December 31, 2011
($000)

	Commission Authorized Adjustments	Misc O&M & A&G Adjustment (S-1)	AMI Savings Adjustment (S-2)	FTE Adjustment DELETED (S-3)	Wage & Salary Adjustment (S-4)	Boardman Fly Ash Adjustment (S-5)	Hydro O&M Adjustment (S-6)	Transmission O&M **DELETED** (S-7)	O&M 1 Time Event Adjustment (S-8)	IT Adjustment (S-9)	O&M Adjustments (S-10)
1	**Operating Revenues**										
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	0	0	0	0	500	0	0	0	0	0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$500**	**$0**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**										
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M (excludes Trojan)	0	0	0	0	(2,600)	(2,600)	0	(6,400)	0	0
9	Trojan O&M	0	0	0	0	0	0	0	0	0	0
10	Transmission O&M	0	0	0	0	0	0	0	0	0	(182)
11	Distribution O&M	(3,554)	0	0	0	0	0	0	0	0	(682)
12	Customer & MBC O&M	0	(1,700)	0	0	0	0	0	0	0	(369)
13	Uncollectibles	0	0	0	0	0	0	0	0	0	0
14	OPUC Fees	0	0	0	0	0	0	0	0	0	0
15	A&G, Ins/Ben, & Gen Plant	(10,291)	0	0	(7,155)	0	0	0	0	(1,471)	(46)
16	**Total Operation & Maintenance**	**($13,845)**	**($1,700)**	**$0**	**($7,155)**	**($2,600)**	**($2,600)**	**$0**	**($6,400)**	**($1,471)**	**($1,279)**
17	Depreciation	0	0	0	0	0	0	0	0	(2,156)	0
18	Amortization	0	0	0	0	0	0	0	0	0	0
19	Property Tax	0	0	0	0	0	0	0	0	0	0
20	Payroll Tax	(35)	0	0	0	0	0	0	0	0	0
21	Other Taxes	0	0	0	0	0	0	0	0	0	0
22	Franchise Fees	(326)	0	0	0	0	0	0	0	0	0
23	Utility Income Tax	5,592	664	0	2,797	1,212	1,016	0	2,502	1,619	500
24	**Total Operating Expenses**	($8,614)	($1,036)	$0	($4,358)	($1,388)	($1,584)	$0	($3,898)	($2,008)	($779)
25	**Net Operating Revenues**	**$8,614**	**$1,036**	**$0**	**$4,358**	**$1,888**	**$1,584**	**$0**	**$3,898**	**$2,008**	**$779**
26	**Average Rate Base**										
27	Electric Plant in Service	(125)	0	0	0	0	0	0	0	(16,999)	0
28	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0
29	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0
30	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0
31	**Net Utility Plant**	($125)	$0	$0	$0	$0	$0	$0	$0	($16,999)	$0
32	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0
33	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0
34	Working Capital	(336)	(40)	0	(170)	(54)	(62)	0	(152)	(78)	(30)
35	Fuel Stock	0	0	0	0	0	0	0	0	0	0
36	Materials & Supplies	0	0	0	0	0	0	0	0	0	0
37	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0
38	Weatherization Loans	0	0	0	0	0	0	0	0	0	0
39	Prepayments	0	0	0	0	0	0	0	0	0	0
40	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0
41	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0
42	**Total Average Rate Base**	**($461)**	**($40)**	**$0**	**($170)**	**($54)**	**($62)**	**$0**	**($152)**	**($17,077)**	**($30)**
41	**Revenue Requirement Effect**	**($14,689)**	**($1,764)**	**$0**	**($7,423)**	**($3,213)**	**($2,698)**	**$0**	**($6,640)**	**($5,624)**	**($1,327)**

Portland General Electric
UE 215
Twelve Months Ending December 31, 2011
($000)

	Commission Authorized Adjustments	T&D Revenue Adjustment (S-11)	Other Transmission Revenues (S-12)	Clakamas Relicensing Adjustment (S-13)	Depreciation & Amortization Expense & RB (S-14)	Capital Projects Adjustment (S-15)	Total Adjustments (Base Rates)
1	**Operating Revenues**						
2	Retail Sales	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	$0
4	Other Revenues	0	300	0	0	0	$800
5	**Total Operating Revenues**	**$0**	**$300**	**$0**	**$0**	**$0**	**$800**
6	**Operating Expenses**						
7	Net Variable Power Costs	0	$0	$0	$0	$0	$0
8	Production O&M (excludes Trojan)	0	0	0	0	0	($11,600)
9	Trojan O&M	0	0	0	0	0	$0
10	Transmission O&M	(250)	0	0	0	0	($432)
11	Distribution O&M	0	0	0	0	0	($4,236)
12	Customer & MBC O&M	0	0	0	0	0	($2,069)
13	Uncollectibles	0	0	0	0	0	$0
14	OPUC Fees	0	0	0	0	0	$0
15	A&G, Ins/Ben, & Gen Plant	0	0	0	0	0	($18,963)
16	**Total Operation & Maintenance**	**($250)**	**$0**	**$0**	**$0**	**$0**	**($37,300)**
17	Depreciation	0	0	0	(5,939)	(1,136)	($9,231)
18	Amortization	0	0	0	0	0	$0
19	Property Tax	0	0	0	0	0	$0
20	Payroll Tax	0	0	0	0	0	($35)
21	Other Taxes	0	0	0	0	0	$0
22	Franchise Fees	0	0	0	0	0	($326)
23	Utility Income Tax	98	117	41	2,321	1,546	$20,025
24	**Total Operating Expenses**	**($152)**	**$117**	**$41**	**($3,618)**	**$410**	**($26,867)**
25	**Net Operating Revenues**	**$152**	**$183**	**($41)**	**$3,618**	**($410)**	**$27,667**
26	**Average Rate Base**						
27	Electric Plant in Service	0	0	(3,471)	0	(95,988)	($116,583)
28	Accumulated Depreciation & Amortization	0	0	0	0	2,970	$2,970
29	Accumulated Deferred Income Taxes	0	0	0	0	0	$0
30	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	$0
31	**Net Utility Plant**	$0	$0	($3,471)	$0	($93,018)	($113,613)
32	Plant Held for Future Use	0	0	0	0	0	$0
33	Acquisition Adjustments	0	0	0	0	0	$0
34	Working Capital	(6)	5	2	(141)	16	($1,046)
35	Fuel Stock	0	0	0	0	0	$0
36	Materials & Supplies	0	0	0	0	0	$0
37	Customer Advances for Construction	0	0	0	0	0	$0
38	Weatherization Loans	0	0	0	0	0	$0
39	Prepayments	0	0	0	0	0	$0
40	Misc. Deferred Debits	0	0	0	0	0	$0
41	Misc. Rate Base Additions/(Deductions)	0	0	0	0		$0
42	**Total Average Rate Base**	**($6)**	**$5**	**($3,469)**	**($141)**	**($93,002)**	**($114,659)**
41	**Revenue Requirement Effect**	**($259)**	**($310)**	**($380)**	**($6,163)**	**($11,364)**	**($61,854)**

Portland General Electric
UE 215
Tax Calculations
Twelve Months Ending December 31, 2011
($000)

	Income Tax Calculations	Misc O&M & A&G Adjustment (S-1)	AMI Savings Adjustment (S-2)	Adjustment DELETED (S-3)	Wage & Salary Adjustment (S-4)	Boardman Fly Ash (S-5)	Hydro O&M Adjustment (S-6)	Transmission O&M DELETED (S-7)	O&M 1 Time Event Adjustment (S-8)	IT Adjustment (S-9)	O&M Adjustments (S-10)
1	Book Revenues	$0	$0	$0	$0	$500	$0	$0	$0	$0	$0
2	Book Expenses Other than Depreciation	(14,206)	(1,700)	0	(7,155)	(2,600)	(2,600)	0	(6,400)	(1,471)	(1,279)
3	State Tax Depreciation	0	0	0	0	0	0	0	0	(2,156)	0
4	Interest	(111)	(1)	0	(5)	(2)	(2)	0	(5)	(518)	(1)
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0
6	State Taxable Income	14,317	1,701	0	7,160	3,102	2,602	0	6,405	4,145	1,280
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$14,317	$1,701	$0	$7,160	$3,102	$2,602	$0	$6,405	$4,145	$1,280
9	State Income Tax	$894	$106	$0	$447	$194	$162	$0	$400	$259	$80
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0
11	Net State Income Tax	$894	$106	$0	$447	$194	$162	$0	$400	$259	$80
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0
14	Federal Taxable Income	$13,423	$1,595	$0	$6,713	$2,908	$2,440	$0	$6,005	$3,886	$1,200
15	Federal Tax @ 35%	4,698	558	0	2,350	1,018	854	0	2,102	1,360	420
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0
17	Current Federal Tax	$4,698	$558	$0	$2,350	$1,018	$854	$0	$2,102	$1,360	$420
18	**ITC Adjustment**										
19	Deferral	0	0	0	0	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0
23	Total Income Tax	$5,592	$664	$0	$2,797	$1,212	$1,016	$0	$2,502	$1,619	$500

REVENUE REQUIREMENTS EFFECTS OF ADJUSTMENTS

	Misc O&M & A&G (S-1)	AMI Savings (S-2)	Adjustment DELETED (S-3)	0 Wage & Salary Adjustment (S-4)	Boardman Fly Ash (S-5)	Hydro O&M Adjustment (S-6)	Transmission O&M DELETED (S-7)	O&M 1 Time Event Adjustment (S-8)	IT Adjustment (S-9)	O&M Adjustments (S-10)
Revenues and Expenses	($14,629)	($1,759)	$0	($7,401)	($3,206)	($2,690)	$0	($6,620)	($3,410)	($1,323)
Rate Base	(60)	(5)	0	(22)	(7)	(8)	0	(20)	(2214)	(4)
Total	($14,689)	($1,764)	$0	($7,423)	($3,213)	($2,698)	$0	($6,640)	($5,624)	($1,327)

Portland General Electric
UE 215
Tax Calculations
Twelve Months Ending December 31, 2011
($000)

	Income Tax Calculations	T&D Revenue Adjustment (S-11)	Other Transmission (S-12)	Clakamas Relicensing Adjustment (S-13)	Depreciation & Amortization Expense & RB (S-14)	Capital Projects Adjustment (S-15)	Total Adjustments (Base Rates)
1	Book Revenues	$0	$300	$0	$0	$0	$800
2	Book Expenses Other than Depreciation	(250)	0	0	0	0	($37,661)
3	State Tax Depreciation	0	0	0	(5,939)	(1,136)	($9,231)
4	Interest	(0)	0	(105)	(4)	(2,823)	($3,577)
5	Schedule M Differences	0	0	0	0	0	$0
6	State Taxable Income	250	300	105	5,943	3,959	$51,269
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	$0
8	Total State Taxable Income	$250	$300	$105	$5,943	$3,959	$51,269
9	State Income Tax	$16	$19	$7	$371	$247	$3,202
10	State Tax Credits	0	0	0	0	0	$0
11	Net State Income Tax	$16	$19	$7	$371	$247	$3,202
12	Additional Tax Depreciation	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	$0
14	Federal Taxable Income	$234	$281	$98	$5,572	$3,712	$48,067
15	Federal Tax @ 35%	82	98	34	1,950	1,299	$16,823
16	Federal Tax Credits	0	0	0	0	0	$0
17	Current Federal Tax	$82	$98	$34	$1,950	$1,299	$16,823
18	**ITC Adjustment**						
19	Deferral	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	$0
							$0
22	Provision for Deferred Taxes	0	0	0	0	0	$0
							$0
23	Total Income Tax	$98	$117	$41	$2,321	$1,546	$20,025

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	T&D Revenue Adjustment (S-11)	Other Transmission (S-12)	Clakamas Relicensing Adjustment (S-13)	Depreciation & Amortization Expense & RB (S-14)	Capital Projects Adjustment (S-15)	Total Adjustments (Base Rates)
Revenues and Expenses	($258)	($311)	$70	($6,145)	$696	($46,986)
Rate Base	(1)	1	(450)	(18)	(12060)	($14,868)
Total	($259)	($310)	($380)	($6,163)	($11,364)	($61,854)

CASE: UE-215
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Moshrek Sobhy. My position is Senior Utility and Energy Analyst with the Public Utility Commission of Oregon (Commission). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am sponsoring Staff testimony with respect to the wages and salaries in Portland General Electric's (PGE or the Company) case UE 215.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared the following exhibits:

Exhibit 200 consisting of pages 1 – 13:	Testimony
Exhibit 201:	Qualifications
Exhibit 202:	Supporting Work Papers

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO PGE'S WAGES AND SALARIES?

A. My recommendation is to reduce PGE's proposed wages and salaries from $202,906,420 to $195,778,769, a net reduction of approximately ($7.1 million).

PGE'S PROPOSED WAGES AND SALARIES

Q. PLEASE DESCRIBE THE COMPANY'S FULL TIME EQUIVALENTS (FTE).

A. In PGE's Exhibit 500, the Company states that it uses the FTE in its annual budgeting process to determine the number of labor hours required to accomplish the work. The number of FTEs is calculated by dividing total labor hours by the number of work hours during the year. The number of work hours during the year is 2080, or the product of 40 hours per week times multiplied by 52 weeks (the number of weeks in a calendar year).

Q. WHY DOES THE COMPANY USE THE FTE NUMBER INSTEAD OF A SIMPLE EMPLOYEES HEAD COUNT TO DETERMINE THE TEST YEAR WAGES AND SALARIES?

A. In PGE exhibit 500, PGE witnesses, Arleen Barnett and Joyce Bell (the witnesses), explain that an employee who was hired in the middle of the year would be budgeted as one half (or 0.5) FTE. In a head count, this employee will count as one.

Q. ARE THERE NECESSARY ADJUSTMENTS TO BE CONSIDERED WHEN CALCULATING FTE?

A. Yes. It is critical to remove paid and non-paid over time both in hours and in dollars when calculating FTEs for historical and future periods. Failure to do this adjustment will result in overstating the number of FTEs and will skew the wages and salaries corresponding to the FTEs. This overstatement will translate into rates charged to the customers.

Q. HOW DID THE COMPANY PRESENT THE FTE IN ITS CALCULATIONS OF TEST YEAR 2011 WAGES AND SALARIES?

A. The witnesses testified in PGE/500 that the overtime was excluded from the actual total FTEs. Also, in response to Staff data request # 157, the company stated that overtime was not included in the FTE calculations of the historical and future periods.

Q. HOW DID THE COMPANY DETERMNE THE WAGES AND SALARIES IN THE TEST YEAR?

A. In PGE/500 and supporting work papers, the Company presented that its' the wages and salaries base budget during 2011 is $211,520,465. Due to significant workforce reduction associated with Advanced Metering Infrastructure (AMI), and increases in other areas, the Company made adjustments to its base budget workforce. Details of the workforce adjustment in the test year are summarized below in Table 1.

Table 1 – PGE's Test Year net FTE reduction

AREA	Increase (decrease) in FTEs
Administrative & General (A&G)/ IT	10.0
Customer service, including AMI	(117.8)
Generation	19.9
Transmission & Distribution	5.2
Total	(82.7)

With respect to the test year salaries adjustment, PGE's witnesses explain in PGE/500 that $8.0 million representing approximately 99 FTEs were removed from wages and salaries' base budget in 2011 to account for vacancies and unfilled positions. Additional details were included in the Company's response to staff data request DR-221 (see copy in exhibit 202). A summary of the company's information is in Table 2 below:

Table 2 – PGE's Test Year wages and salaries adjustment

Description	FTEs adjustment	Salary adjustment ($)
Adjustments for vacant positions	(99.4)	(8,000,000)
Outboard adjustments to revenue requirement	(10.0)	(614,045)
Impact of previously authorized items[1]	(8.2)	0
Total	(117.6)	(8,614,045)

Q. WHAT IS PGE'S PROPOSED WAGES AND SALARIES IN THE TEST YEAR?

A. After making the above adjustments to the base budget, the Company proposes $202,906,420, in test year wages and salaries as summarized in table 3 below:

[1] The Company did not make salary adjustments corresponding to these FTE reductions because no expenses above the 2008 base rates were added (see attachment 221 A in staff exhibit 202)

Table 3 – PGE's proposed Test Year FTE and, wages and salaries

	FTEs	Wages & Salaries
2011 base budget	2,647	$211,520,465
Adjustments	(118)	($8,614,045)
2011 Test Year	2,529	$202,906,420

Q. DID THE COMPANY ALLOCATE THE TEST YEAR'S FTES AND SALARIES AMONG ITS CLASSES OF EXEMPT, NON-EXEMPT, OFFICERS, AND UNION EMPLOYEES?

A. No. The Company reflected the FTEs adjustment in the test year by area of operation, e.g. Administrative and General (A&G/IT), Customer Accounting, Customer Service, Transmission and Distribution (T&D), and Generation.

STAFF ADJUSTMENT

Q. PLEASE DESCRIBE THE BASIS OF YOUR ADJUSTMENT.

A. My adjustment results from using the 2009 Market Compensation for PGE's workforce as the basis to calculate the Company's test year wages and salaries.

Q. HOW DID YOU APPROACH REVIEWING THE COMPANY'S WAGES AND SALARIES IN THIS PROCEEDING?

A. The first step was to review the Company's proposed wages and salaries in the current proceeding, i.e. UE-215, in light of the information provided by the Company, the previous Commission Order No. 09-020, and other information previously provided by the Company in UE-197. The second step was reviewing the Commission's methodology in determining the test year's wages and salaries in Order No. 09-020 in UE-197. The third step was to determine a starting point for the determination for the base year wages and salaries, consistent with the Commission practice in Order No. 09-020. The final step was determining the test year's wages and salaries consistent with the Commission's methodology in Order No 09-020.

Q. PLEASE DESCRIBE THE COMMISSION'S METHODOLOGY IN DETERMINING THE WAGES AND SALARIES IN UE-197.

A. In Order No. 09-020, the Commission started with the base year 2007 actual wages and salaries of $178,505,742, (excluding officers). This represented a workforce of 2,546 FTEs (net of officers). The Commission then applied an annual workforce rate growth of 1.45 % and an annual wage escalation factor of 2.4%. (See copy of page 10 of Order No. 09-020 in staff exhibit 202). The wages and salaries for the 2009 test year in UE-197 was $192,697,069, (excluding officers).

Q. DID PGE PROVIDE INFORMATION WITH RESPECT TO ITS WORKFORCE MARKET COMPENSATION IN UE-197?

A. Yes. In UE-197, the Company's work paper 5 in PGE/800, (see copy in exhibit 202), include the market compensation for the Company's employees (excluding officers) of $179,586,393. This is approximately $1.0 million more the base year wages and salaries as shown in Order No. 09-020. This difference represents approximately 0.6% of the market compensation level.

Q. WHAT IS THE BASE YEAR IN DETERMINING THE WAGES AND SALARIES IN THIS PROCEEDING?

A. I used the historic year 2009 as the base year to determine the test year's wages and salaries.

Q. HOW DO THE WAGES AND SALARIES DURING THE HISTORIC YEARS 2007 THROUGH 2009 COMPARE?

A. Below is a summary of comparison between the actual wages and salaries vs. the market compensation during these years as follows:

Table 4 – Actual W&&S vs. Market Compensation

	Market Compensation (A)	Actual wages and salaries (B)	Difference (B-A)	% difference (B-A)/A
2007	$179,586,393	$178,505,742	($1,080,651)	(0.6%)
2008	$183,884,000	$188,040,000	$4,156,000	2.26%
2009	$188,657,000	$193,799,000	$5,142,000	2.72%

Q. DID THE COMPANY PROVIDE MARKET COMPENSATION FOR ITS WORKFORCE DURING 2008 AND 2009?

A. Yes. In response to staff data request nos. DR-211 and DR-212, the Company provided information on actual wages and salaries and market compensation for 2008 and 2009. (Copies of company responses included in staff exhibit 202). Table 5 is a summary of the information included in Staff exhibit 202:

Table 5 – Comparison market compensation vs. actual salaries ($000)

(2008 & 2009)

	FTEs	Market Compensation	Actual	actual less market
2009	**(A)**	**(B)**	**(C)**	**(D = C-B)**
Exempt	1,215	103,276	109,550	6,274
Non-exempt	576	25,925	24,793	(1,132)
Union	819	59,456	59,456	-
Officer	13	3,520	3,394	(126)
Total 2009	2,623	192,177	197,193	**5,016**
2008				
Exempt	1,188	100,924	106,224	5,300
Non-exempt	589	25,873	24,729	(1,144)
Union	824	57,087	57,087	-
Officer	11	3,300	3,127	(173)
Total 2008	2,612	187,184	191,167	**3,983**
Cumulative 2008 and 2009 combined difference				**8,999**

Q. HOW DID STAFF DETERMINE THAT PGE'S PROPOSED WAGES AND SALARIES ARE EXCESSIVE?

The comparison in Table 5 above demonstrates that the Company paid its employees approximately $9 million in wages and salaries above market compensation during 2008 and 2009 combined (column D) unlike in 2007 as shown previously. Market compensation represents a reasonable and fair basis to determine future test year's wages and salaries after applying appropriate workforce and wages escalation factors.

Q. IS MARKET COMPENSATION FAIR, JUST AND REASONABLE TO DETERMINE WAGES AND SALARIES FOR RATE MAKING PURPOSES?

A. Yes. Allowing wages market compensation based wages and salaries in revenue requirements ensure that the Company pays competitive salaries to hire and retain skilled and qualified workforce needed to operate the utility efficiently. This in turn assures that ratepayers receive reliable and affordable service. Staff recommends that amounts paid in excess of market compensation not to be allowed in revenue requirements.

Q. WHAT IS THE STARTING POINT FOR STAFF ADJUSTMENT?

A. I started with the average salary in PGE's market compensation for exempt and non-exempt employees during 2009. The combined market compensation for these two classes was divided by the sum of their FTEs in the test year to determine the average salary per FTE. The average salary was escalated by an annual wage escalator rate to determine the test year average salary. Salaries for union employees and the Company's officers are determined separately as explained later in the testimony.

Q. HOW DID STAFF DETERMINE THE ANNUAL WAGE ESCALATION RATE?

A. In Order No. 09-020 in docket UE 197, the Commission used the 3-year average of Consumer Price Index (CPI)-all urban, to account for inflation in determining the test year's average salary per FTE. The three-year average in this proceeding would include the 2009 CPI (-0.3). Staff believes that 2009 is an anomaly that is reflective of the severity in the economic downturn that was most significantly during that year. To mitigate this effect, staff calculated the CPI average since 2005 to 2011. The result was 2.4%, the same rate authorized by the Commission in Order No. 09-020 in UE 197. Staff believes this method is reasonable and in concept is consistent with the Commission method in UE 197. It should be noted that the officers and union salaries were not adjusted by this method.

Q. PLEASE DESCRIBE IN DETAILS THE STEPS YOU FOLLOWED TO CALCULATE STAFF PROPOSED WAGES AND SALARIES.

A. First, I needed to calculate a ratio to distribute the test year's FTEs among the classes. To do so, I calculated the average distribution ratio of the Company's workforce from 2007 to 2011. This information was obtained from the Company's work papers in PGE/500 and attachment DR-157-A, which is included in Exhibit 202 of my testimony. Table 6 includes Staff's proposed test year workforce distribution.

Table 6 – Distribution of Test Year Workforce

	EXEMPT	HOURLY	OFFICER	UNION	Grand Total
Sum of 2007 Act FTE	1,147	580	13	809	2,549
Sum of 2008 Act FTE	1,188	589	11	824	2,612
Sum of 2009 Act FTE	1,215	576	13	819	2,623
Sum of 2010 B FTE	1,256	587	12	848	2,703
Sum of 2011 B FTE	1,264	539	12	833	2,648
Total FTE by class	6,071	2,871	61	4,132	13,135
% distribution (average)	46.22%	21.86%	0.46%	31.46%	100%
TY 2011 FTE distribution	1,169	553	12	796	2,529

Next, I calculated a combined average salary per FTE for these two classes by dividing their combined 2009 market compensations by the sum of their FTEs during the same year (Table 7, column B). I then increased the 2009 average salary by 2.4% annually through 2011 (Table 7, columns C & D). The following step was to multiply the number of FTEs in the test year by the average test year salary to determine the wages and salaries of these two classes combined. Next, I added the union and officer salaries (Table 7, column F). Finally, I compared Staff calculations of the test year's wages and salaries with the Company's proposal. The result is a ($7.1 million) reduction in test year's wages and salaries. These calculations are shown in Table 6 below:

Table 7 – Staff Adjustment to Test Year Wages and Salaries, $000

	2009 FTEs	2009 Market Compensation ($000)	2010 at 2.4% increase	2011 at 2.4% increase	Test Year FTEs	
	A	**B**	**C**	**D**	**E**	**F**
Exempt	1,215	103,276			1,169	
Non-exempt	576	25,925			553	
Total	1,791	129,201			1,722	
Average salary per FTE, $000 **(total B/ total A)**		72.1	73.8	75.6		
Staff test year salaries, $000 **(total E*D)**						130,231

Q. WHAT IS STAFF RECOMMENDATION WITH RESPECT TO OFFICERS SALARY?

A. The company's salary level for officers in the base budget during 2011 is $3,251,117. This is below PGE's 2009 market compensation for officers of $3,300,000. Staff agrees with the company's proposed officers' salary level in the base budget for 2011.

Q. HOW DID STAFF DETERMINE THE TEST YEAR'S SALARY FOR UNION EMPLOYEES?

A. As shown in table 4 above, market compensation and the actual salaries for union employees during 2009 are the same. The test year's average salary per employee, was based on the 2009 average salary, and escalated by the appropriate rate increases according to the contracts between the labor union and the Company. A copy of the company's work paper is included in Exhibit 202 of my testimony. The employee's test year average salary was multiplied by the allocated number of union employees in the test year as indicated in Table 2 above.

Table 8 – Union wages and salaries

	2009 average salary (DR157-A) **(A)**	Feb-10 **(B)**	Sep-10 **(C)**	Mar-11 **(D)**
1. Pay rate increase (DR-157E)		2%	2%	3.60%
2. Average salary	$ 72,609	$ 74,061	$ 75,542	$ 78,262
3. Union Test Year FTEs				796
4. Union Test Year wages and salaries, (column D, ln.2*ln.3)				$62,296,552

Q. PLEASE SUMMARIZE STAFF'S PROPOSED TEST YEAR WAGES AND SALARIES.

A. Following is a summary of the Company's proposal vs. Staff proposal.

	Company	**Staff**	**Adjustment**
Exempt and non-exempt		*$130,231,100*	
Union		*$62,296,552*	
Officers		*$3,251,117*	
Total	*$202,906,420*	*$195,778,769*	*$7,127,651*

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

CASE: UE 215
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications

June 4, 2010

Q. MR. SOBHY PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering in 1991 from Alexandria University, Egypt. I am currently attending the Certificate of Public Management (CPM) course at Willamette University, Oregon. In September 1997, I began my employment with the Indiana Department of Natural Resources as engineering assistant. In October 1998, I was promoted to Utility Engineer with the Indiana Utility Regulatory Commission (IURC). Following reorganization of the IURC, from 1998 to 2006 my duties as a Principal Utility Analyst with the Gas/Water/Sewer Division included advising and assisting the Commission on numerous proceedings involving rate cases, acquisitions, rulemaking, investigations, and customer complaints. In November 2006, I accepted the position of Senior Rates Analyst with the Northern Indiana Public Utility Corporation (NIPSCO), a subsidiary of NiSource, where I worked primarily on the cost of service study for the electric utility, in addition to energy efficiency and decoupling issues for the gas utility. From April 200 7 to February 2009, I held the position of Senior Rates and Regulatory Affairs Analyst with Citizens Energy Group, a natural gas and steam utility serving the Marion County, Indiana. In July 2009, I joined the Public Utility Commission of Oregon as Senior Utility and Energy Analyst.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Moshrek Sobhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 4, 2010

UE 215
PGE Response to OPUC Data Request No. 211
Attachment 211-A

Wages and Salary for PGE FTE: 2008

Exempt	FTE	Average Pay ($s)	Actual Salary ($000s)
01	0	-	0
02	0	-	0
03	0	-	0
04	10	59,767	626
05	0	-	0
06	100	55,629	5,552
07	7	58,505	413
08	171	66,852	11,407
09	16	70,984	1,140
10	238	81,628	19,403
11	189	92,778	17,553
12	308	100,562	30,973
13	55	113,923	6,264
14	32	123,492	3,905
15	31	134,072	4,137
16	20	149,515	3,028
17	11	166,542	1,823
Total	1,188		$106,224

Non-Exempt	FTE	Average Pay ($s)	Actual Wage ($000s)
03	0	-	0
04	0	-	0
05	0	-	0
06	4	25,877	107
07	8	29,169	245
08	85	36,666	3,124
09	3	43,584	131
10	315	39,646	12,469
11	0	-	0
12	111	47,947	5,305
13	42	51,766	2,181
14	21	56,734	1,167
Total	589		$24,729

Total Union

FTEs	Ave. per Union FTE ($)	Total ($000s)
824	69,258	$57,087

Total Officers

FTEs	Average per Officer ($)	Total ($000s)
11	274,074	$3,127

	FTE	Wages/Salaries ($000s)
Exempt	1,188	106,224
Non-Exempt	589	24,729
Union	824	57,087
Officer	11	3,127
	2,612	$191,167

UE 215
PGE Response to OPUC Data Request No. 211
Attachment 211-A

Wages and Salary
for PGE FTE: 2009

Exempt	FTE	Average Pay ($s)	Actual Salary ($000s)
01	0	-	0
02	0	-	0
03	0	-	0
04	10	60,546	623
05	0	-	0
06	106	55,832	5,930
07	6	58,970	337
08	175	67,560	11,838
09	19	70,277	1,313
10	246	82,671	20,349
11	180	93,579	16,857
12	316	101,372	32,081
13	59	113,619	6,661
14	34	123,519	4,229
15	32	136,788	4,342
16	21	149,268	3,133
17	11	169,616	1,858
Total	1,215		$109,550

Non-Exempt	FTE	Average Pay ($s)	Actual Wage ($000s)
03	0	-	0
04	0	-	0
05	0	-	0
06	4	27,103	121
07	7	30,722	217
08	83	37,308	3,082
09	3	41,398	124
10	316	40,588	12,820
11	0	-	0
12	101	49,824	5,038
13	41	52,956	2,183
14	21	58,852	1,210
Total	576		$24,793

Total Union

FTE	Ave. per Union FTE ($)	Total ($000s)
819	72,609	$59,456

Total Officers

FTEs	Average per Officer ($)	Total ($000s)
13	265,604	$3,394

	FTE	Wages/Salaries ($000s)
Exempt	1,215	109,550
Non-Exempt	576	24,793
Union	819	59,456
Officer	13	3,394
	2,623	$197,193

UE 215
PGE Response to OPUC Data Request No. 212
Attachment 212-A

Market Compensation for PGE 2008 FTEs

Exempt	FTE	Pay Guide ($s)	Total at Pay Guide ($000s)
01	0	47,688	0
02	0	49,488	0
03	0	51,528	0
04	10	53,880	564
05	0	57,576	0
06	100	60,336	6,022
07	7	63,912	452
08	171	68,568	11,699
09	16	73,464	1,180
10	238	79,104	18,803
11	189	85,656	16,206
12	308	93,216	28,711
13	55	101,616	5,587
14	32	111,696	3,532
15	31	123,096	3,798
16	20	137,088	2,776
17	11	145,608	1,594
Total	1,188		$100,924

Non-Exempt	FTE	Pay Guide ($s)	Total at Pay Guide ($000s)
03	0	26,812	0
04	0	27,976	0
05	0	29,412	0
06	4	31,679	131
07	8	33,488	281
08	85	35,818	3,051
09	3	39,125	117
10	315	42,620	13,405
11	0	45,199	0
12	111	49,068	5,429
13	42	53,498	2,254
14	21	58,552	1,204
Total	589		$25,873

Total Union

FTE	Average per Employee	Total
824	69,258	$57,087

Total Officers @ Market Reference

FTE	Average per Officer	Total
11	289,239	$3,300

	Employees	wages/salaries
Exempt	1,188	100,924
Non-Exempt	589	25,873
Union	824	57,087
Officer	11	3,300
	2,612	$187,184

UE 215
PGE Response to OPUC Data Request No. 212
Attachment 212-A

Market Compensation for PGE 2009 FTEs

Exempt	FTE	Pay Guide ($s)	Total at Pay Guide ($000s)
01	0	47,688	0
02	0	49,488	0
03	0	51,528	0
04	10	53,880	555
05	0	57,576	0
06	106	60,336	6,408
07	6	63,912	365
08	175	68,568	12,015
09	19	73,464	1,372
10	246	79,104	19,471
11	180	85,656	15,429
12	316	93,216	29,500
13	59	101,616	5,957
14	34	111,696	3,824
15	32	123,096	3,908
16	21	137,088	2,878
17	11	145,608	1,595
Total	1,215		$103,276

Non-Exempt	FTE	Pay Guide ($s)	Total at Pay Guide ($000s)
03	0	27,498	0
04	0	28,684	0
05	0	30,160	0
06	4	32,490	145
07	7	34,341	242
08	83	36,733	3,034
09	3	40,124	120
10	316	43,701	13,803
11	0	46,343	0
12	101	50,295	5,085
13	41	54,850	2,261
14	21	60,029	1,234
Total	576		$25,925

Total Union

FTE	Average per Employee	Total
819	72,609	$59,456

Total Officers @ Market Reference

FTE	Average per Officer	Total
13	275,484	$3,520

	Employees	wages/salaries
Exempt	1,215	103,276
Non-Exempt	576	25,925
Union	819	59,456
Officer	13	3,520
	2,623	$192,177

DR-221, Attachment 221-A

Description	Adjustment to Incremental FTEs	$ Adjustment to Total Wages & Salaries	RC	Comments / FTE function
FTE Adjustments:				
Adjustments for vacant positions				
Generation	(31.6)	(2,700,000)	N/A	Applied to operating area, not specific RCs or positions.
Transmission	(1.3)	(100,000)	N/A	Applied to operating area, not specific RCs or positions.
Distribution	(21.5)	(1,700,000)	N/A	Applied to operating area, not specific RCs or positions.
Customer Accounts	(17.4)	(1,000,000)	N/A	Applied to operating area, not specific RCs or positions.
A&G/IT	(27.6)	(2,500,000)	N/A	Applied to operating area, not specific RCs or positions.
Subtotals	(99.4)	(8,000,000)		
Outboard adjustments to revenue requirement				
Adjustment for Coyote Steam Sales	(3.0)	(255,000)	081	Delete 3 FTEs at Coyote Springs related to additional steam sales. Add'l steam sale revenue is not included in case so the FTEs should not be either. (1 Chem tech, 2 Water treatment analysts)
Adjustment for AMI	(7.0)	(359,045)	437	Billing customer sevice representatives
FTE/W&S Adjustments	(109.4)	(8,614,045)		
Less Impact of previously authorized items				
SB 838 - Costs charged to deferred ledger for recovery; no increase to FTEs in base rates over 2008 level.	(0.4)	No adjustment to total wages and salaries	516	Energy efficiency specialist
SB 838 - Costs charged to deferred ledger for recovery; no increase to FTEs in base rates over 2008 level.	(0.3)	No adjustment to total wages and salaries	937	Product and service development specialist
ETO - 2009 and prior, "below-the-line"; 2010-2011, costs offset by ETO revenue; no increase to FTEs in base rates over 2008 level.	(4.3)	No adjustment to total wages and salaries	516	1 supervisor, 3.3 specialists contracted to assist ETO
Biglow Canyon 2	(1.2)	No adjustment to total wages and salaries	091 & 551	One full-time Wind Technician plus a portion of two specialists and an engineer, each of which spend only a fraction of their time on work related to Biglow Canyon Phase 2 on a recurring basis. Included in UE 209 with no adjustments.
Boardman simulator	(2.0)	No adjustment to total wages and salaries	042	One operator trainee and an assistant control operator. Included in UE 197 with no specific adjustment for the Boardman simulator
Subtotal	(8.2)			
Total FTE Adjustments	(117.6)			

Market Compensation
for PGE employee counts EOY 2007

Exempt	Number of Employees*	Market Pay	Total Market Pay Exempt
01	0	46,296	n/a
02	2	48,024	n/a
03	0	50,016	n/a
04	12	52,296	627,552
05	1	55,896	55,896
06	101	58,560	5,914,560
07	13	62,040	806,520
08	181	66,552	12,045,912
09	13	71,304	926,952
10	237	76,800	18,201,600
11	208	83,160	17,297,280
12	297	90,480	26,872,560
13	53	98,640	5,227,920
14	29	108,432	3,144,528
15	29	119,496	3,465,384
16	13	133,080	1,730,040
17	5	141,360	706,800
Total**	1,194		$97,023,504

Non-Exempt	Number of Employees*	Market Pay	Total Market Pay Non-Exempt
03	0	26,021	n/a
04	0	27,144	n/a
05	0	28,538	n/a
06	0	30,743	0
07	12	32,511	390,132
08	92	34,757	3,197,644
09	3	37,981	113,943
10	340	41,372	14,066,480
11	0	43,868	0
12	108	47,632	5,144,256
13	38	51,938	1,973,644
14	21	56,847	1,193,787
Total	614		$26,079,886

Total Union

Number of Employees*	Ave. per Union Employee	Total
868	65,073	$56,483,003

Total Officers @ Market Reference

Number of Employees*	Average per Officer	Total
12	257,225	$3,086,700

	Employees	wages/salaries
Exempt	1,194	97,023,504
Non-Exempt	614	26,079,886
Union	868	56,483,003
Officer	12	3,086,700
	2,688	$182,673,093

* As of December 31, 2007
** EX-02 salaries removed from total b/c no market comparison exists

5 Market Base Pay

TABLE A.1
Mar 2010 - Other Economic Indicators

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
GDP (Bil of 2005 $), Chain Weight (in billions of $)	12,263.8	12,638.4	12,976.3	13,254.1	13,312.2	12,984.1	13,323.5	13,678.3	14,194.3	14,612.1	15,022.8	15,409.8
% Ch	3.6	3.1	2.7	2.1	0.4	(2.5)	2.6	2.7	3.8	2.9	2.8	2.6
Price and Wage Indicators												
GDP Implicit Price Deflator, Chain Weight U.S., 2005=100	96.8	100.0	103.3	106.2	108.5	109.8	110.9	112.7	114.4	116.5	118.6	120.8
% Ch	2.8	3.3	3.3	2.9	2.1	1.2	1.1	1.6	1.5	1.8	1.8	1.9
Personal Consumption Deflator, Chain Weight U.S., 2005=100	97.1	100.0	102.7	105.5	109.0	109.2	110.9	112.8	114.6	116.7	118.7	121.0
% Ch	2.6	3.0	2.7	2.7	3.3	0.2	1.5	1.7	1.6	1.8	1.8	1.9
CPI, Urban Consumers, 1982-84=100												
Portland-Salem, OR-WA	191.2	196.0	201.2	208.6	215.4	213.4	215.7	221.0	225.9	230.9	235.9	241.2
% Ch	2.6	2.5	2.6	3.7	3.3	(0.9)	1.1	2.5	2.2	2.2	2.2	2.2
U.S.	188.9	195.3	201.6	207.3	215.2	214.6	218.3	222.7	227.0	231.6	236.1	241.0
% Ch	2.7	3.4	3.2	2.9	3.8	(0.3)	1.7	2.0	1.9	2.0	1.9	2.1
Oregon Average Wage Rate (Thous $)	37.3	38.5	40.1	41.7	42.6	43.1	44.5	45.4	46.6	48.0	49.5	51.0
% Ch	3.6	3.2	4.2	3.8	2.3	1.1	3.3	2.0	2.6	3.1	3.1	3.1
U.S. Average Wage Wage Rate (Thous $)	41.3	42.6	44.6	46.6	47.8	48.0	49.5	50.7	51.8	53.3	54.9	56.6
% Ch	4.4	3.3	4.6	4.4	2.6	0.4	3.3	2.5	2.2	2.8	3.0	3.1
Housing Indicators												
FHFA Oregon Housing Price Index Housing Index 1987 Q1=100	318.9	371.6	434.1	461.0	451.4	416.8	388.7	385.4	397.5	409.4	418.9	436.4
% Ch	9.5	16.5	16.8	6.2	(2.1)	(7.7)	(6.8)	(0.9)	3.2	3.0	2.3	4.2
FHFA National Housing Price Index (1980Q1=100)	313.1	348.7	374.1	381.4	370.9	355.7	334.5	334.7	347.9	359.8	369.4	386.1
% Ch	9.5	11.4	7.3	1.9	(2.7)	(4.1)	(6.0)	0.0	4.0	3.4	2.6	4.5
Housing Starts												
Oregon (Thous)	27.5	30.9	27.6	21.9	12.8	7.6	8.4	9.8	12.2	16.4	20.7	22.9
% Ch	8.8	12.4	(10.6)	(20.9)	(41.5)	(40.8)	11.4	15.8	25.1	34.1	26.3	10.5
U.S. (Millions)	1.9	2.1	1.8	1.3	0.9	0.6	0.8	1.2	1.6	1.7	1.7	1.8
% Ch	5.2	6.3	(12.6)	(25.9)	(32.9)	(38.2)	42.3	57.0	28.6	8.0	0.2	1.4
Other Indicators												
Industrial Production Index U.S, 2002 = 100	103.8	107.2	109.7	111.3	108.8	98.2	101.8	105.5	110.5	114.4	117.8	120.8
% Ch	2.5	3.3	2.3	1.5	(2.2)	(9.8)	3.6	3.7	4.7	3.5	3.0	2.6
Prime Rate (Percent)	4.3	6.2	8.0	8.1	5.1	3.3	3.3	4.7	6.3	6.6	7.6	7.8
% Ch	5.3	42.5	28.6	1.2	(36.8)	(36.1)	2.5	41.0	35.1	3.3	15.9	2.1
Population (Millions)												
Oregon	3.59	3.64	3.70	3.75	3.79	3.83	3.86	3.91	3.95	4.00	4.05	4.10
% Ch	1.2	1.4	1.6	1.4	1.2	0.9	0.9	1.1	1.2	1.2	1.2	1.2
U.S.	293.7	296.4	299.2	302.1	304.9	307.8	310.9	313.9	316.9	320.0	323.1	326.2
% Ch	0.9	0.9	0.9	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Timber Harvest (Mil Bd Ft)												
Oregon	4,451.0	4,355.0	4,328.0	3,799.0	3,441.0	2,705.0	2,765.9	3,100.9	3,418.3	3,629.2	3,752.2	3,827.7
% Ch	11.2	(2.2)	(0.6)	(12.2)	(9.4)	(21.4)	2.3	12.1	10.2	6.2	3.4	2.0

c. Wage Escalation Factors

Our calculation of PGE's test-period wages and salaries must escalate average 2007 non-officer wages to 2009. In its direct case, PGE forecast a 4.5 percent annualized increase in 2009 non-officer wages and salaries, asserting:

> PGE's philosophy is to provide compensation sufficient to attract and retain employees necessary to provide safe and reliable electric service at a reasonable price with outstanding customer service. At the same time, PGE actively controls costs by targeting our compensation program attributes and costs to reflect market median conditions. As market practices change, PGE responds to ensure that our total compensation package is competitive and generally tracks the market.[22]

In so doing, PGE claims that it relies upon internal studies and review of Bureau of Labor Statistics studies[23] and surveys conducted by the Economic Research Institute.[24] PGE also provided a table on the U.S. Economic Outlook for Inflation, prepared by *Global Insight* in June 2008. That table showed annualized increases in wages and salaries for 2008 and 2009 as 3.1 and 2.8 percent, respectively, substantially less than the 4.5 percent increase requested by PGE for 2009 non-executive labor.[25]

ICNU, with whom CUB conditionally concurs, argues that the PGE-proposed labor escalation rates of 6.0 percent, 4.5 percent, 4.5 percent, and 4.0 percent for the four major groups of employees—officers, exempt, hourly, and union, respectively—should be rejected. ICNU proposes increases of 0.0 percent, 2.0 percent, 3.0 percent, and 2.0 percent for the respective employee groups.[26] ICNU cites PGE testimony regarding retirement eligibility of higher paid employees, the tightening job market caused by the current financial conditions, and rising unemployment in Oregon that will likely make it easier for PGE to hire replacement workers than originally forecast.[27]

In response, PGE identified several "significant problems" with ICNU's analysis, asserting that the wage adjustments selectively excluded unusual historical wage increase information and ignored historical data in favor of anecdotal information. The Company referred to a market survey from the Economic Research Institute and stated that the ICNU proposal would place PGE at a disadvantage in hiring and retaining qualified individuals.[28]

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[22] PGE/800, Barnett-Bell/2.
[23] *Id.* at 6.
[24] PGE/2400, Barnett-Bell/6.
[25] PGE/1903, Piro-Tooman/2; PGE/200, Tooman-Tinker/5.
[26] ICNU Opening Brief at 15-16.
[27] *Id.* at 17.
[28] PGE/2400, Barnett-Bell/4-6.

Resolution

Historically, the Commission has used a three-year wage and salary formula to escalate utility wages. The formula reflects two components: (a) inflation, and (b) real escalation, indicating, in part, market conditions.[29] Using that as our template, we adopt use of the All-Urban CPI Core Index from the June 2008 *Global Insight* report for inflation, which forecasts inflation increasing at 2.4 percent in 2008 and 2.4 percent in 2009.[30] In light of the current economic situation, we choose not to adopt a real escalation factor. We therefore authorize an increase in average non-officer wages and salaries that reflects an annualized growth in exempt, hourly, and union wages and salaries of 2.4 percent for 2008 and 2.4 percent for 2009.[31]

d. Number of Officers

PGE included salaries for 12 officers in the 2009 test period.[32] One of those officers has been loaned out to another organization, and there is no plan for replacement; those duties are being performed by other managers.[33] ICNU argues that the officer count should be reduced from 12 to 11 and that one-twelfth of total officers' salaries, approximately $287,000, should be removed from the revenue-requirement calculation.[34]

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[29] *See* Order No. 95-322 at 9-10 (Docket No. UE 88), Order No. 99-697 at 43 (Docket No. UG 132), and Order No. 01-787 at 39-40 (Docket No. UE 116).
[30] PGE/1903, Piro-Tooman/2.
[31] We note the following actual number of employees by class and their straight-time wages and salaries for the year 2007 and calculate an average wage or salary per employee:

EMPLOYEE CLASS	*EXEMPT*	*HOURLY*	*UNION*
Actual FTEs	1,153	584	809
Wages & Salaries	$100,248,092	$23,790,819	$54,466,831
W&S/Employee	$86,945.44	$40,737.70	$67,326.12

The following table applies our decisions to calculate PGE's allowable 2009 test-year wages and salaries for non-officers; *i.e.*, the 1.45 percent annual FTE growth rate and 2.4 percent wage escalators for both 2008 and 2009:

EMPLOYEE CLASS	*EXEMPT*	*HOURLY*	*UNION*
2009 FTEs	1,187	601	833
2009 W&S/Employee	$91,168.90	$42,716.57	$70,596.55
2009 W&S Rev. Req.	$108,217,484	$25,672,659	$58,806,926

[32] PGE/1402, Tooman-Tinker/3.
[33] Tr. at 25, lines 14-15.
[34] ICNU Opening Brief at 15.

CASE: UE 215
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Michael Dougherty. I am the Program Manager for the Corporate Analysis and Water Regulation Section of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to describe my adjustments to Portland General Electric's (PGE or Company) 2020 Vision and Cyber Security rate base and associated depreciation / amortization expense concerning projects that will not be in service when rates become effective on January 1, 2011.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff 302 consisting of 1 page and Exhibit Staff 303 (PGE's responses to Staff Data Requests) consisting on xx pages.

Q. PLEASE PROVIDE A SUMMARY OF YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments to PGE's 2020 Vision and Cyber Security rate base adjustments. Detailed information is included in Exhibit Staff 302, page 1.

Table 1 - Staff 2020 Vision and Cyber Security Rate Base Adjustments

	PGE	Staff	Adjustment
2020 Vision Capital	$15,153,000	$2,104,000	($13,049,000)
Cyber Security Capital	$5,800,000	$1,850,000	($3,950,000)
Total	**$20,953,000**	**$3,954,000**	**($16,999,000)**

The following table summarizes adjustments to the associated depreciation / amortization expense. Detailed information is included in Exhibit Staff 302, page 1.

Table 2 - Staff 2020 Vision and Cyber Security Depreciation / Amortization Adjustments

	PGE	Staff	Adjustment
2020 Vision Capital	$1,521,000	$210,400	($1,310,600)
Cyber Security Capital	$936,217	$91,129	($845,089)
Total	**$2,457,217**	**$301,529**	**($2,155,689)**

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS

A. My adjustments are based on the requirements of ORS 757.355, *Costs of property not presently providing utility service excluded from rate base; exception*. In its case, the Company used 2011 average rate base[1] for both 2020 Vision and Cyber Security projects. Because of the restrictions of ORS 757.355, I only allowed the cost of 2020 Vision and Cyber Security projects that will be completed and providing utility service by January 1, 2011. ORS 757.355 specifically states:

> (1) Except as provided in subsection (2) of this section, a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates

[1] In discussing 2020 Vision Capital Projects, the Company in UE 215/PGE/600, Henderson-Hosseini/30 states *"Because all the phase 1 projects are expected to close before December 31, 2011 (each component has individual jobs that are projected to close at specific times from late 2010 into 2011), their revenue requirement is based on average rate base similar to any other new plant-in-service.*

> that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.[2]

Q. HAS THE COMMISSION RECENTLY ADDRESSED THE ISSUE OF RATE BASE RECOVERY?

A. Yes. In UE 210 (PacifiCorp General Rate Case), Commission Order No. 10-22, pages 14 and 15 state in part:

> ORS 757.355 prohibits a public utility from collecting in customer rates the costs of any property not presently used for providing utility service to those customers. . . . [t]he undisputed evidence shows that the amount of Oregon-allocated plant contained in the Stipulation is lower than what PacifiCorp's Oregon-allocated net plant in service will be at the time these rates will go into effect. . . . Given this evidence, and despite the parties' contentions about specific rate base adjustments, it is clear that the Stipulation will allow Pacific Power to collect in rates only the costs of property presently providing service to customers in conformance with ORS 757.355.

Q. SHOULD INFORMATION TECHNOLOGY (IT) PROJECTS BE CONSIDERED "PROPERTY" AS REQUIRED BY THE STATUTE?

A. Yes. The 2020 Vision and Cyber Security rate base projects are being recorded in plant accounts and being depreciated / amortized over designated periods based on PGE's depreciation studies.[3] The IT projects that are comprised of both hardware and software components meet the definition of personal property.

> Personal property is property owned by an individual or business which is not affixed to or associated with the land. Basically, personal property is everything except real property. Personal property for a business would include

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[2] The exception in subsection (2) of the statute refers to water utilities.
[3] UE 215/PGE/300, Tooman-Tinker/28 and 29.

> equipment, office furniture and equipment, cars/trucks purchased and used by the business, and, basically, everything that isn't "nailed down."[4]

Q. PLEASE GENERALLY DESCRIBE THE COMPONENTS OF THE IT PROJECT COSTS.

A. Components of IT costs are classified by PGE as labor and non-labor costs. The non-labor costs include numerous items such as hardware (servers, desktops, laptops, etc.), professional services, licenses, training, and travel costs. According to 18 CFR Ch.1, Electric Plant Instructions, *Components of construction costs,* contract work, labor, materials and supplies, training, and engineering services are all costs that are included in plant.[5]

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO DEPRECIATION / AMORTIZATION EXPENSE.

A. Concerning 2020 Vision, I divided the recommended rate base amount, $2,104,000 by PGE's proposed amortization rate of 10 years.[6] As a result, I receive a recommended depreciation expense of $210,400. This results in a recommended adjustment of $1,310,600 as reflected in Table 2 above and in Exhibit Staff 302.

Concerning Cyber Security depreciation expense, I only recommended the inclusion of depreciation expense associated with the recommended Cyber Security rate base of $1,850,000. I used the recommended rate base amount and depreciated the amount over five years to receive a recommended amount

[4] http://biztaxlaw.about.com/od/glossaryp/g/personalprop.htm
[5] 18 CFR Ch. 1, Electric Plant Instructions, pages 367-370.
[6] UE 215/PGE/300, Tooman-Tinker/29.

of $91,129 ($1,850,000 divided by 5 years). In its case, PGE used a three year depreciation expense for the $1,850,000 that will be in service on January 1, 2011. I also removed any depreciation expense for the $3,950,000 that will not be in service by January 1, 2011. As a result, I recommend a Cyber Security depreciation expense adjustment of $845,089 as reflected in Table 2 above and in Exhibit Staff 302.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA Bachelor of Science, Biology and Physical Anthropology, City College of New York
EXPERIENCE:	Employed with the Oregon Public Utility Commission from June 2002 to present, currently serving as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program. Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004. Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002. Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager - Manufacturing, Manager - Quality Assurance, and Supervisor - Mastering and Manufacturing from April 1995 to September 2000. Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer. Member, National Association of Regulatory Commissioners Staff Sub-Committee on Accounting and Finance.

CASE: UE 215
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 4, 2010

UE 215 - 202 Vision and Cyber Security Capital IT Adjustments

Rate Base - Capital - 2020 Vision	PGE - 2020 Average Rate Base (FOM 2011)	$	15,153,000	Phase 1 projects; PGE Exhibit 310
	Staff Recommended Rate Base	$	2,104,000	EAM Foundation closing to plant 2010
	Rate Base - Capital - 2020 Vision Adjustment	**$**	**(13,049,000)**	**Reduction in Rate Base**

Notes:

1. Removes IT Financial System that will not be closed to plant until April 2011. Includes EAM that closes to plant in 2010. Response to Staff Data Request No. 83.
2. ORS 757.355 excludes cost of property not providing utility service.

Rate Base - Capital - Cyber Security	PGE - Cyber Security Rate Base (2010/2011)	$	5,800,000	2010 and 2011; response to Staff Data Request No. 77
	Staff Recommended Rate Base	$	1,850,000	2010; response to Staff Data Request No. 202
	Rate Base - Capital - 2020 Vision Adjustment	**$**	**(3,950,000)**	**Reduction in Rate Base**

Notes:

1. Removes approximately $4 million 2011 plant that is part of general and intangible plant increases.
2. ORS 757.355 excludes cost of property not providing utility service.

Depreciation/Amortization - 2020 Vision	PGE Amortization Expense FOM 2011	$	1,521,000	Response to Staff Data request No. 205
	Staff Recommended	$	210,400	$2,104,000 amortized over 10 years
	Depr/Amort. - 2020 Vision Adjustment	**$**	**(1,310,600)**	**Reduction in 2020 Vision depreciation expense**

Note:

1. Based on 2020 Vision closing to plant in 2010; responses to Staff Data Requests Nos.83 and 205.

Depreciation - Cyber Security	PGE Depreciation Expense FOM 2011	$	146,217	2010 Cyber Security Identified
	Staff Recommended	$	91,129	Used 5-year and not 3-year depreciation rate
	Adjustment	*$*	*(55,089)*	
	General and Intangible Plant	$	790,000	Use 5-year depreciation of $3,950,000 not allowed in rate base
	Staff Recommended	$	-	
	Adjustment	*$*	*(790,000)*	
	Cyber Security Depreciation Adjustment	**$**	**(845,089)**	**Reduction in Cyber security depreciation expense**

Notes:

1. Response to Staff Data Request No. 202
   Changed hardware depreciation rate from 3-year to 5-year. PGE had costs booked into Account 391, Furniture.
2. Removed associated depreciation expense from 2011 rate base additions.

CASE: UE 215
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 4, 2010

March 5, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated February 22, 2010
Question No. 083

Request:

Do any of the amounts in Table 3 of PGE/600, Henderson-Hosseini/30 include the $15 million in IT projects referred to in PGE/300, Tooman-Tinker/48? Please explain and provide a breakdown of the $15 million.

Response:

Yes. The $15 million referenced in PGE/300, Tooman-Tinker/48, reflects the impact on average 2011 rate base of expected 2010 and 2011 closures of 2020 Vision Phase 1 capital projects.

We have the following closure forecast (which can also be found in the Exhibit 300 work paper file: 'Integrated Model 2008 to 2018(010910).xls', tab 'Capital Project'): See also Attachment 082-A.

	Dollars in Millions	
Phase 1	2010	2011
EAM Foundation	$2.1 – Year End	$6.2 – Year End
Financial Systems		$22.0 – April 2011
		$2.1 – Year End
Infrastructure/Project Office		$0.6 – Year End
Totals	$2.1	$30.9

The $15 million figure is the average rate base for 2011 and reflects the relative expected timing of closures as described above.

March 8, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated February 22, 2010
Question No. 077

Request:

Concerning PGE/600, Henderson-Hosseini/19, how much of the $12.5 million cyber security costs for 2010 through 2015 will be placed in rate base by 2011? Please provide the amount that PGE has placed in rate base in UE 215.

Response:

PGE projects that approximately $2.4 million will close to plant in 2010 and $3.4 million will close to plant in 2011. For 2011 rate base, PGE has included approximately $1.1 million as closing to plant in 2010 for software and $750,000 as closing to plant in 2010 for hardware. The remaining $4.0 million for cyber security capital is not separately identified in PGE's rate base additions for 2011 but instead is part of the general and intangible plant increases associated with group asset additions.

March 30, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated March 16, 2010
Question No. 202

Request:

As a follow-up to PGE's response to Staff Data Request No. 77:

a. For each component being added to rate base in 2011, please provide PGE's average rate base in a similar format as PGE's response to Staff Data Request No. 83.

b. What is the associated depreciation expense for these projects? Please include the associated calculations.

Response:

a) Average Rate Base

Account	Dollars in Millions 2010
Software	$1.1 – December
Hardware	$0.75 – Applied evenly throughout 2010
Total	$1.85

b) Associated Depreciation

Attachment 202-A includes the associated depreciation and calculations.

March 25, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated March 16, 2010
Question No. 205

Request:

Concerning PGE's response to Staff Data Request No. 83, what is the associated depreciation expense for these 2020 Vision 2009 – 2011 projects? Please include the associated calculations

Response:

The 2020 Vision projects closing to plant in service identified in PGE's response to Staff Data Request No. 83 will be recorded in Intangible Plant (FERC Account 303) and are amortized (rather than depreciated). We have proposed that these projects be amortized over a 10-year period (See PGE Exhibit 600, Henderson-Hosseini, page 30-31).

The 2011 test year software amortization expense (PGE ledger N62111, FERC Account 404) associated with the closing of 2020 Vision projects is \$1.675 million. However, in developing the estimates for this case, we included only \$1.52 million in 2020 Vision software amortization expense. Attachment 205-A summarizes both the calculations used in the case to develop software amortization expense and the correct computations. Note that those projects identified in PGE's response to Staff Data Request No. 83 that are projected to close at year-end 2011 have no impact on amortization expense in the 2011 test year because amortization would begin in 2012.

Impact of Phase 1 2020 Vision Closings on 2011 Test Year Amortization Expense
Dollars in $000s

Phase 1 Closings (except year-end 2011 closings which have no impact on 2011 Amortization Expense) - **As Developed in the Case**

System (1)	Closing Date (2)	Amount Closing (3)	Amortization Period (yrs) (4)	Monthly Amortization (5) = (3) / (4) / 12	2011 Amortization Months (6)	2011 Amortization Expense (7) = (5) * (6)	
EAM	12/31/2010	$2,104	5	$35.1	12	$421	
Financial System	4/30/2011	$16,500	10	$137.5	8	$1,100	
						$1,521	This amount included in PGE ledger N62111 (Software Amortization)

Phase 1 Closings (except year-end 2011 closings which have no impact on 2011 Amortization Expense) - **Correct Computations**

System (1)	Closing Date (2)	Amount Closing (3)	Amortization Period (yrs) (4)	Monthly Amortization (5) = (3) / (4) / 12	2011 Amortization Months (6)	2011 Amortization Expense (7) = (5) * (6)	
EAM	12/31/2010	$2,104	10	$17.5	12	$210	
Financial System	4/30/2011	$21,967	10	$183.1	8	$1,464	
						$1,675	This is the amount that should have been included.

($154) Difference (Software Amortization expense understated)

CASE: UE 215
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dustin Ball. I am employed by the Public Utility Commission of Oregon as Senior Financial Analyst, Corporate Analysis and Water Regulation Section, in the Economic Research and Financial Analysis Division of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend an adjustment to Portland General Electric's ("PGE") Restore Service – Lines (Storm Damage) expense and to oppose the associated balancing account proposed by PGE.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/402, consisting of 11 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, RESTORE SERVICE – LINES (STORM DAMAGE) EXPENSE

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. In UE 215, PGE submitted a total Restore Service- Lines expense of $16,319,335, an increase of approximately $7 million from 2008 to 2011. Based on a review of historical Restore Service – Lines expense, Staff believes that PGE's estimate is high and recommends an expense of $12,765,564[1].

To arrive at the Staff recommended level of Restore Service – Lines, Staff started with the 2008 actual expense (excluding insurance proceeds),and removed the actual 2008 expenses associated with Level III Storm Damage and allocated transportation. Staff then escalated the net amount to 2011 using CPI-U[2], added the 2011 allocated transportation expense[3] (as forecasted by PGE), and added Level III Storm Damage expense based on a 10-year average. Staff determined this 10-year average by (1) reviewing PGE's actual Level III Storm Damage loss history over the 10-year period of 2000 through 2009; (2) escalating the actual level of Level III Storm Damages from each of these years to 2011 using CIP-U; and (3) averaging the escalated amounts.

Staff's analysis produces a downward adjustment to PGE's Restore Service – Lines expense of $3,553,771.

[1] See Staff Exhibit 402, Ball/1
[2] http://oregon.gov/DAS/OEA/docs/economic/appendixa.pdf, See Staff Exhibit 402, Ball/11. Although Staff has used CIP-U to escalate costs to 2011, Staff is open to consider other escalation indexes.
[3] See Staff Exhibit 402, Ball/10

Q. WHY IS STAFF PROPOSING TO INCLUDE A 10-YEAR AVERAGE OF LEVEL III STORM DAMAGES IN RATES, AS OPOSED TO SIMPLY ESCALATING THE 2008 LEVEL III STORM DAMAGES?

A. Level III outages are the most severe customer outage level, are weather related, and may or may not occur in a given year. Specifically, PGE has suffered Level III Storm Damages in only five of the past 10 years and these loss amounts vary greatly. For example, the loss experienced in 2007 was $941,454, while the loss experienced in 2008 was over six times larger, at $6,363,087.

During 2008, PGE incurred its largest Level III Storm Damage loss of the past 10 years. It is not reasonable to forecast future Level III Storm Damage losses based on a large single loss year. This is especially true given that PGE's actual history shows that Level III Storm Damage losses have occurred in only five of the past 10 years. Based on the information available, Staff believes that a 10-year normalization of Level III Storm Damages is appropriate.

ISSUE 2, PROPOSED LEVEL III OUTAGE BALANCING ACCOUNT

Q. PLEASE SUMMARIZE PGE'S PROPOSED BALANCING ACCOUNT FOR LEVEL III OUTAGES.

A. As described in UE 215, PGE/800, PGE is proposing a balancing account to track differences between the Level III outages costs included in rates, and the actual Level III outage expenses incurred. PGE proposes to collect $4.5 million annually for Level III outages, and subject only $3.5 million of this amount to balancing account treatment. The remaining $1 million ($4.5 million - $3.5 million) would not be subject to balancing account treatment. Only Level III outages expenses exceeding $1 million would be subject to balancing account treatment. PGE proposes that the balancing account would earn interest at PGE's authorized cost of capital and be subject to prudence review and/or audit.

Under PGE's proposal, it appears that if there were no Level III outages during a given year, the Company would collect $4.5 million in rates, but only place $3.5 million into its proposed balancing account. Therefore in each year where there are no Level III outages, the company would retain $1 million not subject to the balancing account, without incurring any associated expenses.

Q. PLEASE EXPLAIN STAFF'S POSITION REGARDING ESTABLISHING A BALANCING ACCOUNT FOR LEVEL III STORM DAMAGE EXPENSES.

A. Staff opposes PGE's proposal of a balancing account for Level III Storm Damage expenses. Costs fluctuate from year to year and Staff does not believe that it is appropriate to establish a balancing account for Level III outages. While it is true that expenses associated with Level III outages can vary from year to year, setting rates based on a historical average addresses these fluctuations, incents the company to operate in a manner to control costs, and does not put the burden of auditing and micro managing the company's efforts to restore service on Staff. Additionally, in a particular year, if costs are substantially greater than the amount included in rates, the Company has the option of requesting deferred accounting of such costs.

Q. PLEASE ADDRESS PGE'S BALANCING ACCOUNT EXAMPLE IN UE 215/PGE/800, TABLE 5.

A. PGE's example is misleading, and based on hypothetical figures not actual historical data. Staff evaluated PGE's proposed balancing account using actual data from the same 10-year period which was used to arrive at a recommended Restore Service – Lines expense, Issue 1 above.

Over the past 10 years PGE has suffered Level III outages in only five of these years, and in only four of these years, did PGE experience Level III Outages in excess of $1 million.

Based on Staff's review, if a balancing account were in place during the 10 year period of 2000 – 2009, this account would have a balance <u>due</u> to ratepayers, without consideration for interest, of over $21 million. In only four of the past 10 years did PGE incur losses above the $1 million base. As a result, in this scenario PGE would have collected an additional $5 million, which would not be subject to balancing account treatment, and therefore would have been retained by PGE[4].

Q. HOW DOES STAFF'S PROPOSED TREATMENT OF SETTING RATES BASED ON A 10-YEAR AVERAGE OF LEVEL III OUTAGES, IN ISSUE 1 ABOVE, ADDRESS FLUCTUATIONS IN LEVEL III OUTAGES?

A. Staff's recommendation is to include a 10-year average of Level III Outages in base rates, therefore, PGE will collect one-tenth ($2,034,613) of the total 10-year expenses ($20,346,133), per year. This annual collection represents an estimate of future expenses, based on the actual 10-year history. If PGE incurs more or less than this amount in future years, then when PGE files its next rate case, Staff proposes to use this same methodology and establish a new 10-year average, which will be adjusted according to the most recent information. Therefore PGE will again be collecting one-tenth of the new 10-year average.

Staff proposes that this recommendation be adopted by the Commission and if costs substantially exceed the amount included in rates, the Company has the option of requesting deferred accounting of such costs at that time.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

[4] See Staff Exhibit 402, Ball/2

CASE: UE 215
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	DUSTIN BALL
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	SENIOR FINANCIAL ANALYSIT, ECONOMIC RESEARCH & FINANCIAL ANALYSIS DIVISION
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.
EDUCATION:	Bachelor of Science, Business focusing in Accounting, Western Oregon University (2003)
EXPERIENCE:	Employed with the Oregon Public Utility Commission since August 2007. I am a Senior Financial Analyst for the Economic Research & Financial Analysis Division. Employed by the Oregon Real Estate Agency as a Financial Investigator in the Regulations Division from January 2006 to August 2007. Employed by the Oregon Department of Revenue as an Income Tax Auditor, in the Personal Tax and Compliance Section from January 2004 to January 2006. Licensed Tax Consultant in the State of Oregon.

CASE: UE 215
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

<u>Contains Confidential Information</u>

June 4, 2010

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 402

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 10-056. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 215

TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

UE 215 PGE - Storm Damage - O&M

2000 - 2009 Actual Level III Storm Damage Losses Escalated to 2011 $ (see DR 140)

CPI	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	$ -									
		$ -								
			$ -							
				$ -						
					$ 3,816,404					
					3.40%	$ -				
3.40%					3.20%	3.20%	$ 4,727,272			
3.20%					2.90%	2.90%	2.90%	$ 941,454		
2.90%					3.80%	3.80%	3.80%	3.80%	$ 6,363,087	
3.80%					-0.03%	-0.03%	-0.03%	-0.03%	-0.03%	$ 2,879,472
-0.03%					1.70%	1.70%	1.70%	1.70%	1.70%	1.70%
1.70%					2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
2.00%										
In 2011 $	$ -	$ -	$ -	$ -	$ 4,510,847	$ -	$ 5,236,175	$ 1,013,415	$ 6,598,704	$ 2,986,991

10 YR Total		$ 20,346,133
10 YR AVE		$ 2,034,613

Total Restore Service - Lines for 2008	$ 15,973,695	Per DR 140
Expense Attributable to Level III Outages	$ (6,363,087)	Per DR 140
Total 2008 Expense Net of Level III Outages	$ 9,610,608	
Less Allocated Transportation	$ (2,540,939)	Per DR 142, Attachment 142-A
Net	$ 7,069,669	
Escalated to 2009	-0.03%	
Escalated to 2010	1.70%	
Escalated to 2011	2.00%	
Forecasted 2011 Net of Level III Outages	$ 7,331,450	
Add 2011 Allocated Transportation	$ 3,399,500	Per DR 142, Attachment 142-A
Forecasted Level III Outage based on 10 YR Average	$ 2,034,613	
Forecasted 2011 Restore Line Service - Lines Expense	$ 12,765,564	
PGE UE 215 Expense	$ 16,319,335	
Adjustment	**$ (3,553,771)**	

1. Staff opposes PGE's proposed storm damage deferral and proposes to set the 2011 storm damage expense as shown above.
2. As a starting point for calculating the forecasting the 2011 storm damage expense, Staff started with the actual 2008 expense and removed the expenses attributable to Level III outages as well as expenses attributable to Allocated Transportation, then escalated this base amount to 2011 at CPI.
3. Staff did not make any adjustments to PGE's forecasted 2011 Allocated Transportation attributable to storm damage expense. Staff added PGE's forecasted 2011 allocated transportation to the base amount. (see Attachment 142-A)
4. Staff proposes to set the storm damage expense for Level III outages at the 10 year average. To arrive at this average, Staff used CPI figures to escalate each year's loss to 2011, then averaged the results.

UE 215 PGE - Proposed Level III Storm Damage Balancing Account Example

An example of PGE's Proposed Balancing (based on actual Level III Outages)							
		Expense Attributable to Level III Outages	Exclusion	Net Cost	Annual Collection	Balancing Account	O&M amount collected above actual expense with no Balancing Account Treatment
Year 1	2000	$ -	$ -	$ -	$ 3,500,000	$ (3,500,000)	$ 1,000,000
Year 2	2001	$ -	$ -	$ -	$ 3,500,000	$ (7,000,000)	$ 1,000,000
Year 3	2002	$ -	$ -	$ -	$ 3,500,000	$ (10,500,000)	$ 1,000,000
Year 4	2003	$ -	$ -	$ -	$ 3,500,000	$ (14,000,000)	$ 1,000,000
Year 5	2004	$ 3,816,404	$ (1,000,000)	$ 2,816,404	$ 3,500,000	$ (14,683,596)	$ -
Year 6	2005	$ -	$ -	$ -	$ 3,500,000	$ (18,183,596)	$ 1,000,000
Year 7	2006	$ 4,727,272	$ (1,000,000)	$ 3,727,272	$ 3,500,000	$ (17,956,324)	$ -
Year 8	2007	$ 941,454	$ (941,454)	$ -	$ 3,500,000	$ (21,456,324)	$ 58,546
Year 9	2008	$ 6,363,087	$ (1,000,000)	$ 5,363,087	$ 3,500,000	$ (19,593,237)	$ -
Year 10	2009	$ 2,879,472	$ (1,000,000)	$ 1,879,472	$ 3,500,000	$ (21,213,765)	$ -
							$ 5,058,546

The above Level III outage data was provided by PGE in response to Staff Data Request No. 140, Attachment 140-A

March 12, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated February 26, 2010
Question No. 140

Request:

In the following table format, please provide a 15 year history of PGE's actual Restore Service Lines expense broken out by outage levels and PGE's transmission and distribution insurance premiums and insurance proceeds for years 1995 through 2009.

Year	Total Restore Service Lines Expense	Expense Attributable to Level I Outages	Expense Attributable to Level II Outages	Expense Attributable to Level III Outages	T&D Insurance Premium (if any)	T&D Insurance Proceeds (if any)
1995	$	$	$	$	$	$
Etc.	$	$	$	$	$	$

Response:

Attachment 140-A contains the above requested information. Attachment 140-A is confidential and subject to Protective Order No. 10-056.

UE 215
Attachment 140-A

Confidential and Subject to Protective Order No. 10-056

15 Year History

Pages 5 through 7 are confidential.

You must have signed Protective Order No. 10-056 in this docket in order to view these pages.

March 12, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated February 26, 2010
Question No. 142

Request:

Regarding vehicle allocations associated with Restore Service Lines expense, what were the actual vehicle allocations for 2006, 2007, 2008, 2009, and forecasted vehicle allocations for 2010 and 2011?

Response:

PGE Attachment 142-A contains actual vehicle allocations for 2006, 2007, 2008, 2009, and forecasted vehicle allocations for 2010 and 2011.

UE 215
Attachment 142-A

Actual Vehicle Allocations

The vehicle allocations for 2006 through 2011 are as follows:

Year	Vehicle Allocation
2006 actual	2,635,007
2007 actual	2,287,240
2008 actual	2,540,939
2009 actual	2,983,933
2010 forecast	3,173,000
2011 forecast	3,399,500

TABLE A.1

Mar 2010 - Other Economic Indicators

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
GDP (Bil of 2005 $),												
Chain Weight (in billions of $)	12,263.8	12,638.4	12,976.3	13,254.1	13,312.2	12,984.1	13,323.5	13,678.3	14,194.3	14,612.1	15,022.8	15,409.8
% Ch	3.6	3.1	2.7	2.1	0.4	(2.5)	2.6	2.7	3.8	2.9	2.8	2.6
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2005=100	96.8	100.0	103.3	106.2	108.5	109.8	110.9	112.7	114.4	116.5	118.6	120.8
% Ch	2.8	3.3	3.3	2.9	2.1	1.2	1.1	1.6	1.5	1.8	1.8	1.9
Personal Consumption Deflator,												
Chain Weight U.S., 2005=100	97.1	100.0	102.7	105.5	109.0	109.2	110.9	112.8	114.6	116.7	118.7	121.0
% Ch	2.6	3.0	2.7	2.7	3.3	0.2	1.5	1.7	1.6	1.8	1.8	1.9
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	191.2	196.0	201.2	208.6	215.4	213.4	215.7	221.0	225.9	230.9	235.9	241.2
% Ch	2.6	2.5	2.6	3.7	3.3	(0.9)	1.1	2.5	2.2	2.2	2.2	2.2
U.S.	188.9	195.3	201.6	207.3	215.2	214.6	218.3	222.7	227.0	231.6	236.1	241.0
% Ch	2.7	3.4	3.2	2.9	3.8	(0.3)	1.7	2.0	1.9	2.0	1.9	2.1
Oregon Average Wage												
Rate (Thous $)	37.3	38.5	40.1	41.7	42.6	43.1	44.5	45.4	46.6	48.0	49.5	51.0
% Ch	3.6	3.2	4.2	3.8	2.3	1.1	3.3	2.0	2.6	3.1	3.1	3.1
U.S. Average Wage												
Wage Rate (Thous $)	41.3	42.6	44.6	46.6	47.8	48.0	49.5	50.7	51.8	53.3	54.9	56.6
% Ch	4.4	3.3	4.6	4.4	2.6	0.4	3.3	2.5	2.2	2.8	3.0	3.1
Housing Indicators												
FHFA Oregon Housing Price Index												
Housing Index 1987 Q1=100	318.9	371.6	434.1	461.0	451.4	416.8	388.7	385.4	397.5	409.4	418.9	436.4
% Ch	9.5	16.5	16.8	6.2	(2.1)	(7.7)	(6.8)	(0.9)	3.2	3.0	2.3	4.2
FHFA National Housing Price Index												
(1980Q1=100)	313.1	348.7	374.1	381.4	370.9	355.7	334.5	334.7	347.9	359.8	369.4	386.1
% Ch	9.5	11.4	7.3	1.9	(2.7)	(4.1)	(6.0)	0.0	4.0	3.4	2.6	4.5
Housing Starts												
Oregon (Thous)	27.5	30.9	27.6	21.9	12.8	7.6	8.4	9.8	12.2	16.4	20.7	22.9
% Ch	8.8	12.4	(10.6)	(20.9)	(41.5)	(40.8)	11.4	15.8	25.1	34.1	26.3	10.5
U.S. (Millions)	1.9	2.1	1.8	1.3	0.9	0.6	0.8	1.2	1.6	1.7	1.7	1.8
% Ch	5.2	6.3	(12.6)	(25.9)	(32.9)	(38.2)	42.3	57.0	28.6	8.0	0.2	1.4
Other Indicators												
Industrial Production Index												
U.S, 2002 = 100	103.8	107.2	109.7	111.3	108.8	98.2	101.8	105.5	110.5	114.4	117.8	120.8
% Ch	2.5	3.3	2.3	1.5	(2.2)	(9.8)	3.6	3.7	4.7	3.5	3.0	2.6
Prime Rate (Percent)	4.3	6.2	8.0	8.1	5.1	3.3	3.3	4.7	6.3	6.6	7.6	7.8
% Ch	5.3	42.5	28.6	1.2	(36.8)	(36.1)	2.5	41.0	35.1	3.3	15.9	2.1
Population (Millions)												
Oregon	3.59	3.64	3.70	3.75	3.79	3.83	3.86	3.91	3.95	4.00	4.05	4.10
% Ch	1.2	1.4	1.6	1.4	1.2	0.9	0.9	1.1	1.2	1.2	1.2	1.2
U.S.	293.7	296.4	299.2	302.1	304.9	307.8	310.9	313.9	316.9	320.0	323.1	326.2
% Ch	0.9	0.9	0.9	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Timber Harvest (Mil Bd Ft)												
Oregon	4,451.0	4,355.0	4,328.0	3,799.0	3,441.0	2,705.0	2,765.9	3,100.9	3,418.3	3,629.2	3,752.2	3,827.7
% Ch	11.2	(2.2)	(0.6)	(12.2)	(9.4)	(21.4)	2.3	12.1	10.2	6.2	3.4	2.0

CASE: UE 215
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ed Durrenberger. I am a Utility Analyst for the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to explain adjustments that I propose for the Portland General Electric (PGE or company) general rate case filing, docketed as UE 215.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I have included a copy of a two page Wall Street Journal article as Exhibit. Staff/502.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First I I provide a summary of all the adjustments that I propose, and then I discuss the nature of each adjustment and explain why I believe the adjustment I propose is justified.

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS.

A. I propose the following adjustments or changes to the PGE filed general rate case:

1. Remove $3.1 million in excess Boardman Coal Plant Fly Ash Disposal Costs and continue to treat ash disposal costs as a routine operating and maintenance (O&M) expense, not as a variable power cost expense in the annual poser cost update;
2. Remove $2.6 million in hydro O&M expenses for a yet to be issued Clackamas Hydro project license renewal;
3. Remove $6.4 million in additions to normalized maintenance expenses for certain "one time" maintenance events;
4. Reject PGE's request to fundamentally alter the way the Power Cost Adjustment Mechanism (PCAM) is applied to power cost variances;
5. Reject a company request to account for certain emission control chemicals as power cost expenses updated in the annual update of net variable power costs rather than as general O&M expenses;
6. Reject a request to characterize certain expenses related to power purchases, including broker fees, revolving credit facility fees, and collateral costs as net variable power costs to be updated annually in the automatic update tariff rather than as a general expenses.

Q. PLEASE DESCRIBE THE BOARDMAN FLY ASH DISPOSAL COST ISSUE.

A. In the PGE general rate case filing, the company proposed an increase in Boardman coal fly ash disposal costs in anticipation of regulations by the United States Environmental Protection Agency (EPA) treating coal fly ash as a hazardous waste. (*See* UE 215/PGE/700 Quennoz-Behbehani/11.) The matter of treating coal fly ash as a hazardous waste is far from certain. I find the potential cost far too speculative to support including the cost increase in rates. In addition, since the company made their initial filing, the EPA has clarified that it will likely not treat coal ash as a hazardous waste. (*See* Exhibit Staff/502 Durrenberger/1-2, Wall Street Journal report from May 4, 2010, "EPA Proposes Competing Approaches to Regulate Coal-Ash Waste.") While coal ash may be subject to regulation, the extent of that regulation is not known and the associated cost is not measurable.

PGE included approximately $2.6 million in additional disposal expenses and reduced revenues by $0.6 million based on the assumption it would no longer be able to sell a portion of the ash as a concrete additive. I conclude that the adjustment to expenses that the company made for additional Boardman fly ash disposal costs is unwarranted and should be removed and that the revenue from sales of fly ash should be restored.

Q. HAS PGE RESPONDED TO THIS PROPOSAL?

A. Yes, the company acknowledged in recent settlement discussions that circumstances have changed since the filing. They have agreed to remove the disposal cost increases and restore the ash sales revenue to their rate case request.

Q. HAVE YOU RESOLVED THE ISSUE OF WHETHER THE FLY ASH DISPOSAL COSTS SHOULD BE PART OF THE NET VARIABLE POWER COSTS SUBJECT TO THE ANNUAL POWER COST ADJUSTMENT MECHANISM?

A. This issue has not been entirely resolved. It is part of an on-going settlement discussion in the power cost phase of the rate case. The point I wish to make on this issue is that the annual power cost adjustment mechanism is a narrowly focused evaluation of variable power cost items such as fuel prices and wholesale power costs and contracts. Adding selected O&M costs such as fly ash disposal to the evaluation is an unwarranted expansion of the evaluation. If disposal costs for fly ash change in a material way, the company can come to the Commission and request recovery of the excess costs.

Q. PLEASE EXPLAIN THE NEXT ISSUE, HYDRO O&M EXPENSES.

A. This issue is related to proposed non-labor operating and maintenance expense increases due to certain hydro relicensing agreements that PGE has entered into with intervening counterparties in order to obtain a renewal license from the Federal Energy Regulatory Commission (FERC) for the Clackamas River Hydroelectric Project. The Clackamas River Hydroelectric Project consists of four facilities, Faraday, North Fork, River Mill Dam and Oak Grove. The operating license for the hydro project has expired and

PGE has a renewal application in with FERC, but the new license has not yet been issued. The renewal application proposes new operational and other requirements for these facilities that were not in effect under the expired license.

I recommend disallowing the O&M costs for the new operational and other requirements because there is no certainty that the FERC license will require PGE to incur these expenses.

PGE testimony at UE 215, PGE/700/ Quennoz- Behbehani, page 19, contains a broad description of expected incremental expenses for the facilities listed above that the company asks to include in permanent rates. I propose that some of those costs be disallowed because they are speculative and not known and measurable:

- Faraday facility -- I recommend that the $0.4 Million increase to meet license requirements be removed.
- North Fork facility -- I recommend that the entire $0.3 million in incremental costs be disallowed.
- Oak Grove facility – I recommend $1.7 million in increases for new projects not required under the expired license be disallowed.

Q. WHEN DOES PGE EXPECT TO RECEIVE THE RENEWAL LICENSE FOR THE CLACKAMAS HYDRO PROJECT?

A. PGE has stated that it anticipates that FERC may issue the license renewal in the summer or fall of 2010.

Q. WHAT IF THE LICENSE RENEWAL INCLUDES ALL OF THE PROJECTED EXPENSES THAT PGE HAS INCLUDED IN THEIR FILING?

A. If the FERC license renewal is issued during these proceedings, I will take another look at the incremental project and expenses that may be part of the new license and re-evaluate my position. A general rate case is the appropriate place for the company to update its operating and maintenance expenses and the new Clackamas Hydro Project license may very well include some new requirements that would increase O&M costs.

Q. PLEASE SUMMARIZE THIS HYDRO O&M ADJUSTMENT.

A. I propose that the incremental O&M expenses for the Clackamas hydro project associated with the relicensing agreement that is not yet approved by FERC be disallowed. The amount I recommend be disallowed is $0.6 million for Faraday, $0.3 million for North Fork, and $1.7 million for Oak Grove, a total of $2.6 million in test year O&M expenses.

Q. WHAT IS YOUR THIRD ISSUE ABOUT?

A. I have proposed that certain, one-time O&M expenses, which do not appear to reoccur every year, be removed from the increase in O&M expenses used to determine normalized rates.

Q. WHAT ONE-TIME EXPENSES ARE YOU REFERRING TO AND WHY DO YOU PROPOSE TO DISALLOW THEM?

A. First, I would like to discuss how O&M expenses are generally determined in a rate case. Then, I will describe how these expenses factor into the revenue requirement that determine rates. After discussing this background I will make it clear why these one-time expenses should not be included in normalized rates.

In the PGE general rate case filing, the company starts with actual O&M expenses recorded in a prior year, in this case, 2008 is the base year. To the base year the company adds all the new ongoing operating and maintenance costs for subsequent years up to the present and finally uses standardized escalation factors to project a forecast of the O&M costs for the test year, in this case, calendar year 2011. The revenue requirement that is ultimately decided upon at the conclusion of a rate case is intended to represent the amount of money the company will need to recover in rates to cover all of its normal expenses and earn a reasonable return on its invested capital. Operating and maintenance expenses are included in their entirety in determining revenue requirement so any expense included will increase rates going forward, whether the expense is a one-time occurrence or represents a reoccurring cost every year.

The one-time expenses I have identified for disallowance include a one-time increase in the Colstrip 3 maintenance outage in the forecast for the 2011 test year of $3.2 million; a similar one-time increase in the Coyote Springs maintenance outage costs forecast for 2011 of $1.2 million; and a one time lead abatement project, intended to occur in 2011 expected to cost $2 million. Each of these projects has been identified by the company as a one-time event, not part of normal O&M. Since expenses set in a rate case continue in place until a subsequent rate case, only normal and ongoing O&M is appropriately included. These three projects clearly are one-time expenses not appropriate to be included in setting rates.

Q. IF THESE EXPENSES ARE NOT ALLOWED IN RATES HOW SHOULD THE COMPANY RECOVER THESE AND OTHER SIMILAR PRUDENTLY INCURRED COSTS?

A. Not all actual costs are exactly the same every year as costs forecast in a general rate case, some years certain costs may be higher while others may be lower. In addition, maintenance costs for individual items can vary from year to year. Normalized rates assume that, over time, the rates are sufficient to allow the company the opportunity to recover its costs and earn a reasonable rate of return. If periodic, more extensive, maintenance outages are required and average maintenance expenses used to set rates are not sufficient to allow the company to recover all of its costs over time, the company has an opportunity to make that argument here, in the general rate case filing, and perhaps average the excess periodic cost out over the expected time period that they would likely reoccur.

The argument made in this case, that Coyote Springs and Colstrip 3 generating plants are planning one-time, higher than average cost, maintenance outages and that the entire cost differences between the average cost and the higher one-time costs need to be added to expenses used to set rates should be rejected. Including the one-time costs increase requested for these maintenance outages, in their entirety, in permanent

O&M expenses is the same as saying that the company will be performing major maintenance every year to both of these units which is not the case and would likely cause the revenue requirement to be greater than normal costs would warrant.

The Oak Grove hydro facility lead abatement project cost is clearly a single project that, once completed, is over and done with. In discussions with PGE about this adjustment, PGE representatives indicated that they felt certain that there would be other similar, as yet unidentified, environmental remediation projects that would happen in subsequent years where they would need this extra O&M expense in rates. I recognize that a large utility like PGE has some exposure to changing requirements for environmental remediation and that there may be future environmental projects needing to be dealt with. If PGE feels that environmental remediation costs are going be an ongoing expense that should be the argument they make. Their argument that the Commission should allow PGE to recover in ongoing rates the costs of a one-time, discrete project should be denied.

Q. ARE YOU PROPOSING AN ENVIRONMENTAL REMEDIATION BALANCING ACCOUNT?

A. No. A balancing account would insinuate that the company would always be able to recover remediation costs from customers. PGE's shareholders should have skin in the game, and PGE's environmental management group should be incented to do what was the best for the company and its customers.

Q. WHAT DO YOU PROPOSE FOR THE TREATMENT OF THE POWER COST ADJUSTMENT MECHANISM (PCAM) CHANGE PROPOSED?

A. The PCAM mechanism should not be revised as requested by the company. PGE has provided no evidence that the mechanism does not yield reasonable results. The present PCAM earnings test and asymmetric dead band provisions insure a fair balance between the interests of the company and its rate paying customers.

Q. IS THERE ANY "MIDDLE GROUND" ACCOMMODATION THAT COULD BE MADE ON THIS MATTER?

A. No. The company has offered up no alternative that could balance out the loss to the interests of customers should the PCAM be modified as requested.

Q. CAN YOU SUGGEST AN ALTERNATIVE THAT MAY BE SUITABLE FOR CUSTOMERS?

A. Not at this time. The present mechanism, earnings tests and asymmetric dead bands, is intended to not come into play unless the power cost variance is extreme and the company earnings are significantly different than the authorized ROE. Although there have not been any incidents of power costs being wildly different than were forecast in the AUT, I believe the wisdom of the Commission in adopting the PCAM in its present form still applies.

Q. THE NEXT ISSUE IS A REQUEST BY PGE TO INCLUDE EMISSION CONTROL CHEMICAL COSTS AS PART OF THE NET VARIABLE

POWER COST ADJUSTMENT. WHY DO YOU RECOMMEND THIS NOT BE ADOPTED?

A. PGE has proposed to characterize the costs associated with chemicals used in its power plants for controlling NOx, mercury, and sulfur emissions as net variable power costs. This proposal is similar to the request to include Boardman fly ash in NVPC and my opposition to it is similar as well. This request, if adopted, would mean that PGE would include annual updates to the use, cost, and inventory of the commodity chemicals that are typically bought in bulk and stored on site in quantity, along with annual updates to wholesale power costs, power contracts, fuel costs and loads in the AUT. Although I do not believe the company specifically asks for it, I would also presume these costs would be part of the PCAM true-up also.

Q. WHY DO YOU OPPOSE THIS PROPOSAL?

A. The AUT is meant to be a narrowly focused examination of the main cost drivers for variable power costs. The evaluation takes place on a fairly short time table. I believe that adding an evaluation of costs, uses and inventories of environmental control chemicals is adding additional complexity to the AUT process without significantly improving the accuracy of variable power costs.

Q. IS PGE HAVING TROUBLE RECOVERING THE COSTS OF THE CONTROL CHEMICALS IN QUESTION?

A. Not that I am aware of. And to be clear, my opposition to this issue is simply that it is not appropriate to add one more cost driver to study in the annual update tariff, not that I oppose the company's recovery of these operating chemical costs. The operating chemical costs should be part of the regular O&M expenses that are updated in a general rate case and should not be part of the annual power cost update.

Q. THE FINAL ISSUE YOU BRING UP CONCERNS INCLUDING EXPENSES FOR BROKER ACCOUNTS, SHORT TERM CREDIT COSTS AND POWER CONTRACT COLLATERAL CARRYING COSTS IN THE ANNUAL POWER COST UPDATE. PLEASE EXPLAIN YOUR ISSUE WITH THE COMPANY'S PROPOSAL.

A. Currently all of these expenses are included in the general expenses updated with the general rate case filing. If the company's proposal were to go forward this would add additional items to the narrowly focused and tightly scheduled annual update tariff filing of forecast net variable power costs. This adds complexity to the evaluation of the power costs without improving the accuracy. In addition, I oppose this proposal because it would make it more difficult for the Staff analysts to keep track of the overall company short term credit instruments and costs if they are accounted for and evaluated in two separate "buckets". And if short term carrying costs were part of expenses updated prospectively each year it would add another cost that would need to be evaluated with the AUT and PCAM, potentially adding complexity to the evaluation for what likely is a low value issue. I am not opposed to the company being able to recover these types of financing costs, only to including them in the annual power cost evaluations.

Q. ARE THERE ANY OTHER ISSUES THAT YOU WISH TO DISCUSS?

A. No. This concludes my testimony.

CASE: UE 215
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	Ed Durrenberger
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst, Electric and Natural Gas Division
ADDRESS:	550 Capitol St. NE, Ste. 215, Salem, Oregon 97301
EDUCATION:	B.S. Mechanical Engineering Oregon State University, Corvallis, Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission of since February of 2004. My current responsibilities include staff research, analysis and technical support on a wide range of electric and natural gas cost recovery issues with an emphasis on electricity and fuel costs.
OTHER EXPERIENCE:	I worked for over twenty years in industrial boiler plant engineering, maintenance and operations. In this capacity I managed plant operations, fuel supplies and utilities, environmental compliance issues and all aspects of boiler machinery design, installation and repair. I have also worked as a production manager and machine shop manager in an ISO certified high tech equipment manufacturing plant that sered the silicon wafer fabrication and biomedical business sectors.

CASE: UE 215
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

June 4, 2010

- U.S. NEWS
- MAY 4, 2010, 4:33 P.M. ET

EPA Proposes Competing Approaches to Regulate Coal-Ash Waste

By MARK PETERS

The U.S. Environmental Protection Agency announced plans Tuesday to regulate coal-ash waste from power plants, but didn't choose a single approach in the face of pressure from industry and environmental groups.

The federal agency plans to take public comment on how to handle the waste from coal-fired generators and eventually decide on the final rules. The EPA began looking at the storage of the post-combustion material in ash ponds after a December 2008 spill at a Tennessee Valley Authority power plant sent about a billion gallons of ash and water over as many as 300 acres.

The regulation of coal ash has pitted utility companies concerned over the cost and complexity of eliminating wet-ash storage against health and environmental advocates who say arsenic, selenium and other contaminants in coal ash are a threat to human health and the environment.

The EPA's proposal doesn't take a stance on whether to regulate coal ash as a hazardous waste, only offering that approach as one of two possibilities. The hazardous-waste approach would put enforcement powers in the hands of federal and state officials, creating disposal restrictions and effectively phasing out the use of the ponds. The second proposal would put in place new restrictions, but enforcement would happen through lawsuits by states and individuals.

"In the course of developing these proposals, it became clear that there are people who feel very strongly about one or the other," said EPA Administrator Lisa Jackson during a press briefing.

Although one of the two proposals would treat coal ash as hazardous waste, Ms. Jackson said the EPA wouldn't use that term. Instead, the agency would refer to the ash as having a special-waste listing, if that option is chosen. The new classification would be used so as not to negatively impact the reuse of the waste material in such products as cement and drywall.

According to White House records, the issue of coal-ash waste was the subject of nearly 20 meetings between President Barack Obama's regulatory czar, Cass Sunstein, and industry groups last year. Watchdog groups have said it is unusual for Mr. Sunstein's office to insert itself so prominently, and so early, into the process. Environmentalists have long pushed for the EPA to tighten regulation of coal-combustion byproducts.

A utility-industry group in a statement Tuesday said regulation of coal ash as a non-hazardous waste alongside new federal standards for impoundment safety would be the only "prudent" course for the EPA.

"Adoption of more stringent regulation—including regulating coal combustion byproducts as hazardous waste or mandating closure of certain types of ash-management facilities—will drive up costs for our customers without providing a commensurate health or environmental benefit," said Jim Roewer, executive director of the Utility Solid Waste Activities Group, in a statement.

Environmental and health groups continue to push for the opposite, saying hazardous-waste regulations are essential to ensure federal officials can track and enforce standards for coal-ash facilities.

"Enforcement is what makes [the rules] real to the regulated industries," said Eric Schaeffer, executive director of the Environmental Integrity Project.

—Siobhan Hughes, Neil King Jr. and Rebecca Smith contributed to this article.

Write to Mark Peters at mark.peters@dowjones.com

CASE: UE 215
WITNESS: Kelcey Brown-Linnea Wittekind

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 600

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Linnea Wittekind. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Utility Analyst in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kelcey Brown. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Senior Economist in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/602.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. We present Staff's recommended Capital rate base reductions to Portland General Electric's (PGE) request to recover $65.6 million related to the Clackamas Hydro Relicensing Project. In addition, we address PGE's request for an accounting treatment of self-build study costs.

Q. PLEASE SUMMARIZE THE BASIS FOR STAFF'S RECOMMENDED CAPITAL COST ADJUSTMENTS.

A. PGE is requesting rate recovery for relicensing costs of the Clackamas Hydro Project. Staff's recommended adjustments to PGE's request are for costs related to pending license requirements and unapproved terms of a settlement agreement and not costs associated with obtaining the license. FERC has not yet issued its license for the Clackamas hydro Project; therefore, the license requirements are unknown at this time.

With regard to the costs PGE is requesting for food and other entertainment, Staff believes it is unreasonable and harmful to customers to allow PGE to capitalize food and entertainment expenses of $128,503 over a 50 year period.

Q. PLEASE PROVIDE A SUMMARY OF STAFF'S CLACKAMAS HYDRO RELICENSING PROJECT ADJUSTMENTS.

A. Staff recommends the following adjustments to the requested $65.6 million in Clackamas Hydro Relicensing Project costs:

1. A reduction of $1,500,000 for capital costs described as "a move from job 20512" in PGE's transaction summary. This cost is for riparian restoration projects that will potentially be required by the Federal Energy Regulatory Commission (FERC) in PGE's new license and should not be part of relicensing costs.
2. A reduction of $515,000 for capital costs used to reimburse Western Rivers Conservancy for the acquisition of North Mountain wetlands. The

acquisition of the wetlands is a potential requirement by FERC and should not be part of relicensing costs.

3. A reduction of $750,000 for capital costs used for the implementation of the Clackamas River Off Channel Restoration Project. This cost is for a project that will potentially be required by FERC and should not be included in costs associated with obtaining the license.
4. A reduction of $77,412 for capital costs paid to CXT Precast Products for the purchase and installation of a new restroom located at PGE’s Timber Park. As stated by PGE this was done per the proposed conditions in the relicensing settlement agreement. This is a potential requirement by FERC and should not be part of relicensing costs.
5. A reduction of $500,000 for capital costs described as “from N23913 job RXMOU” in PGE’s transaction summary. Further details of this cost are being pursued through data requests.
6. A reduction of $128,503 for capital costs for food and other entertainment. Staff believes that capitalizing the cost of food and entertainment is not in the best interest of customers.

The total rate base adjustment for the Clackamas Hydro Relicensing Project is $3,470,915.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION WITH REGARD TO PGE’S REQUEST FOR ACCOUNTING TREATMENT OF SELF-BUILD STUDY COSTS.

A. Staff recommends that the Commission deny PGE’s request for accounting treatment of self-build study costs. Staff believes that were the Commission to grant PGE’s request it would remove the incentive for the Company to use discretion on whether or not to bid into an RFP process and, by guaranteeing cost recovery, would place it on unequal footing with regard to other bidders.

Clackamas Hydro Project

Q. PLEASE DESCRIBE PGE’S REQUEST FOR RATE RECOVERY WITH RESPECT TO THE CLACKAMAS HYDRO PROJECT.

A. PGE has been involved in the relicensing process at FERC for the Clackamas Hydro Project since 1996. In that time, PGE has incurred costs to obtain its license for professional services, Allowance for Funds Used During Construction (AFDC), direct labor, and tax and license fees.

Q. DOES THE COMPANY BELIEVE IT WILL RECEIVE ITS LICENSE PRIOR TO JANUARY 1, 2011?

A. Yes.

Q. PLEASE DESCRIBE STAFF’S ANALYSIS OF PGE’S REQUEST FOR RELICENSING PROJECT COSTS.

A. Staff has reviewed PGE’s accounting from 1996 to now of all transactions associated with the Company’s efforts to obtain its license from FERC. However, in that review Staff has determined that a small portion of these costs are related to terms of a settlement agreement pending before FERC. Whether these terms will be conditions of the license is a discretionary decision and one that FERC has not yet made.

Q. WHY ARE TERMS OF THE SETTLEMENT AGREEMENT NOT REASONABLE COSTS FOR PGE TO INCLUDE IN RATES AT THIS TIME?

A. PGE has not yet received its license, and it is not improbable for terms of the settlement agreement to be rejected by FERC and therefore not a requirement of the license.

Q. DOES STAFF HAVE AN EXAMPLE OF EXPENDITURES THAT MAY NOT BE PART OF THE LICENSE?

A. Yes. PGE paid $515,000 to the Western Rivers Conservancy in 2009 for the purchase of the 320-acre parcel known as North Mountain wetlands. This wetland acquisition was part of the terms of the settlement agreement. However, FERC staff has recommended that the acquisition and inclusion of the site not be a term of the license. FERC staff cited several reasons for not recommending this site be included in the license. Most notably, the site is in an adjacent river basin and has no hydraulic connection to the project, and therefore, has little relationship to project purposes or effects.

Q. SINCE PGE HAS NOT RECEIVED ITS LICENSE FROM FERC, IS STAFF ABLE TO DETERMINE THE PRUDENCE OF EXPENDITURES ASSOCIATED WITH SETTLEMENT TERMS?

A. No. Even though FERC staff did not recommend the inclusion of this site, and other settlement measures, the final determination and associated requirements will not be known until FERC issues the license.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Since PGE has not yet received its license from FERC, Staff is unable to determine the prudence of measures associated with the settlement agreement and anticipated terms of the license. This includes the Western Rivers Conservancy purchase of North Mountain wetlands, the riparian restoration projects, new restrooms at Timber Park, the Clackamas River Off Channel Restoration Project, and further investigation of a reclassified expenditure.

Q. IS PGE PRECLUDED FROM REQUESTING RECOVERY OF THESE COSTS IN A FUTURE PROCEEDING?

A. No. Staff's recommendation with respect to the relicensing costs, excluding food and entertainment, is simply that they are not appropriate to include in rates at this time.

Q. PLEASE DISCUSS STAFF'S RECOMMENDATION TO EXCLUDE FOOD AND ENTERTAINMENT COSTS FROM THE RELICENSING PROJECT.

A. PGE has charged $128,503 in capital costs for food and other entertainment. This includes vendors such as World Trade Center Catering, Starbucks, Paradise Bakery, McMenamins, and Elephants Deli. Capitalization of these expenditures is harmful to customers, and is equivalent to buying a meal at Burger King with your credit card and paying it off over 50 years.

Q. IS PGE REQUIRED TO PROVIDE FOOD OR STARBUCKS COFFEE TO PARTICIPANTS IN THE RELICENSING PROCESS?

A. No. The FERC relicensing process, similar to a Commission proceeding, is composed of intervenors that include many state and federal agencies, public interests and tribes. Their participation in meetings and settlement discussions does not require PGE to provide food. More importantly, PGE should have expensed these items as they occurred, rather than attempting to capitalize items that have no material value or future use.

Accounting Treatment

Q. PLEASE DESCRIBE PGE'S REQUEST FOR PRELIMINARY STUDY COSTS FOR SELF-BUILD OPTIONS.

A. PGE has requested two types of accounting treatment with regard to self-build study costs for purposes of submitting a self-build option into a Request For Proposal (RFP). These two accounting treatments are: to accrue Allowance for Funds Used During Construction (AFDC) on its study costs, and in the event that its self-build option is not selected in the RFP process, to place the study costs in a regulatory asset account amortized over a five year period.

Q. WHAT REASONING DOES PGE PROVIDE FOR NEEDING TO ACCRUE AFDC ON STUDY COSTS PRIOR TO HAVING THE PROJECT SELECTED AS THE FINAL BID?

A. At PGE/300, Tooman-Tinker/10, PGE states that it is incurring "financing costs" for these self-build studies prior to having a project approved, for which they are not able to recover.

Q. DOES STAFF BELIEVE IT IS APPROPRIATE FOR PGE TO ACCRUE AND POTENTIALLY RECOVER FINANCING COSTS ASSOCIATED WITH ITS SELF-BUILD STUDIES?

A. No. PGE's "financing costs", or its use of operating cash flow, is already built into the Company's regular operations. In any given year there are projects, filings, or other matters that require the Company to perform studies relating to any number of things, e.g. environmental regulations, wind integration, and wholesale market changes. While all of these events would be considered infrequent, at any given time the Company is performing any number of studies and therefore, the costs associated with these events is currently included in the Company's overall operating cash flow.

Q. IS PGE REQUIRED TO SUBMIT A SELF-BUILD STUDY OPTION INTO AN RFP?

A. No. It is PGE's choice to submit a self-build study option into an RFP; the Commission does not require them to do so.

Q. DOES STAFF BELIEVE THAT PGE'S DEVELOPMENT OF A SELF-BUILD STUDY OPTION IS A BENEFIT TO CUSTOMERS?

A. PGE's submittal of a self-build option into an RFP only benefits customers if that bid is chosen as the lowest cost/best alternative compared to other bidders. Since PGE cannot guarantee this outcome customers are indifferent as to whether PGE submits a self-build option or not.

Q. SINCE PGE IS NOT REQUIRED BY THE COMMISSION TO SUBMIT A BID INTO AN RFP PROCESS IS IT REASONABLE FOR THE COMPANY TO RECOVER THESE SELF-BUILD STUDY COSTS FROM CUSTOMERS IN THE EVENT THAT THE BID IS NOT SELECTED?

A. No. Staff has three reasons why PGE's request is unreasonable. First, this violates ORS 757.355 (i.e. the used and useful standard). Second, this would create a situation of unfairness with regard to the others bidders in the process who do not have guaranteed cost recovery. Third, this would take away any incentive for cost control or discretion on the part of the Company on whether it should be bidding into the RFP with a self-build option.

Q. DOES THE COMPANY CLAIM THAT RECOVERY OF THESE SELF-BUILD STUDY COSTS, IN THE EVENT THAT AN ALTERNATIVE BID IS CHOSEN, AVOIDS THE LEGAL QUESTION OF "USED AND USEFUL"?

A. Yes. PGE makes the statement at PGE/300, Tooman-Tinker/12, Lines 16-19, that this request avoids the legal question of whether the costs are for something that is used and useful because the Company is proposing that these costs would not include any of the previously accrued AFDC and would not earn a "return on" in any fashion.

Q. DOES STAFF AGREE WITH PGE, THAT BY NOT GETTING A RATE OF RETURN ON THESE COSTS IT SOMEHOW AVOIDS THE QUESTION OF USED AND USEFUL?

A. No. Staff's counsel advises that the statute in reference in this discussion, ORS 757.355, does not distinguish recovery of costs so that it only precludes a "return on." The statute is not limited in this manner, and precludes any recovery in rates for the costs specified in the statute that are not presently used for providing utility service to the customer.

Q WHAT IS THE CURRENT OPERATING PRACTICE OF PUBLIC UTILITIES WITH REGARD TO RECOVERY OF EXPENDITURES FOR PRELIMINARY SURVEYS, PLANS AND INVESTIGATIONS MADE FOR THE PURPOSE OF CONSTRUCTING A UTILITY PROJECT?

A. The Code of Federal Regulations (CFR) states that if construction results from this work than the appropriate utility plant account will be charged. However, in the event that construction does not result from these studies, and the work is abandoned, the charges shall be made to account 426.5, Other Deductions, or to the appropriate operating expense account. Account 426.5 is a "below the line" account and not considered for ratemaking purposes.

Q. WHY DOES STAFF BELIEVE THAT BY GUARANTEEING THE COMPANY COST RECOVERY OF THESE COSTS IT WOULD CREATE A DISINCENTIVE FOR THE COMPANY?

A. As stated previously, the Company is not required to submit a self-build option into an RFP, nor are customers benefited by this submittal if the Company's bid is not chosen. PGE should be treated as equally as possible in the bidding process; this means that the Company should use discretion when it chooses to bid into an RFP, similar to any other bidder.

Q. DOES THE RFP PROCESS ENCOURAGE DISCRETION ON BEHALF OF BIDDERS PARTICIPATING IN THE PROCESS?

A. Yes. It is common in an RFP process to charge a bidding fee, with the intent of discouraging superfluous bids into the process and only receiving quality bids that have the possibility of being chosen. Were the Commission to guarantee cost recovery, not only would this remove the incentive for discretion on the part of the Company, but in the event that the Company's bid was not chosen Staff would then have to review the prudence of the Company even submitting a bid.

Q. PGE MAKES THE CLAIM THAT ALTERNATIVE BIDDERS MUST SOMEHOW RECOVER THEIR COSTS OR THEY WOULD GO OUT OF BUSINESS, THEREFORE, PGE SHOULD BE ALLOWED TO RECOVER THESE COSTS. DO YOU AGREE?

A. No. PGE is correct, if a bidder into an RFP, whose sole practice is to build utility resources, is consistently not selected as the winning bidder they will go out of business. However, it is this reality which forces the alternative bidder to maintain cost controls on the relevant study and proposal costs, and requires the bidder to use discretion on which processes it participates in.

Q. DOES STAFF HAVE A RECOMMENDED MONETARY ADJUSTMENT ASSOCIATED WITH YOUR RECOMMENDATION?

A. No. PGE has not requested cost recovery for self-build study costs for resources supported in the current IRP. Therefore, PGE has not included a forecast of regulatory asset amortization for 2011 associated with this proposal. However, if the Commission were to approve PGE's request for accounting treatment of these costs it will increase customer rates in the future

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Kelcey Brown-Linnea Wittekind

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME: Linnea Wittekind

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst, Electric and Natural Gas Division

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: B.S. Western Oregon University
Major: Business with focus in Accounting
Minor: Entrepreneurship

EXPERIENCE: Since November 2009 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric utilities. I am working on the Portland General Electric and Idaho Power Integrated Resource Plans. I have also reviewed and analyzed a number of energy efficiency tariff filings, filed by Idaho Power Company. I've written several public meeting memos summarizing my analysis of the energy efficiency tariff filings, for an example of some of the memos see the April 26, 2010 & May 25, 2010 agendas.

From July 2005 to November 2009 I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UE 215
WITNESS: Kelcey Brown-Linnea Wittekind

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME: Kelcey Brown

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Electric and Natural Gas Division, Resource and Market Analysis

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: All course work towards Masters in Economics
University of Wyoming

B.S. University of Wyoming
Major: Business Economics
Minor: Finance

EXPERIENCE: Since November 2007 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric utilities. I have provided testimony in UE 199, UE 200, UE 207, UE 210, UM 1355, and UE 204. I have also filed comments on several dockets such as LC 47, UM 1466 and UM 1467.

From June 2003 to November 2007 I worked as the Economic Analyst for Blackfoot Telecommunications Group, a competitive and incumbent telephone provider in Missoula, Montana. I conducted all long and short term sales and revenue forecasts, resource acquisition cost-benefit analysis, business case analysis on new products and build-outs, pricing, regulatory support, market research, and strategic planning support.

From May 2002 to August 2002 I worked as an intern at the Illinois Commerce Commission in Springfield, Illinois. I performed competitive market analysis, spot market monitoring and pricing review, and extensive research on locational marginal pricing and transmission system incentives for development.

My course work, towards a Master’s degree at the University of Wyoming, focused heavily on the regulatory economics of network industries such as electricity, natural gas, and telecommunications.

CASE: UE 215
WITNESS: Kenneth R. Zimmerman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kenneth R. Zimmerman. I am a Senior Analyst with the Oregon Public Utility Commission, Electric and Gas Rates Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/702.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support and explain staff's removal of the costs associated with two items PGE proposes to include in its rate base in the instant docket. These items are the upgrade of the Coyote Springs turbine planned for 2011 and the pollution control upgrades for the Boardman coal generation plant also planned for 2011.

Q. PLEASE DESCRIBE THE UPGRADES.

A. The Coyote Springs upgrade includes a new compressor rotor, blades, vanes and casings; new turbine rotor; new dry, low NOx combustion system; and a new cooling package. For the Boardman plant PGE plans to install new low NOx burners, mercury controls and over fire air ports, and a combustion monitoring system and new boiler cleaning equipment as well as replace one third of the boiler convection pass re-heater, In other words both upgrades are quite extensive.

Q. IN THE CONTEXT OF A PUBLIC UTILITY SUCH AS PGE WHAT IS RATE BASE?

A. Rate base is the total of the investor funded or supplied plant, facilities, and other investments used by the utility in providing utility services to its customers. The rate base is the investment base to which a fair rate of return is applied to arrive at the net operating income requirement (i.e., the amount of authorized return).

Q. WHAT ARE THE CRITERIA FOR ADDING COSTS OF PLANT, FACILITIES, ETC. TO ANY UTILITY'S RATE BASE?

A. Oregon Statute 757.355 is quite clear about the circumstances under which property of any sort may be added to a utility's rate base. The property must be "presently in use" and that use must "provide utility service to the utility's customers."

> **757.355 Costs of property not presently providing utility service excluded from rate base.** No public utility shall, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates which are derived from a rate base which includes within it any construction, building, installation or real or personal property not presently used for providing utility service to the customer. [1979 c.3 §2]

Q. DO THE COSTS RELATED TO THE UPGRADES TO COYOTE SPRINGS AND BOARDMAN MEET THESE CONDITIONS?

A. No. None of the upgrades are presently in use and none will be in use prior to the January 1, 2011 date when the rates allowed by the Commission in the instant docket become effective. Per PGE Exhibit 700 (Quennoz – Behbehani), page 27 the Coyote Springs upgrades will be completed during

2011. PGE Exhibit 308 indicates the Boardman upgrades will also be completed during 2011. As to the second requirement of 757.355 neither the Boardman nor the Coyote Springs upgrades are "….providing utility service to the customer," and based on PGE's testimony they cannot and will not do so until sometime in 2011.

Q: DO YOU HAVE ADDITIONAL CONCERNS ABOUT ALLOWING THESE UPGRADES INTO RATE BASE?

A: Yes. These upgrades have not been adequately vetted and analyzed by PGE via the Commission's IRP process. PGE's 2007 IRP (LC 43) was not acknowledged by the Commission. Even had it been acknowledged it provides no detailed analysis of the proposed Boardman upgrades and no analysis what so ever of the proposed upgrades at the Coyote Springs gas-fired generation station.[1] Obviously PGE's current IRP cannot settle this issue since the Commission has not yet acknowledged it and will not make that decision for several months at least.

Q. **WHAT IS YOUR RECOMMENDATION CONCERNING THE COSTS PGE PROPOSES TO INCLUDE IN RATE BASE FOR THESE UPGRADES?**

A. I recommend the Commission deny PGE's request that the costs for these upgrades be included in rate base, for the reasons cited in this testimony. The

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[1] PGE's 2007 IRP (LC 43) was not acknowledged by the Commission. The Boardman environmental upgrades are discussed in that IRP but not in detail (p. 95). The Coyote Springs upgrades are not discussed in this 2007 IRP although general generation efficiency upgrades are considered. PGE's IRP filed November 5, 2009 includes a detailed discussion of the Boardman environmental upgrades in Section 12, beginning as page 291. The Coyote Springs efficiency upgrades are discussed briefly at pages 139-141 of this IRP.

actual dollar amounts staff recommends be excluded from rate base are in Staff/701.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/701, consisting of one page.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Kenneth R. Zimmerman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Exhibits in Support
Of Opening Testimony

June 4, 2010

Portland General Electric
UE 215
Test period ending December 31, 2011

Staff Exhibit/701

Capital Expenditures - Strategic	2010 ($, '000s)	2011 ($, '000s)	Totals Strategic ($, '000s)	Adjustments ($, '000s)	Comments
Boardman Emissions - Full Implementation		$ 29,188	$ 29,188	$ (29,188)	Note 2.
Coyote Springs Upgrade		$ 33,212	$ 33,212	$ (33,212)	Note 1.
Total Removed from Rate Base	$ -	$ 62,400	$ 62,400	$ (62,400)	Note 3.

Note 1: Not in-service by January 1, 2011. Thus not used and useful. Per PGE / 700 Quennoz – Behbehani / 27 upgrades will be completed during 2011.

Note 2. Not used and useful. PGE Exhibit 308 indicates the project will not be completed until sometime in 2011.

All based on responses to DR 272, particularly WP-2 (close)

CASE: UE 215
WITNESS: Kenneth R. Zimmerman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATIONS STATEMENT

NAME	Kenneth R. Zimmerman
EMPLOYER	Oregon Public Utility Commission
TITLE	Senior Utility Analyst
ADDRESS	550 Capitol Street NE Suite 215 Salem, OR 97301

EXPERIENCE

Dr. Zimmerman retired as Chief of Energy with the Oklahoma Corporation Commission's Public Utility Division (1985 – 2005). In that position he was the Administrator supervising a staff of accounts, economists, financial analysts, and engineers assigned to prepare and oversee all work relating to the regulation of electric, natural gas, water, and cotton gin utilities operating in Oklahoma; advising Commissioners in these areas; preparing testimony; testifying under oath. This work included preparation of and supervision of the preparation of:

1. Integrated resource plan analyses (demand forecasting; fuel price forecasting; review of supply-side and demand-side resource availability, costs, and operations; action plans; and public planning processes).
2. General rate reviews (rate base; cost of equity; cost of debt; rate of return; general expenses; allocations; propriety of accounting; depreciation; and rate design).
3. Accounting and management audits.
4. Legal and legislative reviews.
5. Analysis of renewable and "clean" energy sources; environmental impacts of utility operations; and alternative rate and regulatory designs (e.g., real-time, marginal, dynamic pricing, nonlinear pricing, incentive regulation, and retail/wholesale markets for utility services).

He is now Senior Utility Analyst with the Oregon Public Utility Commission (2005 – Current). His primary responsibilities in that position are: natural gas price and demand forecasting; natural gas integrated resource planning; the flow through of natural gas costs to end-users by gas utilities; and analysis of the general structure and operation of the current, past, and future networks for energy exploration, production, and distribution (including energy markets).

Prior to his work in energy utility regulation, Dr. Zimmerman was a legislative staffer, private consultant, and university professor. Dr. Zimmerman holds a PhD in Sociology/Anthropology from the University of North Texas; an MA (Sociology and Psychology) from St. Mary's University (TX); an MA from Lancaster University (UK) in Economics, Science, and Technology; and undergraduate degrees Baylor University (TX).

CASE: UE 215
WITNESS: Juliet Johnson

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 800

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Juliet Johnson. I am employed by the Public Utility Commission of Oregon as a Financial Analyst, Corporate Analysis and Water Regulation Section, in the Economic Research and Financial Analysis Division of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/801.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend the Commission deny Portland General Electric's (PGE or Company) request for an accounting order to establish a balancing account to track differences between projected and actual environmental mitigation and remediation costs for Portland Harbor, Harbor Oil, and Oak Grove projects.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. No.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I state my understanding of what PGE is proposing and then provide a summary of the Company's recent application for a deferral renewal for these same projects. Next, I summarize the projects for which the balancing account is being requested, and lastly I present Staff's recommendation.

Q. WHAT IS BEING REQUESTED BY THE COMPANY?

A. PGE is proposing a balancing account to track variances from Superfund[1] (or Superfund-like) projects. A baseline amount would be included in a test year and collected each year in rates and applied to the balancing account. Approved environmental expenses related to the identified projects would be withdrawn from the balancing account, with remaining funds returned to customers when the account was reset. The balancing account would track differences between actual and forecasted costs. Monies accrued in the balancing account would earn interest at PGE's authorized rate of return. The Commission would review and approve balancing account transactions through an audit that would occur at the time of a new general rate case or at least every two years. The balancing account would only be used for those projects where PGE was identified as a responsible party by a federal or state agency, which at this time includes Portland Harbor, Harbor Oil, and Oak Grove.

Q. HAS PGE PREVIOUSLY REQUESTED COST TRACKERS OR DEFERRED ACCOUNTING FOR THESE ENVIRONMENTAL PROJECTS?

A. Yes. On May 31, 2008, PGE submitted a request for a deferral for costs associated with Portland Harbor and Harbor Oil (Docket No. UM 1373). That request was approved by the Commission on February 6, 2009 (Order No. 09-052) for the 12-month period starting March 31, 2008. On March 30, 2009 PGE filed an application for reauthorization of the deferral with the addition of

[1] [1] Superfund is the name given to the environmental program established to address abandoned hazardous waste sites. It is also the name of the fund established by the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended. http://www.epa.gov/superfund/about.htm

costs associated with Oak Grove Remediation. A preconference hearing was held on July 20, 2009, after which both Staff and the Citizen's Utility Board (CUB) submitted testimony. In January 6, 2010, PGE withdrew the deferral renewal application and the docket was closed.

Q. WHAT IS THE RELEVANCE OF PGE'S PAST DEFERRAL TO THIS REQUEST?

A. Deferrals and balancing accounts are both cost trackers whereby costs can be recovered outside of, or through a variation of the ratemaking process. In both cases, designated costs are separated out for subsequent potential recovery. In a deferral, approved costs are recovered directly in future rates. In a balancing account, approved costs are recovered through a designated fund contributed to each year from rates. Funds in the balancing account accrue interest and if not used, are returned to customers. Proceeds, such as insurance settlements, can also be added to the balancing account. Staff opposed a deferral renewal for environmental costs in Docket No. UM 1373 and many of Staff's contestations also apply to this request for a balancing account.

Q. WHAT WERE STAFF'S OBJECTIONS TO THE DEFERRAL RENEWAL IN UM 1373?

A. Staff believed a deferral was not warranted because, among other things, the amounts at issue were not sufficient to trigger a general rate case filing (one of the Commission's criteria for a deferral) nor would non-recovery of the proposed costs have a material financial impact on the Company and diminish their *opportunity* to earn the authorized rate of return.

Q. FOR WHAT PROJECTS IS PGE REQUESTING A BALANCING MECHANISM?

A. PGE is proposing to include three environmental cleanup projects in the balancing account. Two of the sites are Environmental Protection Agency (EPA) Superfund Sites: Portland Harbor and Harbor Oil. The third site is at PGE's Oak Grove Facility where there are two cleanups required, one for Polychlorinated biphenyl (PCBs) and another for lead.

Q. WHAT IS THE STATUS OF PORTLAND HARBOR?

A. PGE has been named a Potentially Responsible Party (PRP) along with 79 others entities for the Portland Harbor Superfund site. PGE is not one of the approximately 10 entities that make up the Lower Willamette Group (LWG) who are conducting a Remedial Investigation (RI) and Feasibility Study (FS). The final RI and FS are expected in the fall of 2010. Meanwhile, PRPs, including PGE are working to select an allocator for a voluntary settlement process. PGE has indicated that due to a lack of consensus, the allocator position has not yet been filled. After the RI/FS is issued, PGE expects the EPA to issue a Record of Decision in June 2012. In the meantime, PRPs will work through the allocation process. PGE expects an Allocation Report to be generated in May 2012, after which PRP's will submit a good faith offer to EPA, probably in the Fall of 2012. Consent Decree negotiations are expected to begin the following spring with a Consent Decree entered by EPA in December

2013. The Consent Decree will indicate which PRPs are responsible for remediation, and will likely specify their allocation of remediation costs.

Q. ALTHOUGH PGE IS NOT A MEMBER OF THE LWG AND A FINAL CONSENT DECREE IS NOT EXPECTED UNTIL DECEMBER 2013, IS PGE INCURRING COSTS ASSOCIATED WITH PORTLAND HARBOR?

A. Yes. In January 2008, the EPA served PGE with a formal CERCLA data request 104(e) that required research and response. Additionally, PGE is helping to develop and implement the Allocation Process, which according to Direct Testimony in UM 1373/PGE/100 page 19, PGE expects to take several years to complete. PGE is also working with U.S. Fish and Wildlife and various Tribes on a Natural Resources Damages Assessment Process (NRDA) process.

Q. WHAT IS THE STATUS OF HARBOR OIL?

A. PGE was named as one of 14 PRPs for the federal Superfund site Harbor Oil in June 2005. Harbor Oil is an oil re-refiner located in north Portland and was utilized by PGE to process used oil from power plants and electrical distribution system from at least 1990 until 2003. In 1974 and 1979 major oil spills occurred there leading to contamination with metals, lead and PCBs. In May 2007, an Administrative Settlement Agreement and Order of Consent was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The final revised work plan for the RI/FS has been submitted to the EPA, and phases 1 and 2 of the site characterization are complete. The RI is scheduled to be submitted to EPA in 2010. The Feasibility

Study is scheduled to be completed in 2011. Once these are complete, the EPA will provide a ROD to all parties identifying the remedy and costs.

Q. WHAT IS THE STATUS OF OAK GROVE?

A. There are two environmental cleanups required at Oak Grove, one for PCBs downhill of a storm water outfall near the maintenance shop and another for lead contamination from previous paint removal near the Cripple Creek, Pint Creek, and Canyon Creek support trestles. PGE completed a site investigation regarding the PCBs in five phases between August 2005 and April 2008. Regarding the PCB cleanup, PGE has completed the Engineering Evaluation/Cost Analysis (EE/CA) for the site and expects to clean it up in summer 2010. Regarding lead contamination, PGE has notified the U.S. Forest Service and is waiting for its determination on the site for cleanup protocol. PGE expects the Forest Service to require resolution of the lead contamination issue in a comprehensive Administrative Order on Consent (AOC) under CERCLA. PGE anticipates further investigation in 2010 and cleanup activities in 2011. Cost of Oak Grove lead cleanup is estimated at $2 million.

Q. ARE THESE THE SAME PROJECTS FOR WHICH PGE WAS REQUESTING A DEFERRAL RENEWAL?

A. Yes.

Q. HAS THERE BEEN ANY MAJOR CHANGES IN STATUS OR PROJECTED COSTS SINCE THE DEFERRAL RENEWAL APPLICATION?

A. Staff is not aware of any major changes in status or projected costs.

Q. HOW ARE BALANCING ACCOUNTS TYPICALLY USED?

A. Although there are exceptions, balancing accounts are generally limited to costs such as property sales and purchases, merger credits, decoupling, PGA's, PCAM's, and other special situations. They have not traditionally been used for environmental costs.[2] Balancing accounts are not generally used for discrete O&M costs that can be included in the revenue requirement.

Q. PLEASE EXPLAIN WHY STAFF OPPOSES A BALANCING ACCOUNT FOR THESE ENVIRONMENTAL COSTS.

A. In forward-looking test year based rate making there is a balance of costs and benefits between the utility and its customers. Utilities have incentives to actively manage their costs within the approved rate in the context of their full financial picture. PGE's authorized rate of return is based on the risk premium partially accounted for in the earnings volatility from fluctuations in costs or revenues from the test year and across categories within the Company. PGE is not guaranteed its authorized rate of return, but rather is given the *opportunity* to realize it through prudent and efficient management.

In theory, cost trackers such as deferrals and balancing accounts can reduce incentives for a Company to spend time and money actively managing costs because the company now has a potential alternative method to recover costs. Cost trackers can allow a Company to insulate itself from the risks inherent in the context of forward-looking rate setting while providing only minimal benefit to the customers.

[2] In Docket No. UM 1078 Northwest Natural was granted a deferral (not a balancing account) by the Commission for environmental mitigation costs. UM 1373 Testimony addresses this.

Q. SHOULD THESE ENVIRONMENTAL COSTS BE AN EXCEPTION TO THE RULE OF FORWARD-LOOKING TEST YEAR RATE MAKING?

A. No. As discussed in Docket No. UM 1373, PGE has a general understanding of its role in all three projects and the next steps and projected timelines for these projects are fairly well understood. As well, historically PGE has been able to project their total net environmental costs reasonably well. As a result, Staff believes that PGE can forecast and model the environmental costs that are going to be incurred in the next 24 months in rates reasonably well. Staff believes a balancing account to capture the incremental variation from what is projected to what might be realized is not warranted and creates unnecessary complexity and work.

Q. ARE THERE OTHER REASONS STAFF OPPOSES A BALANCING ACCOUNT IN THIS CASE?

A. Yes. Staff would need to review and audit the balancing account which would place the burden on Staff to cross check which costs were transferred into the balancing account and whether other categories of costs were reduced by an equivalent amount to avoid double billing customers. It is preferable that environmental costs be viewed together within the Company's larger financial picture as a part of a general rate proceeding.

Q. ANYTHING ELSE YOU WOULD LIKE TO ADD?

A. Yes. Because balancing accounts are not traditionally used for these types of costs, there is a potential for Commission approval to set a precedence for other companies to request the use balancing accounts to true-up actual with forecasted costs for many other categories of costs, potentially disproportionately increasing company revenues and decreasing company risks while increasing costs to customers.

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION.

A. Staff believes it is the responsibility of PGE to manage costs and risks within the rates set by the Commission and that the risks and rewards of budget management should remain with PGE. Staff believes that the current status and projected costs associated with Portland Harbor, Harbor Oil and Oak Grove do not warrant a balancing account and that the level of uncertainty around these projects over the next two years falls within the acceptable range of risk inherent in the utility business and provided for within the allowed rate of return. Staff's position is that a balancing account unfairly favors PGE shareholders at the expense of the customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Juliet Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	JULIET JOHNSON, P.E.
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	FINANCIAL ANALYST, ECONOMIC RESEARCH AND FINANCIAL ANALYSIS DIVISION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Master of Science, Civil and Environmental Engineering, Arizona State University, Tempe, AZ Bachelor of Science in Engineering, Civil and Environmental Engineering, Tempe, AZ
EXPERIENCE:	Employed with the Oregon Public Utility Commission from April 2010 to present, currently serving as Financial Analyst for Corporate Analysis and Water Regulation in the Economic Research and Financial Analysis Division. Registered professional engineer in Oregon and Arizona and member American Center for Life Cycle Assessment. From October 2008 through May 2010 worked as an Independent Consultant on water, energy, sustainability, and finance projects including evaluating costs and risks associated with different types of energy generation. Long-term Development and Sustainability Manager for the Esalen Institute in Big Sur, California from September 2004 to September 2008, oversaw infrastructure development, performed cost/benefit analysis of alternative development scenarios and managed permits and regulatory compliance. Employed by Greeley and Hansen LLC in Phoenix, Arizona from May 1997 to April 2003 as a project manager and water engineer managing water and wastewater designs, studies and research and performing cost allocations for regional water infrastructure.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as Program Manager of the Economic and Policy Analysis Section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is included as Exhibit Staff/901.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I develop the cost of common equity[1] estimates for the rate-regulated property of Portland General Electric Company ("PGE"). I provide a point estimate recommendation, as well as a range of estimates, of PGE's cost of common equity for consideration by the Public Utility Commission of Oregon ("Commission") in establishing PGE's authorized return on equity (ROE) within PGE's current general rate case in Docket No. UE 215. Additionally, I provide a recommended capital structure associated with the recommended ROE and the recommended rate of return (ROR) based on recommendations in my testimony and the recommended costs of long-term debt as presented

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1 Common equity, or common stock, is an "ownership" investment of, say, a corporation, where stockholders "have a general preemptive right to anything of value that the company may wish to distribute." Holders of common stock are the owners of the corporation, unlike holders of preferred stock or debt securities of the corporation. *See* Brealey and Myers; *Principals of Corporate Finance*, 3rd Edition, 1988, page 305.

in Exhibit Staff/1000, Ordonez. The costs of long-term debt, of common equity, and PGE's capital structure are collectively identified as issue S-0.

My testimony constitutes Staff's response, in part, to that provided by PGE witnesses Hager - Valach (PGE/1100) and Zepp (PGE/1200).

Additionally, I provide a brief discussion regarding PGE's decoupling mechanism. This testimony constitutes Staff's response to portions of testimony provided by PGE witnesses Hager - Valach (Exhibit PGE/1100) and Kuns – Cody (Exhibit PGE/1500).

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/902, consisting of 30 pages; Exhibit Staff/903, consisting of nine pages; Exhibit Staff/904, consisting of two pages; Exhibit Staff/905, consisting of 85 pages; Exhibit Staff/906, consisting of 31 pages; Exhibit Staff/907, consisting of 16 pages; Exhibit Staff/908, consisting of 12 pages; Exhibit Staff/909, consisting of 26 pages; Exhibit Staff/910, consisting of 41 pages; Exhibit Staff/911, consisting of 28 pages; Exhibit Staff/912, consisting of 26 pages; Exhibit Staff/913, consisting of 17 pages; Exhibit Staff/914, consisting of 38 pages; Exhibit Staff/915, consisting of 11 pages; Exhibit Staff/916, consisting of 18 pages; Exhibit Staff/917, consisting of one page; Exhibit Staff/918, consisting of 17 pages; Exhibit Staff/919, consisting of one page; Exhibit Staff/920, consisting of 33 pages; Exhibit Staff/921, consisting of 12 pages; Exhibit Staff/922, consisting of 50 pages; Exhibit Staff/923, consisting of 11 pages; and Exhibit Staff/924, consisting of three pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

A. A summary of recommendations;

B. A brief discussion of return and risk associated with investments in common equity;

C. A discussion of my cost of equity estimation, including the Discounted Cash Flow (DCF) models used, comparable companies used, inputs and sensitivities, and the implications of differing capital structures;

D. A short discussion of PGE's proposed capital structure;

E. A discussion of PGE's DCF models and associated PGE-recommended rates of return on common equity;[2]

F. A discussion of other methods used by PGE to estimate the Company's cost of equity capital;

G. A short discussion regarding PGE's risks; and

H. A brief discussion of certain aspects of PGE's Sales Normalization Adjustment (SNA) decoupling mechanism.

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[2] Reference to "common equity" and "equity" within this portion of testimony are meant to be synonymous. Where reference to some other form of equity is intended, the form will be specified. Similarly, the terms "common stock" and "stock" within this portion of testimony are used synonymously and are equivalent to "common equity" and "equity."

SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. Table 1 (following) illustrates returns on long-term debt and common stock; as well as capital structure; as currently authorized, as proposed in PGE's direct testimony, and as recommended in this testimony.

Table 1

PGE Capital Structure and Component Returns

Currently Authorized (UE-197)

		Percent of Total	Authorized Return	Weighted Average
Component				
Long Term Debt		50.00%	6.567%	3.097%
Preferred Stock				
Common Stock[3]		50.00%	10.000%	5.000%
	Total	100.00%		8.284%

PGE Proposed (UE-215)

		Percent of Total	Authorized Return	Weighted Average
Component				
Long Term Debt		50.00%	6.077%	3.039%
Preferred Stock				
Common Stock		50.00%	10.500%	5.250%
	Total	100.00%		8.289%

Staff Recommended (UE-215)

		Percent of Total	Authorized Return	Weighted Average
Component				
Long Term Debt		50.00%	6.071%	3.036%
Preferred Stock				
Common Stock		50.00%	9.200%	4.600%
	Total	100.00%		7.636%

[3] The currently authorized ROE of 10.0 percent includes a 10 basis point reduction associated with PGE's SNA (decoupling) and LRR (Lost Revenue Recovery) mechanisms.

I recommend a range of return on equity of 8.7 to 9.6 percent, with a point estimate of 9.2 percent,[4] both associated with a capital structure as proposed by PGE;[5] i.e., 50 percent long-term debt and 50 percent common stock. This results in a recommended rate of return, when combined with Staff's recommendations[6] for the cost of long-term debt, of 7.59 percent. The 9.2 percent ROE recommended for PGE meets the *Hope* and *Bluefield* standards, as well as those established by Oregon Revised Statue (ORS) 756.040. This level of authorized return on equity for PGE supports establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[7]

I recommend the Commission continue to associate a no less than 10 basis point reduction in ROE with PGE's SNA and LRR mechanisms.[8]

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4 Both the recommended range and recommended point estimate include a 10 basis point reduction in ROE associated with PGE's SNA decoupling and LRR revenue recovery mechanisms. Neither the range nor the point estimate reflects any changes from the current PGE PCAM; i.e., they assume no change to the PCAM.

5 *See* PGE/1100 Hager - Valach/25.

6 *See* Staff/1000 Ordonez for Staff's recommended costs of long-term debt.

7 *See* ORS 756.040(1)(a) and (b).

8 Although the recommended 9.2 percent point estimate of ROE is inclusive of a 10 basis point downward adjustment associated with reduced risk with PGE's decoupling and lost revenue recovery mechanisms, a future discontinuance of the mechanisms would argue for an ROE point estimate of 9.3 percent.

Additionally, I propose modest changes in the SNA mechanism for consideration by parties to this proceeding.

RISKS AND RETURNS OF COMMON EQUITY INVESTMENTS

Q. WHAT DOES "RISK" MEAN WITH RESPECT TO COMMON EQUITY INVESTMENTS?

A. The literature of finance[9] typically defines risk as the variability in outcomes, where outcomes are divergent investor returns[10] over some holding period when compared with an *a priori* expected return for the asset held over a like period. Risk has two aspects: unique risk and market risk. Unique risk is applicable only to the common stock of a specific company;[11] i.e., "unique" to that company. "Unsystematic risk," "idiosyncratic risk," and "diversifiable risk" are other terms by which the concept of unique risk is known. Unique risk can potentially be eliminated by the addition of diversifying investments[12] to an investment portfolio. As emphasized by the authors of a widely used corporate finance textbook,[13] "the risk of a well-diversified portfolio

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9 This discussion follows that in Brealey and Myers, *op. cit*., especially that on page 132ff.

10 Investor returns are total returns; i.e., those resulting from dividends received as well as from realized gains or losses due to security price changes.

11 I recognize companies can and do have different classes of common stocks, typically differing in voting rights.

12 A diversifying investment in this context is one whose returns are imperfectly correlated with the portfolio as a whole.

13 Brealey and Myers, *op. cit.*, page 134.

depends on the market risk of the securities included in the portfolio" (emphasis added).

Q. HOW IS THE MARKET RISK OF AN INDIVIDUAL STOCK MEASURED?

A. The market risk[14] of an individual stock,[15] in a well-diversified portfolio, is the sensitivity of the stock's return to those of the stock market as a whole. This measure of sensitivity is termed "beta" and is typically represented by the Greek letter β, or beta.[16]

Q. WHAT IS A "WELL-DIVERSIFIED PORTFOLIO?"

A. A well-diversified stock portfolio is one whose dispersion of actual returns, measured by standard deviation, approaches that of the stock market as a whole. The stock market as a whole, by the standard

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[14] Market risk is also known by the terms "systematic risk" and "undiversifiable risk."

[15] In the current context "stock" refers to common stock and "stock market" refers to the market or markets for such common stocks.

[16] The beta (β) of an asset or portfolio is a number describing the relation of its returns with that of the market as a whole. An asset with a beta of zero (0) means that its returns are not at all correlated with the market; the returns of the asset are independent from those of the market. A positive beta means that the asset's returns generally follow those of the market. A negative beta shows that the asset's returns inversely follow those of the market; the asset generally decreases in value if the market goes up and vice versa.

The formula for the beta of an asset within a portfolio is

$$\beta_a = \frac{\mathrm{Cov}(r_a, r_p)}{\mathrm{Var}(r_p)},$$

where r_a measures the rate of return of the asset, r_p measures the rate of return of the portfolio, and $\mathrm{Cov}(r_a,r_p)$ is the covariance between the rates of return. In the Capital Asset Pricing Model (CAPM) formulation, the portfolio is the market portfolio that contains all risky assets, and so the r_p terms in the formula are replaced by r_m, the rate of return of the market.

Beta is also referred to as financial elasticity or correlated relative volatility, and can be thought of as a measure of the sensitivity of the asset's returns to market returns, and the asset's non-diversifiable risk (or systematic risk or market risk).

definition, has a beta of 1.0, so a well-diversified portfolio also has a beta of 1.0 (or very nearly so). If returns of a stock portfolio are perfectly (and positively) correlated[17] with the stock market as a whole, the portfolio has a beta of exactly 1.0. Additionally, since the market beta is 1.0, the beta of the "average" stock is 1.0.

Q. HOW, WITHIN THE CONSTRUCT OF A WELL-DIVERSIFIED PORTFOLIO, ARE RISK AND RETURN RELATED?

A. The answer to this question forms a good deal of that part of finance theory concerned with investments.[18] A basic conclusion is that investments with higher undiversifiable risks require, in well-functioning capital markets, a higher *a priori* expected rate of return than do investments having lower undiversifiable risks.

Q. WHY IS THE RELATIONSHIP BETWEEN RISK AND RETURN IMPORTANT TO CONSIDER WHEN ESTABLISHING AN AUTHORIZED RETURN ON EQUITY FOR A RATE OF RETURN REGULATED UTILITY?

A. Understanding this relationship serves to define boundaries around a fair rate of return on common equity for utilities operating under one or

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[17] Perfectly (and positively) correlated means the correlation coefficient (a statistical measure) between portfolio returns and market returns is +1.0.

[18] A working definition of investment theory might be that it is the body of knowledge used to support the decision-making process of choosing investments for various purposes. Topics included are portfolio theory, a variety of asset pricing models, and the efficient market hypothesis.

more rate of return regulatory regimes. The average annual return,[19] including dividends, of Standard & Poor's S&P 500 index[20] from 1926 through 2000 was 10.7 percent.[21] This index has performed less well since 2000, as implied by the following quote from Standard & Poor's:

> "From January 1926 through March 2009 the annualized total return for the S&P 500 was 9.51% per year vs. 9.69% for December 2008. The dividend component consists of 44.00% of the return vs. 43.27% for December 2008. The annualized return consists of both capital appreciation and dividends reinvested."[22, 23]

Assuming the S&P 500 index is an adequate representation of the U.S. stock market,[24] the average beta of stocks in the index is

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19 Average annual returns cited in my testimony, unless otherwise specified, are of the geometric mean construction.

20 The S&P 500 is a market capitalization-weighted index of 500 large companies and is often used as a proxy for the entire U.S. stock market. *See* the S&P 500 fact sheet at http://www2.standardandpoors.com/spf/pdf/index/SP_500_Factsheet.pdf .

21 *See* in Exhibit Staff/902 a prepublication version of Roger Ibbotson's "Stock Market Returns in the Long Run: Participating in the Real Economy," page 4. The 10.7 percent annual average total return was calculated on a geometric basis. *See* also "Long-Run Stock Returns: Participating in the Real Economy," by R. Ibbotson and P. Chen, *Financial Analysts Journal*, January/February 2003, Vol. 59, No. 1: pages 70 – 87.

22 From the Standard & Poor's website at http://www2.standardandpoors.com/portal/site/sp/kr/kr/page.topic/indices_500anniv/2,3,2,2,0,0,0,0,0,4,4,0,0,0,0,0.html .

23 *See* also Exhibit Staff/903, where the annual average total return of "large company stocks" over the period 1926 – 2008 on a geometric basis is 9.6 percent.This information was provided with PGE's response to Staff data request number 45.

24 Stocks in the S&P 500 index account for approximately 75 percent of the U.S. equity market's total value. *See* http://www2.standardandpoors.com/spf/pdf/index/SP_500_Factsheet.pdf .

(positive) 1.0. Beta values[25] from Value Line's *Investment Survey* (Value Line) for companies in both my and PGE's groups of comparable companies[26] average less than 1.0, at 0.69 and 0.71,[27,28,29] respectively. This indicates the comparable companies, whether mine or PGE's, on average have materially less market risk than the stock market as a whole.[30,31] A logical conclusion is that a forward-looking long-term fair rate of return on equity (ROE), all else

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25 Per Value Line at http://www.valueline.com/sup_glossb.html , Value Line betas are based on "the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index." Notably, composition of the NYSE Composite Index is approximately 83% U.S. companies; i.e., a material portion of the index consists of non-U.S. stocks. This index has, as of May 7, 2010, 1,519 U.S. companies. *See* http://www.nyse.com/about/listed/nya_characteristics.shtml . Per Bloomberg at http://www.bloomberg.com/apps/quote?ticker=NYA:IND , the NYSE Composite Index "encompasses 61% of the total market capitalization of all publicly traded companies around the world."

26 I use the terms "comparable companies," "peer companies," and "cohort companies" synonymously in this testimony. A discussion of my group of comparable companies and a brief discussion regarding certain attributes of PGE's group of comparable companies are presented later in this testimony.

27 These are the mean values of each group of comparable companies. Median values are 0.70 for each of the two groups of companies.

28 Beta values for Northwestern Corp. of PGE's cohort group were not available to include in calculating either the mean or median values for PGE's group of comparable companies. Value Line's September, 25, 2009 report, provided with PGE's response to Staff data request number 45, lists this company's beta as "NMF," or "not meaningful;" presumably related to Value Line's lack of provided information for the company prior to 2005.

29 Note that PGE, included in PGE's group of comparable companies, has a beta of 0.75, or slightly higher than the average for either group. Note also that PGE's beta is less than the market as a whole and therefore less than that of the average stock. These relative beta values imply the following: investors view PGE as less risky than the market as a whole and less risky than the average stock.

30 More precisely, they have, on average, materially less risk than the stocks comprising the New York Stock Exchange (NYSE).Composite Index.

31 All companies in both my and PGE's lists of comparable companies are in the NYSE Composite Index with the exception of MGE Energy, Inc., which trades on the NASDAQ.

being equal,[32] is less than the historical (1926 forward) annual average return, including dividends, of the S&P 500 index. This would seem to hold whether the historical rate of return on the index is the 10.7 percent annual average rate from 1926 through 2000 or the lower (than 10.7 percent) annual average rate from 1926 through the more recent past; e.g., 9.5 percent through March, 2009.[33] Less risk implies a lower expected return on equity required by investors.[34]

STAFF'S COST OF EQUITY ANALYSIS

Q. DID YOU USE VALUES FROM COMPARABLE COMPANIES TO ESTIMATE PGE'S COST OF EQUITY?

A. Yes. I selected a group of peer companies by starting with the 54 electric utilities covered by Value Line. I applied the screening criteria sequentially,[35] reducing the 54 companies to a 13 company cohort group. My criteria, in addition to coverage by Value Line, were:

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32 Implications of relaxing certain *ceteris paribus* assumptions, such as that pertaining to capital structure, are discussed later in this testimony.

33 March, 2009 included the lowest closing price of the S&P 500 stock index in the decade 2000 through 2009, inclusive.

34 The combination of rational investors and efficient capital markets imply risk associated with PGE's unique, or diversifiable, risk has been eliminated by investors holding diversified portfolios, with PGE's stock price reflecting this diversification from PGE's unique risks. The remaining risk, that of PGE stock's market risk, is evaluated by investors to be a) slightly higher than the average utility in either mine or PGE's group of comparable companies and b) materially less (beta of 0.75 vs. 1.00 for the average stock) than the average company's common stock.

35 Data used for screening companies included both year-end 2008 and year-end 2009 data.

1. Value Line estimated 2010 long-term debt between 45% and 55% of capital structure;
2. No dividend decline in the prior five years;[36]
3. Value Line forecast of a dividend growth rate ≥ 0%;
4. S&P Issuer credit rating between BB+[37] and BBB+ (inclusive);
5. Regulated assets equal or exceed 80% of total assets;[38] and
6. No merger or acquisition activity within the past five years.

Table 2 (following) lists the 13 companies I found to be comparable to PGE as well as those companies PGE found "comparable."

Q. WHAT TYPES OF MODELS DID YOU USE TO DEVELOP STAFF'S RECOMMENDED RETURN ON EQUITY FOR PGE?

A. I relied primarily on two different multistage discounted cash flow models[39,40] for estimating the expected return on common equity required by PGE's investors.

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[36] This criterion eliminates companies that, within the past five years, have reduced or eliminated dividends. Dividend growth rates for such companies, including companies re-establishing dividend payments previously eliminated, may be uncharacteristically high, even "exceptionally high." *See*, in Docket No. UE 147, PPL/200 Hadaway/14 beginning at 16.

[37] Any companies having the BB+ S&P Issuer rating were removed by preceding screening criteria; i.e., there are no companies with an issuer rating of BB+ in my group of comparable companies.

[38] *See* Edison Electric Institute's *2008 Financial Review*, pages 25-26

[39] *See* Exhibit Staff/904 for the mathematical expressions of these multistage DCF models.

[40] *See* the Commission's discussion of multistage versus single stage DCF models in Order No. 01-777, page 27.

Table 2

Companies Comparable to PGE

	Ticker	Staff's List	PGE's List
Allegheny Energy Inc.	AYE		✓
ALLETE Inc.	ALE	✓	✓
Alliant Energy Corp.	LNT		✓
Ameren Corp.	AEE		✓
American Electric Power Co.	AEP	✓	✓
Avista Corp.	AVA		✓
Cleco Corp.	CNL	✓	✓
CMS Energy Corp.	CMS		✓
DPL Inc.	DPL		✓
DTE Energy Co.	DTE		✓
Duke Energy Corp.	DUK		✓
Edison International	EIX		✓
Empire District Electric Co.	EDE	✓	✓
Entergy Corp.	ETR		✓
FPL Group Inc.	FPL		✓
Great Plains Energy Co.	GXP		✓
Hawaiian Electric Industries	HE		✓
IDACORP, Inc.	IDA	✓	✓
MGE Energy Inc.	MGEE		✓
NorthWestern Corp.	NWE		✓
OGE Energy Corp.	OGE		✓
PG&E Corp.	PCG	✓	✓
Pinnacle West	PNW	✓	✓
Portland General Electric	POR		✓
Progress Energy Inc.	PGN	✓	✓
Southern Co.	SO		✓
TECO Energy, Inc.	TE	✓	✓
UIL Holdings	UIL	✓	
UniSource Energy	UNS		✓
Westar Energy Inc.	WR	✓	✓
Wisconsin Energy Corporation	WEC	✓	✓
Xcel Energy, Inc	XEL	✓	✓
Total		13	31

Q. WHAT IS A DISCOUNTED CASH FLOW MODEL?

A. A discounted cash flow, or DCF, model estimates the rate of return for an investment using cash flows over a suitable valuation timeframe.[41] As used in return on equity studies, a DCF model provides an estimate of the expected annual rate of return investors require on a specific investment before they will invest.

The "cash flow" portion of these models refers to the assumption that an investor cares about the amounts and timing of money they pay or receive associated with, say, their investing in a company's stock. Note that the cash flows are those going to and coming from the investor, not to and from the company; i.e., the investor directly cares about cash flows he or she will experience and only indirectly about cash flows the company will experience. The typical pattern of cash flows used in DCF models can be characterized as: a) a cash outflow from the investor, as the investment is made; b) multiple cash inflows over time to the investor, as the company pays cash dividends; and c) a "terminal" cash flow to the investor, occurring at that time in the future when the stock is sold.[42] In a corporate structure,[43] dividends

[41] Technically referred to as the internal rate of return (IRR), the discount rate that results in an NPV [Net Present Value] of $0 is the rate of return. *See* Brealey and Myers, *op. cit.*, page 78.

[42] I refer to this class of DCF models as having a terminal valuation "stage."

[43] Limited partnerships and REITs are two examples of structures which may differ from this. *See* FERC Opinion 486-B, in Exhibit Staff/905 for a discussion of Master Limited Partnerships in proxy groups of oil and natural gas pipeline firms for use in determining ROE.

paid to the investor represent returns on capital[44] and the proceeds from selling the stock in the future represents an additional return on investment and the return of investment.[45]

The term "discount" refers to the assumption that investors have a positive time preference; i.e., all else being equal, an investor prefers receiving a dollar today over receiving a dollar in a future period. Therefore, to reflect this time preference, future cash flows are discounted by some factor and the further into the future a cash flow takes place, the greater the numerical value by which it is discounted.

The "result" of analysis using a DCF model is the rate at which future periodic[46] cash inflows to the investor are discounted such that they equal, in total, the current cash outflow, which is the price paid by the investor for the stock.[47] In other words, the rate resulting from a DCF model is the rate which, when used to discount future cash flows, equates the present value of future (net) cash inflows with the (negative of[48] the) current cash outflow.

Q. PLEASE DESCRIBE EACH OF THESE TWO DCF MODELS.

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44 The reference here is to normal dividends; i.e., not special dividends. One definition of special dividends is non-recurring distribution of company assets, usually in the form of cash, to shareholders. A special dividend is a non-recurring distribution of company assets, usually in the form of cash, to shareholders. They are typically larger in comparison with normal dividends paid out by the company.

45 This assumes that the cash received for selling the stock is more than was paid for it.

46 And the terminal cash flow, if applicable.

47 *See*, for example, the discussion on this in Brealey and Meyers, *op. cit.*, pages 77 - 78.

48 "Negative of" as, to the investor, the present value of future cash flows is positive—a net inflow—while the initial cash transaction is an outflow, or "negative cash flow."

The first model is a three-stage DCF model requiring the following values as inputs: a “current” market price per share of common stock; estimates of dividends per share[49] for years 2010 through 2015; an annual rate of dividend growth over the 2016 through 2020 period, and a long-term sustainable growth rate.[50] The three stages of the model refer to the 2010 through 2015 period (Stage 1), where I use Value Line forecasts of dividends per share; the 2016 through 2020 period (Stage 2), where I incorporate forecasts of nominal GDP, and the 2021 through 2159 period (Stage 3), which is the long-term sustained growth period. This DCF model has a 150 year valuation timeframe.

The “current” market price used for the analysis was the average of the closing prices for each comparable company (see Table 2) on three consecutive Tuesdays this spring: the 30th of March and the 6th and 13th of April.

Stages one and two of my second multistage[51] DCF model are identical with that of the first DCF model discussed, but the third, long-term sustainable growth stage is limited to the period 2021 through

[49] The price per share and estimated dividends per share are different for each of the comparable companies. The long-term sustainable growth rate is common across the comparable companies.

[50] This multistage DCF model directly applies the long-term growth estimate to dividends per share over the 2021 through 2159 period. Dividends per share for the 2010 through 2015 period are based on information supplied by Value Line.

[51] This DCF model might also be described as a three-stage model with a terminal valuation.

2049. This multistage DCF model has a 40 year valuation timeframe and is augmented with a terminal valuation in 2049 (Stage 4).[52].

Q. HOW ARE STOCK PRICES AND DIVIDENDS OBTAINED FROM VALUE LINE FOR THE COMPARABLE COMPANIES USED IN YOUR MULTISTAGE DCF MODELS?

A. I develop an explicit estimate of the investor-required rate of return for each comparable company. From these individual estimates for each of the comparable companies, I calculate both mean and median ROE values for assessment.

Q. DO YOUR MULTISTAGE DCF ANALYSES PRODUCE A RANGE OF RETURNS ON EQUITY?

A. Yes. Depending on the rate of long-term sustainable growth used, the models produce a range of ROE estimates, including my recommended range of ROE for Commission consideration of 8.7 percent to 9.6 percent. Notably, using values for each company in PGE's group of comparable companies[53] in either of my multistage DCF models,[54] with the same method and timing for calculating current stock prices as used for my group of comparable companies, the same

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52 The terminal valuation produces an explicit estimation of the stock price, which is then "sold," producing the terminal "cash flow." This involves calculating the value of a growing perpetuity as of the period in which the investment is sold and discounting this value to the initial period. *See* Brealey and Myers, *op. cit.,* pages 32 – 33.

53 NorthWestern Corp. was not used in my analysis of PGE's list of comparable companies, as Value Line information is reported somewhat differently for this firm.

54 Twelve of the 31 companies in PGE's group of comparable companies appear in my group of comparable companies; i.e., 12 of my 13 comparable companies are in PGE's group as well. *See* Table 2.

estimates of future dividends, and the same long-term sustainable growth rate, produced approximately the same ROE estimates as did my group of comparable companies. Alternatively stated, using 30 or the 31 comparable companies used by PGE in my multistage DCF models provided approximately the same ROE estimates as did my 13 comparable companies.

Somewhat similarly, there were minimal differences in results between using the 40-year valuation horizon with terminal value DCF model and using the 150-year valuation horizon DCF model.

Q. WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A. I conclude that differences in valuation horizon[55] and selection of comparable companies[56] are not responsible for any material differences in estimates of investors' required return on equity.

Q. GIVEN THIS RESULT OF COMPARABLE COMPANY ANALYSIS, WHAT ARE, IN THIS PROCEEDING, THE IMPORTANT CONSIDERATIONS IN YOUR MULTISTAGE DCF MODELS?

A. One important consideration is the methodology for developing estimates of dollar values of dividends per share for Stage One

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55 That is, the difference between my 40-year valuation horizon with terminal valuation in year 2049 multistage DCF model and my 150-year valuation horizon through year 2159 multistage DCF model.

56 My conclusion as to the group of comparable companies is qualified in that it is based on these two specific groups of comparable companies. Other groups of comparable companies could be selected that would not necessarily support this same conclusion. Additionally, my conclusion is qualified by being limited to results obtained using the specific input parameters of estimated dividends and current stock price.

periods; i.e., for the years 2011 through 2015. These are the estimated per share cash flows to investors over this period. As clarified by Roger Morin in his *New Regulatory Finance* textbook, “DCF theory states clearly that it is the expected future cash flows in the form of dividends that constitute investment value.”[57]

Q. YOU STATED YOU OBTAINED SUCH VALUES FROM VALUE LINE. WHAT ADDITIONAL DEVELOPMENT WAS REQUIRED?

A. Value Line’s *Investment Survey* provides the annual dollar value of dividends per share, including at this time forecasts for 2010 and, for most of my comparable companies, 2011. Due to the “rolling update” over three issues of coverage for electric utilities, Value Line has not yet provided dollar value estimates of dividends per share for 2011 for four companies.[58]

Additionally, Value Line provides information useful in developing dollar value estimates of future dividends per share for years other than 2010 and 2011. This information includes an estimate of an average for the dollar value of dividends paid over the three-year period of 2013-15[59] and an estimate of the annual rate of change in the

[57] Page 284; emphasis added.

[58] The exceptions are the companies covered in the “western” edition; i.e., IDACORP, PG&E, Pinnacle West, and Xcel.

[59] For the current “exception” utilities, the average for 2012 – 2014 is provided by Value Line.

dollar value of dividends per share from a base period of 2007-09[60] through 2013-15.[61]

In summary, for my comparable companies at this time, Value Line has provided estimated dollar values of dividends per share for 2010 (all companies), 2011 (some companies), and the estimated average dollar value of dividends per share for the period 2013-15 (or, for three companies, the period 2012-14).

Q. HOW THEN DID YOU DERIVE DOLLAR VALUES OF DIVIDENDS FOR 2011 (FOR SOME COMPANIES), AND 2012 THROUGH 2015 (FOR ALL COMPANIES)?

A. First, I assumed the average value for a period of three future years was the value for the middle year; e.g., I considered Value Line's estimated average dollar value of dividends per share for the period 2013-15 to be the estimated dollar value for 2014. Next, for extrapolated estimates, I used the supplied average annual rate of change to "grow" the dollar value[62] of dividends per share from the

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60 For five companies. For four other companies, the estimates through 2013-15 are from a base period of 2006-08.

61 For the current "exception" utilities, the respective periods are base years 2006-08 and through 2012-14. Additionally, this estimated rate of annual change uses a base period of 2006-08 and is applicable to 2013-15 for Cleco, Progress Energy, TECO Energy, and UIL.

62 Recall the screening criteria of a Value Line non-negative estimated growth rate in dividends.

provided estimate for the "middle" year to the subsequent year, and, where necessary, to the following year (2015).[63]

Given that Value Line provided estimates of the dollar values of dividends per share for 2010 or both 2010 and 2011, and that the dollar values of dividends per share for either 2014 (or 2013[64]) were also provided by Value Line, estimated dollar values of dividends per share for 2012 and 2013 (or 2011 and 2012) were interpolated from these two values on the basis of a geometric progression. In other words, the same annual growth rate was used to estimate values for each of the two years by interpolation.[65]

Q. WHAT IS ANOTHER IMPORTANT CONSIDERATION IN DEVELOPING MULTISTAGE DCF MODELS?

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63 Dollar values for the following year (2015) were estimated for the four current "exception" companies in this manner. For these four companies, the same annual rate of change estimate was applied to the result obtained for year 2014, which for these companies is the year subsequent to the middle year. This resulted in an estimated dollar value per share for these companies that was increased at a compounded rate. In other words, the dollar values of estimated dividends for these companies were established on the basis of a geometric progression, rather than on the basis of an arithmetic progression. This approach is congruent with the manner in which growth rates are used throughout my testimony, unless specified otherwise.

64 Again, for the current "exception" companies, the estimate values were for both 2014 and 2015.

65 As a perhaps more illustrative example, when given the value for the initial year, the value for the first intervening year was calculated by multiplying the given value by 1+g, where "g" is the annual rate of growth on a geometric basis between the values of the initial year and the value for the next directly supplied by Value Line (the "middle" year of 2012-14 or 2013-15). The value for the second intervening year was calculated by multiplying the value of the first intervening year by the same 1+g factor.

A. An important consideration is how to choose or develop the long-term sustainable growth rate[66] used for estimating annual dividends (investor "cash flows") after 2015 and through the end of the valuation horizon for each of the two models.

Q. HOW DID YOU DEVELOP AN APPROPRIATE LONG-TERM SUSTAINABLE GROWTH RATE?

A. First, as I had dividend estimates for 2010 through 2015 from information supplied by Value Line, a growth rate or rates applicable to dividend payouts was needed only for years subsequent to 2015. I considered alternative approaches to estimating a long-term sustainable growth rate for dividends. First, I examined historical dividends per share growth rates for the cohort group of companies. For all but three of my comparable companies, dividend per share data from Value Line was available for 1994 forward. These 10 companies, on average, experienced an average annual compound growth rate in dividends per share of 0.2 percent. This average included the negative average growth rates[67] for IDACORP (negative 2.7 percent annually),

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[66] This conclusion has been reached before. *See*, in Docket No. UE 179, Staff/800 Morgan/4 at 16: "…the main driver of the differences in DCF results are related to the input assumptions related to growth rates…"

[67] The dollar value of IDACORP's dividends per share on an annual basis declined from $1.86 in 2002 to $1.20 in 2004. The dollar value of TECO Energy's dividends per share on an annual basis declined from $1.41 in 2002 to $0.76 in 2004. The dollar value of Westar Energy's dividends per share on an annual basis declined from $2.14 in 1999 to $0.80 in 2004. The decline in dividends per share for these three companies cannot be attributed solely to a greater number of common shares outstanding, as the largest annual increase in common shares outstanding over this timeframe for each company was: +10% for IDACORP, +6% for TECO Energy, and +18% for Westar Energy; with each of these increases occurring in 2004.

TECO Energy, Inc. (negative 1.4 percent annually), and Westar Energy, Inc. (negative 2.9 percent annually). I concluded growth rates, with or without inclusion of those companies having a negative growth rate in dividends over this period, were too low for credible use as the long-term sustainable growth rate.

As multiple organizations have provided GDP projections for the intermediate term,[68] I developed the sustainable long-term growth rate as two stages: 2016 through 2020 and 2021 forward, using different approaches for each period.

I considered several different longer-term GDP forecasts for use in estimating a growth rate for the 2016 through 2020 period, including forecasts from the White House Office of Management and Budget (OMB),[69] the Congressional Budget Office (CBO),[70] the Energy Information Administration (EIA),[71] the Federal Reserve,[72] and the Blue

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68 These typically covered several consecutive years between 2012 and 2020.

69 *See* OMB's Analytical Perspectives – Economic and Budget Analyses, Table 2-1, on page 13 of the document. This is attached as Exhibit Staff/906.

70 *See* CBO's "The Budget and Economic Outlook: Fiscal Years 2010 to 2020," January 2010, Summary Table 2. This is attached as Exhibit Staff/907.

71 *See* Table 20 "Macroeconomic Indicators," associated with EIA's Annual Energy Outlook 2010 Early Release (reference case; released December 14, 2009), and available at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html . The Introduction and Macroeconomic Activity Module of EIA's "Assumptions to the Annual Energy Outlook 2010 with Projections to 2035" comprise Exhibit Staff/908.

72 *See* Table 1 on page 1 of the Summary of Economic Projections from the "Minutes of the Federal Open Market Committee" (FOMC), January 26-27, 2010, attached as Exhibit Staff/909.

Chip Financial Forecast (Blue Chip).[73] After some development, I used an average of four organizations' forecasts of nominal GDP for the period 2016-20 as a base for my growth rate of dividends over this period. These are shown in Table 3 (following).

[73] *See* page 14 "Long Range Forecasts" from the December 1, 2009 *Blue Chip Financial Forecasts*, included with PGE's response to Staff data request 45. This page is included in Exhibit Staff/903.

Table 3

Nominal GDP Growth 2016-20

Organization	Annual Average Growth Rate
OMB[74]	4.59%
EIA[75]	4.93%
Federal Reserve (FOMC)[76]	4.50%
Blue Chip Financial Forecast[77]	4.96%
Average	4.75%

The CBO forecast was not used, as CBO's 4.1 percent annual growth rate for nominal GDP over the 2016-20 period was approximately 60 basis points under the average of the other four

[74] OMB's forecasted rate is on a geometric basis. *See also* the discussion of "longer-term growth" at pages 14-15 of the OMB document in Exhibit Staff/906.

[75] Obtaining EIA's rate of nominal GDP growth required multiplying the forecast real GDP values by the forecast values of the GDP Price Index. As a compound annual growth rate was calculated, the year in which the index had value 1 was not relevant. The calculated EIA growth rate is on a geometric basis.

[76] I used the midpoint of the 2.4% to 3.0% range of the FOMC's forecast of an annual growth rate for real GDP for the "longer run." In context it is clear that this is the range of the annual rate to apply to multiple years subsequent to 2012. I multiplied this rate by the midpoint of the 1.5% to 2.0% range of the FOMC's forecast of the annual rate of change in the Personal Consumption Expenditures index. I believe any distortion introduced by using forecast values for a consumer price index versus a (not available) Federal Reserve forecast of the GDP Price Index to be more than offset by the increased robustness resulting from the use of another independent forecast. *See* also the discussion on pages 1 and 3 of the Summary of Economic Projections, including on the latter page the statement "participants generally anticipated that real GDP would converge over time to an annual rate of 2.5 to 2.8 percent, the longer-run pace that appeared to be sustainable in view of the expected demographic trends and improvements in labor productivity" (from the Summary of Economic Projections from the "Minutes of the Federal Open Market Committee" (FOMC), January 26-27, 2010, attached as Exhibit Staff/909). I presume all of the FOMC's forecast growth and inflation rates to be on an arithmetical basis.

[77] Obtaining Blue Chip's rate of nominal GDP growth over the period required multiplying (1+) the forecast for 2016-20 five year average annual rate of change in real GDP by (1+) the annual rate of change in the GDP Price Index over this same period. I presume Blue Chip's forecast rates are on an arithmetic basis.

forecasts.[78] Additionally, I omitted the CBO forecast based in part on the following:

> "In its August 2009 projections (the most recent available) the Congressional Budget Office (CBO) projected long-run growth of 2.2 percent per year.[79] Most of the difference between the Administration and CBO's long-run growth comes from a difference in the expected rate of growth of the labor force. Both forecasts assume that the labor force will grow more slowly than in the past because of population aging, but the Administration bases its population projections on the Census Bureau's projections, which tend to run higher than the CBO projections. The Administration also believes that labor force participation could be somewhat stronger in the future. The net difference in the two forecasts is only a few tenths of a percentage point.[80] All economic forecasts are subject to error, and the forecast errors are usually much larger than the forecast differences discussed above. As discussed in chapter three, past forecast errors among the Administration,[81] CBO, and the Blue Chip have been similar."[82]

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[78] After due consideration of the traditional admonishment to "examine your outliers."

[79] CBO's updated 2016-20 forecast increased the real GDP growth rate from the 2.2 percent annual rate to 2.3 percent. See Summary Table 1 of CBO's "The Budget and Economic Outlook: Fiscal Years 2010 to 2020;" January 2010; in Exhibit Staff/907. I derived the 2.3% value from the GDP values at the bottom of this table.

[80] Actually, close to one-half of a percentage point (4.59% - 4.12% = 0.47%) on a nominal basis over the 2016-20 period.

[81] The "Administration" reference is to the federal budget document produced by OMB. *See* page 22 of OMB's "Analytical Perspectives…," *op. cit.*

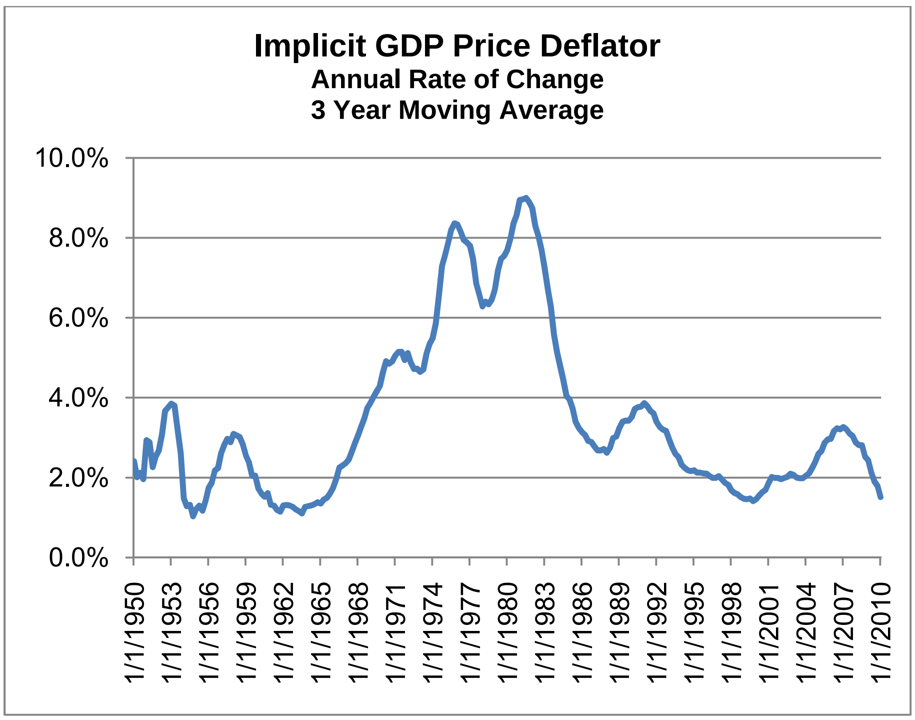
[82] OMB's "Analytical Perspectives…," *op. cit.*, page 16.

Averaging the remaining four forecasts yielded an average annual growth rate for nominal GDP of 4.75 percent over the 2016-20 period.

Q. HOW DID YOU ESTIMATE A GROWTH RATE IN NOMINAL GDP FOR YEARS BEYOND 2020?

A. As can be seen in Figure 1 (following), the rate of inflation[83] since 1947 increased dramatically beginning in the late 1960s and had a dramatic decline in the 1980s.

Figure 1



[83] As measured by the GDP Implicit Price Deflator and expressed in Figure 1 using a three-year moving average of annual rates of change in this index. Data supporting this chart is available from the Federal Reserve at http://research.stlouisfed.org/fred2/series/GDPDEF/downloaddata?cid=21 .

For this reason, a more methodologically appealing approach is to use an historical growth rate in real GDP and appliqué an independently developed estimate of future inflation.

I reviewed real GDP growth rates for a variety of periods. The growth rates for certain periods are presented in Table 4 (following). Due to the oil price shocks in the 1970s,[84] and the ensuing "stagflation," I chose 1980 through 2007 as the period most applicable for estimating future growth in real GDP.[85,86]

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[84] *See* Pierre Perron's discussion of the impact of the 1973 oil price "shock" on the change in the trend rate of real GNP growth, including the observation that "…after that [1973] date, the slope of the trend function has sensibly decreased. This phenomenon is consistent with the much discussed slowdown in the growth rate of real GNP since the mid-seventies;" on page 1382 of "The Great Crash, the Oil Price Shock, and the Unit Root Hypothesis'" in *Econometrica*, Vol. 57, No. 6 (November,1989). I have attached this article as Exhibit Staff/910.

[85] I chose this period in part due to both the beginning year (1980) and ending year (2007) containing business cycle peaks as defined by the Business Cycle Dating Committee of the National Bureau of Economic Research (NBER) *See* at http://www.nber.org/cycles/cyclesmain.html .

[86] Note that no statistical tests were conducted on this or any other period's values of real GDP.

Table 4

U.S. Real Gross Domestic Product

Historical Period	Annual Average Real GDP Growth[87]
1959 – 2008	3.3%
1969 – 2008	2.9%
1979 – 2008	2.8%
1989 – 2008	2.8%
1999 – 2008	2.6%

Source: Federal Reserve

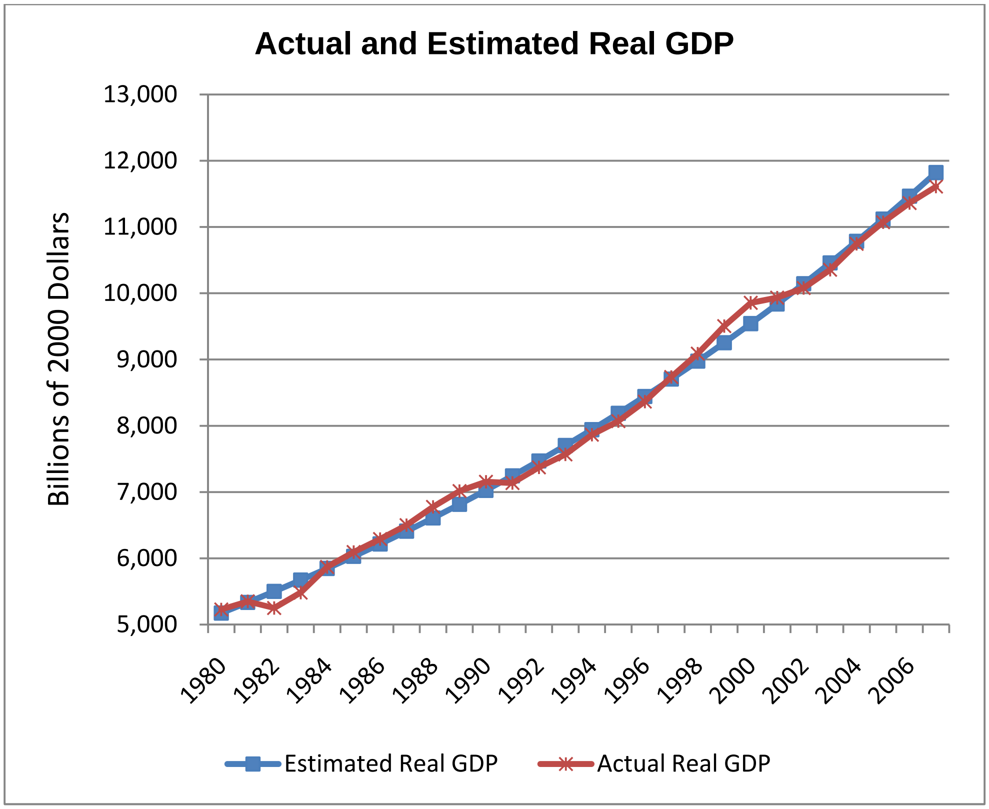
An ordinary least squares (OLS) regression of the natural logarithm of annual values of real GDP over the period 1980 through 2007[88] provided a compound annual growth rate for real GDP over the period of 3.06 percent. Figure 2 (following) plots actual versus estimated values of real GDP using this rate of growth over the 1980 through 2007 period.[89]

[87] These rates are compound annual growth rates; i.e., the growth rate at which the beginning value, when annually compounded over the respective period by the growth rate, equals the value at the end of the period,

[88] That is to say, the natural logarithms of annual values of real GDP were regressed against values for time; i.e., a semi-log regression model.

[89] *See* John Cochrane's "How Big is the Random Walk in GNP" from the October, 1988 *Journal of Political Economy* in Exhibit Staff/911 for an assessment of real GNP growth having mean-reversionary versus random walk qualities.

Figure 2



Q. HOW DID YOU TRANSFORM THE ESTIMATED 3.06 PERCENT ANNUAL GROWTH RATE FOR REAL GDP INTO AN ANNUAL GROWTH RATE FOR NOMINAL GDP?

A. As the purpose is to develop a forecast of the dollar value of dividends per share paid in future periods,[90] I developed a forecast of inflation using the TIPS[91] breakeven method of estimating inflationary

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[90] Future dividends are valued in nominal dollars.

[91] Treasury Inflation-Protected Securities (or TIPS) are the inflation-indexed notes and bonds issued by the U.S. Treasury. With these debt securities, the principal is adjusted with changes in the Consumer Price Index, the commonly used measure of inflation. The coupon rate is constant, but generates a different amount of interest when multiplied by the inflation-adjusted principal, thus protecting the holder against

expectations.[92] This involved constructing a forward curve of dollars, priced in terms of today's dollar;[93] i.e., a forecast of future price levels. This inflation forecast provided an average annual inflation rate forecast for 2021 through 2029 of 2.72 percent. An advantage is that such a forecast is actually "being made" by economic agents (investors) collectively having considerable amounts (trillions of dollars) at risk. The global market for debt securities issued by the U.S. Treasury is almost certainly the world's largest financial market for securities of a single issuer.

I multiplied the 2.72 percent estimated annual inflation rate by the historical 3.06 percent annual rate of growth in real GDP to obtain an estimated long-term annual growth rate for nominal GDP of 5.86 percent.[94,95]

(or compensating the holder for) inflation. TIPS are currently offered in five-year, seven-year, 10-year, and 20-year maturities.

92 *See*, in Exhibit Staff/912, "Inflationary Expectations: How the Market Speaks," S. Kwan, *Federal Reserve Bank of San Francisco's Economic Letter*, Number 2005-25, October 3, 2005. *See also* in Exhibit Staff/912 "Empirical TIPS," R. Roll, *Financial Analysts Journal*, January/February 2004, Vol. 60, No. 1: pages 31 - 53

93 This analysis used U.S. Treasury securities' monthly average interest rates for the months of February and March, 2010, available in the Federal Reserve's Statistical Release H.15.

94 As one validation of this approach, *see* Morin, *op. cit.*, page 311: "A long-term forecast of nominal growth in GDP…can be formulated by combining a long-term inflation estimate with a long-term real growth rate forecast…The growth rate in U.S. real GDP has been reasonably stable over time. Therefore, its historical performance is a reasonable estimate of expected long-term future performance…The long-term expected inflation rate can be obtained by comparing the yield on long-term U.S. Treasury bonds with the yield on inflation-adjusted bonds of the same maturity."

95 By "compounding," or multiplying, the two rates; i.e., (1 + 0.0272) X (1 + 0.0306) – 1 = 0.0586, or 5.86% (rounded to two decimal places).

Q. WHAT OTHER ESTIMATES OF LONG-TERM GDP GROWTH ARE AVAILABLE TO YOU?

A. The Energy Information Administration (EIA), part of the U.S. Department of Energy, produces forecasts of values for both real GDP and the GDP Price Index.[96,97] From these forecasts, I derived a forecast of nominal GDP. From these forecasted dollar values of nominal GDP, I calculated the compound annual growth rate in nominal GDP over the period 2021-35 to be 4.71 percent.[98]

I averaged the 4.71 percent EIA rate with the 5.86 percent annual rate resulting from combining the historical growth rate of real GDP with the TIPS breakeven inflation forecast to obtain an estimated compound annual growth rate in nominal GDP for 2021 forward of 5.28 percent.

Q. IS 5.28 PERCENT YOUR ESTIMATED LONG-TERM SUSTAINABLE ANNUAL GROWTH RATE IN DIVIDENDS PER SHARE FOR THE COMPARABLE ELECTRIC UTILITY COMPANIES OVER PERIODS BEGINNING IN 2021?

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96 A year-by-year version of Table 20 of the 2010 Annual Energy Outlook (reference case) is available at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html .

97 EIA's forecasts have been used in other jurisdictions. *See* 79 FERC 61,309, Opinion 96-B, attached as Exhibit Staff/913, and especially page 13.

98 A summary of forecasted annual growth rates of nominal GDP now includes, over some portion of the 2016-20 period: 4.50 percent (Federal Reserve, and for perhaps a somewhat earlier period), 4.59 percent (OMB), 4.93 percent (EIA), and 4.96 percent (Blue Chip). The EIA forecast for the 2021-35 period of 4.71 percent is similar to (and within the range of) the shorter period forecasts. Clearly the outlier over the 2016-35 period is the 5.86 percent based on the historical real rate with the TIPs inflation forecast.

A. No. The 5.28 percent annual growth rate represents an economy-wide growth rate. However this rate is not appropriate for the electric utility industry. While a typical approach is to use some estimated rate of growth in nominal GDP as the presumed appropriate rate by which to increase dividends per share over a longer-term, I contend this overstates likely dividend growth rates for electric utilities[99] other than those in an unusual combination of circumstances.

The electric utility industry in the U.S. is a mature industry. Figure 3 (following) is a conceptual depiction of the successive phases of growth through which a product or service, a product (or service) line, or an industry pass.[100]

The U.S. electric utility industry is well past the “high growth”[101] phase of the industry’s lifecycle and is in the “mature” phase; i.e., the right-hand portion of the graph in Figure 3. This phase is characterized by slower growth and is well represented in the graph in Docket No. 210’s Exhibit PPL/209 Hadaway/23,[102] where total kilowatt hour (kWh) electricity sales, a unit measure, is clearly shown to be growing at a

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[99] Such a rate may be appropriate for some aggregation of firms across diverse industries. Note that even this type of restriction has implications on the growth rate of government spending and net exports-imports relative to the domestic and private sector of the economy.

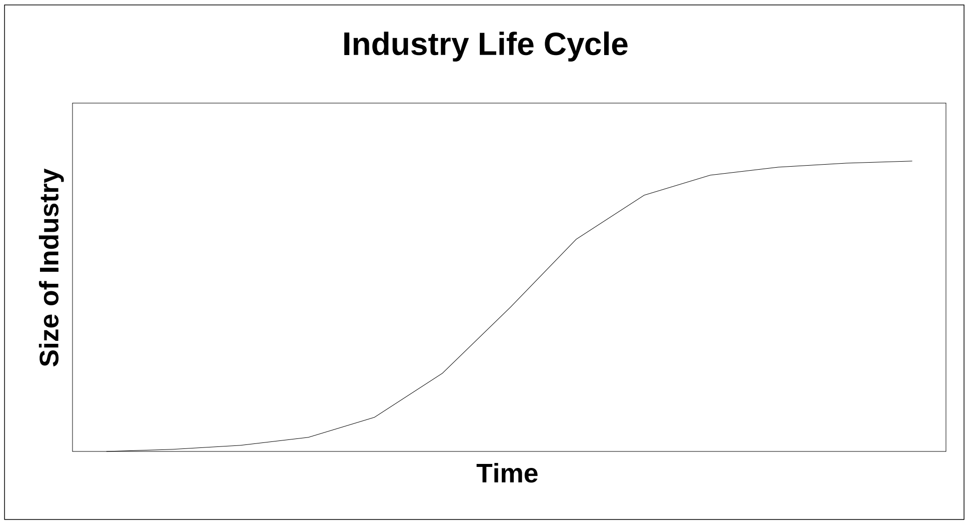
[100] The functional (mathematical) form of the equation producing this graph is a logistic function.

[101] The “high growth” phase is the steep section of the curve in the middle of the graph. Slower rates of growth pertain to both a nascent and to a mature industry, which are respectively positioned on the left and right portions of the curve.

[102] The graph is on page 26 of the cited document.

materially slower rate than real GDP over the 1984 through 2008 period.[103]

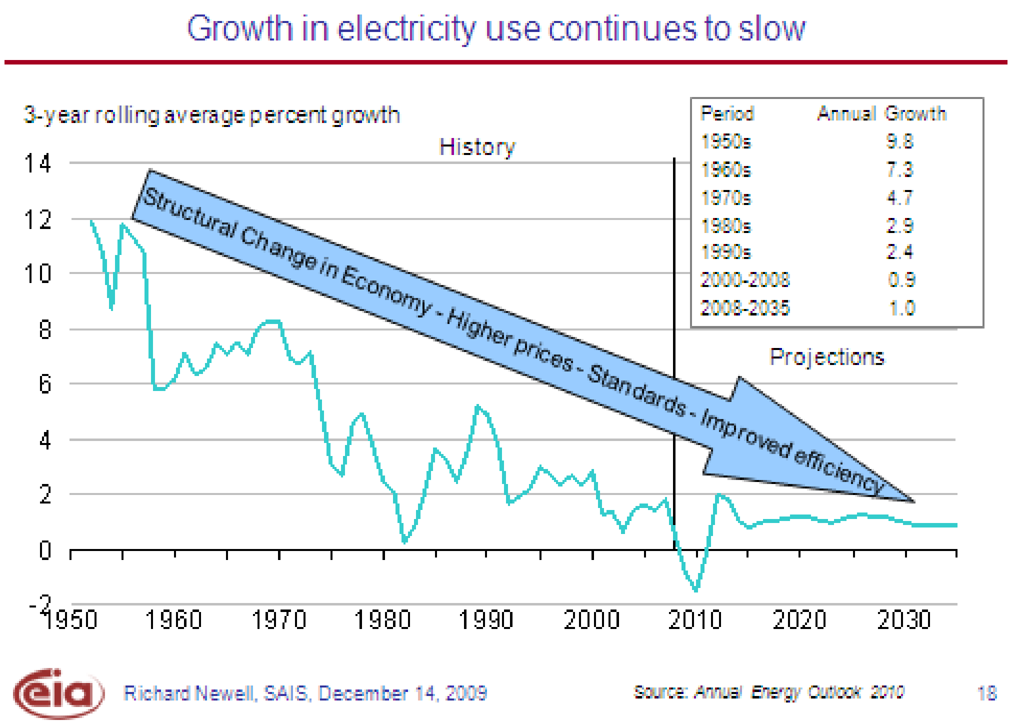
Figure 3



This slower rate of growth is also evident in Figure 4 (following), which shows not only the decline since 1950, but the relatively low rates of growth anticipated beyond 2009.

[103] Note in particular the "less than real GDP" rate of growth in kWh sales from, say, 1992 forward.

Figure 4[104]



Additionally, a 2007 presentation by Susan Tierney of the Analysis Group shows an overall decline in expenditures on electricity as a percent of U.S. GDP from 1983 through 2005.[105] Per Tierney, "…as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than what we spent during the 1980s."[106] I believe this long-term secular trend will continue. Therefore, the future long-term

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[104] Source is EIA's *Annual Energy Outlook 2010*.

[105] *See* Figure 6 on page 7 of Tierney's "Decoding Developments in Today's Electric Industry — Ten Points in the Prism," attached as Exhibit Staff/914.

[106] *Ibid.*, page 7.

growth rate in earnings[107] for the industry is highly likely to be less than the future long-term growth rate in nominal GDP.[108]

Figure 5 (following), compiled from EIA forecasts, depicts electricity expenditures as a percent of nominal GDP declining over the 2009-35 period.

The following regarding electric utility stocks is from the February 26, 2009, Standard and Poor's *Industry Surveys – Electric Utilities*: "For firms in the S&P Electric Utilities index…shares tend to trade at a discount to the market multiple *because of the slow-growth nature of utilities' regulated operations*"[109] (emphasis added). Presumably, by "slow-growth nature," Standard and Poor's is making an implicit growth comparison with an average of all industries or the economy as a whole.[110,111]

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107 Earnings growth is necessary for dividends to grow. I provide additional discussion on this point later.

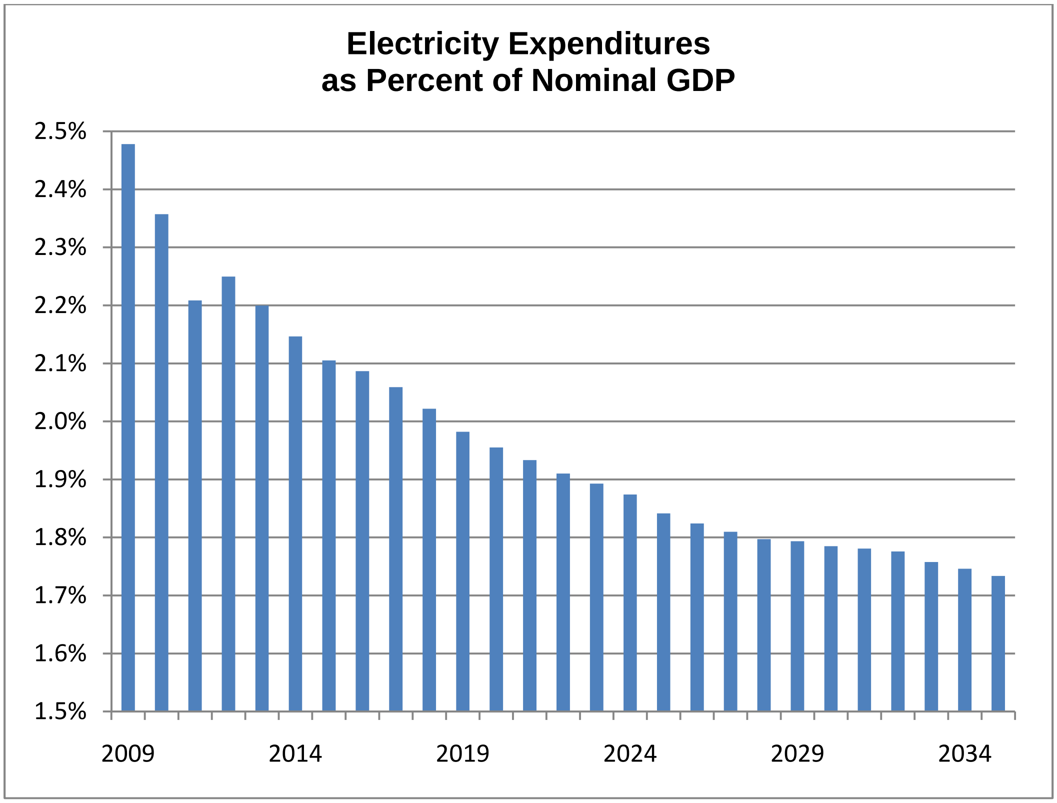
108 The only way this is not possible is if electricity unit prices increase not only at a higher rate than general inflation, but also at a rate sufficiently high to more than offset the lower than real GDP rate of growth in electricity volumes. See also the graph "Cost of Electricity vs. Consumer Prices" in Docket No. 210's Exhibit PPL/209 Hadaway/17, where, by visual inspection, it appears the "electricity component of CPI" price measure has not risen at a rate greater than the rate of overall price inflation as measured by the Consumer Price Index (CPI) over the 1992 through 2008+ period. In other words, over the past 16 years, the price of electricity has increased at a rate similar to (not greater than) consumer prices generally.

109 *See,* in Docket No. 210, Exhibit PPL/209 Hadaway/28 (page 26 of the document, last paragraph).

110 Arguably, S&P is, contrary to my interpretation, comparing "slow-growth nature of utilities' regulated operations" with the growth for electric utilities overall or for electric utilities' non-regulated operations. This is, in part, the reason my screen of comparable companies includes a criterion that regulated assets account for 80% or more of total assets.

111 Also note that this "slow-growth nature" pertains to future growth; the market establishes stock prices on a forward-looking basis. While S&P may be describing

Figure 5[112]



Q. ARE FORECASTS OF FINANCIAL METRICS FOR ELECTRICITY PROVIDERS AVAILABLE BEYOND 2015?

A. Yes. EIA provides a long-term forecast of both electricity sales (in billions of kWh) and end-user prices (in nominal cents per kWh).[113] The revenue result obtained by multiplying the two forecasts' values for each year provides electricity revenue estimates for future years in nominal (current dollar) terms. Compound annual revenue growth rates

historical growth, they must also be describing a "slow growth" future; otherwise market multiples for electric utility stocks would be higher.

[112] Source: EIA's year-by-year version of Tables 8 and 20 of the 2010 Annual Energy Outlook (reference case).

[113] *Ibid*.

are 3.39 percent for 2016-20 and 3.87 percent for 2021-35. Using these growth rates in the 2016-20, and 2021 forward periods, respectively, as dividend growth rates[114] for the two periods, resulting average ROE estimates were in the 8.4 to 8.6 percent range. I evaluated these results as sufficiently low as to appear unreasonable.

The use of electric utility revenue forecasts implicitly assumes the relationship between revenues, earnings, and dividends[115] remain similar, if not precisely constant. Standard DCF assumptions include a static, or fixed, relationship between earnings and dividends. What I am adding here is the assumption that the ratio of earnings to revenue[116] remains constant, or at least “stable.”

It seems unlikely that electric utilities collective revenue will grow more slowly than will earnings. My perception is that the electric utility industry has, like many other American industries, become more capital intensive over time, not less. To the extent this is true, the proportion of revenue requirement based on aspects of rate base value has increased. I believe this trend is likely to continue, which would

[114] It seems more reasonable to me that dividends might grow over some longer period at the rate of electric utility revenues than at the rate of nominal GDP.

[115] Or, alternatively to dividends, the payout ratio.

[116] This ratio, earnings to revenue, is also known as the return on sales (or ROS).

seem to indicate a tighter link between revenue and earnings growth than would otherwise be the case.[117]

Wanting to make use of both EIA's revenue forecasts and of the averaged nominal GDP forecasts, I computed the ratio of EIA's revenue growth rates to the nominal GDP growth rates for the two periods 2016-20 and 2021 forward. The results, 0.72 and 0.81, for the respective periods, were multiplied by the average nominal GDP forecasts of 4.75 percent and 5.28 percent for the 2016-20 and 2021 forward periods, respectively.[118] This provided annual revenue growth rates of 3.42 percent for the 2016-20 period and 4.30 percent for the 2021 forward period. Using these values for dividend growth rates in the 150-year DCF model produced the results in Table 5 (following).

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[117] In any event, an electric utility revenue forecast, or more precisely, forecasts of electric utility prices and quantities that, when multiplied, provide a revenue forecast, are available on an annual basis through 2035.

[118] One way to view this is that EIA has a meaningful forecast of electricity revenues relative to nominal GDP growth rates, and that using the averaged nominal GDP growth rates serves to potentially increase the robustness of the resulting estimates for electricity revenues versus using only EIA's forecast of electricity revenues.

Table 5

Comparable Company	Internal Rate of Return[119]
ALLETE	8.5%
American Electric Power Co. Inc.	8.8%
Cleco Corp.	8.6%
Empire District Electric Co.	10.3%
IDACORP, Inc.	7.5%
PG&E Corp.	8.9%
Pinnacle West	9.0%
Progress Energy Inc.	9.6%
TECO Energy, Inc.	9.0%
UIL Holdings	9.2%
Westar Energy Inc.	9.3%
Wisconsin Energy Corporation	8.4%
Xcel Energy	8.6%
Group Average	8.9%
Group Median	8.9%

Q. DO MOST DCF ANALYSES ASSUME A TERMINAL RATE OF GROWTH THAT IS EQUAL TO SOME FORECAST OF GDP GROWTH?

A. I cannot speak to "most," but many that I have seen do make this assumption. As an example, see FERC's discussion on this topic in Opinion 396-B at page 9,[120] where the statement is made that:

> "First, the record shows that as companies reach maturity over the long-term, their growth slows, and their growth rate will approach that of the economy as a whole."

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[119] IRR is the abbreviation for Internal Rate of Return. Note that the lowest estimated IRR (7.5 percent) is well above both the Moody's Baa Utility Bond Index for January, 2010 (6.16 percent) and PGE's cost of long-term debt (6.07 percent).

[120] *See* Exhibit Staff/913.

This reader is curious as to which firms are growing more slowly than is "the economy as a whole," as mathematically, not all can be growing more rapidly.[121]

Q. YOU RECOMMEND AN ROE OF 9.2 PERCENT. HOW DID YOU ARRIVE AT THIS VALUE FROM THE RESULTS ABOVE?

A. A three-stage with terminal valuation DCF model produced an average internal rate of return of 8.9 percent for the 13 companies in my sample group, or the same results as the three-stage, 150-year valuation horizon DCF model. I make two additional adjustments to these results of 8.9 percent. First, I make an adjustment for differences between the comparable companies' capital structures and PGE's target capital structure for the 2011 test year of 50 percent long-term debt and 50 percent common equity. I use the Hamada equation[122] to make this adjustment[123] for each individual comparable company, with the

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[121] To me, some discussions on this point of growth relative to GDP have a sense of illusory superiority and appear to be the regulatory equivalent of fictional Lake Wobegon, where "…all the children are above average."

[122] *See* "New Regulatory Finance" by Roger Morin; 2006; pages 221-225. *See also* pages 4-8 of the rebuttal testimony of Robert G. Rosenberg in *Rochester Gas & Electric Corporation*, Case Nos. 03-E-0765, 02-E-0198, and 03-G-0766. Mr. Rosenberg's testimony is attached as Exhibit Staff/915. Attached as Exhibit Staff/916 is Robert S. Hamada's "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks," published in *The Journal of Finance*, Vol. 27, No. 2 (May, 1972).

[123] An adjustment using the Hamada equation requires as inputs the observed capital structure, the tax rate, the target capital structure and one of: the historical values for the risk-free rate and the market rate, or the historical risk premium. I used Value Line's 2010 (or 2011, if available) *Investment Survey* estimates for the comparable companies for the first two parameters, and the 50% long-term debt – 50% common equity proposed in PGE's UE 215 filing as the target capital structure. I used rates of return from page 23 of the 2009 Ibbotson SBBI Valuation Yearbook, supplied by PGE in response to Staff data request 45, using the 3.7 percent average T-bill rate as the

resulting adjustment to estimated ROE for each comparable company in Table 6 (following).[124]

Table 6

Comparable Company	ROE Adjustment using Hamada Equation
ALLETE	0.3%
American Electric Power Co. Inc.	-0.4%
Cleco Corp.	-0.1%
Empire District Electric Co.	-0.2%
IDACORP, Inc.	-0.1%
PG&E Corp.	0.0%
Pinnacle West	0.1%
Progress Energy Inc.	-0.2%
TECO Energy, Inc.	-0.3%
UIL Holdings	0.0%
Westar Energy Inc.	-0.2%
Wisconsin Energy Corporation	-0.3%
Xcel Energy	-0.2%
Mean	-0.1%
Median	-0.2%

The Commission has previously provided guidance on adjustments to risk for different capital structures, as in Order No. 01-777:

"It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common

historical risk-free rate and the 9.6 percent average return on large company stock as the historical market risk. I used the average of the average 90 day T-bill rate for the months of March and April of 2010, obtained from the Federal Reserve's H.15 report, as the current risk-free rate. Page 23 of the Ibbotson/Morningstar publication is included in Exhibit Staff/903.

124 Note that using as historical rates a market rate of 11.0 percent and the intermediate government bond rate of 5.4 percent as the risk-free rate (implied risk premium 5.6 percent) coupled with the average of the average yields over the months of March and April of 2010 for the 10-year U.S. Treasury (3.79 percent), provided approximately the same results.

> equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly."[125]

This adjustment results in an estimated ROE for the comparable companies of 8.8 percent.[126]

Q. WHAT IS THE SECOND ADJUSTMENT YOU MAKE?

A. Future economic conditions are uncertain, as are future changes in financial metrics and parameters associated with electric utilities, by themselves or relative to the economy. Therefore, as a check on reasonableness of the combination of estimates and inputs used in deriving the ROE estimates described above, I used the higher rates of nominal GDP growth[127] in the 150-year DCF model. This resulted in an estimated ROE of 9.6 percent.[128] The average of the two results is 9.2 percent.

Q. DOES YOUR RECOMMENDED POINT ESTIMATE OF PGE'S COST OF EQUITY CAPITAL REQUIRE ADDITIONAL ADJUSTMENT FOR

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[125] Order No. 01-777 at 36.

[126] This is the 150-year DCF model result. The result of the 40-year with terminal valuation DCF model is 8.7 percent.

[127] That is, 4.75 percent for the 2016-20 period and 5.28 percent for the 2021 forward periods.

[128] This 9.6 percent result includes the net effect of using the Hamada equation to adjust for capital structures differing from that targeted by PGE.

PGE'S DECOUPLING AND LOST REVENUE RECOVERY MECHANISMS?

A. No. According to Exhibit PGE/1201 Zepp/1, of the 12 companies present in both my list and PGE's list of comparable companies, eight have decoupling or a "lost revenue adjustment mechanism" in place in at least one of the jurisdictions in which the company operates. Additionally, the presence or absence of a decoupling mechanism, in all or a portion of a company's service area, is presumed by me to be reflected in its stock price.

Q. DOES YOUR RECOMMENDED POINT ESTIMATE OF PGE'S COST OF EQUITY CAPITAL REQUIRE ADDITIONAL ADJUSTMENT FOR PGE'S EXPOSURE TO ANY SPECIFIC RISK?

A. No. See my discussion on this point in the "Risk and Return Revisited" section appearing later in this testimony.

PGE'S CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES PGE REQUEST FOR RATEMAKING PURPOSES?

A. PGE requests a capital structure of 50 percent long-term debt and 50 percent common equity.[129]

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[129] *See* Table 1 of Exhibit PGE/1100 Hager – Valach/3 and Hager – Valach/25-26.

Q. HOW DOES THIS STRUCTURE COMPARE WITH THAT CURRENTLY AUTHORIZED AND WITH WHAT THE COMPANY HAS RECENTLY REPORTED?

A. The 50/50 capital structure is identical to that currently authorized.[130] PGE's most recent Form 10-K filing with the Securities and Exchange Commission (SEC)[131] has a capital structure as of December 31, 2009 composed of 53.1 percent long-term debt and 46.9 percent "Total Portland General Electric Company shareholders' equity."

Value Line *Investment Survey*[132] has a 2010 estimate of 53 percent long-term debt and 47 percent common equity and, for the average of years 2012-14, a capital structure of 50/50. Additionally, slide 20 of PGE's March 11, 2010 Investor Presentation lists an estimated 2010 debt to capitalization rate of 54 percent.[133]

Q. WHY IS A 50/50 CAPITAL STRUCTURE REASONABLE WHEN THE ACTUAL EQUITY PROPORTION HAS RECENTLY BEEN LESS?

A. PGE's March 11, 2010 Investor Presentation specifies a "Target Capital Structure 50% Debt and 50% Equity."[134]

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130 *See* Order No. 08-601, page 5 and page 7.

131 Filed on February 25, 2010. *See* Item 6, *Selected Financial Data*.

132 The issue dated February 5, 2010.

133 *See* slide 20 of the presentation, currently available at http://files.shareholder.com/downloads/POR/734924977x0x358161/10158c7b-3dc3-4c16-80d8-7e14cdd22087/PGE%20Presentation.pdf .

134 *See* slide 18 of the presentation.

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. I recommend the Commission accept PGE's proposed capital structure having a composition of 50 percent long-term debt and 50 percent shareholders' equity.

PGE'S TESTIMONY REGARDING ROE

Q. PGE USES 31 COMPARABLE COMPANIES, COMPARED WITH YOUR 13. PLEASE EXPLAIN THE DIFFERENCES IN THE TWO LISTS OF COMPARABLE COMPANIES.

A. You may recall I used six different screening criteria to select electric utility companies I consider comparable to PGE (seven, if we include the criterion of coverage by Value Line). I repeat my criteria below, indicating in parentheses the number of companies in PGE's list eliminated with each criterion:[135]

1. Value Line estimated 2010 long-term debt between 45% and 55% of capital structure (8);
2. No dividend decline in the prior five years (2);
3. Value Line forecast of a dividend growth rate ≥ 0% (0);
4. S&P Issuer credit rating between BB+ and BBB+ (inclusive) (2);
5. Regulated assets equal or exceed 80% of total assets (5); and
6. No merger or acquisition activity within the past five years (0).

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[135] The criteria were used in the order indicated. Some companies would have been screened-out by multiple criteria.

Subtracting the 17 companies in PGE's list eliminated by these criteria leaves 14 companies. I excluded PGE as it is the target company and NorthWestern Corp. as Value Line coverage is materially different from coverage of the remaining companies on my or PGE's lists. The remaining 12 companies are on both my and PGE's lists. Additionally, I include UIL Holdings, while PGE does not; completing the reconciliation of my 13 comparable companies to the 31 used by PGE.

Q. WHAT ANALYTICAL APPROACHES DID PGE USE TO ESTIMATE THE COMPANY'S COST OF EQUITY?

A. The Company provided estimated ranges and point estimates of ROEs using three Discounted Cash Flow (DCF) models, and three risk premium analyses. I will discuss each approach in turn.

Q. WHAT IS THE FIRST DCF MODEL USED BY PGE?

A. The Company provides the results of a constant growth DCF model[136] in Exhibit PGE/1207 for each of the 31 comparable companies used by PGE, including an average (mean) estimate of 11.5 percent. The dividend yields used in the constant growth model, per footnote "a" of Exhibit PGE/1207, are listed in Exhibit PGE/1205. The constant growth rates, per footnote "b" of Exhibit PGE/1207, are listed in Exhibit PGE/1206.

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[136] The constant growth DCF model is also known as the "Gordon growth" DCF model.

Q. WHAT ISSUES DO YOU HAVE WITH PGE'S CONSTANT GROWTH DCF MODEL RESULTS?

A. The constant growth DCF model has three inputs: a stock price in period "0," an estimate of dividends paid in period "1," and a constant rate of growth applied to the initial value of dividends. The differences in average estimated ROE for PGE's group of sample companies are largely unrelated to differences in the initial yields[137] I have calculated, based on my previously described approach to dividend estimation and calculation of stock prices for use in my multistage DCF models, versus those PGE has calculated. My calculation of 2010 dividends, divided by my average of three dates' closing stock prices, results in an average yield of 4.95 percent[138] versus PGE's result of 5.08 percent. This is a 13 basis point difference. Indeed, my calculation using PGE's growth (or "g") rate for each sample company provides an average estimated ROE of 11.32 percent, which is but 18 basis points less than PGE's estimated average of 11.5 percent.

The issue I have is with the values of constant growth used by PGE.[139] These average 6.4 percent across the averages for each company. By way of comparison, the compound annual growth rate

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[137] Initial yield, or period "1" yield is the period "1" dividend per share divided by the stock's price (or an average of the stock's price at different times) in period "0." Standard notation designates this as ${D_1}/{P_0}$.

[138] My calculations omit Northwestern Corp., while PGE's does not.

[139] *See* Exhibit Staff/917, which includes values from Exhibit PGE/1206. PGE's method for estimating these growth rates is described in Exhibit PGE/1200 Zepp/23 line 16 through Zepp/24 line 7.

computed from my 2025 estimated dividend values versus my 2010 estimated dividend values is 4.2 percent. I view this latter rate as much more likely over a timeframe that is of more than a few near-term years, especially if the 6.4 percent average growth rate assumes an economy recovering from the recent recession.

Q. PGE'S ESTIMATED AVERAGE GROWTH RATE HERE (6.4 PERCENT) IS MORE THAN 50 PERCENT GREATER THAN STAFF'S COMPUTED AVERAGE GROWTH RATE (4.2 PERCENT). WHY IS THERE SUCH A LARGE DIFFERENCE?

A. There are a couple of potential reasons. Reviewing the source of the Zacks and Yahoo estimates used in Exhibit PGE/1206 suggests that the estimates are predominantly from analysts employed by sell-side firms. A review of the source of estimates for one company, PG&E, is illustrative. Yahoo specifies PG&E's earnings estimates are made by 19 (for 2010) and 17 (for 2011) analysts. Yahoo lists as "star analysts" of PG&E employees from the following firms: Oppenheimer & Co., Wells Fargo Securities, JP Morgan, Credit Suisse, Sanford C. Bernstein, UBS, BMO Capital Markets, Deutsche Bank Securities. Yahoo lists as "other analysts" employees from Citi, FBR Capital Markets & Co., BofA Merrill Lynch, Barclays Capital, Jefferies & Co., Morgan Stanley, Argus Research, RBC Capital Markets, Goldman Sachs, and Macquarie Research Equities.[140]

The Zacks earnings estimates for PG&E specifies its earnings estimates are made by 18 (for 2010) and 16 (for 2011) analysts. Zacks includes the following information regarding identification of estimates by analyst:

> “You may wonder why the names of so many of the brokerage firms and analysts are displayed as "Not Identified". That is because many of the brokerage firms believe that the research they produce is their most valuable asset. Thus, they only allow us to show their estimates if we remove the name of the firm and analyst. Luckily there is little value in knowing which firm produced which estimate as it has little affect on the stock price. What's important is being able to see the flow of estimates which is clearly detailed below.”[141]

Attached as Exhibit Staff/918 is a *Journal of Finance* article from 2001 discussing bias in analyst’s forecasts. The article concludes "[r]ational analysts who aim to produce accurate forecasts may optimally report optimistically biased forecasts.”[142] Value Line estimates for a given company are presumably made by one analyst,

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[140] I have no insights into the degree to which the 18 “named” analysts overlap with the group of analysts providing the estimates. Presumably, it is the same, or nearly the same, group.

[141] Zacks Investment Research See online at http://www.zacks.com/help/est_research.php .

[142] Page 383 of “Rationality and Analysts’ Forecast Bias;” Terence Lim; *Journal of Finance*, February 2001. This article is attached as Exhibit Staff/918.

Notably, the average of Value Line's estimates, as calculated by PGE, is 6.1 percent; very similar to PGE's 6.4 percent average of averages.

Consider also Roger Morin's statement that "[u]nlike investment banking firms and stock brokerage firms, independent research firms such as Value Line have no incentive to distort earnings growth estimates in order to bolster interest in common stocks."[143]

Another issue I have is with the *type* of growth rates in Exhibit PGE/1206 and used for the growth rate of dividends. In all four estimates used by PGE, the estimated growth rate applies to earnings, not dividends.

Q. WHY IS USING ESTIMATED EARNINGS PER SHARE GROWTH RATES AN ISSUE?

A. Two reasons. First, as total returns from electric utility stocks have a material income component, I presume a firm's management is reluctant to reduce the dollar amount of dividends paid; i.e., dollar payouts of dividends per share are "sticky," and especially "sticky downward," with presumably more management resistance to a reduction than to an increase. At the same time, earnings do vary between annual reporting periods, with both increases and decreases common. This leads to changes in (or management of) the payout

[143] Morin, *op. cit.*, page 300.

ratio,[144] so as to moderate volatility in the dollar amount of dividends per share paid to and received by shareholders. Exhibit Staff/917 lists, for the utilities in PGE's group of peer companies, estimates of future earnings per share growth rates. The 6.4 percent average of these growth rates (in column e) are used by the Company in its first DCF model.[145,146] PGE's estimated average annual growth rate, using estimates from Value Line and estimates reported by[147] Zacks, Yahoo!, and Reuters, averages 6.4 percent.[148]

In short, the issue here is one of timing. Exhibit Staff/919 shows PGE's list of comparable companies, after excluding NorthWestern Corp., had an average growth rate in earnings from 2007 to 2008 of 1.8 percent and an annual rate of growth from 2008 to 2009 of 19.0 percent,[149] and an average rate of growth over the two-year

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[144] The payout ratio is the fraction of earnings in a period that are paid out to shareholders as dividends. Note that subtracting the payout ratio from "one" yields the plough-back ratio, or that portion of earnings retained within the business.

[145] Exhibit Staff/917 replicates data in columns a-e of Exhibit PGE/1207.

[146] *See* Exhibit PGE/1200 Zepp/24, lines 4-7.

[147] See Exhibit PGE/1200 Zepp/23, lines 19-21 and footnote 2. Value Line's analysts develop most of (all of, for my comparable companies) the estimates they supply, while the Zacks, Yahoo!, and Reuters report estimates made by other parties. Note in footnote 2 the exception of Northwestern Corporation, where Value Line reports estimates developed largely, if not entirely, by outside analysts.

[148] As I review the different estimates by company, I see that for no less than 10 companies the estimated growth rate reported by Zacks equals that reported by Yahoo. Several other companies are very close. From this and the earlier discussion on analysts, I question the degree of diversity between these two reporters of estimates.

[149] The earnings per share for UniSource increased 593.2% (from $0.39 to $2.70) for 2009 versus 2008, following a decline from $1.55 in 2007 to $0.39 in 2008. Excluding Unisource from the calculation, the 2009 over 2008 growth in earnings per share for

period 2007-09 of 1.5 percent. The latest recession began in December, 2007 ("peak") and as of late May, 2010 has not had an ending date ("trough") designated.[150] Presumably due to recessionary pressures, the earnings of PGE's group of cohort electric utilities increased at a materially lower rate than what otherwise would have been the case in the absence of recessionary conditions, whether we are considering the 1.8 percent average increase in earnings in 2008 over 2007, or the 1.5 percent average annual increase over the two-year period 2007-09. Certainly the 6.4 percent estimated growth rate in earnings used by PGE includes a certain amount of "bounce," as recovery from the recession continues.

My third issue with PGE's use of estimated growth rates for earnings in DCF models concerns the availability of qualitatively better forecasts of dividends per share. While Dr. Zepp states "[g]rowth rates used with the DCF model should be based on the best available forecasts of future growth,"[151] his approach does not use the most relevant information. Repeating Roger Morin's conclusion previously stated in part:

> "DCF proponents have variously based their historical computations on earnings per share, dividends per share, and

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the remaining 29 PGE comparable companies (not including NorthWestern Corp.) averages <u>negative</u> 0.8%.

[150] Per the NBER Business Cycle Dating Committee's April 12, 2010 announcement. See at http://www.nber.org/cycles/april2010.html .

[151] Exhibit PGE/1200 Zepp/23 lines 17 – 18.

book value per share. Of the three possible growth rate measures, growth in dividends per share is likely to be preferable, at least conceptually. DCF theory states clearly that it is expected future cash flows in the form of dividends that constitute investment value."[152]

The most relevant forecasts are those of dividends, and Value Line provides an estimated rate of annual growth in dividends per share for the average of 2012-14 over the average of 2006-08.[153]

Q. WHAT IS THE AVERAGE VALUE OF VALUE LINE'S FORECAST ANNUAL RATE OF CHANGE IN DIVIDENDS PER SHARE FOR PGE'S GROUP OF COMPARABLE COMPANIES?

A. It is 4.9 percent.[154,155]

Q. WHAT, AGAIN, IS THE AVERAGE OF VALUES USED BY PGE FOR THE GROWTH RATES OF ITS 31 COMPARABLE COMPANIES?

A. It is 6.4 percent.

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152 *See* page 284 of the "New Regulatory Finance," Roger Morin, 2006; emphasis added.

153 As before, I use more current Value Line information than was used in PGE's testimony. As of the dates of Value Line's publication used in my analysis, 13 companies had estimated annual rates of change in dividends per share for the average of 2012-14 over the average of 2006-08, eight companies had 2013-15 over 2006-08, and ten companies had the 2012-14 over 2006-08.

154 This average does not include values for two of the 31 companies in PGE's group of comparable companies: NorthWestern Corp. and Duke Energy. Value Line designates the annual rate of change in dividends per share for the latter utility as "NMF," or "not meaningful" (the company did not pay dividends in 2006).

155 This average is based on company information taken from the same three issues of Value Line (February 5th, 26th, and March 26th of 2010) I used in my DCF analyses; i.e., ten growth rate estimates are for 2012-14 from a 2006-08 base, eight are for 2013-15 from 2006-08, and 13 are for 2013-15 from 2007-09.

Q. SHOULD THE COMMISSION CONSIDER THE RESULTS FROM PGE'S CONSTANT GROWTH DCF MODEL?

A. No. I recommend the Commission not consider results from single-stage, constant growth DCF models in this proceeding due to the inherent limitations of this form of DCF model.[156]

Q. WHAT IS THE SECOND DCF MODEL USED BY PGE TO ESTIMATE RETURN ON EQUITY?

A. The second DCF model is described on pages 24-27 of Exhibit PGE/1200 and is labeled on Exhibit PGE/1209 as "the FERC Multi-period DCF Method." Dr. Zepp describes this DCF model as a "…two-stage DCF analysis based on concepts relied upon by the FERC in a number of cases and fully discussed in *Southern California Edison Company*, Opinion No. 445,[157] 92 F.E.R.C. 61,070 (2000) and in Opinion 396-B,[158] *Northwest Pipeline Company*, 79 F.E.R.C. 61,309 (1997)."[159]

Q. WHAT ARE YOUR THOUGHTS ON THE DCF MODEL DISCUSSED BY FERC IN OPINION NO. 445, AS USED BY DR. ZEPP?

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[156] *See* Order No. 01-777 at 27, where the Commission in a previous docket rejected consideration of results from parties' single-stage DCF models. The Commission also rejected consideration results from parties' single-stage DCF models in Docket No. UE 116. *See* Order No. 01-787 at 24.

[157] Attached as Exhibit Staff/920.

[158] Attached as Exhibit Staff/913.

[159] *See* PGE Exhibit PGE/1200 Zepp/24 lines 9 – 12. *See* also Exhibit PGE/1200 Zepp/45, where Exhibit PGE/1209 is labeled "Application of the FERC Multi-period DCF Method."

A. This model, while described by Dr. Zepp as "two-stage," is really a variation on the constant growth, or Gordon growth DCF model; i.e., it has only one stage[160] and a constant growth rate.[161] FERC, in the above cited *SoCal Edison* opinion, refers to this model as one employing a "two-step" DCF methodology.[162] Of some perhaps limited interest, there is also an implicit description of FERC's transition in DCF methodology as of the date this opinion was issued:[163]

> "The DCF analyses submitted in the supplemental record are similar to both the DCF analyses submitted by SoCal Edison and trial staff in the original proceeding and the DCF analysis adopted by the Presiding Judge. Each of these analyses relies on a <u>weighted</u> <u>averaging</u> of a short-term and a long-term growth rate, and purports to comply with the Commission's <u>two-step</u> DCF methodology, as set forth in Opinion No. 396-B.
>
> The Commission, to date, has not expressly addressed the differing approaches taken in setting ROEs for gas pipelines and for electric utilities. This proceeding, however, presents the Commission with its first opportunity to calculate an ROE for an electric utility company where the positions advocated by the parties, and the record evidence contains both short-term and

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[160] I believe a more suitable definition of a two-stage DCF model includes a distinction that different growth rates uniquely apply to different future valuation periods. In other words, each period in the valuation horizon has a growth rate and, if the effective growth rate is not the same for all periods, it is a multi-stage DCF model.

[161] This model, as used by Dr. Zepp, is of the form $r = {}^{D_1}/_{P_0} + g$. *See* the electronic (Excel) format of the Company's Attachment A portion of the response to Staff data request 334; e.g., cells D10, F10, and G10. *See* also Exhibit PGE/1200 Zepp/22 line 1 (Equation 2) through line 5.

[162] *See* the first paragraph on page 14 of the document in Exhibit Staff/920.

[163] FERC issued Opinion No. 445 on July 26, 2000.

> long-term growth data, consistent with our latest formulation of a <u>two-step</u> DCF methodology for natural gas pipeline companies. The issue present here therefore, is whether the Commission's preferred DCF methodology for natural gas pipeline companies should be applied, without variation, to an electric utility company, in place of the Commission's standard, constant growth DCF model, previously relied upon by the Commission in calculating an ROE for an electric utility company."[164]

Clearly FERC is here considering replacing, for use in determination of electric utilities' ROEs, a constant growth DCF model with a constant growth DCF model where the rate of growth ("g") is composed of some linear combination of two distinct rates of growth; i.e., a "blended," or "weighted average" rate of growth. One growth rate is intended to represent the "short-term" and one rate the "long-term."

FERC, in Opinion 396-B[165] concerning Northwest Pipeline Corporation, describes the Commission's "preferred approach," which includes the growth rate "g" to be used in FERC's constant growth DCF model being derived by averaging the short- and long-term growth rates; i.e., "g" is composed of 50 percent long-term rate and 50 percent short-term rate.[166]

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[164] *See* FERC Opinion 445, page 14 of the document in Exhibit Staff/920. I have omitted footnotes present in the original and added emphasis.

[165] FERC Opinion 396-B (92 FERC 61,309) was issued June 11, 1997 and is attached as Exhibit Staff/913.

[166] *Ibid.*, at pages 12 – 13.

FERC Opinion 445 (SoCal Edison) has much to say regarding calculation of one or more growth rates for use in FERC's DCF model. The mention of a weighting scheme where the short-term growth rate is weighted 2/3 and the long-term growth rate 1/3 is restricted to a footnote (footnote 19), describing the weighting of the two growth rates used by the presiding judge in the case, whose ruling is being reversed[167] by the Commission in Opinion 445. The footnote describes the judge's weighting scheme as "…consistent with the Commission's recent natural gas pipeline company cases."[168,169]

FERC takes note, on pages 16 – 17 of Opinion 445, of several facts important to determination of PGE's authorized ROE in Docket No. UE 215:

1. "[E]lectric utilities typically have much higher dividend payout ratios (i.e., high dividend yields) as compared to most other industrial companies…"[170]

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167 *See* Exhibit Staff/920, page 15; i.e., "…we will not adopt the Initial Decision's ROE of 9.68 percent…"

168 *Ibid*., page 9.

169 Between the issuance of Opinion 396-B on June 11, 1997 and Opinion 445 on July 26, 2000, FERC modified the weighting of growth rates from 50 percent short-term and 50 percent long-term to the 1/3 short-term, 2/3 long-term mentioned in footnote 19 of the latter Opinion. PGE's testimony on this point supplies no citation as to the FERC docket or opinion in which this change is discussed.

See FERC Opinion No. 486-B in *Kern River Gas Transmission Company*, (issued January 15, 2009) at page 18, where paragraph 37 indicates a FERC policy change "…regarding the weighting of the short- and long-term growth components of the DCF model…" in *Williston v. FERC*.

170 *See* Exhibit Staff/921, which is a report, also currently available at http://www.indexarb.com/dividendYieldAlphasp.html , listing each stock in the S&P 500 and its dividend yield. Yields are estimated for the year ahead beginning May 12, 2010 and stock prices are as of May 12 at approximately Noon PST. Note that, of the 31 electric utilities in PGE's group of comparable companies, 16 are

2. "[R]etained earnings are a key source of dividend growth."
3. "The higher payout ratios attributable to electric utilities cause these companies to have significantly lower expected dividend growth rates than most other industrial companies…"
4. "…we find that it would be premature, at this time, to incorporate GDP in the DCF model applicable to an electric utility company."[171,172]

Dr. Zepp's approach with this model is to use a blended growth rate, comprised one-third of an estimated 5.82 percent future growth rate in nominal GDP and two-thirds of either the lowest analyst estimate for earnings growth for each individual company in PGE's group of comparable companies (providing his "Low Equity Cost Estimate" values in Exhibit PGE/1209) or the highest analyst estimate for earnings growth (providing his "High Equity Cost Estimate" values in Exhibit PGE/1209). The "low" and "high" values are averaged for the 31 companies, providing an average "low" estimated ROE of 10.1 percent and an average "high" estimated ROE of 12.9 percent. These

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currently in the S&P 500 index. The report lists the average forward dividend yield for stocks in the S&P 500 index as 1.72 percent. The lowest yielding stock in the Company's group, Allegheny Energy, is listed as having a forward yield of 2.93 percent. This relatively current evidence is clearly supportive of FERC's statement here with respect to the dividend yields of electric utilities relative to "most other industrial companies."

171 Note that I question some of FERCs reasoning and conclusions expressed in Opinion 445, including that evidenced in portions of the second paragraph of page 15.

172 This statement seems at odds with Dr. Zepp's claim that his second DCF model "[a]dopt[s] the FERC method of relying on a GDP forecast as the terminal growth rate estimate. One of the two FERC opinions he cites has FERC reversing the judge on the use of GDP growth for the long-term growth rate while the other uses a short- and long-term growth rate split of 50 percent each (not 1/3 and 2/3, respectively).

two results are averaged, producing his second constant growth DCF model's 11.5 percent estimate of ROE.[173]

Q. WHAT ARE YOUR THOUGHTS WITH RESPECT TO THE VALUES USED IN THIS DCF MODEL TO REPRESENT SHORT-TERM GROWTH IN DIVIDENDS?

A. I have the same objection as previously described to using, as a short-term rate for dividend growth, the lowest (highest) values of Value Line and three analyst consensus reports of estimates for near-term earnings growth. These estimates are of earnings growth rates, not dividend growth rates, and are likely to overstate long-term growth in dividends per share, as the rates reflect some amount of recovery from recessionary business conditions.

Q. WHAT ARE YOUR THOUGHTS WITH RESPECT TO THE VALUES USED IN THIS DCF MODEL TO REPRESENT LONG-TERM GROWTH IN DIVIDENDS?

A. PGE averages two nominal GDP annual growth rates to arrive at the 5.82 percent annual growth rate for nominal GDP. The first is based on a "past long-term annual average GDP growth of 6.7%"[174] used by the Staff of the Arizona Corporation Commission (ACC) "to determine

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[173] *See* Exhibit PGE/1200 Zepp/27 lines 2 – 4. See also Exhibits PGE/1208 and PGE/1209, and Exhibit PGE/1200 Zepp/24 line 8 through Zepp/27 line 4. Note that Dr. Zepp adjusts his 11.5 percent ROE estimate upward by 0.2 percent to account for "PGE's exposure to…various positive and negative risks." See Exhibit PGE/1200 Zepp/18 lines 10 – 11.

[174] *See* Exhibit PGE/1200 Zepp/25 lines 13 – 17.

growth for the second stage of its multi-stage DCF analysis" in a water company docket.

Reviewing annual growth rates of nominal GDP values obtained from the Federal Reserve, I note that a total of six years since 1980 have had an annual rate of nominal GDP growth[175] higher than 6.7 percent and 23 have had a rate lower than 6.7 percent.[176] I have identified in Table 3 four forecasts of nominal GDP growth over future periods from credible sources that are between 4.5 and 4.96 percent.[177] Dr. Zepp adjusts the 6.7 percent rate downward to 6.6 percent to reflect a lower Value Line inflation forecast for some future period (3.0 percent) than the 3.1 percent rate reported by Morningstar for the period 1926-2008.[178] I believe the 6.6 percent rate used by PGE as 50 percent of a forward-looking average long-term nominal GDP growth rate is substantially overstated.

The second rate of annual nominal GDP growth used by PGE is obtained by multiplying a Value Line forecast of annual growth in real GDP for 2013 by Value Line's forecast of the 2013 rate of change in the GDP price deflator index; arriving at an estimate of "future near-

[175] These growth rates are on an arithmetic basis.

[176] These are: 1981, 1983, 1984, 1985, 1988, and 1989. Six years in the past 29. The average annual growth rate over the 29 year period is 5.82 percent and is comparable to the 5.86 percent rate I used as input into a long-term growth rate.

[177] Five from credible sources if the CBO's 4.1 percent annual rate of growth is included.

[178] Exhibit PGE/1200 Zepp/25 lines 17 – 23.

term (nominal) GDP growth of 5.1%…"[179] This second rate is similar to the 4.75 percent average of four organizations' estimated rate of annual growth in nominal GDP over the 2016 – 2020 period that I present in Table 3.

Dr. Zepp then averages the 6.6 percent and 5.1 percent growth rates, arriving at an estimated annual rate of growth in nominal GDP of 5.8 percent. This result is materially greater than the long-term rate I used in my multistage DCF models, and is very similar to my 5.86 percent estimated growth rate of nominal GDP based on historical values of real GDP and an inflation forecast specific to the 2016 forward periods.

The constant growth rates "g" used in this second DCF model are weighted 2/3s the lowest (highest) analyst estimate for annual earnings rate of growth for each company in PGE's group of comparable companies and 1/3 the 5.8 percent rate described above; i.e., the result is two growth rates ("low" and "high"), applicable to all periods, that is different for each company.

Q. SHOULD THE COMMISSION CONSIDER THE RESULTS FROM PGE'S SECOND CONSTANT GROWTH DCF MODEL?

A. No. I recommend the Commission not consider these additional results from another single-stage, constant growth DCF model in this proceeding due to the inherent limitations of this form of DCF model

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[179] *See* Exhibit PGE/1200 Zepp/25 line 23 through Zepp/26 line 2.

and the specific methods by which the growth rate "g" has been estimated.[180]

Q. WHAT IS THE THIRD DCF MODEL USED BY PGE TO ESTIMATE RETURN ON EQUITY?

A. Dr. Zepp describes PGE's third DCF model at Exhibit PGE/1200 Zepp/27. This model is described as a multistage model having three stages, with different rates of growth applicable in each. The first stage is described by Dr. Zepp as the period 2011-15,[181] while direct examination of this model reveals the initial year of dividends per share included in the internal rate of return is 2010.[182] Therefore, this model's initial period of dividend payments ("cash flows") are 2010 through 2015, which matches the first stage in each of my multistage DCF models. The second stage covers the period 2016-25,[183] and a terminal value is calculated as of the end of the final year (2025). Model results, in aggregate and for each company in PGE's group of comparable companies, are in Exhibit PGE/1210. The average internal rate of return (IRR) of PGE's group of comparable companies is 11.2 percent.

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[180] *See* Order No. 01-777 at 27, where the Commission in a previous docket rejected results from parties' single-stage DCF models. The Commission also rejected results from parties' single-stage DCF models in Docket No. UE 116. *See* Order No. 01-787 at 24.

[181] *See* Exhibit PGE/1200 Zepp/27 line 11.

[182] *See* Attachment A to PGE's response to Staff data request 334, Tab "10," cells E11 through E42.

[183] My second stage, in each of my two DCF models, is the period 2016-20 and the third stage in each model is composed of years beyond 2020; that is, 2021 forward.

Q. WHAT AGAIN WERE YOUR MULTISTAGE DCF MODEL RESULTS?

A. My 150-year three stage model had, for my 13 electric utilities comparable to PGE, an average IRR of 8.9 percent and my 40-year three stage with terminal valuation model had an average IRR of 8.9 percent.

Q. YOU PREVIOUSLY TESTIFIED THERE WAS LITTLE DIFFERENCE USING YOUR DCF MODEL, WITH SAME TIMING AND PARAMETER ESTIMATION METHODOLOGY, ON PGE'S GROUP OF COMPARABLE COMPANIES. WHAT WERE YOUR RESULTS?

A. The average internal rates of return I obtained, using 30 of the 31 companies in PGE's group, were 8.9 percent with my 150-year DCF model and 8.8 percent with my 40-year with terminal valuation DCF model. Recall that NorthWestern Corp. was not included in my analysis of PGE's group of comparable companies. Given that there are 31 companies in this group, the impact of omitting one when calculating averages is small.[184]

Q. WHY IS THERE SUCH A LARGE DIFFERENCE BETWEEN YOUR MODELS' RESULTS FOR PGE'S SAMPLE COMPANIES AND THE 11.2 PERCENT IRR RESULT FROM DR. ZEPP'S MULTISTAGE DCF MODEL?

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[184] Weighting the 12.49 percent result in Exhibit PGE/1210 for NorthWestern Corp at a 1/31 proportion and the 8.9 percent IRR from my 150-year DCF model at a 30/31 proportion yields 9.0 percent (with rounding).

A. Table 7 (following) reconciles the internal rate of return results from Dr. Zepp's third DCF analysis and my 40 year with Terminal Valuation DCF model.[185]

The answers to this question, as indicated by Table 7, are multiple. Dr. Zepp adjusts the estimated dollar amount of the annual dividend as the "[p]rices investors pay for utility stocks reflect the benefit investors receive by utilities paying dividends every quarter but equation (3)[186] assumes the $100 is paid only once a year. My calculation adjusts the dividend upward by just enough to offset the time value of receiving the $100 in four quarterly installments of $25 each."[187,188]

I reviewed this calculation in Tab 5 of the spreadsheet[189] supplied as Attachment A in PGE's response to Staff data request 334. Dr. Zepp has adjusted for investors' quarterly receipt of dividends (as opposed to annual) using an annualized rate of 10.8 percent, which value I find satisfactory given that his resulting IRR is 11.2 percent.[190]

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185 Of the two DCF multistage models I used in my analysis, this is the one most like that used in Dr. Zepp's third DCF analysis.

186 *See* Exhibit PGE/1200 Zepp/22 line 6.

187 *See* Exhibit PGE/1200 Zepp/23 line 5 through line 8.

188 Morin, *op. cit.*, discusses this type of adjustment on page 357.

189 *See*, in Tab 5, cells in columns D, E, J, and K as well as the 10.8% value in cell M9.

190 A higher rate than the IRR outcome tends to "pull-up" the average IRR, while a lower rate has the opposite result.

Table 7

Reconciliation: PGE and Staff Multistage DCF Analyses

Change (cumulative)	IRR[191]
PGE Result (before adjustment)	11.2%
Correct cell references presumed to be mis-specified[192]	11.1%
Remove NorthWestern Corp.	11.0%
Remove Adjustment to 2010 Dividends for the TVM[193]	10.8%
Staff's March/April 2010 Stock Prices	10.5%
Staff's 2010 Dividend Values[194]	10.6%
Staff's Dividend Values: 2011 - 2015[195]	10.3%
Staff's Dividend Values: 2016 - 2020[196]	9.9%
Staff's Dividend Values: 2021 - 2025[197]	9.6%
Staff's Terminal Growth Rate[198]	8.8%
Add Years 2026 - 2049	8.8%
Staff's Results for PGE sample[199]	8.8%
Staff's Three Stage with Terminal Valuation DCF Analysis (using Staff's comparable companies and before adjustments)	8.9%

[191] Note that the IRR values are presented to one decimal place while the actual calculation was not rounded.

[192] This change corrects for two mis-specified cell references related to 2010 dividends for Allegheny Energy and ALLETE. In PGE's Attachment A response to Staff's data request 334, Tab 10/cell E12 references Tab 5/E15 and presumably should reference Tab 5/E14 and Tab 10/E13 references Tab 5/E16 and presumably should reference Tab 10/E15. This results in the 2010 dividend for Allegheny Energy changing from $1.86 to $0.62 and the 2010 dividend for ALLETE changing from $1.61 to $1.86.

[193] TVM: Time Value of Money. Note that this also reduces the dollar values of dividends for 2011 and following years and the dollar amounts of the terminal valuation.

[194] Note that this increases the average dollar value of dividends for all years and the average dollar amount of the terminal valuation.

[195] Note that this also reduces the average dollar value of dividends for years subsequent to 2016 and the average dollar amount of the terminal valuation.

[196] Note that this also reduces the average dollar value of dividends for years subsequent to 2020 and the average dollar amount of the terminal valuation.

[197] Some Internal Rate of Return values are below 7.00%. These are included in the average.

[198] Many Internal Rate of Return values are below 7.00%. These are included in the average.

[199] Thirty of PGE's 31 comparable companies; i.e., Northwestern has been excluded.

This adjustment is shown in Table 7 as resulting in a 20 basis point increase[200] in IRR. The calculation using percentage results to four decimal places is: 11.0195 less 10.8239 equals 0.1966 percent (or about 20 basis points). Morin's textbook shows three examples where the average difference is 29 basis points.[201]

The increase in stock prices as of the time I collected the data results in a 0.3 percent decline between the two models' results.

The initial dividend values are represented within both Dr. Zepp's Alternative Multi-Stage DCF Analysis and my DCF models as being for 2010. I used the estimated dollar amount of dividends per share for 2010 from the February 5, February 26, and March 26, 2010, issues of Value Line's *Investment Survey*, February 26, 2010. Dr. Zepp used Value Line's estimated dividends per share for the next 12 months from the December 4, 2009 *Summary & Index.* The average dollar value of dividends over the 30 companies from PGE's sample for 2010 is $1.44 using my methodology, while the comparable value resulting from Dr. Zepp's methodology is $1.40.[202] This adjustment results in a 0.1 percent difference between the two models' results.

Using my methodology for calculating dividends for the 2011 through 2015 period, versus that used by Dr. Zepp, results in a 0.3

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[200] An increase, as when the adjustment is "undone," it reduces the average IRR by 0.2 percent.

[201] Morin, *op. cit.*, page 358.

[202] Both dollar values are after the preceding adjustments in Table 7 have been made.

percent decline from Dr. Zepp's results. My methodology uses the maximum amount of information provided by Value Line's *Investment Survey* that is specifically related to changes in the values of dividends per share with respect to this period. Dr. Zepp's approach for the 2011 through 2016 period uses:

> "the averages of forecasted EPS[203] growth rates reported in PGE Exhibit 1206. I have assumed—as does the FERC—that EPS growth is the critical concern of knowledgeable investors who realize that earnings enable the utility to increase dividends."[204]

I appreciate that, over some extended period, it is earnings growth that allows for dividend growth. However, Dr. Zepp's use of estimated earnings growth rates for this period, to estimate the near-term growth in the dollar value of dividends per share, as the economy recovers from what is likely the most severe recession since at least the early 1980s, is totally separated from the reality of how electric utilities appear to manage dividend payouts over the course of a business cycle.[205] Of the 30 companies in PGE's sample,[206] 13 had declines in earnings per share for 2009 versus 2008. Of these 13, 11 <u>maintained</u>

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[203] EPS refers to the dollar value of earnings per share.

[204] Exhibit PGE/1200 Zepp/27 lines 10 through 15.

[205] The term business cycle as used here refers to a "peak" to "peak" period in economic activity, with a "trough" (recession) between peaks.

[206] NorthWestern Corp. is excluded.

or increased the dollar value of dividends per share.[207,208] Clearly the payout ratio increased for these 11 electric utilities in 2009. Somewhat analogously, as business activity and EPS for electric utilities rebounds from recessionary conditions, DPS (the dollar value of dividends per share) is not expected, by me or by Value Line, to grow at the same (or higher!) rate as EPS over some near-term period, such as 2011 through 2015. A theory that matches the rate of growth in DPS with that of EPS, over an extended timeframe and where values of EPS both increase and decrease, must have that dividends decline when earnings decline. Such a theory would appear invalid for the 2008-09 experience for these 11 electric utilities in PGE's group of comparable companies. Additionally, recall Roger Morin's statement that "DCF theory states clearly that it is the expected future cash flows in the form of dividends that constitute investment value."[209] Consider also Morin's "…if one is looking at historical data, or at short-term growth forecasts where payout ratios are not stable, then earnings and dividends may not grow at the same rate over some past historical period or over some short forecast period."[210] Nor should multistage DCF models reflect an equality of growth rates in such situations.

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207 Source: Value Line *Investment Survey*. The exceptions were Great Plains Energy and Ameren Corp.

208 This is an example of the "sticky downward" aspect to changes in DPS.

209 Morin, *op. cit.*, page 58, emphasis added.

210 *Ibid*, page 293, emphasis added.

Using my methodology for calculating dividends for the 2016 through 2020 period results in a 0.4 percent decline in IRR between the two DCF models. This result merits additional explanation. I use the method previously described, which resulted in a 3.42 percent annual rate of increase in the dollar value of dividends per share over this period. Dr. Zepp's methodology, used over the 2016 through 2025 period, uses the average of the four estimates for near-term growth in earnings in Exhibit PGE/1206,[211] which I discussed above, blended with his estimated 5.8 percent long-term nominal GDP growth rate, which I previously discussed. As described,[212] he used this ten-year period to "blend" the two rates in different proportions. The blend in 2016 is 90 percent the average of Value Line's and the analyst's growth rates in EPS for each individual company and 10 percent the 5.8 percent nominal GDP growth rate. This blend decrements/increments by 10 percent in each year until the blend proportions are reversed in 2024; i.e., a blend of 10 percent average growth rates in EPS and 90 percent the 5.8 percent nominal GDP rate. Over the ten year period, the average rate of dividend growth for PGE's 31 companies varies from 6.16 percent in 2016 to the 5.8 percent rate in 2025, which is the terminal valuation year of Dr. Zepp's multistage DCF model.

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[211] The average is 6.4 percent for the 31 companies.

[212] *See* Exhibit PGE/1200 Zepp/27 lines 16 - 18.

I use the 4.3 percent long-term rate of growth, previously described, for the period 2021 through 2025. The two different approaches to dividend growth in this period result in an additional 0.3 percent decline in IRR.

Terminal valuation in each of the two models uses the same approach. The dollar value of the final year's dividends per share for each company is divided by the difference between the IRR value for that company and the terminal growth rate. As the two terminal growth rates (my 4.3 percent and PGE's 5.82 percent) are materially different, this serves to reduce the IRR result between the two models 0.8 percent.

The extension of valuation timeframe from the 15 year horizon used in Dr. Zepp's multistage DCF model to the 40 year horizon in my most comparable DCF model did not result in any changes in results.

The remaining adjustments, which are the correction of cell mis-references and the removal of NorthWestern Corp., together result in a 0.2 percent reduction in the IRR between the two models.

Q. PLEASE SUMMARIZE THE ISSUES YOU HAVE WITH PGE'S MULTISTAGE DCF MODEL.

A. I take issue with the use of estimated earnings growth rates to grow dividends in the 2011 through 2015 period, when the U.S. economy is presumably still recovering from recession. I also take issue with the over 6 percent growth rate[213] used to grow dividends over the 2016 through 2024 period. My third issue is the use of the 5.8 percent growth rate used in the calculation of terminal value in 2025.

Q. SHOULD THE COMMISSION CONSIDER THE RESULTS FROM PGE'S MULTISTAGE DCF MODEL?

A. The Commission should reject the results from PGE's multistage DCF model, for the reasons discussed above.

PGE'S RISK PREMIUM MODELS

Q. WHAT IS THE RISK PREMIUM APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL?

A. The risk premium method[214] estimates the equity cost of capital by using the additional expected return equity investors require over some less risky asset[215] (the "risk premium"), added to a forecast value of the return of the less risky asset for a future period such as a future test year. In essence, some historical relationship of the equity cost of capital to the returns of a less risky asset are combined with a forecast return of the less risky asset with the result being the estimated expected cost of equity capital.

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213 This is based on averages across the companies in PGE's sample.

214 Also referred to as the "stock-bond-yield-spread" method, the "risk positioning" method, and the "bond-yield plus risk-premium" method. See Morin, *op. cit.*, page 107.

215 The "less risky" asset is typically a fixed income security, such as a Treasury bill, note, or bond; or a type of bond containing a "spread," or risk premium, over Treasury securities. Such bonds include a variety of types of taxable corporate bonds.

Q. WHAT RISK PREMIUM METHODS DOES PGE USE TO DEVELOP EQUITY COSTS OF CAPITAL?

A. The Company uses three different approaches, which I will discuss in turn. The first approach, described in Exhibit PGE/1200 Zepp/32 – 33, uses annual averages of actual returns on book equity for 12 electric utilities as compared with Baa Corporate Bond rates as reported by the Federal Reserve.[216]

Dr. Zepp subtracts the average annual bond rate from the average ROE for each year in the 1999 through 2008 period to obtain the "risk premium" for each year. He then obtains a 10-year (1999 – 2008) average risk premium and a five-year (2004 – 2008) average risk premium. These risk premium values are, respectively 3.78 percent and 4.18 percent.

Based on averages of forecasts of Baa corporate bond rates by Blue Chip and Global Insight for 2011, 2012, and 2013, Dr. Zepp obtains an average 2011 through 2013 "future" Baa corporate bond rate of 7.14 percent. When added to the two risk premium estimates, he obtains a range of "estimated equity costs for benchmark utilities" of 10.9 percent to 11.3 percent.[217]

Q. DID YOU MODIFY DR. ZEPP'S FIRST RISK PREMIUM ANALYSIS IN ANY WAY?

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216 Exhibit PGE/1212 contains the summary information and some results from this approach.

217 *See* Exhibit PGE/1216.

A. Yes. I added values for 1998,[218] and updated with values for 2009.[219] The update for 2009 resulted in an estimated risk premium over Baa corporate bond rates of 3.69 percent for the most recent 10 year period (2000 – 2009) and 3.91 percent for the most recent five year period. Combined with the 7.14 percent forecast 2011 – 2013 Baa corporate bond rate Dr. Zepp used, this update resulted in an updated range of "estimated equity costs for benchmark utilities" of 10.8 to 11.0 percent.

Note that if you restrict the forecasted rate of Baa corporate bonds to the year 2011 only, the range is now 10.5 percent to 10.7 percent; a reduction of 40 to 60 basis points from the range in Exhibit PGE/1216. Dr. Zepp reasons that the "cost of equity estimates should be for the period when new rates will be in effect," and anticipates that "the new rates set for 2011 will be in effect for more than one year."[220] I consider this assumption inconsistent with the notion of a test year. The cost of capital should be specifically applicable to the test year and generally applicable to some period beyond.

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218 The average earned ROE had already been calculated in the relevant worksheet, supplied as Attachment A to PGE's response to Staff data request 334. I obtained the average 1998 and 2009 Baa corporate bond rates from the Federal Reserve.

219 The update for 2009 uses 2009 values from Value Line to calculate the earned ROEs on average book value per share. Note that I used estimated Value Line values of 2009 book value per share for five of the 12 companies and Value Line's estimated value of 2009 earnings per share for IDACORP, Inc.

In the course of gathering the "update" values from Value Line, I made corrections to 11 values of book value per share and five values of earnings per share in the spreadsheet furnished in response to Staff data request 334. These correcting entries were generally of minor magnitude, and had generally minor impacts on overall results. The 2008 actual ROE value declined by 21 basis points as a result of these corrections, however.

220 *See* Exhibit PGE/1200 Zepp/30 lines 1 – 6.

Q. WHAT OTHER THOUGHTS DO YOU HAVE ON THIS RISK PREMIUM ANALYSIS?

A. To use a "risk premium" as an estimation tool, contingent upon a reliable estimation of the underlying security's future return, requires some stability in the value of the "risk premium;" i.e., stability in the relative values of, in this example, actual returns on average book value and average annual rates on Baa corporate bonds.

Using MS Excel's statistical capabilities to examine data in Exhibit PGE/1212, I found the correlation[221] between the two data series, as presented in Exhibit PGE/1212, to be 0.577, where a value of 1.000[222] would indicate the two series to be perfectly (and positively) correlated. The correlation on the larger data set of values for 1998 through 2009 (12 years, including the 10 years producing the correlation of 0.577) was even lower, at 0.366. This is often an issue with risk premium analyses, the changing relationship between the rate of return on the underlying security and the security for which you are estimating an expected future return. See, as an illustration of this issue, the two graphs on page 895 and the discussion on pages 895 and 896 of the article I have included as Exhibit Staff/922.[223,224] Figure 6 (following)

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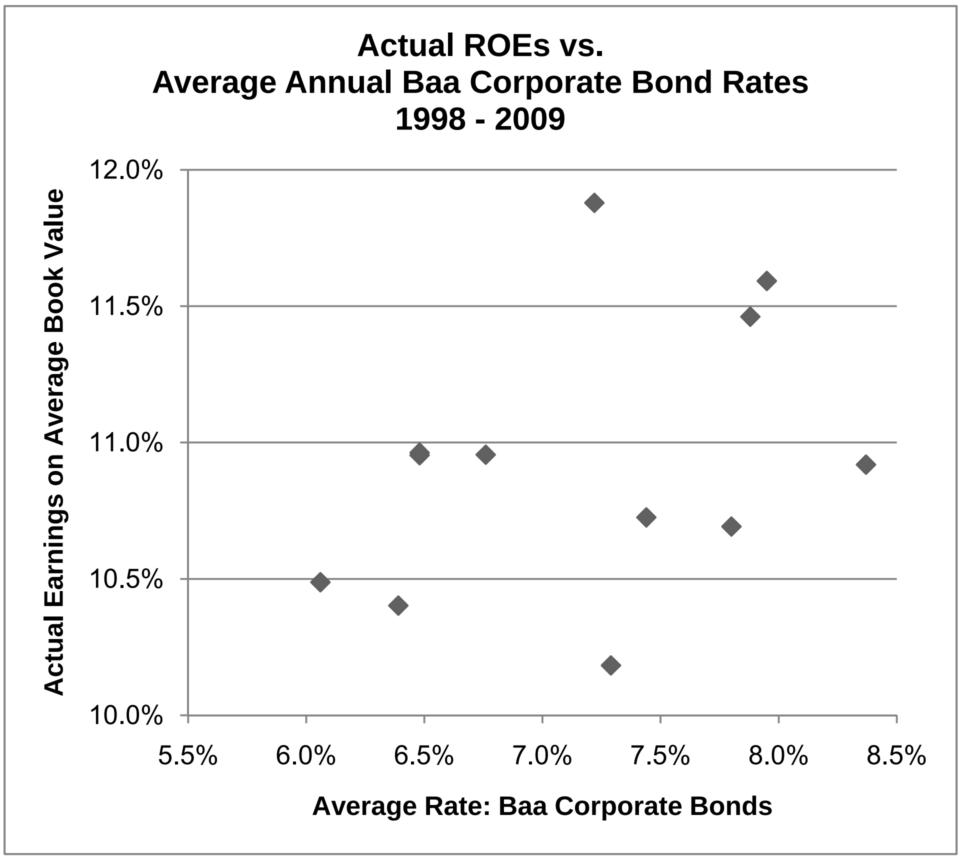
221 A basic and non-technical definition is that correlation is a measure of the relation between two or more variables.

222 A value of negative 1.000 would indicate the two to be perfectly and negatively correlated.

223 *See* "The Equity Premium in Retrospect," by Mehra and Prescott, This article comprises Chapter 14 in the *Handbook of the Economics of Finance*; edited by G. M.

illustrates the low correlation between the data series used in this risk premium analysis when the data is extended one year on each end; i.e., each series now covers the period 1998 through 2009.

Figure 6



Consider, as a hypothetical analogy, the following situation. I know only the average height of adult American males living today and the average height of adult American females living today. Based on these

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Costantinides, M. Harris and R. Stulz; 2003. This article is included as Exhibit Staff/922.

[224] Note in particular the authors' finding on page 895 that there have been periods when the equity (risk) premium has been *negative*.

two statistics, I know the difference in average height between these two populations is, say, six inches. If I observe a male of a given (known) height, to what extent does knowing his height help me predict the height of the next female, randomly observed?[225] This is the situation with many risk premium analyses, including this one, where values for the two averages are calculated, except the height of the male is not observed (known), it is somehow estimated.

The observed relationship between the value of the underlying security's return and that of the security of interest is an *ex post* analysis, not an *ex ante* comparison of the forecasted value of underlying security's return and the future return on the security of interest.

Q. PLEASE DESCRIBE PGE'S SECOND RISK PREMIUM ANALYSIS.

A. This analysis computes an annual risk premium as the difference between historical yields on Baa corporate bonds (as of the preceding December[226]) and the historical total returns of an index of electric utilities. The resulting average risk premium is then used with the estimated average yield on Baa corporate bonds over the 2011 through 2013 period. This analysis also incorporates a "linear but now one-half" adjustment for differences between the forecast Baa bond

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[225] By "randomly observed," I assume for purposes of the analogy that there is no correlation between the heights of observed males and females. This risk premium analysis, with extension to include 1998 and 2009, has a correlation between paired observations of 0.366.

[226] *See* footnote "a" to Exhibit PGE/1213.

rate and the historical average; i.e., if the forecasted bond rate is 0.8 percent less than the historical average, the decline in the cost of equity is 0.4 percent.

Q. WHAT ARE YOUR THOUGHTS ON THIS ANALYSIS?

A. My thoughts on this analysis are much the same as with the first PGE risk premium analysis.

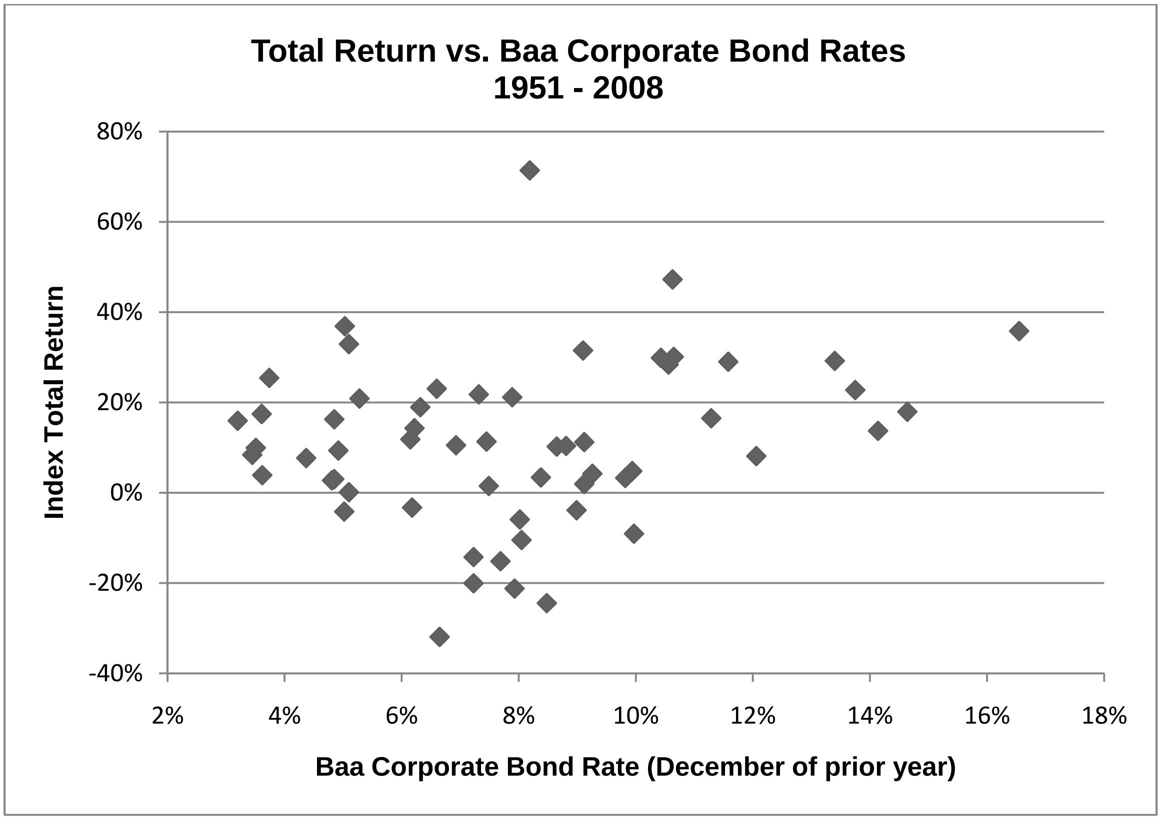
On this data set,[227] the correlation between total rate of return on the index (including its extension through 2008) and average yields of Baa corporate bonds for the preceding Decembers, at 0.2055, is less than the correlation in the last analysis. Additionally, I performed an OLS regression on the data, regressing the total returns on the index on the average yields of Baa corporate bonds for the preceding December. This regression resulted in an R^2 coefficient of 0.0422, which essentially means the level of Baa corporate bond rates had extremely limited explanatory power with respect to the total return of the index. The observed values of the Baa corporate bond rates and the total return of the index over the 1951 through 2008 period are depicted in Figure 7 (following).

The short story, given these statistics, is that the ability to estimate a forward cost of equity is very limited in this analysis, even if the future

[227] This analysis includes Dr. Zepp's work-up of both the dividend yield and price return for surviving electric utilities formerly in the Moody's index for the period 2001 through 2008. *See* Exhibit PGE/1200 Zepp/34 line 9 through line 15.

rate of the underlying security (here, the rate on Baa corporate bonds) is *known*.

Figure 7



Q. PLEASE DESCRIBE PGE'S THIRD RISK PREMIUM ANALYSIS.

A. Dr. Zepp cites as support of his approach in this third analysis Roger Morin's description of a technique whereby the value of an observed risk premium, defined as the difference between an authorized return on equity and an observed bond rate, is statistically related to Treasury rates. To obtain a cost of equity estimate, the "current (or projected) long-term Treasury bond yield…is substituted" in the statistically-derived equation.[228] Dr. Zepp's third risk premium analysis takes a similar approach, using Baa bond rates[229] and authorized ROE values over the period 1985 to 2008, the latter values as proxies for actual costs of equity, to determine values of risk premia. The resulting risk premium values are then regressed on the respective Baa bond rates to obtain a linear equation relating values of risk premium to Baa bond rates.

Dr. Zepp uses this equation to determine the value of the risk premium given the 7.14 percent average of the forecasted Baa corporate bond rate for each of 2011, 2012, and 2013. Dr. Zepp then adds the 3.72 percent risk premium to the 7.14 percent forecasted average 2011 – 2013 Baa corporate bond rate to obtain an equity cost of 10.9 percent for "a typical electric utility" in 2011 through 2013.[230]

Q. WHAT ARE YOUR THOUGHTS ON THIS THIRD PGE RISK PREMIUM ANALYSIS?

A. Both Dr. Zepp's equation[231] and presumably Dr. Morin's as well suffer from two flaws. The first flaw involves using the same set of values—those for the bond rate—on both sides of the regression model, or equation. The dependent variable in the regression model is the observed risk premium and the independent variable is the bond yield

[228] *See* Morin, *op. cit.*, pages 125-126.

[229] The bond rates are those prevailing six months prior to the issuance of the Order authorizing the specific ROE.

[230] *See* Exhibits PGE/1200 Zepp/37 line 12 through line 17 and PGE/1214.

[231] *See* the "Formula" equation in Exhibit PGE/1214.

(or rate). The risk premium, however, is defined as the difference between the observed authorized ROE and the bond rate. While not specifically mentioned in his description of this analysis, Dr. Zepp obtains the observed risk premium by subtracting the observed bond rate from the observed authorized ROE values.[232] Exhibit PGE/1214 does shed some light on the approach used in this analysis. Note that Dr. Zepp defines as "Formula:"

Risk Premium = A_0 + (A_1 x Baa Bond Rate);

where the values of A_0 and A_1 are estimated coefficients resulting from the regression analysis. This is the regression analysis having the statistics reported as the "Regression Output:" in this Exhibit. While not shown in this Exhibit, values of "Risk Premium" are defined, in the Exhibit's heading, as "Determined by Relationship Between Authorized ROEs and Baa Corporate Bond Rates…" This relationship is more precisely defined as:

Risk Premium = Authorized ROE – Baa Bond Rate.

This is not the first occasion Staff has had this issue with a risk premium analysis presented in PGE testimony. In Docket No. UE 180, Staff provided testimony on the same issue, in that docket regarding what PGE then termed its Risk Positioning Model, or RPM:

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[232] *See* also Exhibits PGE/1212 and PGE/1213. In the former, the "Average Annual Risk Premium" is obtained by subtracting the "Baa Corporate Bond Rates" from the observed "Return on Equity." In the latter, the "Risk Premium" is obtained by subtracting the "Baa Corporate Bond Rate" for December of the prior year from the "Total Return" of the index.

"Q. PLEASE DISCUSS YOUR SECOND MAJOR CONCERN THAT THE STATISTICAL RESULTS OF PGE'S RPM ARE FALLACIOUS.

A. PGE's model subtracts either a Treasury rate or a corporate rate from the Commission authorized ROE and then regresses that difference on the same Treasury or corporate rate. Mathematically this can be express as the following: $(AROE_{i,t} - T_{i,t-1}) = \alpha + \beta * T_{i,t-1} + \varepsilon$. Because the term $T_{i,t-1}$ is on both sides of the equation, the results are a "finding" that the interest rate that was subtracted from the authorized cost of equity helps explain the difference between the authorized cost of equity and that same interest rate. This circular reasoning results in statistical tests that appear to show a high degree of statistical significance."[233]

Q. WHAT IS THE SECOND FLAW IN THIS THIRD RISK PREMIUM ANALYSIS?

A. The risk premium analysis described in Exhibit PGE/1200 Zepp/35 through Zepp/38 and documented at a high level in Exhibit PGE/1214 uses historical authorized ROEs as an explanatory variable in estimating that "…a typical electric utility can expect to face a cost of equity of 10.9% in 2011-13."[234,235]

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[233] *See*, in Docket No. UE 180, Exhibit Staff/1100 Conway/6 lines 10-20.

[234] Exhibit PGE/1200 Zepp/37 lines 16-17.

[235] Note that if the estimated 2011 Baa corporate bond rate in Exhibit PGE/1211 of 6.8 percent is used, the estimated equity cost for the typical electric utility for 2011, PGE's test year in this proceeding, is (3.72% + 6.80% =) 10.52 percent.

This third risk premium analysis is similar to the "risk positioning" model used by PGE in Docket No. UE 180, where PGE calculated "the difference between the cost of equity found appropriate in non-stipulated, authorized ROE decisions by regulatory bodies, on average, since 1983, and either electric utility corporate bonds or Treasuries."[236]

Q. WHAT DID THE COMMISSION INCLUDE IN ORDER NO. 07-015 WITH RESPECT TO PGE'S RISK POSITIONING MODEL IN DOCKET NO. UE 180?

A. Included in the Commission's Order was the affirmation that "the position taken by the Commission in Docket No. UE 115, that the Commission will not rely on ROEs authorized in other jurisdictions to determine an Oregon utility's authorized ROE, but will use those decisions to gauge the reasonableness of our decision" and that "[i]n addition, for the reasons given in docket UE 115, we reject the risk positioning model…we find, based on the evidence in this record, that the reasoning expressed in that order remains sound."[237]

Q. WHAT DO YOU KNOW ABOUT THE EXPLANATORY POWER OF PGE'S THIRD RISK PREMIUM ANALYSIS?

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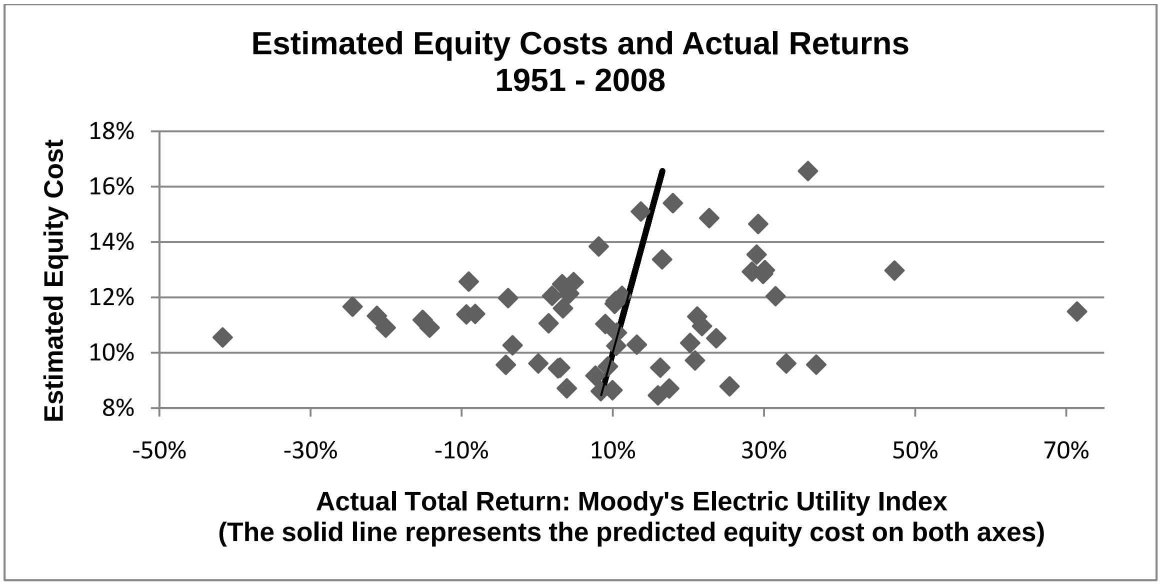
[236] Order No. 07-015, page 42.
[237] Order No. 07-015, page 47.

A. PGE has provided, in Exhibit PGE/1213, Baa corporate bond rates[238] and the realized total return on Moody's Electric Utilities index, as updated by Dr. Zepp, for the period 1951 – 2008. The provided bond rates are for December of the preceding year, which is not the same as the six-month lag from the date each decision was issued used by Dr. Zepp in Exhibit PGE/1214, and neither is the actual Index total return the same measure as jurisdictionally authorized ROEs. Recognizing that rates on the same underlying security used in PGE's third risk premium analysis and actual ("market"[239]) returns of an electric utility index were each available for 1951 through 2008, I developed a chart of these actual electric utility index equity returns against the costs of equity resulting from use of the values and coefficients in Exhibit PGE/1214. This chart is depicted in Figure 8 (following), where the solid line represents equality between the cost of equity predicted by PGE's third risk premium analysis and the actual total return on the index; i.e., the locus where all observations would plot if PGE's third risk premium analysis had perfect explanatory power. To be sure, this is a simple illustration of the predicted cost of equity given a wide variety (58 years' worth) of levels of Baa corporate bond rates versus actual market returns for an index of electric utility stocks.

[238] Baa corporate bonds are the underlying security in PGE's third risk premium analysis, as documented in Exhibit PGE/1214.

[239] *See* Exhibit PGE/1200 Zepp/34 line 2.

Figure 8



Acknowledging some intuitive veracity in the sentiment that "[i]f a model explains well, then it will generally forecast well, given similar circumstances,"[240] I conclude PGE's third risk premium analysis neither explains well,[241] nor does it "generally forecast well."

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THE COST OF EQUITY ESTIMATES PGE OBTAINS FROM THESE THREE RISK PREMIUM ANALYSES?

A. I recommend the Commission reject the results of these analyses for the reasons discussed above.

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[240] Exhibit PGE/2700 Hager – Valach/21 lines 16 – 18 in Docket No. UE 180.

[241] The R^2 (coefficient of determination) value reported in Exhibit PGE/1214 is 58.2%.

RISK AND RETURN REVISITED

Q. YOU DISCUSSED SOME ASPECTS OF RISK AND RETURN EARLIER IN THIS TESTIMONY. DO YOU HAVE ANY THOUGHTS ON THIS TOPIC AS APPLIED TO PGE SPECIFICALLY?

A. PGE provided a chart of the Chicago Board Options Exchange (CBOE) Volatility Index (symbol "VIX")[242] in testimony,[243] and I believe a brief, non-technical description may be useful. Prices of the VIX are in terms of percentage points and translate, roughly, to the expected movement in the S&P 500 index over the next 30-day period, on an annualized basis. For example, if the VIX is at 15, this represents an expected annualized change of 15 percent over the next 30 days; thus one can infer that the index option markets expect the S&P 500 to move up or down over the next 30-day period. That is, index options are priced with the assumption of a 68 percent likelihood (one standard deviation) that the magnitude of the S&P 500's 30-day return will be less than 1.17 percent (up or down).[244,245]

[242] The Volatility Index or VIX is a popular measure of the implied volatility of S&P 500 index options. It is not backed by anything and positions held are merely a prediction of a future. A high value corresponds to a more volatile market and therefore more costly options, which can be used to defray risk from this volatility by selling options. Often referred to as the *fear index*, it represents one measure of the market's expectation of volatility over the next 30-day period.

[243] *See* Exhibit PGE/1100 Hager – Valach/13.

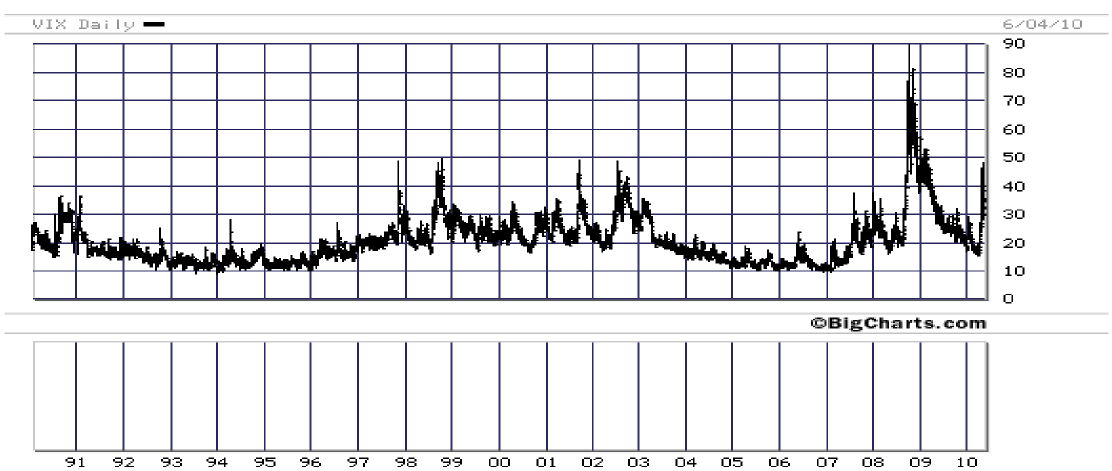
[244] Adapted from Wikipedia.

[245] The 30-day return of 1.17 percent, compounded 12 times (approximately "monthly"), implies an annualized rate of ±14.98 percent.

The VIX chart in the Company's testimony spanned roughly the period 2005 through 2009. I thought it might be useful to update PGE's chart to include all data available, as depicted in Figure 9 (following).[246] At some risk, I will identify a few "peaks" in the index over the past 20 years: the Asian crisis ("Asian contagion") – 1997; the Russian financial crisis – 1998; the events of 9/11 and after – 2001; and the current "Greek/Euro" crisis of 2010. Other than 2002 (post- 9/11?), the only other time the index has been above 40 in its now 20-year history is in the 2007 – 2009(?) recession.

Figure 9

VIX Index – Available History



One potential conclusion from reviewing the above is that the big crisis—of at least the last 20 years, as measured by the VIX—now is

[246] Source: BigCharts at http://bigcharts.marketwatch.com .

behind us, and we are currently in one of what might be described as "periodic crises," such as those listed above. Higher volatility in the S&P 500 stock index than the average experience over the last 20 years seems indicated between now (late May) and late June; i.e., within the next 30 days as I write this.

Q. WILL THE PRICE OF PGE STOCK EXPERIENCE HIGHER THAN AVERAGE VOLATILITY OVER THE NEXT 30 DAYS?

A. I don't know.

Q. IS PGE LESS RISKY THAN THE MARKET?

A. Yes. PGE's testimony provides some level of detail around various risks to which the Company is described as being exposed.[247] The rational investor however, does diversify away these risks. The result is that PGE's stock price fully[248] reflects all risks considered relevant by all entities that impact its price by buying or selling PGE stock.

Q. ARE THE RISKS PGE DESCRIBES IN TESTIMONY ALL INCLUSIVE OF RISKS FACED BY THE COMPANY?

A. Probably not. I have attached as Exhibit Staff/923 the risk factors listed in the Company's most recent SEC Form 10-K filing.[249]

All of the listed risks, and almost certainly some that are not listed, are reflected in PGE's stock price.[250]

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[247] *See* especially Exhibit PGE/1100 Hager – Valach/26-30.

[248] The extent of "fully" depends on which variation of the efficient market hypothesis (E-M-H) is valid, or "true." For a discussion of the E-M-H, *see*, for example, Brealey and Myers, *op. cit.*, pages 287-298.

[249] This filing was for the fiscal year ending December 31, 2009.

Q. IF PGE FACES ALL OF THE RISKS DESCRIBED IN TESTIMONY, AND ALL OF THE RISKS DESCRIBED IN THE MOST RECENT SEC FORM 10-K FILING, HOW DOES THE COMPANY'S RISK COMPARE WITH THE RISK OF OTHER ELECTRIC UTILITIES?

A. PGE's risk is average relative to the other electric utilities on its list of comparable companies. Figure 10[251] (following) decomposes the market risk,[252] which is the risk that matters to investors in the Company's common stock, into two categories: financial risk[253] and business risk. The vertical axis represents the value of the Company stock's beta, or total risk of the Company, and the horizontal axis represents the financial risk to the company. Note that, if PGE was entirely equity financed, the total risk would equal the business risk. Another way to think of this is that the volatility of PGE's stock increases (market risk increases), all else being equal, as the proportion of debt in its capital structure is increased.

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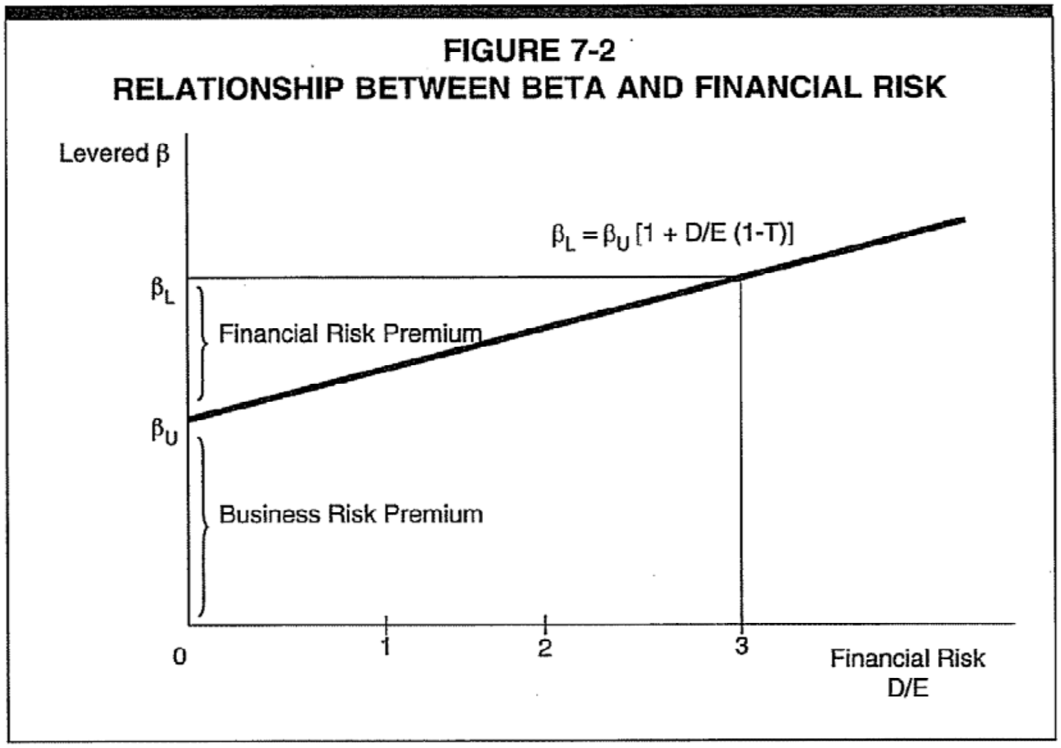
250 The Commission has previously expressed what I take as concurrence with the "risk reflected in stock price" reasoning. Language at page 24 in Order No. 01-777 included the following: "The DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. <u>The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation</u>;" emphasis added.

251 This figure was taken from Morin, *op. cit.*, page 222.

252 It is clear here that Morin is describing market risk, as he states that "beta is a measure of the systematic risk…" *Ibid.,* page 222. Recall that the terms "market risk" and "systematic risk" are synonymous.

253 The financial risk is due PGE's capital structure being composed of not only shareholders' or common equity, but also debt.

Figure 10



To reasonably compare PGE's risk with other electric utilities, it makes sense to "put them on the same basis" with respect to financial risk. One way to do that is to "deleverage"[254] each of the companies in PGE's list of comparable companies (including PGE)[255] so that each has a hypothetical capital structure of 100 percent common equity.[256]

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[254] The terms "delever," "unlever," "unleverage," and "deleverage," and the respective variants of each (e.g., delevering, unlevering, unleveraging, and deleveraging) are used synonymously in my testimony. I trust my meaning is, in context, clear with each usage.

[255] I work with the companies on PGE's list and not my list only because it includes more companies. There is no more than a 0.02 difference between the two groups of companies for either the average observed (leveraged) beta or for the average unleveraged beta. Recall that 12 of my 13 comparable companies are on PGE's list of comparable companies.

[256] I used the Hamada equation, previously discussed in my testimony, to calculate the unleveraged beta for each company.

The deleveraging compensates for any difference in risk due to differences in the degree of financial leverage; with the result that the unleveraged betas now reflect each company's business risk, as depicted in Figure 10, and no financial risk.

Q. WHAT ARE THE RESULTS OF THE DELEVERAGING? CAN WE NOW COMPARE THE BUSINESS (NON-FINANCIAL) RISK BETWEEN THESE DIFFERENT ELECTRIC UTILITIES?

A. Table 8 (following) lists, for each company in PGE's list of comparable companies except NorthWestern Corp., the beta value after deleveraging[257] to reflect capital structures composed entirely of common equity; i.e., without any debt:

Table 8

Non-financial Risk

PGE's Comparable Companies[258]	Value Line Beta	Unleveraged Beta
Allegheny Energy Inc.	0.95	0.55
ALLETE	0.70	0.45
Alliant Energy Corp	0.70	0.47
Ameren Corp.[2]	0.80	0.49
American Electric Power Co. Inc.	0.70	0.38
Avista Corp.	0.70	0.43
Cleco Corp.	0.65	0.38
CMS Energy Corp.	0.75	0.31
DPL Inc.	0.60	0.36
DTE Energy Co.	0.75	0.44
Duke Energy Corp.[2]	0.65	0.42
Edison International	0.80	0.44

[257] The beta value after deleveraging is represented in Figure 10 as β_U.

[258] Does not include NorthWestern Corp.

Empire District Electric Co.	0.70	0.41
Entergy Corp.	0.70	0.38
FPL Group, Inc.	0.75	0.37
Great Plains Energy Inc.[2]	0.75	0.43
Hawaiian Electric Industries	0.70	0.45
IDACORP	0.70	0.41
MGE Energy Inc.	0.65	0.47
OGE Energy Corp.	0.75	0.43
PG&E Corp.	0.55	0.33
Pinnacle West	0.75	0.46
Portland General	0.75	0.41
Progress Energy Inc.	0.60	0.34
Southern Co.	0.55	0.31
TECO Energy, Inc.	0.85	0.49
UniSource Energy	0.70	0.32
Westar Energy Inc.	0.75	0.43
Wisconsin Energy Corporation	0.65	0.37
Xcel Energy	0.65	0.37
Average	0.71	0.41

The Value Line beta for PGE is 0.75 and averages 0.71 for the group as a whole. This result, with PGE slightly more risky than the average company in the group, is due entirely to the slightly more leveraged capital structure reported by Value Line for PGE versus the average company in the group; i.e., capital structures reflecting long-term debt proportions of 53.0 percent and 51.6 percent,[259] respectively.

[259] The relative proportions of long-term debt and common equity (some companies have preferred stock) I used came from the latest discrete year for which Value Line provided estimates of these two values. This year was either 2010 or 2011, depending on which issue of Value Line *Investment Survey* was used. This includes Value Line's forecast of PGE's capital structure having a 53.0% long-term debt component for 2010. I point this out, as Exhibit PGE/1201 Zepp/1 has different capital structure components, as reflected in the "Expected Common Equity Ratio." It is not clear to which year these pertain. As an example, reviewing the February 5, 2010 issue of the *Investment Survey* for Portland General, Value Line lists the following proportions, and whether the value is actual or estimated, for common equity: 53.8% (actual 2008), 50.0% (estimated 2009), 47.0% (estimated 2010, the value I used), and 50.0% (the estimated three-year average for 2012-14). I surmise either a) the Value Line forecast changed from the forecast in the December 4, 2009 issue of *Investment Survey, Summary & Index* used by Dr. Zepp (*see* Exhibit

After deleveraging the capital structure for each company, PGE's unleveraged (and without financial risk) beta is 0.41 and the average unleveraged beta of the companies in the group is also 0.41. PGE has the same level of business risk, as reflected in Value Line's beta, as the average of the Company's (self-chosen) comparable electric utilities.

Dr. Zepp claims that "PGE is more risky [compared to the sample of electric utilities in PGE Exhibit 1201] because it (a) has significant exposure to the wholesale market due to its reliance on wind and hydro generation, (b) is smaller than the average utility in my benchmark sample, (c) has greater risk than in the past due to its larger capital expenditures program, (d) has debt imputation related to purchased power contracts, (e) currently has a PCAM that does not reduce risk as much as the typical PCAM authorized for other electric utilities in my sample, and (f) has other unique risks described by Mr. Valach and Mr. Hager."[260]

Taking Dr. Zepp's statements one-at-a-time as I read them: "a" makes no comparison with the sample companies or any other electric utilities; "b" is true, PGE is smaller (but not the smallest) than the

PGE/1201, footnote "b"), or b) he used a value estimated for 2009 or the estimated average value for 2012-14.

[260] Exhibit PGE/1200 Zepp/11 line 18 through Zepp/12 line 3.

average sample company;[261] "c" has greater risk <u>than in the past;</u> i.e., "c" compares PGE with PGE and with no other electric utilities; "d" makes no comparison of relative or actual values of debt imputation versus the sample or other electric utilities;[262] "e" (PGE's PCAM) is discussed elsewhere in Staff's testimony; and "f" references testimony in Exhibit PGE/1100.

Alternatively stated and excepting any comparison of PGE's PCAM mechanism, PGE is, from the cited passage after distillation, more risky than the other electric utilities in PGE's list of comparable companies because PGE "is smaller than the average utility" in the sample group and has "other unique risks" described elsewhere. On the other hand, PGE's "more risk[iness]" is "offset to some extent by PGE having decoupling."[263]

Assuming Dr. Zepp's "f'" reference is to pages 27 through 30 of Exhibit PGE/1100, there is not one risk listed on pages 27 through 30 that is unique to PGE, except the "[u]ncertainty regarding an adverse Trojan decision." To my knowledge, no other electric utility in PGE's list of comparable companies has that particular risk; as defined, it

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[261] Seven of the comparable companies (eight including PGE itself) have lower levels of market capitalization than does PGE. Notably, market capitalization is computed as the "number of shares times price per share at November 16, 2009 as reported by AUS Utility Reports in December 2009." *See* Exhibit PGE/1201 Zepp/2 footnote "g."

[262] What statement "d" compares is the percent of purchased power, using values from Value Line.

[263] Exhibit PGE/1200 Zepp/12 line 3.

appears to be uniquely PGE's.[264] Notably, PGE is not "uniquely" exposed to the ramifications of Oregon's Senate Bill 408.

Staff data request 391, attached as Exhibit Staff/924, lists several features or attributes where I think PGE may have less risk (or greater positive exposure, such as demographics) than some other electric utilities. As indicated in the Company's response, Dr. Zepp[265] has not conducted any studies, has not performed any literature searches, or is otherwise not aware of how PGE stacks-up with the risks (and opportunities) listed in parts "a" through "k" of Staff data request 391.

How risky is PGE as compared with other electric utilities? I believe the Company has approximately average business risk based on the deleveraged beta value of 0.41, which equals the average of the 30 electric utilities in PGE's list of comparable companies.[266] Of some interest, as PGE mentions the risk of companies with smaller capitalization than the average electric utility in PGE's sample,[267] is the following: of the six smaller-than-PGE electric utilities in PGE's list of comparable companies,[268] one (UniSource) has a lower unleveraged

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264 Obviously, another electric utility may be exposed to the risk of an adverse decision with respect to one or more <u>other</u> nuclear facilities.

265 Somewhat curiously, the Company's response to Staff data request 391 is entirely in terms of what Dr. Zepp did or did not do and special studies that are beyond the scope of his testimony or analysis. Note that the request references "risks faced by PGE" discussed in both Exhibits PGE/1100 Hager – Valach/26 - 30 and PGE/1200 Zepp/11 - 19.

266 NorthWestern Corp. is excluded.

267 Exhibit PGE/1200 Zepp/8 lines1-2.

268 I have again excluded NorthWestern Corp.

beta (0.32); two (IDACORP and Empire District) have the same 0.41 unleveraged beta; and three (ALLETE, Avista, and MGE Energy) have higher unleveraged betas (0.45, 0.43, and 0.47, respectively). The average unleveraged beta of these six electric utilities, each having a smaller - than - PGE market capitalization (as defined by PGE[269]), is 0.41—the same value as PGE's.[270]

DECOUPLING

Q. WHERE DOES PGE PROVIDE TESTIMONY ON DECOUPLING?

A. PGE's primary testimony with respect to the Sales Normalization Adjustment (SNA) decoupling mechanism and the Lost Revenue Recovery (LRR) mechanism is in Exhibits PGE/1100 Hager – Valach/8 - 9 and PGE/1500 Kuns – Cody/34 – 36.

Q. WHAT WAS STAFF'S PRIMARY OBJECTION TO THE SNA AND LRR MECHANISMS PGE PROPOSED IN DOCKET NO. UE 197?

A. My primary objection was the potential for PGE over-collecting revenue due to the design of the SNA mechanism.[271] This is possible under circumstances involving the rates of residential customer growth and

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[269] *See* footnote "g" of Exhibit PGE/1201 Zepp/2.

[270] Note that in the absence of intermediate rounding, the 0.41 average of these six beta values is the result of a <u>nearest</u> rounding to two decimal places.

[271] *See*, in Docket No. 197, Exhibits Staff/600 Storm/17 – 21, Staff/1300 Storm/11 – 15 (including the September 23, 2008 errata filing), and Staff/1301.

the rates of change in weather-adjusted usage per residential customer.[272]

Q. WHERE THE PROPOSED MECHANISMS IMPLEMENTED?

A. Yes. As a two year pilot, the mechanisms were implemented as PGE's Rate Schedule 123.

Q. DID THE COMMISSION INCLUDE CONDITIONS ON THE SNA AND LRR MECHANISMS' PILOT?

A. Yes. The Commission, in Order No. 09-020,[273] as modified by Order No. 09-176, included seven conditions associated with approval of PGE's pilot. One condition concerned PGE's submission of an assessment, with a requirement that six issues listed by the Commission be addressed in the assessment. PGE provides this assessment in Exhibit PGE/1507.

Q. DO YOU HAVE ANY THOUGHTS ON ONE OR MORE OF THE ISSUES AND PGE'S RELATED ASSESSMENT?

A. Yes. The last question, or issue, addressed is the question of:

> "Did the mechanism improve the utility's ability to recover its fixed costs? To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in this proceeding?"

PGE's assessment regarding this issue is as follows:

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[272] This also potentially applies to the small commercial customer class as well.

[273] *See* Order No. 09-020, pages 28 through 30.

"The decoupling mechanism improves PGE's ability to recover its per customer fixed costs at forecasted levels approved by the Commission in its most recent rate case (UE-197); however, Schedule 123 is not a full decoupling mechanism in that the mechanism reflects only weather normalized sales and does not fully true-up fixed cost recovery because large nonresidential customers are not decoupled. Because PGE's customer count was below that forecast in UE 197, PGE is unable [to] evaluate whether fixed costs increased due to customer growth beyond what was included in the test-year load forecast."

I would expand this passage, leaving aside the issue of non-applicability to all customer classes, first agreeing that the SNA mechanism improves the Company's ability to recover its residential and small commercial per customer fixed costs, and that "Schedule 123 is not a full decoupling mechanism in that the mechanism reflects only weather normalized sales" on a per (residential and small commercial) customer basis and is not a full decoupling mechanism because fixed costs for the generation and transmission functions are not incurred on a per customer basis. Fixed costs for these functions, like others, are largely recovered on volumetric rates. They differ in that PGE could over-recover these fixed costs in a situation where, with a decline in usage per customer and growth in the number of customers interacting in such a way (the rate of customer growth more than off-setting the rate of decline in usage per customer) that the total volume of energy (kWhs) is greater than that in rates. This is the issue I addressed in testimony in Docket No. UE 197.

Q. DO YOU PROPOSE CHANGES THAT WOULD BOTH MAKE THE SNA MECHANISM A MORE "FULLY DECOUPLED" MECHANISM AND POTENTIALLY ELIMINATE THIS OUTCOME?

A. Yes. I propose the SNA mechanism be "split in two" with the usage per customer comparative values[274] composed of fixed costs other than those representing generation and transmission and new comparative values composed of fixed costs associated with generation and transmission, which are established on a total volume (not volume per customer) basis. This would remove the potential for over-collection in situations where total volumes and total revenue collected volumetrically increase due to customer growth while usage per customer and the per customer revenue value decline.

As PGE operates with functional accounting and currently establishes revenue requirements separately by function, implementation of this modification from an accounting and costing perspective would seem straightforward.

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[274] "Values" (plural), as there is one value for each of the residential and small commercial customer classes.

Q. WHAT RECOMMENDATIONS DO YOU MAKE TO THE COMMISSION REGARDING PGE'S SNA AND LRR MECHANISMS?

A. I recommend the Commission continue to associate PGE's SNA and LRR mechanisms with a no less than 10 basis point reduction in authorized ROE. Although the recommended 9.2 percent point estimate of ROE is inclusive of a 10 basis point downward adjustment for PGE's reduced risk associated with decoupling and lost revenue recovery mechanisms, a 2011 test year discontinuance of the mechanisms would argue for an upward adjustment of my recommended 9.2 percent ROE point estimate to 9.3 percent.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME	Steven T. Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Program Manager, Economic Research and Financial Analysis Division
ADDRESS	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2148
EDUCATION	M.B.A. University of Oregon; Eugene, Oregon A.B. (Economics); Harvard; Cambridge, Massachusetts
EXPERIENCE	Employed by the Public Utility Commission of Oregon since October 2007, I am currently Program Manager of the Economic and Policy Analysis Section. My responsibilities include leading a team of analysts engaged in economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in multiple dockets. Prior regulatory experience includes four years in which my responsibilities included developing responses to data requests regarding the financial analysis of new products and services at US WEST Communications.
OTHER EXPERIENCE	I was a self-employed financial planner for eight years following an 18 year career in management positions engaged in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing (rate spread and rate design) and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct for 5 years. I was responsible for departmental budgeting and management reporting functions for three years at US West Direct and was responsible for corporate financial planning, analysis, and management reporting for one year at Electric Lightwave. I have seven years experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

June 4, 2010

Stock Market Returns in the Long Run:
Participating in the Real Economy

(Forthcoming Financial Analyst Journal)

Roger G. Ibbotson, Ph.D.
Professor in the Practice of Finance
Yale School of Management
135 Prospect Street
New Haven, CT 06520-8200
Phone: (203) 432-6021
Fax: (203) 432-6970

Chairman
Ibbotson Associates, Inc.
225 N. Michigan Ave. Suite 700
Chicago, IL 60601-7676
Phone: (312) 616-1620
Fax: (312) 616-0404

Peng Chen, Ph.D., CFA
Vice President, Director of Research
Ibbotson Associates, Inc.
225 N. Michigan Ave. Suite 700
Chicago, IL 60601-7676
Phone: (312) 616-1620
Fax: (312) 616-0404
E-mail: pchen@ibbotson.com

July 9, 2002

ABSTRACT

We estimate the forward-looking long-term equity risk premium by extrapolating the way it participated in the real economy. We decompose the 1926-2000 historical equity returns into supply factors including inflation, earnings, dividends, price to earnings ratio, dividend payout ratio, book value, return on equity, and GDP per capita. There are several key findings: First, the growth in corporate productivity measured by earnings is in line with the growth of overall economic productivity. Second, P/E increases account for only a small portion of the total return of equity (1.25% of the total 10.70%). The bulk of the return is attributable to dividend payments and nominal earnings growth (including inflation and real earnings growth). Third, the increase in factor share of equity relative to the overall economy can be more than fully attributed to the increase in the P/E ratio. Fourth, there is a secular decline in the dividend yield and payout ratio, rendering dividend growth alone a poor measure of corporate profitability and future growth. Contrary to several recent studies, our supply side model forecast of the equity risk premium is only slightly lower than the pure historical return estimate. The long-term equity risk premium (relative to the long-term government bond yield) is estimated to be about 6% arithmetically, and 4% geometrically. Our estimate is in line with both the historical supply measures of the public corporations (i.e., earnings) and the overall economic productivity (GDP per capita).

I. INTRODUCTION

Numerous authors are directing their efforts toward estimating expected returns on stocks incremental to bonds.[1] These equity risk premium studies can be categorized into four groups based on the approaches they have taken. The first group of studies try to derive the equity risk premiums from historical returns between stocks and bonds as was done in Ibbotson and Sinquefield (1976a,b). The second group, which includes our current paper, uses fundamental information such as earnings, dividends, or overall economic productivity to measure the expected equity risk premium. The third group adopts demand side models that derive expected equity returns through the payoff demanded by investors for bearing the risk of equity investments, as in the Ibbotson, Siegel, and Diermeier (1984) demand framework, and especially in the large body of literature following the seminal work of Mehra and Prescott (1985). The fourth group relies on opinions of investors and financial professionals through broad surveys.

Our paper uses supply side models. We first used this type of model in Diermeier, Ibbotson, and Siegel (1984). There have been numerous other authors who have also used supply side models, usually focusing on the Gordon (1962) constant dividend growth model. For example, Siegel (1999) predicts that the equity risk premium will shrink in the future due to low current dividend yields and high equity valuations. Fama and French (2002) use a longer time period (1872 to 1999) to get historical expected geometric equity risk premiums of 2.55% using dividend growth rates, and 4.32% using earnings growth rates.[2] They argue that the increase in P/E ratio has resulted in a realized equity risk premium that has been higher than ex ante expected. Campbell and Shiller (2001) argue for low returns, because they believe the current market is overvalued. Arnott and Ryan (2001) argue that the forward-looking equity risk premium is actually negative. This stems from using the low current dividend yield plus their very low forecast dividend growth.

Arnott and Bernstein (2002) argue similarly that the forward-looking equity risk premium is near zero or negative. We later argue that mixing the current low dividend yields and payout ratios with historical dividend yield growth violates Miller and Modigliani (1961) dividend theory.

The survey results generally support somewhat higher equity risk premiums. For example, Welch (2000) conducted a survey among 226 academic financial economics on equity risk premium expectations. The survey shows that the geometric long horizon equity risk premium forecast is almost 4%.[3] Graham and Harvey (2001) conducted a multi-year survey of CFOs of U.S. corporations, they find that the expected 10-year geometric average equity risk premium ranges from 3.9% to 4.7%.

In this paper, we link historical equity returns with factors commonly used to describe the aggregate equity market and overall economic productivity. Unlike some studies, our results are portrayed on a per share basis (per capita in the case of GDP). The factors include inflation, earnings per share, dividends per share, price to earnings ratio, dividend payout ratio, book value per share, return on equity, and GDP per capita.[4] We first decompose the historical equity returns into different sets of components based on six different methods. Then, we examine each of the components within the six methods. Finally, we forecast the equity risk premium through supply side models using historical data.

Our long-term forecasts are consistent with the historical supply of U.S. capital market earnings and GDP per capita growth over the period 1926-2000. In an important distinction from the forecasts of many others, our forecasts assume market efficiency and a constant equity risk premium.[5] Thus the current high P/E ratio represents the market's forecast of higher earnings growth rates. Furthermore, our forecasts are consistent with Miller and Modigliani (1961) theory so that dividend payout ratios do not affect P/E ratios and high earnings retention rates (usually associated with low yields) imply higher per share future growth. To the extent that corporate cash is not used for reinvestment, it is assumed to be used to repurchase a company's own shares or perhaps more frequently to purchase other companies' shares. Finally, our forecasts treat inflation as a pass-through, so that the entire analysis can be done in real terms.

II. THE SIX METHODS FOR DECOMPOSING HISTORICAL EQUITY RETURNS

We present six different methods of decomposing historical equity returns. The first two methods (especially method 1) are models based entirely on historical returns. The other four methods are models of the supply side. We evaluated each method and its components by applying historical data from 1926 to 2000. The historical equity return and earnings data used in this study are obtained from Wilson and Jones (2002).[6] The average compounded annual return for the stock market over the period 1926-2000 is 10.70%. The arithmetic annual average return is 12.56% and the standard deviation is 19.67%. In as much as our methods use geometric averages, we focus on components of the geometric return (10.70%). Later in the paper when we do our forecasts, we convert geometric average returns to arithmetic average returns.

Method 1 – Building Blocks Method

Ibbotson and Sinquefield (1976a,b) develop a building blocks method to explain equity returns. The three building blocks are inflation, real risk-free rate, and equity risk premium. Inflation is represented by the changes in the Consumer Price Index (CPI). The equity risk premium and the real risk-free rate for year t, ERP_t and RRf_t , are given by

$$ERP_t = \frac{1+R_t}{1+Rf_t} - 1 = \frac{R_t - Rf_t}{1+Rf_t} \qquad (1)$$

$$RRf_t = \frac{1+Rf_t}{1+CPI_t} - 1 = \frac{Rf_t - CPI_t}{1+CPI_t} \qquad (2)$$

$$R_t = (1+CPI_t)\times(1+RRf_t)\times(1+ERP_t) - 1 \qquad (3)$$

R_t is the return of U.S. stock market represented by the S&P 500 index. Rf_t is the return of risk-free assets represented by the income return of long-term U.S. government bonds. The compounded average for equity return is 10.70% from 1926-2000. For the equity risk premium, we can interpret that investors were compensated 5.24% per year for investing in common stocks rather than long-term risk-free assets like the long-term US government bonds.[7] This also shows that roughly half of the total historical equity return has come from the equity risk premium, and the other half is from inflation and long-term real risk-free rate. The average U.S. equity returns from 1926 and 2000 can be reconstructed as follows:

$$\begin{aligned} \overline{R} &= (1+\overline{CPI})\times(1+\overline{RRf})\times(1+\overline{ERP}) - 1 \\ 10.70\% &= (1+3.08\%)\times(1+2.05\%)\times(1+5.24\%) - 1 \end{aligned} \qquad (4)$$

Method 2 – Capital Gain and Income Method

The equity return can be broken into capital gain (cg) and income return (Inc) based on the form in which the return is distributed. Income return of common stock is distributed to investors through dividends, while capital gain is distributed through price appreciation. Real capital gain

(Rcg) can be computed by subtracting inflation from capital gain. The equity return in period t can then be decomposed as follows:

$$R_t = [(1+CPI_t)\times(1+Rcg_t)-1]+Inc_t+Rinv_t \tag{5}$$

The average income return is calculated to be 4.28%, the average capital gain is 6.19%, and the average real capital gain is 3.02%. $Rinv$, the re-investment return, averages 0.20% from 1926 to 2000. The average U.S. equity return from 1926 to 2000 can be computed according to

$$\begin{aligned}\overline{R} &= [(1+\overline{CPI}\ )\times(1+\overline{Rcg})-1]+\overline{Inc}+\overline{Rinv} \\ 10.70\% &= [(1+3.08\%)\times(1+3.02\%)-1]+4.28\%+0.20\%\end{aligned} \tag{6}$$

Figure 1 shows the decomposition of the building blocks method and the capital gain and income method from 1926 to 2000.

Method 3 – Earnings Model

The real capital gain portion of the return in the capital gain and income method can be broken into growth in real earnings per share (g_{REPS}) and growth in the price to earnings ratio ($g_{P/E}$),

$$Rcg_t = \frac{P_t}{P_{t-1}}-1=\frac{P_t/E_t}{P_{t-1}/E_{t-1}}\times\frac{E_t}{E_{t-1}}-1=(1+g_{P/E,t})\times(1+g_{REPS,t})-1 \tag{7}$$

Therefore, the equity's total return can be broken into four components: inflation; the growth in real earnings per share; the growth in the price to earnings ratio; and income return.

$$R_t = [(1+CPI_t)\times(1+g_{REPS,t})\times(1+g_{P/E,t})-1]+Inc_t+Rinv_t \tag{8}$$

The real earnings of US equity increased 1.75% annually from 1926. The P/E ratio was 10.22 at the beginning of 1926. It grew to 25.96 at the end of 2000. The highest P/E (136.50) was recorded during the depression in 1932 when earnings were near zero, while the lowest (7.26) was recorded in 1979. The average year-end P/E ratio is 13.76.[8] Figure 2 shows the price to earnings ratio from 1926 to 2000. The U.S. equity returns from 1926 and 2000 can be computed according to

$$\begin{aligned}\overline{R} &= \left[(1+\overline{CPI})\times(1+\overline{g_{REPS}})\times(1+\overline{g_{P/E}})-1\right]+\overline{Inc}+\overline{Rinv} \\ 10.70\% &= \left[(1+3.08\%)\times(1+1.75\%)\times(1+1.25\%)-1\right]+4.28\%+0.20\%\end{aligned} \quad (9)$$

Method 4 – Dividends Model

Dividend (Div) equals the earnings times the dividend payout ratio (PO); therefore, the growth rate of earnings can be calculated by the difference between the growth rate of dividend and the growth rate of the payout ratio.

$$EPS_t = \frac{Div_t}{PO_t} \quad (10)$$

$$(1+g_{REPS,t}) = \frac{(1+g_{RDiv,t})}{(1+g_{PO,t})} \quad (11)$$

We substitute dividend growth and payout ratio growth for the earnings growth in equation 8. The equity's total return in period t can be broken into five components: 1) inflation; 2) the growth rate of the price earnings ratio; 3) the growth rate of the dollar amount of dividend after inflation; 4) the growth rate of the payout ratio; and 5) the dividend yield.

$$R_t = \left[(1+CPI_t)\times(1+g_{P/E,t})\times\frac{(1+g_{RDiv,t})}{(1+g_{PO,t})}-1\right]+Inc_t+Rinv_t \quad (12)$$

Figure 3 shows the annual income return (dividend yield) of U.S. equity from 1926 to 2000. The dividend yield dropped from 5.15% at the beginning of 1926 to only 1.10% at the end of 2000. Figure 4 shows the year-end dividend payout ratio from 1926 to 2000. On average, the dollar amount of dividends grew 1.23% after inflation per year, while the dividend payout ratio decreased 0.51% per year. The dividend payout ratio was 46.68% at the beginning of 1926. It decreases to 31.78% at the end of 2000. The highest dividend payout ratio (929.12%) was recorded in 1932, while the lowest was recorded in 2000. The U.S. equity returns from 1926 and 2000 can be computed according to

$$\overline{R} = \left[(1+\overline{CPI}) \times (1+\overline{g_{P/E}}) \times \frac{(1+\overline{g_{RDiv}})}{(1+\overline{g_{PO}})} - 1 \right] + \overline{Inc} + \overline{Rinv} \tag{13}$$

$$10.70\% = \left[(1+3.08\%) \times (1+1.25\%) \times \frac{1+1.23\%}{1-0.51\%} - 1 \right] + 4.28\% + 0.20\%$$

Method 5 – Return on Book Equity Model

We can also break the earnings into book value of equity (BV) and return on equity (ROE).

$$EPS_t = BV_t \times ROE_t \tag{14}$$

The growth rate of earnings can be calculated by the combined growth rate of BV and ROE.

$$(1+g_{REPS,t}) = (1+g_{RBV,t})(1+g_{ROE,t}) \tag{15}$$

We substitute BV growth and ROE growth for the earnings growth in the equity return decomposition. The equity's total return in period t can be computed by,

$$R_t = \left[(1+CPI_t) \times (1+g_{P/E,t}) \times (1+g_{RBV,t}) \times (1+g_{ROE,t}) - 1\right] + Inc_t + Rinv_t \tag{16}$$

We estimate that the average growth rate of the book value after inflation is 1.46% from 1926 to 2000.[9] The average ROE growth per year is calculated to be 0.31% during the same time period.

$$\overline{R} = \left[(1+\overline{CPI})\times(1+\overline{g_{P/E}})\times(1+\overline{g_{BV}})\times(1+\overline{g_{ROE}})-1\right]+\overline{Inc}+\overline{Rinv}$$
$$10.70\% = \left[(1+3.08\%)\times(1+1.25\%)\times(1+1.46\%)\times(1+0.31\%)-1\right]+4.28\%+0.20\% \quad (17)$$

Method 6 - GDP Per Capita Model

Diermeier, Ibbotson, and Siegel (1984) proposed a framework to analyze the aggregate supply of financial asset returns. Since we are only interested in the supply model of the equity returns in this study, we developed a slightly different supply method based on the growth of the economic productivity. This method can be expressed by the following equation:

$$R_t = \left[(1+CPI_t)\times(1+Rg_{GDP/POP,t})\times(1+g_{FS,t})-1\right]+Inc_t+Rinv_t \quad (18)$$

The return of the equity market over the long run can be decomposed into four components: 1) inflation; 2) real growth rate of the overall economic productivity (the GDP per capita ($g_{GDP/POP}$)); 3) the increase of the equity market relative to the overall economic productivity (increase in the factor share of equities in the overall economy (g_{FS})); and 4) dividend yields. Instead of assuming a constant factor share, we examine the historical growth rate of factor share relative to the overall growth of the economy.

Figure 5 shows the growth of the stocks market, GDP per capita, earnings, and dividends initialized to unity at the end of 1925. In the early 1930s, the stock market, earnings, dividends, and GDP per capita level dropped significantly. Overall, GDP per capita slightly outgrew earnings and dividends, but they all grew at approximately the same rate. In other words, overall economic productivity increased slightly faster than corporate earnings and dividends through the past 75 years. Although GDP per capita outgrew earnings and dividends, the overall stock market price grew faster than GDP per capita. This is primarily because the P/E ratio increased 2.54 times during the same time period. We calculate that the average annual increase in the factor share of the equity market relative to the overall economy to be 0.96%. The factor share increase is less than the annual increase of P/E ratio (1.25%) over the same time period. This suggests that the increase in the equity market share relative to the overall economy can be fully attributed to the increase in the P/E ratio.

$$\overline{R} = \left[(1+\overline{CPI})\times(1+\overline{Rg_{GDP/POP}})\times(1+\overline{g_{FS}})-1\right]+\overline{Inc}+\overline{Rinv} \tag{19}$$
$$10.70\% = [(1+3.08\%)\times(1+2.04\%)\times(1+0.96\%)-1]+4.28\%+0.20\%$$

Summary of Historical Equity Returns and its Components

Figure 6 shows the decomposition of models two through six into their components. The differences across the five models are the different components that represent the capital gain portion of the equity returns.

There are several important findings. First, as shown in Figure 5, the growth in corporate earnings is in line with the growth of the overall economic productivity. Second, P/E increases account for only 1.25% of the 10.70% total equity returns. Most of returns are attributable to dividend payments and nominal earnings growth (including inflation and real earnings growth). Third, the increase in relative factor share of the equity can be fully attributed to the increase in the P/E ratio. Overall economic productivity outgrew both corporate earnings and dividends from 1926 through 2000. Fourth, despite the record earnings growth in the 1990s, the dividend yield and the payout ratio declined sharply, which renders dividends alone a poor measure for corporate profitability and future earnings growth.

III. THE LONG -TERM FORECAST OF THE SUPPLY OF EQUITY RETURNS

Supply side models can be used to forecast the long-term expected equity return. The supply of stock market returns is generated by the productivity of the corporations in the real economy. Over the long run, the equity return should be close to the long run supply estimate. In other words, investors should not expect a much higher or a much lower return than that produced by the companies in the real economy. We believe the investors' expectations on the long-term equity performance should be based on the supply of equity returns produced by corporations.

The supply of equity returns consists of two main components: current returns in the form of dividends and long-term productivity growth in the form of capital gains. We focus on three supply side models: the earnings model, the dividend model, and the GDP per capita model (Method 3, Method 4, and Method 6 in section III).[10] We study the components of the three methods. Specifically, we identify which components are tied to the supply of equity returns, and which components are not. Then, we estimate the long-term sustainable return based on historical information on these supply components.

Method 3F – Forward-Looking Earnings Model

According to the earnings model (equation 8), the historical equity return can be broken into four components: the income return; inflation; the growth in real earnings per share; and the growth in the P/E ratio. Only the first three of these components are *historically* supplied by companies. The growth in P/E ratio reflects investors' changing prediction of *future* earnings growth. Although we forecast that the past supply of corporate growth will continue, we do not forecast any change in investors' predictions. Thus, the supply of the equity return (SR) only includes inflation, the growth in real earnings per share, and income return.

$$SR_t = \left[(1+CPI_t)\times(1+g_{REPS,t})-1\right]+Inc_t+Rinv_t \tag{20}$$

The long-term supply of U.S. equity returns based on the earnings method is 9.37%. This model uses the historical income return as an input for reasons that are discussed in the later section "Differences Between the Earnings Model (3F) and the Dividends Model (4F)".

$$\begin{aligned}\overline{SR} &= \left[(1+\overline{CPI})\times(1+\overline{g_{REPS}})-1\right]+\overline{Inc}+\overline{Rinv}\\ 9.37\% &= \left[(1+3.08\%)\times(1+1.75\%)-1\right]+4.28\%+0.20\%\end{aligned} \tag{21}$$

The supply side equity risk premium ($SERP$) based on the earnings model is calculated to be 3.97%. This is shown in Figure 7.

$$\overline{SERP} = \frac{(1+\overline{SR})}{(1+\overline{CPI})\times(1+\overline{RRf})}-1=\frac{1+9.37\%}{(1+3.08\%)\times(1+2.05\%)}-1=3.97\% \tag{22}$$

Method 4F – Forward-Looking Dividends Method

The forward-looking dividend model is also referred to as the constant dividend growth model (or the Gordon model), where the expected equity return equals the dividend yield plus the expected dividend growth rate. The supply of the equity return in the Gordon model includes inflation, the growth in real dividend, and dividend yield. As is commonly done with the constant dividend growth model, we have used the current dividend yield of 1.10%, instead of the historical dividend yield of 4.28%. This reduces the estimate of the supply of equity returns to 5.44%. The equity risk premium is estimated to be 0.24%. Figure 8 shows the equity risk premium estimate based on the earnings model and the dividends model. In the next section, we show why we disagree with the dividends model and prefer to use the earnings model to estimate the supply side equity risk premium.

$$\overline{SR} = \left[(1+\overline{CPI}\ )\times(1+\overline{g_{RDiv}})-1\right]+Inc(00)+\overline{Rinv}$$
$$5.54\% = [(1+3.08\%)\times(1+1.23\%)-1]+1.10\%+0.20\% \tag{23}$$

$$\overline{SERP} = \frac{(1+\overline{SR})}{(1+\overline{CPI}\ )\times(1+\overline{RRf})}-1 = \frac{1+5.54\%}{(1+3.08\%)\times(1+2.05\%)}-1 = 0.24\% \tag{24}$$

Differences Between the Earnings Model (3F) and the Dividends Model (4F)

There are essentially two differences between the earnings model (3F) and the dividends model (4F). The two differences are reconciled in the two right bars (4F') in Figure 8. The differences relate to the low current payout ratio, and the high current P/E ratio.

First, the earnings model uses the historical earnings growth to reflect the growth in productivity, while the dividend model uses historical dividend growth. Historical dividend growth underestimates historical earnings growth because of the decrease in the payout ratio. Overall, the dividend growth underestimated the increase in earnings productivity by 0.51% per year from 1926 to 2000. The low current payout ratio is also reflected in today's low dividend yield. The payout ratio is at a historic low of 31.8%, compared to the historical average payout of 59.2%. Applying such a low rate forward would mean that even more earnings would be retained in the future than in the historical period. Had more earnings been retained, the historic earnings growth would have been 0.95% per year higher. Thus, it is necessary to adjust the 1.10% current yield upward by 0.95% assuming the historical average dividend payout ratio.

Using the current dividend payout ratio in the dividend model, 4F, creates two errors, both of which violate Miller and Modigliani (1961) theory. The firms' dividend payout ratio only affects the form in which shareholders receive their returns, (i.e. dividends or capital gains), but not their total return. Using the low current dividend payout ratio should not affect our forecast, thus the dividend model has to be upwardly adjusted by 1.46% (both 0.51% and 0.95%), so as not to violate M&M Theory. Firms today likely have such low payout ratios in order to reduce the tax burden of their investors. Instead of paying dividends, many companies reinvest earnings, buy back shares or use their cash to purchase other companies.[11]

The second difference between models 3F and 4F is related to the current P/E ratio (25.96) being much higher than the historical average (13.76). The current yield (1.10%) is at a historic low both because of the previously mentioned low payout ratio and because of the high P/E ratio. Even assuming the historical average payout ratio, the current dividend yield would be much lower than its historical average (2.05% vs. 4.28%) This difference is geometrically estimated to be 2.28% per year. The high P/E ratio can be caused by 1) mis-pricing; 2) low required rate of return; and/or 3) high expected future earnings growth rate. Mis-pricing is eliminated by our assumption of market efficiency. A low required rate of return is eliminated since we assume a constant equity risk premium through the past and future periods that we are trying to estimate. Thus, we interpret the high P/E ratio as the market expectation of higher earnings growth.[12]

$$\begin{aligned} \overline{SR} &= \left[(1+\overline{CPI})\times(1+\overline{g_{RDiv}})\times(1-\overline{g_{PO}})-1\right]+Inc(00)+AY+AG+\overline{Rinv} \\ 9.67\% &= \left[(1+3.08\%)\times(1+1.23\%)\times(1+0.51\%)-1\right]+1.10\%+0.95\%+2.28\%+0.20\% \end{aligned} \tag{25}$$

To summarize, there are three differences between the earnings model and the dividends model. The first two differences relate to the dividend payout ratio and are direct violations of the Miller

& Modigliani (1961) theorem. We interpret that the third difference is due to the expectation of higher than average earnings growth, predicted by the high current P/E ratio. These differences reconcile the earnings and dividend models. Equation 25 presented model 4F', which reconciles the difference between the earnings model and the dividends model.

Geometric vs. Arithmetic

The estimated equity returns (9.37%) and equity risk premiums (3.97%) are geometric averages. The arithmetic average is often used in portfolio optimization. There are several ways to convert the geometric average into an arithmetic average. One method is to assume the returns are independently log-normally distributed over time. Then the arithmetic and geometric roughly follows the following relationship:

$$R_A = R_G + \frac{\sigma^2}{2}, \qquad (26)$$

where R_A is the arithmetic average, R_G is the geometric average, and σ^2 is the variance. The standard deviation of equity returns is 19.67%. Since almost all the variation in equity returns is from the equity risk premium (rather than the risk free rate), we need to add 1.93% to the geometric equity risk premium estimate to convert into arithmetic. $R_A = R_G + 1.93\%$. Adding the 1.93 percent to the geometric estimate, the arithmetic average equity risk premium is estimated to be 5.90% for the earnings model.

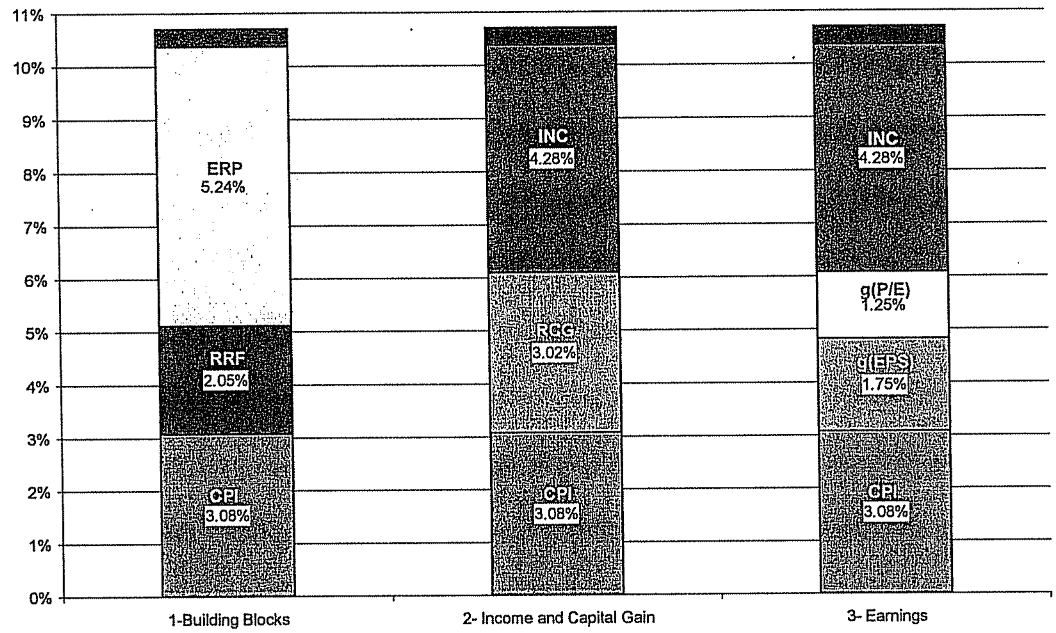
To summarize, the long-term supply of equity return is estimated to be 9.37% (6.09% after inflation) conditional on the historical average risk free rate. The supply side equity risk premium is estimated to be 3.97% geometrically and 5.90% arithmetically.[13]

IV. CONCLUSIONS

We adopt a supply side approach to estimate the forward looking long-term sustainable equity returns and equity risk premium. We analyze historical equity returns by decomposing returns into factors commonly used to describe the aggregate equity market and overall economic productivity. These factors include inflation, earnings, dividends, price-to-earnings ratio, dividend-payout ratio, book value, return on equity, and GDP per capita. We examine each factor and its relationship with the long-term supply side framework. We forecast the equity risk premium through supply side models using historical information. A complete tabulation of all the numbers from all models is presented in Appendix. Contrary to several recent studies on equity risk premium that declare the forward looking equity risk premium to be close to zero or negative, we find the long-term supply of equity risk premium is only slightly lower than the straight historical estimate. The equity risk premium is estimated to be 3.97% in geometric terms and 5.90% on an arithmetic basis. This estimate is about 1.25% lower than the straight historical estimate. The differences between our estimates and the ones provided by several other recent studies are principally due to the inappropriate assumptions used, which violate the Miller and Modigliani Theorem. Also our models interpret the current high P/E ratios as the market forecasting high future growth, rather than a low discount rate or an overvaluation. Our estimate is in line with both the historical supply measures of the public corporations (i.e., earnings) and the overall economic productivity (GDP per capita).

Our estimate of the equity risk premium is far closer to the historical premium than being zero or negative. This implies that stocks are expected to outperform bonds over the long run. For long-term investors, such as pension funds or individuals saving for retirement, stocks should continue to one of the favored asset classes in their diversified portfolios. Due to our lowered equity risk premium estimate (compared to historical performance), some investors should lower their equity allocations and/or increase their savings rate to meet future liabilities.

Figure 1: Decomposition of Historical Equity Returns 1926-2000
Geometric Mean = 10.70%



ERP is equity risk premium, RRF is the real risk free rate, CPI is the Consumer Price Index (inflation), INC is dividend income, RCG is real capital gain, g(P/E) is growth rate of P/E ratio, and g(EPS) is growth rate of earnings per share. The block on the top is the re-investment return plus the geometric interactions among the components. Including the geometric interactions ensures the components sums up to 10.70% in this and subsequent figures. Table 1 in the appendix gives the detailed information on the reinvestment and geometric interaction for all the methods.

Figure 2: P/E Ratio 1926-2000

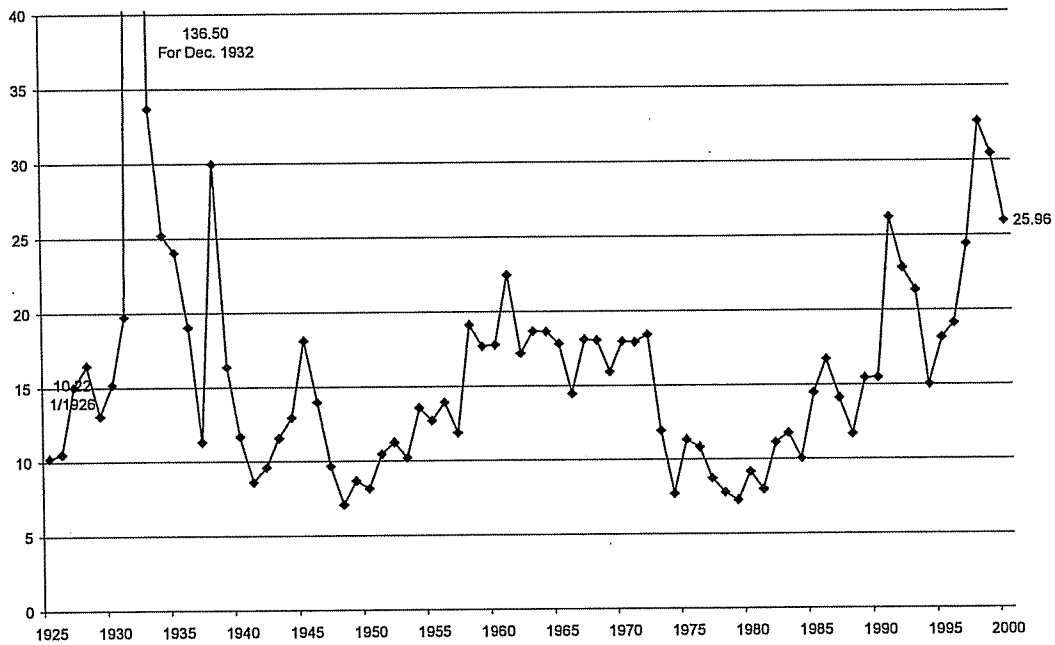


Figure 3: Income Return (Dividend Yield) % 1926-2000

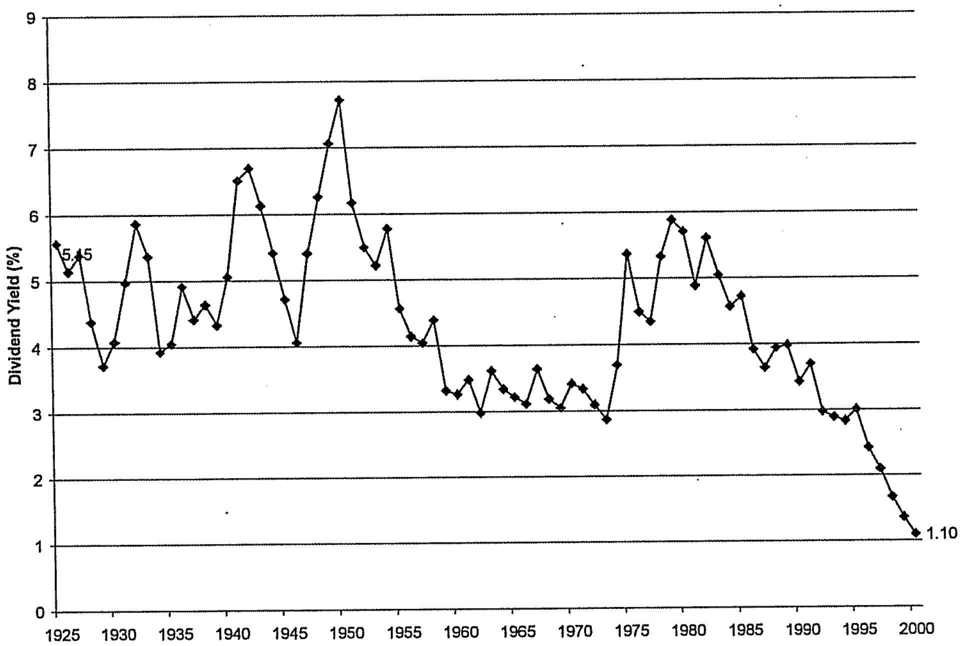


Figure 4: Dividend Payout Ratio % 1926-2000

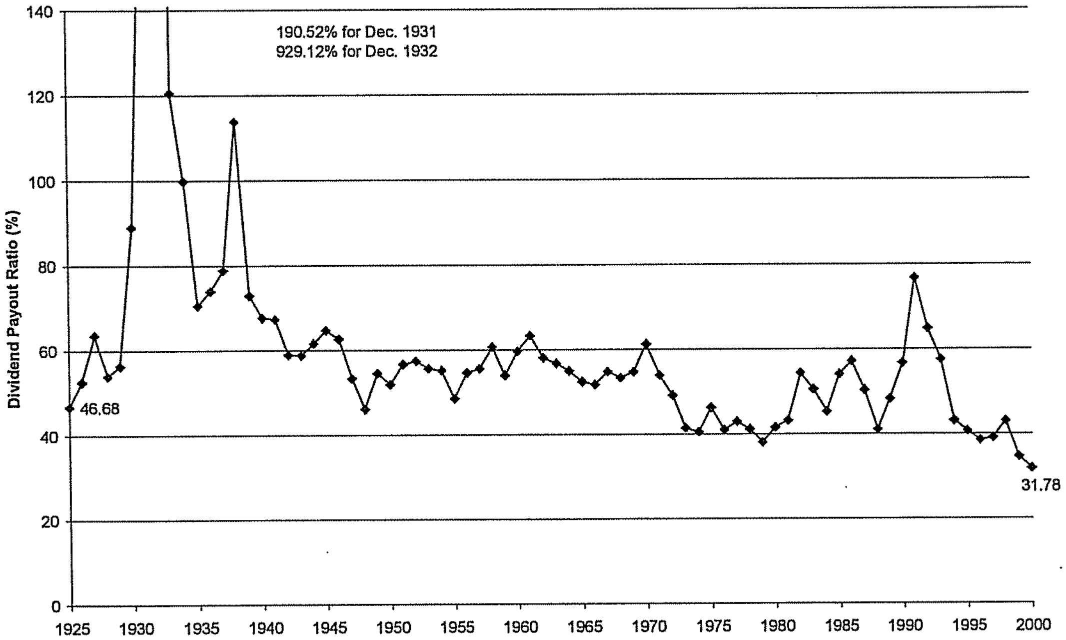


Figure 5: Growth of $1 at the beginning of 1926
1926-2000

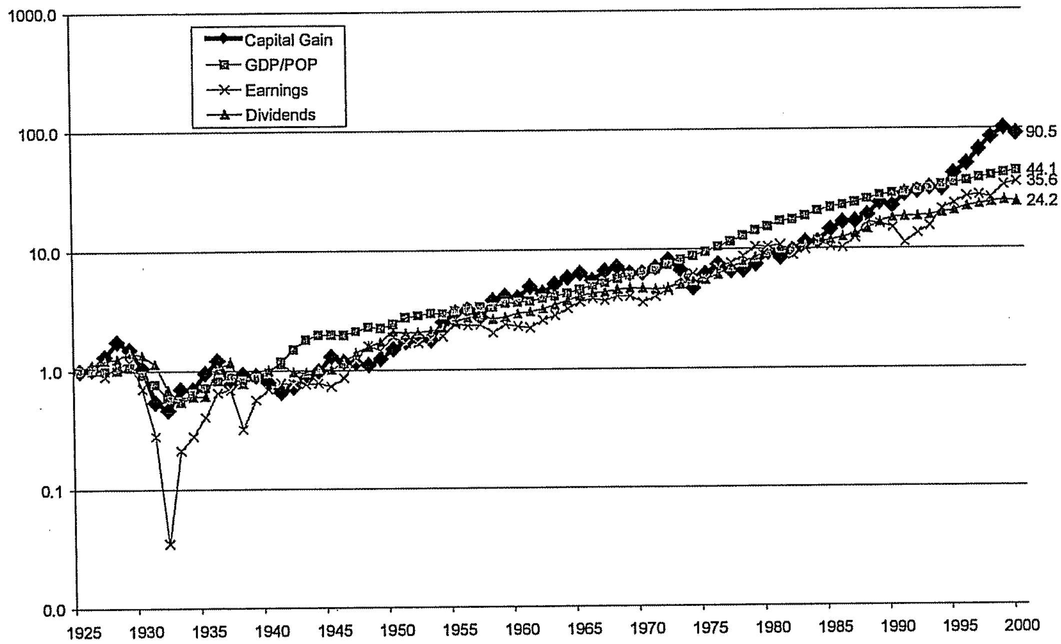
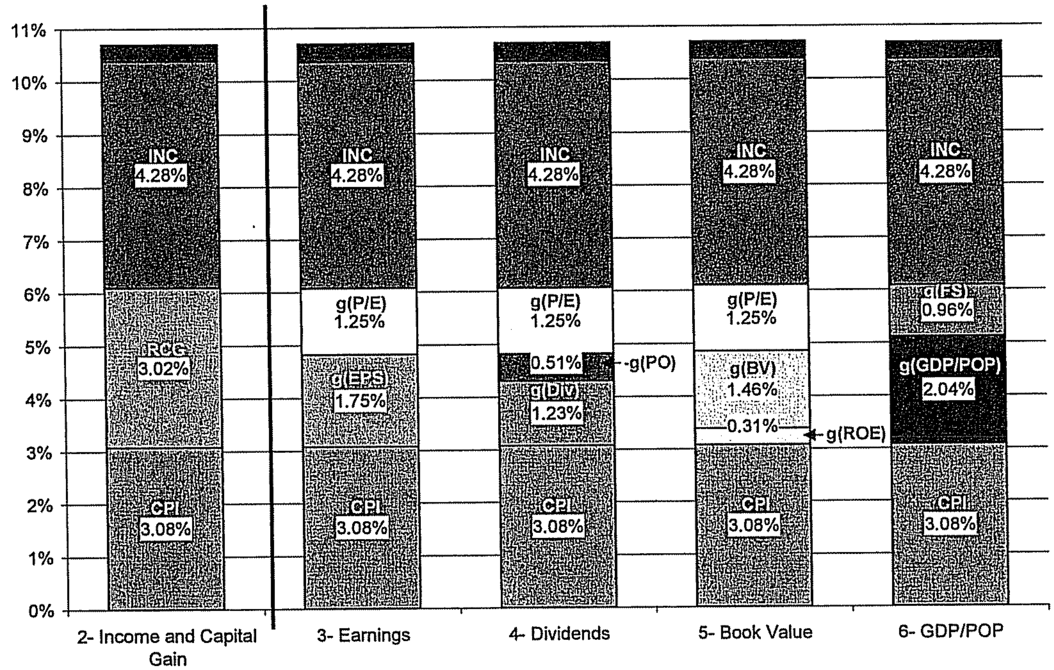


Figure 6: Decomposition of Historical Equity Returns 1926-2000



g(PO) is growth rate of dividend payout ratio, g(Div) is growth rate of dividend, g(BV) is the growth rate of book value, g(ROE) is the growth rate of return on book equity, g(FS) is the growth rate of equity factor share, and g(GDP/POP) is the growth rate of GDP per capita.

Figure 7: Historical Earnings and Forecasted Equity Returns Based on Earnings Models: Model 3, 3F, & 3F(ERP)

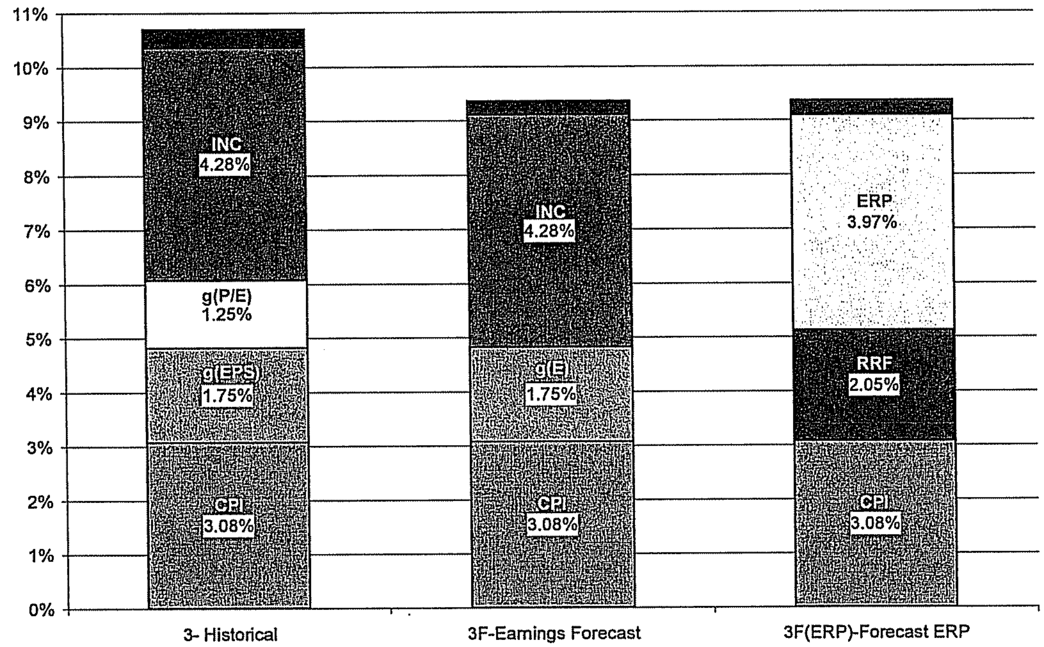
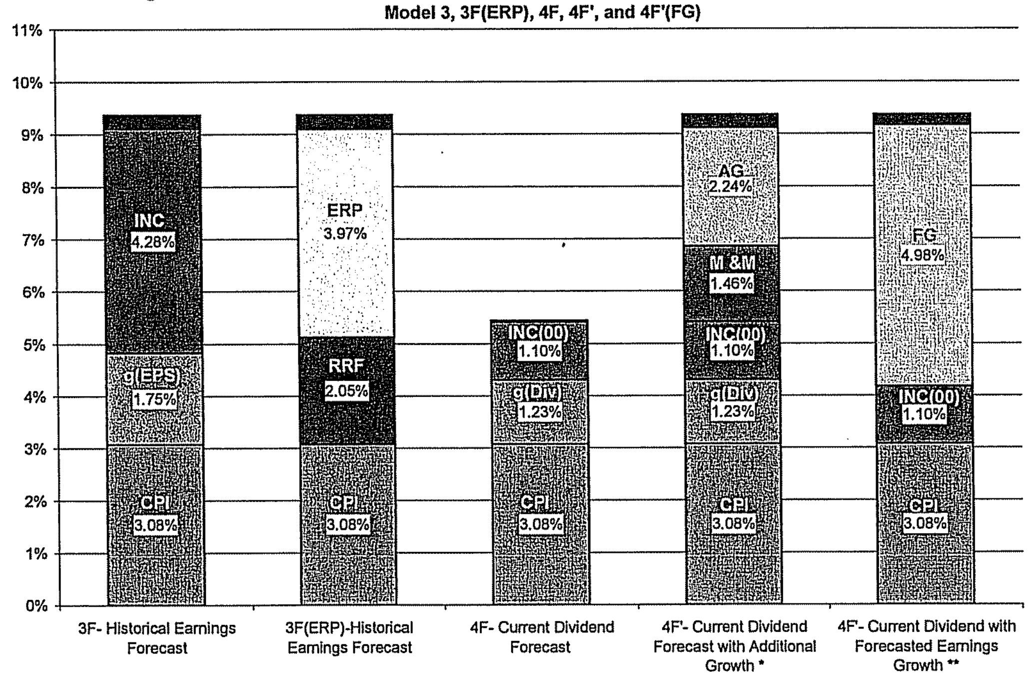


Figure 8: Historical vs. Current Dividend Yield Forecasts Based on Earnings and Dividend Models: Model 3, 3F(ERP), 4F, 4F', and 4F'(FG)



INC(00) is the dividend yield in the year 2000.

* Model 4F' attempts to correct the errors in model 4F: a) add 1.46% to correct Miller and Modigliani (M&M) violations; b) add the additional growth (AG), 2.24%, implied by the high current market P/E ratio.
** Based on Model 4F', we forecast the real earnings growth rate (FG) will be 4.98%.

Appendix

Table 1 Historical and Forecasted Equity Returns – All Models (Percent).

	Sum (%)	Inflation =3.08%	Real Risk-Free Rate=2.05%	Equity Risk Premium=5.24%	Real Capital Gain=3.02%	g(Real EPS)=1.75%	g(Real Div)=1.23%	- g(Div Payout Ratio)= 0.51%	g(BV)= 1.25%	g(ROE) = 0.31%	g(P/E)= 1.25%	g(Real GDP/POP)=2.04%	g(FS-GDP/POP)=1.96%	Income Return= 4.28%	Reinvestment + Interaction	Additional Growth =2.28%	Forecasted Earnings Growth =4.98%
Historical																	
Method 1	10.70	3.08	2.05	5.24											0.33		
Method 2	10.70	3.08			3.02									4.28	0.32		
Method 3	10.70	3.08				1.75					1.25			4.28	0.34		
Method 4	10.70	3.08					1.23	0.51			1.25			4.28	0.35		
Method 5	10.70	3.08							1.25%	0.31%	1.25			4.28	0.31		
Method 6	10.70	3.08										2.04	0.96	4.28	0.32		
Forecast with Historical Dividend Yield																	
Method 3F	9.37	3.08				1.75								4.28	0.26		
Method 3F (ERP)	9.37	3.08	2.05	3.97											0.27		
Method 6F	9.67	3.08										2.04		4.28	0.27		
Method 6F (ERP)	9.67	3.08	2.05	4.25											0.29		
Forecast with Current Dividend Yield																	
Method 4F	5.44	3.08					1.23							1.10*	0.03		
Method 4F (ERP)	5.44	3.08	2.05	0.24											0.07		
Method 4F'	9.37	3.08					1.23	0.51						2.05**	0.21	2.28	
Method 4F' (FG)	9.37	3.08												1.10*	0.21		4.98

*2000 dividend yield

** Adjust the 2000 dividend yield up 0.95% assuming the historical average dividend payout ratio.

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[1] In our study, we define the equity risk premium as the difference between the long-run expected return on stocks and the long-term risk free (U.S. Treasury) yield. We do all of our analysis in geometric form, then convert at the end so the estimate is expressed in both arithmetic form and geometric form. Some other studies, including Ibbotson & Sinquefield (1976a,b), used the short-term U.S. Treasury Bills as the risk free rate.
[2] It is sometimes difficult to compare estimates from one study with another, due to changing points of reference. The equity risk premium estimate can be significantly different simply due to the use of arithmetic vs. geometric, or long-term risk free rate vs. short-term risk free rate (Treasury Bills), or the bond's income return (yield) vs. the bond's total return, or long-term strategic forecast vs. short-term market timing estimate. A more detailed discussion on arithmetic vs. geometric can be found in section III.
[3] Welch's (2000) survey reported a 7% equity risk premium measured as the arithmetic difference between equity and U.S. Treasury bill returns. To make an apple to apple comparison, we converted the 7% number into a geometric equity risk premium relative to the long term U.S. Government bond income return, which gives an estimate of almost 4%.
[4] Each per share quantity is per share of the S&P 500 portfolio. Hereafter, we will merely refer to each factor without always mentioning per share, for example, earnings instead of earnings per share.
[5] There are many theoretical models that suggest that the equity risk premium is dynamic over time. However, recent empirical studies (e.g. Goyal & Welch (2001)) and Ang & Bekaert (2001)) show there is no evidence of long-horizon return predictability by either earnings or dividend yields. Therefore, instead of trying to build a model for a dynamic equity risk premium, we assume that the long-term equity risk premium is constant. This provides a benchmark for analysis and discussion.
[6] We updated the series with data from Standard & Poor's to include the year 2000.
[7] The 5.24% is the compounded average of the historical equity risk premium. The arithmetic average is 7.02%. Unless specified, we use geometric averages in the calculations for the entire study.
[8] The average P/E ratio is calculated by reversing the average E/P ratio from 1926 to 2000.
[9] Book Values are calculated based on the book-to-market ratios reported in Vuolenteenaho (2000). The aggregate book-to-market ratio is 2.0 in 1928 and 4.1 in 1999. We use the book value growth rate calculated during 1928 to 1999 as the proxy for the growth rate during 1926 to 2000. The average ROE growth rate is calculated from the derived book value and the earnings data.
[10] We decided not to use model 1, 2, and 5 in forecasting, because the forecast of model 1 & 2 would be identical to the historical estimate reported in section II. The forecast of model 5 would require more complete book value and ROE data than we currently have available.
[11] The current tax code provides incentives for firms to distribute cash through share repurchases rather than through dividends. Green and Hollifield (2001) find that the tax savings through repurchases are on the order of 40-50% of the taxes that would have been paid by distributing dividends.
[12] Contrary to the efficient market models, Shiller (2000) and Campbell and Shiller (2001) argue that the price to earnings ratio appears to forecast the future stock price change.
[13] We could use the GDP Per Capita model to estimate the long-term equity risk premium as well. The GDP Per Capita model implies the long run stock returns should be in line with the productivity of the overall economy. The equity risk premium estimated using the GDP Per Capita model would be slightly higher than the ERP estimate from the earnings model. This is because the GDP Per Capita grew slightly faster than corporate earnings. A similar approach can be found in Diermeier, Ibbotson, and Siegel (1984), which proposed using the growth rate of the overall economy as a proxy for the growth rate in aggregate wealth in the long run.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Exhibits in Support
Of Opening Testimony

June 4, 2010

March 8, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated February 22, 2010
Question No. 045

Request:

Please provide the requested information for each company used as a comparable company in the cost of equity analyses. Please specify whether the Company or its cost of capital consultant relied on the particular information in developing the Company's cost of equity recommendation. If neither the Company nor its consultant can answer the question (supply the data), please so indicate. Please provide responses for each subsidiary for those companies having multiple subsidiaries and, where applicable, for each jurisdiction for those companies providing service in multiple jurisdictions.

a. **Date and jurisdiction of the last general rate case decision**
b. **Current bond rating for senior-secured long-term debt**
c. **Debt rating for both secured and unsecured securities**
d. **Regulated revenue, EBIT, and earnings as a percent of total revenue**
e. **Regulated revenue, EBIT and earnings as a percent of the net book value of regulated investment**
f. **Dollar amount of assets (gross and net)**
g. **Dollar amount of regulated assets**
h. **Percent of regulated assets to total assets**
i. **Methods and models used to determine the cost of equity by the company and by the commission (e.g., DCF, CAPM, APM, etc.)**
j. **What final rate(s) were allowed by the commission(s), e.g., ROE(s), cost(s) of debt, cost(s) of preferred stock, and allowed (or authorized) rates of return**
k. **What capital structure(s) was requested by the company and what capital structure(s) was approved by the commission**

l. Current long-term debt to total capital ratio(s)
m. Current short-term debt to total capital ratio(s)
n. Current preferred stock to total capital ratio(s)
o. What was the rate-making treatment(s) (e.g., Traditional? Performance-based?)
p. Does the company use any rate-mitigation strategies? If "yes," please describe each such strategy.
q. Does the company currently use weather derivatives?
r. Does the regulatory treatment(s) base rates on embedded costs of debt?
s. Does the regulatory treatment(s) use market value or book value to determine capitalization rates?
t. Are there Purchased Power or Purchased Fuel Adjustment mechanisms?
u. Does the company have any earnings-sharing mechanism(s)? If "yes," please provide details for each such mechanism.

Response:

The cost of equity analysis referred to in this data request was performed by Dr. Zepp and the response refers to his analysis.

a. Date and jurisdiction of the last general rate case decision
Please see Attachment 045-A, pages 157 – 171, 045-B, and 045-C for the historical rate case information available to Dr. Zepp when he determined the RROE for PGE.

b. Current bond rating for senior-secured long-term debt
As stated in Dr. Zepp's testimony in PGE Exhibit 1200, pages 10 and 18 – 19, please see PGE Exhibit 1201 which provides S&P's and Moody's senior secured debt ratings.

c. Debt rating for both secured and unsecured securities
As stated in Dr. Zepp's testimony in PGE Exhibit 1200, pages 10 and 18 – 19, please see PGE Exhibit 1201 which provides S&P's and Moody's senior secured debt ratings.

Unsecured debt ratings were not considered by Dr. Zepp when he determined the RROE for PGE.

d. Regulated revenue, EBIT, and earnings as a percent of total revenue
Please see Attachments 045-A, 045-B, and 045-C for the revenue and earnings information available to Dr. Zepp when he determined the RROE for PGE.

e. Regulated revenue, EBIT and earnings as a percent of the net book value of regulated investment

Please see Attachments 045-A, 045-B, and 045-C for the revenue and earnings information available to Dr. Zepp when he determined the RROE for PGE.

f. Dollar amount of assets (gross and net)

Attachments 045-A, 045-B, and 045-C for the asset value information available to Dr. Zepp when he determined the RROE for PGE.

g. Dollar amount of regulated assets

Attachments 045-A, 045-B, and 045-C for the asset value information available to Dr. Zepp when he determined the RROE for PGE.

h. Percent of regulated assets to total assets

Attachments 045-A, 045-B, and 045-C for the asset value information available to Dr. Zepp when he determined the RROE for PGE.

i. Methods and models used to determine the cost of equity by the company and by the commission (e.g., DCF, CAPM, APM, etc.)

This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE. Dr. Zepp's experience is that such models change from case to case and vary depending on the witnesses testifying for the parties.

j. What final rate(s) were allowed by the commission(s), e.g., ROE(s), cost(s) of debt, cost(s) of preferred stock, and allowed (or authorized) rates of return

Please see Attachment 045-A, pages 157 – 171, 045-B, and 045-C for the historical rate case information available to Dr. Zepp when he determined the RROE for PGE.

k. What capital structure(s) was requested by the company and what capital structure(s) was approved by the commission

Please see Attachment 045-A, pages 157 – 171, 045-B, and 045-C for the historical rate case information available to Dr. Zepp when he determined the RROE for PGE.

l. Current long-term debt to total capital ratio(s)

This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

m. Current short-term debt to total capital ratio(s)

This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

n. Current preferred stock to total capital ratio(s)

This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

o. What was the rate-making treatment(s) (e.g., Traditional? Performance-based?)
This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

p. Does the company use any rate-mitigation strategies? If "yes," please describe each such strategy.
This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

q. Does the company currently use weather derivatives?
This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

r. Does the regulatory treatment(s) base rates on embedded costs of debt?
This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

s. Does the regulatory treatment(s) use market value or book value to determine capitalization rates?
This information was not available to Dr. Zepp and was not considered by Dr. Zepp when he determined the RROE for PGE.

t. Are there Purchased Power or Purchased Fuel Adjustment mechanisms?
Please see PGE Exhibit 1203 and the document titled "PCAM Analysis.xls" provided as a work paper accompanying PGE Exhibit 200 for the available information regarding purchased fuel and power adjustment mechanisms.

u. Does the company have any earnings-sharing mechanism(s)? If "yes," please provide details for each such mechanism.
Please see PGE Exhibit 1203 and the document titled "PCAM Analysis.xls" provided as a work paper accompanying PGE Exhibit 200 for the available information regarding "sharing mechanisms" as they relate to purchased fuel and power adjustment mechanisms.

UE 215
Attachment 045-A

Provided Electronically (CD)

Yahoo!, Reuter's, Zacks, Value Line, RRA, IHS Global Insight, Blue Chip Financial, Federal Reserve, and Morningstar data

Staff/903
Storm/6

Long Range Forecasts:

The table below contains results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2011 through 2015 and averages for the five-year periods 2011-2015 and 2016-2020. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
Interest Rates		**2011**	**2012**	**2013**	**2014**	**2015**	**2011-2015**	**2016-2020**
1. Federal Funds Rate	**CONSENSUS**	**1.9**	**3.2**	**3.7**	**4.0**	**4.1**	**3.4**	**4.2**
	Top 10 Average	2.8	4.3	4.6	4.7	4.9	4.2	4.9
	Bottom 10 Average	1.1	2.1	2.9	3.2	3.1	2.5	3.4
2. Prime Rate	**CONSENSUS**	**4.9**	**6.1**	**6.7**	**7.0**	**7.0**	**6.4**	**7.1**
	Top 10 Average	5.9	7.3	7.6	7.7	7.9	7.3	7.9
	Bottom 10 Average	4.0	5.1	5.8	6.1	6.0	5.4	6.3
3. LIBOR, 3-Mo.	**CONSENSUS**	**2.3**	**3.5**	**4.0**	**4.3**	**4.3**	**3.7**	**4.4**
	Top 10 Average	3.1	4.5	4.9	5.1	5.1	4.6	5.1
	Bottom 10 Average	1.5	2.5	3.2	3.3	3.3	2.7	3.7
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**2.2**	**3.2**	**3.7**	**4.0**	**4.1**	**3.5**	**4.2**
	Top 10 Average	3.0	4.3	4.7	4.8	4.9	4.4	4.9
	Bottom 10 Average	1.5	2.2	2.7	3.1	3.1	2.5	3.4
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**1.9**	**3.1**	**3.6**	**3.9**	**4.0**	**3.3**	**4.1**
	Top 10 Average	2.8	4.2	4.6	4.7	4.8	4.2	4.8
	Bottom 10 Average	1.1	2.0	2.6	3.1	3.1	2.4	3.3
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**2.1**	**3.3**	**3.8**	**4.0**	**4.2**	**3.5**	**4.2**
	Top 10 Average	3.0	4.3	4.7	4.8	4.9	4.4	5.0
	Bottom 10 Average	1.3	2.3	2.9	3.1	3.2	2.6	3.5
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**2.4**	**3.5**	**4.0**	**4.2**	**4.3**	**3.7**	**4.4**
	Top 10 Average	3.2	4.5	4.9	5.0	5.1	4.5	5.1
	Bottom 10 Average	1.6	2.5	3.2	3.4	3.4	2.8	3.7
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**2.8**	**3.8**	**4.3**	**4.5**	**4.6**	**4.0**	**4.7**
	Top 10 Average	3.7	4.8	4.3	5.3	5.4	4.7	5.3
	Bottom 10 Average	2.0	3.0	3.7	3.7	3.7	3.2	4.0
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**3.7**	**4.4**	**4.9**	**5.0**	**5.1**	**4.6**	**5.1**
	Top 10 Average	4.4	5.2	5.6	5.8	5.9	5.4	5.8
	Bottom 10 Average	3.0	3.7	4.3	4.2	4.2	3.9	4.5
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**4.5**	**5.0**	**5.3**	**5.5**	**5.5**	**5.2**	**5.5**
	Top 10 Average	5.0	5.7	6.1	6.3	6.5	5.9	6.3
	Bottom 10 Average	4.0	4.5	4.8	4.8	4.8	4.6	4.9
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**5.1**	**5.5**	**5.8**	**5.9**	**6.0**	**5.6**	**5.9**
	Top 10 Average	5.6	6.1	6.5	6.8	6.9	6.4	6.8
	Bottom 10 Average	4.7	5.0	5.3	5.3	5.2	5.1	5.3
13. Corporate Aaa Bond Yield	**CONSENSUS**	**5.9**	**6.3**	**6.6**	**6.7**	**6.7**	**6.4**	**6.8**
	Top 10 Average	6.6	7.0	7.3	7.6	7.7	7.2	7.6
	Bottom 10 Average	5.3	5.6	5.8	5.9	5.9	5.7	6.1
13. Corporate Baa Bond Yield	**CONSENSUS**	**7.0**	**7.4**	**7.6**	**7.7**	**7.8**	**7.5**	**7.8**
	Top 10 Average	7.7	8.1	8.3	8.6	8.8	8.3	8.7
	Bottom 10 Average	6.3	6.5	6.8	6.8	6.8	6.7	7.0
14. State & Local Bonds Yield	**CONSENSUS**	**5.0**	**5.4**	**5.5**	**5.5**	**5.6**	**5.4**	**5.6**
	Top 10 Average	5.6	6.0	6.2	6.3	6.4	6.1	6.3
	Bottom 10 Average	4.5	4.8	4.9	4.8	4.8	4.8	4.9
15. Home Mortgage Rate	**CONSENSUS**	**6.0**	**6.5**	**6.8**	**7.0**	**7.0**	**6.7**	**6.9**
	Top 10 Average	6.6	7.3	7.7	7.8	7.9	7.5	7.8
	Bottom 10 Average	5.5	5.8	6.1	6.2	6.1	5.9	6.1
A. FRB - Major Currency Index	**CONSENSUS**	**74.4**	**75.1**	**75.6**	**76.2**	**76.9**	**75.7**	**77.1**
	Top 10 Average	79.9	82.8	83.5	84.8	86.4	83.5	87.8
	Bottom 10 Average	69.3	68.0	67.8	67.4	67.5	68.0	66.3
		Year-Over-Year, % Change					**Five-Year Averages**	
		2011	**2012**	**2013**	**2014**	**2015**	**2011-2015**	**2016-2020**
B. Real GDP	**CONSENSUS**	**3.1**	**3.2**	**3.0**	**2.8**	**2.8**	**3.0**	**2.6**
	Top 10 Average	4.0	3.9	3.7	3.4	3.3	3.7	3.0
	Bottom 10 Average	2.2	2.4	2.4	2.3	2.3	2.3	2.2
C. GDP Chained Price Index	**CONSENSUS**	**1.8**	**2.0**	**2.2**	**2.3**	**2.3**	**2.1**	**2.3**
	Top 10 Average	2.4	2.7	2.9	3.0	3.0	2.8	2.9
	Bottom 10 Average	1.0	1.3	1.6	1.8	1.8	1.5	1.7
D. Consumer Price Index	**CONSENSUS**	**2.1**	**2.4**	**2.5**	**2.6**	**2.6**	**2.4**	**2.5**
	Top 10 Average	2.9	3.2	3.3	3.3	3.3	3.2	3.0
	Bottom 10 Average	1.4	1.6	1.8	2.0	2.0	1.7	1.9

Table 2-1: Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes: Summary Statistics of Annual Returns

Series	Geometric Mean (%)	Arithmetic Mean (%)	Standard Deviation (%)	Serial Correlation
Large Co Stock				
Total Returns	9.6	11.7	20.6	0.04
Income	4.2	4.2	1.6	0.90
Capital Appreciation	5.3	7.3	19.8	0.03
Ibbotson Small Co Stock				
Total Returns	11.7	16.4	33.0	0.07
Mid-Cap Stock*				
Total Returns	10.5	13.4	24.9	-0.01
Income	4.0	4.0	1.7	0.89
Capital Appreciation	6.4	9.2	24.2	-0.02
Low-Cap Stock*				
Total Returns	10.9	14.9	29.4	0.04
Income	3.6	3.6	2.0	0.89
Capital Appreciation	7.2	11.0	28.7	0.03
Micro-Cap Stock*				
Total Returns	11.6	17.7	39.2	0.09
Income	2.5	2.6	1.8	0.91
Capital Appreciation	9.0	15.1	38.6	0.08
Long-Term Corporate Bonds				
Total Returns	5.9	6.2	8.4	0.08
Long-Term Government Bonds				
Total Returns	5.7	6.1	9.4	-0.07
Income	5.2	5.2	2.7	0.96
Capital Appreciation	0.3	0.6	8.2	-0.20
Intermediate-Term Government Bonds				
Total Returns	5.4	5.6	5.7	0.16
Income	4.7	4.7	2.9	0.96
Capital Appreciation	0.6	0.7	4.5	-0.16
Treasury Bills				
Total Returns	3.7	3.8	3.1	0.91
Inflation	3.0	3.1	4.2	0.64

Data from 1926–2008. Total return is equal to the sum of three component returns: income return, capital appreciation return, and reinvestment return.

*Source: Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2009 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Annual Total Returns

Table 2-2 shows the annual total returns for seven basic asset classes for the full 83-year time period. This table can be used to compare the performance of each asset class for the same annual period. Monthly total returns for large company stocks, small company stocks, long-term corporate bonds, long-term government bonds, intermediate-term government bonds, Treasury bills, and inflation rates are presented in Appendix B.

Real Rates versus Nominal Rates

The cost of capital embodies a number of different concepts or elements of risk. Two of the most basic concepts in finance are real and nominal returns. The nominal return includes both the real return and the impact of inflation.

The real rate of interest represents the exchange rate between current and future purchasing power. An increase in the real rate indicates that the cost of current consumption has risen in terms of future goods. It is the real rate of interest that measures the opportunity cost of foregoing consumption.

The relationship between real rates and nominal rates can be expressed in the following equation:

$$\text{Real} = \left[\frac{1+\text{Nominal}}{1+\text{Inflation}}\right] - 1$$

$$\text{Nominal} = \left[(1+\text{Real}) \times (1+\text{Inflation})\right] - 1$$

It is important to note that the conversion of nominal and real rates is not an additive process; rather, it is a geometric calculation. The arithmetic sum or difference is calculated by adding or subtracting one number from the other. As illustrated in the above equation, the real rate of return involves taking the geometric difference of the nominal rate of return and the rate of inflation. Conversely, the nominal rate of return can be determined by taking the geometric sum of the real rate of return and the rate of inflation. For example, if the real rate is 2.5 percent and the inflation rate is 5.0 percent, the nominal rate of interest is not 7.5 percent (2.5+5.0) but 7.625 percent, or [(1.025)×(1.05)−1]. Similarly, if the nominal rate is 7.625 percent and the inflation rate is 2.5 percent, the real rate is not 5.125 percent (7.625−2.5) but 5.0 percent, [(1.07625/1.025)−1].

Discount rates are most often expressed in nominal terms. That is, they usually have an inflation estimate included in them. Unless stated otherwise, the cost of capital data presented in this book are expressed in nominal terms.

UE 215
Attachment 045-B

Provided Electronically (CD)

AUS Electric December 2009 Data

UE 215
Attachment 045-C

Provided Electronically (CD)

AUS Electric December 2009 Data – Expanded Set

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

Exhibits in Support
Of Opening Testimony

June 4, 2010

The generalized constant growth or "Gordon growth" Discounted Cash Flow (DCF) model has the form:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1+K)^t}$$

where:

P_0 = current price per share
D_1 = dividend payment in period t
K = cost of equity capital

The generalized multistage DCF model has the form:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \cdots + \frac{D_n}{(1+K)^n} + \frac{D_n(1+g)}{(K-g)} \times \frac{1}{(1+K)^n}$$

where:

P_0 = current price per share
D_n = dividend payment in period t
K = cost of equity capital
g = the constant rate of growth beyond the nth period

Staff's multistage with terminal valuation DCF model has the form:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \cdots + \frac{D_n}{(1+K)^n} + \frac{D_{n+1}}{(1+K)^{n+1}} + \frac{D_{n+1}(1+g)}{(1+K)^{n+2}} +$$
$$\frac{D_{n+1}(1+g)^2}{(1+K)^{n+3}} + \cdots + \frac{D_T(1+g)^{T-(n+1)}}{(1+K)^T} + \frac{P^T}{(1+K)^T}$$

Where:

P_0 = current price per share → Value Line (VL)
D_n = dividend payment in period t
K = cost of equity capital
g = the long-term growth rates for all t > n

Staff's 150-year multistage DCF model has the form:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \cdots + \frac{D_n}{(1+K)^n} + \frac{D_{n+1}}{(1+K)^{n+1}} + \frac{D_{n+1}(1+g)}{(1+K)^{n+2}} +$$
$$\frac{D_{n+1}(1+g)^2}{(1+K)^{n+3}} + \cdots + \frac{D_t(1+g)^t}{(1+K)^t}$$

Where:

t = 150 years

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 905

Exhibits in Support Of Opening Testimony

June 4, 2010

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905
PART A

June 4, 2010

Staff/905
Storm/1

126 FERC ¶ 61,034
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Kern River Gas Transmission Company

Docket Nos. RP04-274-000
RP04-274-009
RP00-157-015

OPINION NO. 486-B

ORDER ON REHEARING, PROPOSED SETTLEMENT AND PAPER HEARING

(Issued January 15, 2009)

TABLE OF CONTENTS

1. This order addresses the paper hearing on return on equity (ROE) issues established by Opinion No. 486-A,[1] BP Energy Company's (BP) rehearing request of that opinion, and a contested settlement filed by Kern River Gas Transmission Company (Kern River) on September 30, 2008. Based on the record established in the paper hearing, the Commission finds that Kern River's ROE should be 11.55 percent. That is the median ROE of a revised proxy group which includes both master limited partnerships (MLPs) and corporations, consistent with the Policy Statement adopted in *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*.[2] Upon review of the comments on the settlement, the Commission finds that the higher 12.50 percent ROE embedded in the proposed settlement rates renders the settlement rates unjust and unreasonable, and accordingly the Commission rejects the settlement. The Commission also denies BP's rehearing request of certain ROE and other issues. Finally, the Commission directs Kern River to make a revised compliance filing.

I. **Background**

2. The background of this proceeding is described in detail in Opinion No. 486[3] and Opinion No. 486-A. To summarize, when the Commission authorized Kern River to construct its Original System in 1990, the Commission approved initial rates based, among other things, on a levelized cost of service and a 25-year depreciation life.[4] In addition, the Commission accepted Kern River's proposal for separate levelized rates for three different periods: (1) the 15-year term of the firm shippers' initial contracts, (2) the period from the expiration of those contracts to the end of Kern River's depreciable life, and (3) the period thereafter. The levelized rates for the first period (hereafter Period One Rates) were designed to permit Kern River to recover approximately 70 percent of its original investment, an amount approximately equal to the portion of its invested capital funded through debt. Since this would allow Kern River to recover more invested capital during Period One than it would under ordinary straight-line depreciation for the

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[1] *Kern River Gas Transmission Co.*, 123 FERC ¶ 61,056 (2008) (Opinion No. 486-A).

[2] *Policy Statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return On Equity*, 123 FERC ¶ 61,048 (2008), *reh'g dismissed*, 123 FERC ¶ 61,259 (2008) (Policy Statement).

[3] *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077 (2006) (Opinion No. 486).

[4] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069, at 61,150 (1990). *Kern River Gas Transmission Co.*, 58 FERC ¶ 61,073, at 61,242-44, *order on reh'g*, 60 FERC ¶ 61,123, at 61,437 (1992).

depreciable life of the project, the rates for the second two periods (hereafter Period Two and Period Three Rates) were lower than the Period One rates.

3. In May 2000, Kern River proposed to lower its rates by refinancing its debt and providing for longer debt recovery periods by extending the terms of its firm contracts. The Commission accepted a settlement containing this proposal, the 2000 Extended Term Settlement (2000 ET Settlement).[5] As a result of the 2000 ET Settlement, all of Kern River's firm shippers extended their contracts. One group of customers extended their contract terms by five years and entered into revised contracts with ten-year terms (October 1, 2001 to 2011); the other group extended their contract terms by 10 years and entered into revised contracts with 15-year terms (October 1, 2001 – 2016). The 2000 ET Settlement provided that the firm shippers' rates under these contracts would be designed consistent with the principles espoused in its Original Certificate Order described above, permitting Kern River to recover 70 percent of the costs of the plant being depreciated by the end of the new repayment periods.[6] Therefore, after the 2000 ET Settlement, two customer groups existed: 10-year ET shippers and 15-year ET shippers.

4. In May 2002, Kern River completed an expansion project by adding additional compression to its system.[7] The costs associated with the 2002 Expansion project were rolled into the original system costs. As before, the 2002 Expansion shippers were permitted to choose 10- or 15-year terms for this additional capacity. Kern River stated that the rolled-in rate treatment of the costs for this project would result in recovery of the total debt-related depreciation expenses over the primary terms of the expansion

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[5] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000) (*2000 ET Settlement*), *order on reh'g*, 94 FERC ¶ 61,115 (2001). Under the 2000 ET Settlement, Kern River did not require a general reallocation of revenue responsibility among its shippers and maintained that its cost of service (other than financing and depreciation components) would remain unchanged. *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061, at 61,156 (2000).

[6] *Id.* at 61,157. Kern River stated that in designing its rates, cost of service and rate base components would first be allocated to each rate option based upon the percentage of contract demand of those shippers electing to pay the new 10-year rates, the new 15-year rates, and the existing rates. Then, the levelized rates for the 10-year and 15-year rate options would be calculated by levelizing the cost of service over the extended contracts terms, and the existing rates would be reduced as appropriate.

[7] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137 (2001).

shippers' contracts.[8] In May 2003, Kern River completed another expansion project.[9] Kern River priced these services on an incremental basis and again permitted shippers to choose either 10-year or 15-year firm contracts.

5. On April 30, 2004, Kern River filed the instant general rate case under section 4 of the NGA. Kern River proposed to continue using the rate levelization methodology and cost of service rate principles as approved in the original Kern River certificate,[10] the 2000 Extended Term Settlement,[11] the 2003 Expansion certificate,[12] and the prior Kern River rate case settlements,[13] with certain modifications.[14] The Commission accepted and suspended the rates subject to refund, conditions, and hearing.[15] The Presiding Administrative Law Judge (ALJ) issued her Initial Decision (ID) on March 2, 2006,[16] addressing numerous cost of service and rate design issues, including Kern River's continuation of its levelized rate methodology and its proposed ROE.

6. On October 19, 2006, the Commission issued Opinion No. 486, addressing the briefs on and opposing exceptions to the ID, and on April 18, 2008, the Commission issued Opinion No. 486-A, addressing the requests for rehearing of Opinion No. 486. As a result of those opinions, the Commission has finally resolved on the merits most issues in this proceeding. The only issues which the Commission did not finally resolve concerned Kern River's levelized rates and its ROE.

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[8] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137, at 61,591 (2001).

[9] *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056, *order on reh'g*, 101 FERC ¶ 61,042 (2002).

[10] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990).

[11] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000), *reh'g denied,* 94 FERC ¶ 61,115 (2001).

[12] *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056 (2002).

[13] *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995); *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124, *order on reh'g*, 91 FERC ¶ 61,103 (2000).

[14] A more detailed history of recent regulatory proceedings on Kern River's system is available in Opinion No. 486 at P 4-17.

[15] *Kern River Gas Transmission Co.*, 107 FERC ¶ 61,215, *order on reh'g*, 109 FERC ¶ 61,060 (2004).

[16] *Kern River Gas Transmission Co.*, 114 FERC ¶ 63,031 (2006).

7. On the levelized rate issue, Opinion No. 486 affirmed the ALJ's holding that Kern River's rates should continue to be designed based upon the levelized methodology.[17] The Commission recognized that Kern River's Period One rates will recover more depreciation expense than it will have depreciated on its books. However, the Commission stated that Kern River books a regulatory asset or liability for the difference between the annual regulatory depreciation expense it recovers in rates and its book depreciation expense. Therefore, at the end of Period One, Kern River's books would reflect a regulatory liability, and this would serve to lower its Period Two rates. The Commission rejected a variety of arguments as to why shippers might not receive the benefit of the lower Period Two rates. However, in order to increase the assurance that Kern River's shippers will obtain the benefit of the lower Period Two rates if they continue service beyond the terms of their existing contracts, the Commission directed that Kern River include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire. Opinion No. 486-A denied rehearing of all of Opinion No. 486's holdings concerning Kern River's levelized rates. However, in its request for rehearing of Opinion No. 486-A, BP has requested that the Commission clarify certain issues concerning the design of Kern River's Period Two rates. BP also requests that the Commission clarify that Kern River's shippers will continue to get the benefit of their bargain in Period Three.

8. On the issue of Kern River's ROE, Opinion No. 486 reversed the ALJ's holding that Kern River's ROE should be 9.34 percent, holding that the ALJ had erred in her findings concerning the proxy group to be used in determining a range of reasonable returns in which to set Kern River's ROE. In Opinion No. 486, the Commission adopted a four-company proxy group consisting of Kinder Morgan Inc. (KMI), Equitable Resources, Inc. (Equitable), National Fuel Gas Co. (National Fuel), and Questar Corporation (Questar). In adopting this proxy group, Opinion No. 486 applied a revised proxy group policy, which had been developed in two recent cases, *Williston Basin Interstate Pipeline Co.*[18] and *High Island Offshore System, L.L.C.*[19] Before *Williston II* and *HIOS*, the Commission had required that each company included in the proxy group satisfy the following three standards.[20] First, the company's stock must be publicly traded. Second, the company must be recognized as a natural gas company and its stock must be recognized and tracked by an investment information service such as Value Line.

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[17] Opinion No. 486, 117 FERC ¶ 61,077 at P 37.

[18] *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036, at P 34-43 (2003) (*Williston II*).

[19] *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, *reh'g denied*, 112 FERC ¶ 61,050 (2005) (*HIOS*).

[20] *Id.* at 61,933.

Third, pipeline operations must constitute a high proportion of the company's business. This standard could only be satisfied if a company's pipeline business accounted for, on average, at least 50 percent of a company's assets or operating income over the most recent three-year period.[21]

9. However, in its July 2003 Order in *Williston II*, the Commission found that, because of mergers, acquisitions, and other changes in the natural gas industry, only three corporations remained that satisfied the Commission's historical proxy group standards. Therefore, the Commission relaxed the requirement that natural gas business account for at least 50 percent of the corporation's assets or operating income. Instead, the Commission approved the pipeline's proposal to use a proxy group based on the corporations in the Value Line Investment Survey's list of firms in the "Natural Gas (Diversified) Industry"[22] that own Commission-regulated natural gas pipelines, without regard to what portion of the company's business comprises pipeline operations. When the Commission decided *HIOS* in early 2005, the *Williston II* proxy group had shrunk to six corporations. Moreover, the Commission found that two of those corporations, the Williams Companies (Williams) and El Paso Corporation (El Paso), should be excluded from the proxy group on the ground that their financial difficulties had lowered their ROEs to such a low level as to render them unrepresentative.[23] That left the four company proxy group made up of KMI, Equitable, National Fuel, and Questar.

10. In Opinion No. 486, the Commission adopted the same four-company proxy group as it had in *HIOS*. The Commission held that the ALJ erred in failing to exclude Williams and El Paso from the Kern River proxy group. Consistent with *HIOS*, the Commission found that those companies continued to be unrepresentative because of their lower returns and dividend payments.[24] In Opinion No. 486, as it had in *HIOS*, the Commission rejected the pipeline's proposal to address the problem of the shrinking proxy group by including MLPs in the proxy group. Kern River asserted that MLPs have a much higher percentage of their business devoted to pipeline operations than most of the corporations eligible for the proxy group under *Williston II*, and therefore are more representative of the risks faced by pipelines. As in *HIOS*,[25] Opinion No. 486 concluded

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[21] *Williston II*, 104 FERC ¶ 61,036 at P 35 n.46.

[22] *See* Ex. S-3 at 7.

[23] *HIOS*, 110 FERC ¶ 61,043 at P 118. Opinion No. 486, 117 FERC ¶ 61,077 at P 140-41.

[24] *Id.* P 140-41, and n.227-29.

[25] *HIOS*, 110 FERC ¶ 61,043 at P 125-26.

that data concerning dividends paid by the proxy group members is a key component in any discounted cash flow (DCF) analysis, and expressed concern that MLP cash distributions may not be comparable to the corporate dividends the Commission uses in its DCF analysis. That was because MLP distributions generally exceed the MLP's reported earnings, and thus include a return *of* invested capital, as well as a return *on* invested capital. By contrast, corporations pay dividends in order to distribute a share of their earnings to stockholders. As such, dividends do not include any return *of* invested capital to the stockholders. Rather, dividends represent solely a return *on* invested capital. For this reason, Opinion No. 486 expressed concern that a DCF analysis based on an MLP's full distribution in excess of earnings, without any adjustment, could lead to a distorted result. The Commission stated that it was not making a generic finding that MLPs could not be considered for inclusion in the proxy group if a proper evidentiary showing is made,[26] but stated that any party proposing to include MLPs in a ROE proxy group must establish that the MLP's distributions were equivalent to corporate dividends.[27]

11. Unlike in *HIOS*, the Commission concluded in Opinion No. 486 that the four corporation proxy group it approved included firms of lower risk than Kern River. The Commission, therefore, added 50 basis points to the median return of the selected proxy group for an equity return of 11.2 percent.[28] In contrast, in *HIOS* in the Commission set the pipeline's ROE at the median of the four-corporation proxy group based on HIOS's average risk.[29]

12. There were many requests for rehearing of Opinion No. 486, including those of the ROE determinations by both the shipper parties and Kern River. In its rehearing request, Kern River asserted, among other things, that the Commission had erred in excluding MLPs from the proxy group. It argued that MLPs have a much higher percentage of their business devoted to pipeline operations than most of the corporations eligible for the proxy group under *Williston II*, and therefore are more representative of the risks faced by pipelines.[30] It also argued that Opinion No. 486 erred in finding that an

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[26] Opinion No. 486, 117 FERC ¶ 61,077 at P 149-150. *See also HIOS*, 110 FERC ¶ 61,043 at P 125.

[27] This was later revised. *See* Opinion No. 486-A, 123 FERC ¶ 61,056 at P 147.

[28] *Id.* P 2.

[29] *HIOS*, 110 FERC ¶ 61,043 at P 154, 158.

[30] *Id.* P 118; Opinion No. 486, 117 FERC ¶ 61,077 at P 140-41.

MLP's cash distributions in excess of reported earnings could distort the DCF analysis. Kern River made its compliance filing on December 18, 2006.[31]

13. While the requests for rehearing of Opinion No. 486 were pending, the Commission concluded that its proxy group arrangements for both gas and oil pipelines must be reexamined in light of the fact there are so few diversified natural gas companies available for inclusion in the proxy group which may reasonably be considered representative of the risk profile of a natural gas pipeline firm. In addition, there were no publicly traded oil pipeline firms available for the oil pipeline proxy group other than MLPs. Accordingly, on July 17, 2007, the Commission issued a proposed policy statement concerning the composition of the proxy groups used to determine both gas and oil pipeline ROEs.[32] The Commission proposed to permit inclusion of MLPs in a ROE proxy group. However, the Commission proposed to cap the "dividend" used in the DCF analysis at the MLP's reported earnings, thus adjusting the amount of the distribution to be included in the DCF model. The Commission left to individual cases the determination of which MLPs and corporations should be included in the proxy group.

14. On August 7, 2007, the Court of Appeals for the D.C. Circuit issued its opinion in *Petal Gas Storage, L.L.C. v. FERC*,[33] reversing the Commission's earlier determinations on the return on equity in *HIOS* and *Petal Gas Storage, L.L.C.*[34] Both these appeals turned explicitly on the issue of the relative risk of the proxy group members selected to determine the ROE. The court considered the *Petal* and the *HIOS* appeals together and vacated and remanded the proxy group rulings in both cases. The court emphasized that the Commission's "proxy group arrangements must be risk-appropriate."[35] The court further explained that this means that firms included in the proxy group should face similar risks to the pipeline whose ROE is being determined, and any differences in risk

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[31] *See Kern River Gas Transmission Co.*, 119 FERC ¶ 61,106 (2007), which required Kern River to provide its shippers additional information, including computer models, to support its compliance filing.

[32] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity,* 120 FERC ¶ 61,068 (2007) (Proposed Policy Statement).

[33] *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695 (D.C. Cir. 2007) (*Petal v. FERC*).

[34] *Petal Gas Storage, L.L.C.*, 97 FERC ¶ 61,097 (2001), *reh'g granted in part and denied in part*, 106 FERC ¶ 61,325 (2004) (*Petal*).

[35] *Petal v. FERC*, 496 F.3d 695 at 699 (*quoting Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289 (D.C. Cir. 2001) (*CAPP v. FERC*)).

should be recognized in determining where to place the pipeline in the proxy group range of reasonable returns. The court recognized that changes in the gas pipeline industry compelled a change in the Commission's traditional approach to determining the proxy group, and the court stated that "controversy about how it should change has been bubbling up in a number of recent cases," citing both *Williston II* and Opinion No. 486. But the court found that the cases on appeal "seem to represent an arrival point of sorts for the Commission," pointing out that Opinion No. 486 had reversed an administrative law judge for deviating from the *HIOS* proxy group.

15. The court held that the Commission had not shown that the proxy group arrangements it approved in *Petal* and *HIOS* were risk-appropriate. The court pointed out that the Commission had rejected the inclusion of MLPs in the proxy group on the ground that MLP distributions, unlike dividends, might provide returns *of* equity as well as returns *on* equity. While stating that this proposition is not "self-evident," the court accepted it for the sake of argument. Nonetheless, the court stated that nothing in the Commission's decision explained why the companies selected by the Commission for inclusion in the proxy group were risk-comparable to HIOS. The court stated that when the goal is a proxy group of comparable companies, it is not clear that natural gas companies with highly different risk profiles should be regarded as comparable.[36]

16. The court further stated that in placing Petal and HIOS in the middle of the proxy group in terms of return on equity, the Commission expressly relied on the assumption that gas pipelines generally fall into a broad range of average risk compared to other pipelines. However, the court stated, this assumption is decisive only given a proxy group composed of other comparable gas pipelines. The court reasoned that if gas distribution companies generally face lower risk than gas pipelines, a risk-appropriate placement would be at the high end of the group. The court stated that the Commission erred by failing to explain how the proxy group selected reflected the principle of relative risk. Therefore, the court vacated the Commission's orders on the proxy group issue. The court also stated that on remand it did not require any particular proxy group structure, but stated that the overall arrangement must make sense in terms of the relative risk and the statutory command to set just and reasonable rates that are commensurate with returns on investments in other enterprises having corresponding risks.[37]

17. Thus, in the fall of 2007, the Commission was pursuing its Proposed Policy Statement and the rehearing requests of Opinion No. 486 in the shadow of the *Petal v. FERC* remand. After an initial round of comments and reply comments, the Commission concluded that it required additional comment on the growth rates of MLPs. After notice

[36] *Id.* at 700.

[37] *Id.*

to that effect and the receipt of an additional round of initial and reply comments, Staff held a technical conference involving an eight member panel on January 23, 2008, which was transcribed for the record. Comments and reply comments were filed thereafter.

18. Subsequently, on April 17, 2008, the Commission issued its Policy Statement concerning the composition of the proxy groups used to determine jurisdictional gas and oil pipelines' ROE under the DCF model.[38] The Commission concluded: (1) MLPs could be included in the ROE proxy group for both oil and gas pipelines; (2) there should be no cap on the level of distributions included in the Commission's current DCF methodology; (3) the Institutional Brokers Estimated System (IBES) forecasts would remain the basis for the short-term growth forecast used in the DCF calculation; (4) there should be an adjustment to the long-term growth rate used to calculate the equity cost of capital for an MLP; and (5) there would be no modification to the current respective two-thirds and one-third weightings of the short- and long-term growth factors.

19. The Commission stated that the Policy Statement made no findings as to which particular corporations and/or MLPs should be included in the gas or oil proxy groups. The Commission left that determination to each individual rate case. However, the Commission stated that, in order to assist it in determining the most representative possible proxy group in those cases, the parties and other participants should provide as much information as possible regarding the business activities of each firm they propose to include in the proxy group, including their recent annual SEC filings and investor service analyses of the firms. The Commission also held that the Policy Statement should govern all gas and oil rate proceedings regarding a pipeline's ROE that were pending before the Commission and for which there had not been a final determination.[39] The American Public Gas Association (APGA) filed a request for rehearing or reconsideration, which the Commission dismissed on June 13.[40]

20. Contemporaneously with the Policy Statement, the Commission issued Opinion No. 486-A. It denied all requests for rehearing other than those related to the ROE issues.[41] On those issues, Opinion No. 486 granted rehearing to permit the inclusion of

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[38] Policy Statement, 123 FERC ¶ 61,048.

[39] *Id.* P 2.

[40] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return On Equity*, 123 FERC ¶ 61,259 (2008). The Commission explicitly stated that the questions raised by APGA could be addressed in individual proceedings with specific reference to the paper hearing in the instant Kern River proceeding. *Id.* P 6 and n.13.

[41] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 1.

MLPs in the proxy group, but denied the Shipper Parties' request to include El Paso and Williams in the proxy group.[42] Drawing on the extensive public record in the Policy Statement, the instant Kern River proceedings, and the remand decision in *Petal v. FERC*, Opinion No. 486-A reiterated the Policy Statement's conclusions that: (1) MLPs are appropriately included in the proxy group;[43] (2) there should be no cap on the distributions to be included in the DCF model;[44] and (3) long term growth should be limited to 50 percent of gross domestic product (GDP).[45] Opinion No. 486-A also concluded that there should be no adjustment to the results of the DCF model to reflect the depreciation, the use of external funds, or the income tax advantages of MLPs.[46]

21. Recognizing that the Kern River record did not address all of the issues set forth in the Policy Statement, Opinion No. 486-A reopened the record for a paper hearing in order to give all participants, including Trial Staff, an opportunity to submit additional evidence as to (1) which specific MLPs should be included in the proxy group consistent with the Policy Statement, (2) the appropriate DCF analysis of each entity proposed for inclusion in the proxy group, and (3) where Kern River's ROE should be set in the resulting range of reasonable returns. The Commission stated that, because a primary goal of the new policy is to develop proxy groups made up of a firm whose risk profiles correspond as closely as possible to that of the pipeline who's ROE is being determined, all participants were free to propose whichever MLPs will best accomplish that goal. In addition, parties were permitted to modify their prior positions concerning which corporations to include in the proxy group in light of the addition of MLPs to the proxy group, subject to the Commission's reaffirmation of its ruling that El Paso and Williams must not be included in the proxy group.[47]

22. Only BP requested rehearing of Opinion No. 486-A, focusing primarily on these ROE issues, but also requesting clarification on certain levelized rate issues. During the paper hearing, extensive comments, reply comments, and rebuttal comments were filed

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[42] *Id.* P 188-89.

[43] *Id.* P 167-173.

[44] *Id.* P 174, 178-180.

[45] *Id.* P 181-183.

[46] *Id.* P 184-187.

[47] *Id.* P 167, 188, 190, Ordering Paragraph C.

by all the parties and the Commission's Trial Staff.[48] On September 30, 2008, Kern River filed a settlement proposal supported by most parties to the proceeding, but opposed by the Trial Staff, BP, and Southwest Gas Corporation (Southwest), and is summarized below.

II. The Settlement Proposal

23. On September 30, 2008, Kern River filed an Offer of Settlement and Stipulation (Settlement) on behalf of the Settling Parties.[49] On October 8, 2008, Kern River filed work papers supporting the Period One Settlement rates. The Settlement was contested by several parties including BP Energy Company, Southwest Gas Corporation and Trial Staff. As explained further below, the Settlement prohibits severance of issues or parties. The Settlement establishes Kern River's transportation rates for a period of at least five years following the effective date of the Settlement, but reserves certain issues pertaining to Period Two rates for future Commission resolution. The Settlement's resolution of Period One rates would eliminate the need or opportunity for the Commission to resolve the rate of return issues reopened by Opinion No. 486-A. All parties agree that the Settlement provides for a ROE of 12.5 percent. Kern River requests the Commission refrain from issuing an order resolving the paper hearing issues pertaining to ROE pending the Commission's action on the Settlement.

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[48] The active participants were Trial Staff, Kern River, BP, Calpine Energy Services (CES), Kern River, Reliant Energy Services (Reliant), and the Rolled-In Customer Group (RCG). The RCG group includes Area Energy LLC, Anadarko Petroleum Corporation, Anadarko E&P Company, LP, Chevron U.S.A. Inc. (on its on behalf and on behalf of Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2), Occidental Energy Marketing, Inc., and Shell Energy North America (formerly Coral Energy Resources, L.P.).

[49] Settling Parties include the following participants: Kern River; Aera Energy LLC; Allegheny Energy Supply Co., LLC; Anadarko Petroleum Corporation; Anadarko E&P Company, L.P.; Chevron U.S.A. Inc.; El Paso Merchant Energy LP; Occidental Energy Marketing, Inc.; Shell Energy North America; Calpine Energy Services, L.P.; Nevada Cogeneration Associates #1; Nevada Cogeneration Associates #2; Nevada Power Company; Pinnacle West Capital Corporation; Questar Gas Company; High Desert Power Trust; Reliant Energy Services Inc.; Reliant Energy Wholesale Generation, LLC, Southern California Gas Company; Concord Energy LLC; Enserco Energy Inc.; Merrill Lynch Commodities, Inc.; Questar Energy Trading Company; Sacramento Municipal Utilities District; Seneca Resources Corp.; Williams Gas Marketing Inc.; Edison Mission Energy; and the Los Angeles Department of Water and Power.

24. Regarding Kern River's Period One rates, the Settlement establishes transportation rates for Kern River's firm shippers with existing transportation service agreements for the period beginning November 1, 2004 and ending no later than five years from the effective date of the Settlement. Pursuant to the Settlement, all customers would receive the benefits of Period One Settlement rates in the form of refunds, with interest, of any amounts collected in excess of the locked-in Period One rates during the period from November 1, 2004, until the Period One Settlement rates are made effective. The Settling Parties would be eligible for immediate refunds as of October 1, 2008 (subject to recoupment by Kern River in the event the Settlement is not approved). Non-settling parties would not receive refunds pertaining to Period One reduced rates until the Settlement is approved by the Commission. Regarding Kern River's Period Two rates, the Settlement reserves for resolution through litigation or further Settlement the establishment of Period Two (step-down) rates that will apply after expiration of existing mainline shippers' firm transportation service agreements.

A. <u>The Articles of the Settlement</u>

25. Article 1 of the Settlement describes the issues settled and reserved. Article 2 describes the Period One and Period Two rates to be charged. This article describes the rate elements comprising the cost-of-service and Period One rates as well as the annual depreciation and amortization rates. Article 3 describes the obligations of the Settling Parties in the event the Settlement is not approved. This article also describes the negotiated rate agreement between Kern River and High Desert Power Trust. Article 4 addresses the manner in which the Settlement rates will become effective. Appendix D to the Settlement includes revised tariff sheets setting forth the locked-in period rates and the Period One settlement rates. Article 5 sets forth Kern River's refund obligations. This article also provides that Kern River will receive repayment of refunds from the Settling Parties in the event the Settlement is not approved. Article 6 establishes the dates and conditions under which the Period Two rates will be available to shippers upon expiration of their current firm transportation service agreements. Article 7 establishes a five-year moratorium period during which Kern River is precluded from seeking a section 4 rate increase and prohibits all shippers from filing a section 5 complaint to the maximum extent permitted by law during the same five year period.

26. Article 8 explains that the Settlement rates reflect an amount deducted from rate base for the reserve for accumulated deferred federal income taxes for liberalized tax depreciation. Article 9 requires Kern River to file revised tariff sheets to implement the Settlement rates within 10 days after the Settlement becomes effective. Article 10 defines the term of the Settlement. Article 11 describes the procedures by which the Settlement shall become binding on all parties. Article 12 provides that the provisions of the Settlement are not severable. This article provides that if the Commission severs any party or issue from the Settlement, the Settlement is void. Article 13 addresses the procedures attendant to reversal or modification of a final Commission order approving the Settlement on judicial review or after remand. Article 14 establishes that

Commission approval of the Settlement will constitute the necessary authority for Kern River to revise its tariff in order to place Period One Settlement rates into effect and will constitute the final disposition of all issues. This article also provides that Commission approval of the Settlement will terminate the paper hearing established by Opinion No. 486-A with respect to ROE. Article 15 describes the enforcement of the Settlement as subject to the Commission's Natural Gas Act jurisdiction. Article 16 states the Settlement will be legally binding on all parties, is privileged and not admissible in evidence. Article 16 also contains a *Mobile-Sierra* clause providing that the Commission shall apply, to the fullest extent allowed by law, the "public interest" standard to any changes to the Settlement once it has been approved.

27. As noted, as a part of the Settlement, Kern River proposed to immediately place into effect interim rates and provide early refunds for settling parties pending the outcome of the proposed Settlement. Accordingly, Kern River filed tariff sheets set forth in the Appendix to be effective for settling parties for the locked-in period[50] from November 1, 2004, until the date the Period One rates become effective October 1, 2008. The Appendix also reflects the Period One rates effective October 1, 2008, for settling parties and lists the currently effective motion rates for Kern River's services applied to non-settling parties. Kern River requested the Commission to accept the proposed tariff sheets listed in the Appendix to become effective as proposed. In the event the Settlement is not approved by the Commission, Kern River also proposed it be allowed the right in accordance with section 2 of Article 3 of the Settlement, to recoup from settling parties the refunds Kern River is to pay on October 1, 2008, and/or collect the difference between the locked-in motion rates and the Period One Settlement rates for the interim period. The filing was noticed on October 6, 2008, with comments due on or before October 14, 2008. No adverse comments were filed and the Commission accepted the proposed tariff sheets with one modification by letter order on October 28, 2008.[51]

B. Comments

28. Comments and reply comments supporting the Settlement were filed by Kern River, RCG and Calpine Energy Services, L.P. (Calpine). Kern River states that both settling and non-settling parties will receive the Settlement rates and refunds on all amounts collected by Kern River since November 1, 2004, in excess of the locked-in period rates. Kern River also states that the Settlement effectively accepts the Commission's cost-of-service and cost allocation determinations set forth in Opinion

[50] Kern River has filed numerous tariff sheets for the locked-in period with various effective dates to reflect adjustments pertaining to fuel, annual charge adjustments, and leap year.

[51] 125 FERC ¶ 61,108 (2008).

Nos. 486 and 486-A in this proceeding. Kern River states that the Settlement's pre-tax, overall rate of return of 11.63 percent (1) is below the pre-tax equivalent of the low end of Kern River's DCF proxy ranges;[52] (2) corresponds with a return on equity of 12.5 percent that is within the range of proxy returns on equity on which the Commission relied in Opinion No. 486;[53] and (3) is within the range of returns sponsored by Trial Staff[54] and by every intervenor that submitted supplemental evidence in the paper hearing established by Opinion No. 486-A.[55] RCG and Calpine state that the Settlement (1) provides immediate, significant benefits in the form of refunds, lower rates, and rate stability to Kern River's shippers; (2) preserves participants' ability to address Period Two rate issues; and (3) eliminates the need for continued litigation on all other matters.

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[52] Kern River notes that it presented calculations of proxy returns both with and without the MLP Policy Statement's 50 percent adjustment of the GDP growth rate for MLPs. Kern River cites the Supplemental Initial Brief of Kern River Gas Transmission Company in response to Opinion No. 486-A, Docket No. RP04-274-000 at 2 (filed June 17, 2008).

[53] Kern River notes that the proxy group the Commission used in Opinion No. 486 produced equity returns ranging from 8.94 percent to 13.62 percent. *See Opinion No. 486*, 123 FERC ¶ 61,056 at P 138. Kern River also notes that calculations similar to those shown in the Appendix to its Initial Comments in Support of the Settlement will confirm that the Settlement's pre-tax return is within the range of pre-tax returns that correspond with this range of equity returns.

[54] Kern River cites to the Initial Brief of the Commission Trial Staff (Staff Initial Brief) at 3 (filed June 17, 2008). Kern River notes that the median ROEs of Trial Staff's three alternate proxy groups for the 2004 period are 10.35 percent, 10.77 percent, and 10.95 percent, respectively. Kern River also notes that the median ROEs for Trial Staff's two alternative proxy groups for the current period are 11.81 percent and 11.71 percent, respectively.

[55] Kern River notes the following. Reliant's 2008 proxy group yielded a range of ROEs from 9.25 percent to 12.53 percent, with a median of 11.22 percent (*See* Initial Brief of Reliant Energy Services, Inc. (Reliant Initial Brief) at 2 filed June 17, 2008). The RCG's proxy group produced a range from 8.74 percent to 12.87 percent, with a median of 10.83 percent (*See* Initial Brief of RCG in response to Opinion No. 486-A (RCG Initial Brief) at 2 filed June 17, 2008). BP proposed using its 2004 proxy group, producing a range of returns from 7.31 percent to 13.62 percent, with a median of 9.34 percent (*See* Prepared Direct and Answering Testimony of Elizabeth Crowe on behalf of BP Energy Company at 15 (filed December 3, 2004); and Initial Brief of BP Energy on Reopened Record Issues (BP Initial Brief) at 3 (filed June 17, 2008).

29. Comments and reply comments opposing the Settlement were filed by BP, Southwest and Trial Staff. BP opposes the Settlement for various reasons. Among other things, BP argues that (1) the Settlement presents genuine issues of material fact; (2) the Settlement limits the NGA section 5 rights of non-consenting parties; (3) the Settlement's cost-of-service is unreasonable; (4) the Settlement is inconsistent with the allocation of risk under Kern River's levelized rate methodology; and (5) the Settlement rates are contrary to the Commission's decision in Opinion No. 486-A, are unjust and unreasonable, and are unduly discriminatory. Southwest argues that the Settlement places restrictions on the availability of Period Two rates. Southwest and Trial Staff argue that the rate moratorium prohibits non-settling parties from initiating action under section 5 of the Natural Gas Act to modify any Settlement rate for five years. Trial Staff believes that the Commission should not impose the Settlement on contesting parties. All three of these parties assert that the 12.5 percent ROE is an unjust and unreasonable part of the settlement rates.

III. Overview of the Commission's Rulings in this Order

30. In this order, the Commission (1) finds, based on the record established through the paper hearing, that Kern River's ROE should be 11.55 percent, (2) rejects the settlement, and (3) denies BP's request for rehearing on all issues, except for a clarification concerning the design of Kern River's Period Two levelized rates.

31. In order to approve the Settlement, the Commission would have to find that the Settlement rates are just and reasonable. That is because the settlement is contested by two current shippers on Kern River's system and the settlement expressly prohibits the severance of contesting parties. While the settlement is described as a black-box settlement, Kern River and the other supporting parties assert that the settlement rates include an ROE of about 12.5 percent and are otherwise consistent with all of the non-ROE merits rulings of Opinion Nos. 486 and 486-A. Therefore, approval the Settlement would require a finding that awarding Kern River an ROE of 12.5 percent is just and reasonable.

32. Accordingly, this order first addresses the parties' contentions concerning Kern River's ROE. For the reasons discussed below, the Commission (1) denies BP's contention on rehearing of Opinion No. 486-A that the Commission should not apply the Policy Statement in this proceeding, (2) approves a five member proxy group including two corporations and three MLPs based on the paper hearing record, (3) finds that the median ROE of that proxy group is 11.55 percent, and (4) finds that Kern River is a pipeline of average risk and therefore its ROE should be set at the median of the proxy group.

33. Based on this holding concerning Kern River's ROE, the Commission then addresses the parties' contentions concerning the settlement. The Commission finds that the parties supporting the settlement have not shown that the settlement provides

sufficient offsetting benefits to justify imposing on the contesting parties settlement rates reflecting an excessive ROE. Therefore, in light of the settlement's provision that contesting parties may not be severed, the Commission must reject the settlement.

34. Finally, the Commission generally denies BP's request for rehearing concerning Kern River's Periods Two and Three levelized rates, but does grant one clarification.

IV. <u>Application of Proxy Group Policy Statement and the Establishment of the Paper Hearing on ROE</u>

35. Before reaching the merits of the ROE issue, we first address several procedural issues raised by BP. In its request for rehearing of the Opinion No. 486-A, BP argues that the Commission (1) incorrectly applied the Policy Statement retroactively to the instant Kern River proceeding, (2) improperly afforded Kern River another opportunity to supplement its ROE case, (3) unlawfully relied on extra record evidence for some of its conclusions, and (4) improperly relied on *Petal* to justify the paper hearing and developing a further record.

36. The Commission rejects these contentions. While it is true that a policy statement is a guide to future behavior, there is no inconsistency between that precept and Opinion No. 486-A's decision to apply the Policy Statement in this proceeding. As the background section of this order makes clear, the issue of whether MLPs should be included in Kern River's proxy group was squarely before the Commission on rehearing at the time the Policy Statement issued. Thus, the future action at issue in Opinion No. 486-A was the policy to be applied to Kern River's request for rehearing of the prior determination rejecting Kern River's proposed inclusion of MLPs in the proxy group. At bottom, BP argues that once a proceeding begins, a policy statement may only be applied to cases for which the Commission has not issued some form of a merits decision.

37. However, the law is otherwise. In *Williston v. FERC*,[56] the Commission changed its policy on the weighting of the short- and long term growth components of the DCF model while the pipeline's appeal of a Commission order determining its ROE based on the old policy was pending before the court. The court found that the Commission's change in policy might entitle the pipeline to a recalculation of its ROE, and remanded the case to the Commission to consider whether to apply the new policy. On remand, the Commission applied its new policy and awarded the pipeline a somewhat increased

[56] *See Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54 (D.C. Cir. 1999) (*Williston v. FERC*).

ROE.[57] Similarly, in *Panhandle Eastern*,[58] the court had remanded the case subsequent to a change in Commission policy. Therefore the issue had remained open and the Commission applied the new policy to the remanded proceeding.[59] Thus, contrary to BP's argument, both the cited cases followed the rule that the Commission usually applies current policy when it decides an issue still before it.

38. It is true that in another case, *Consolidated Edison*, the court held the Commission can decline to apply a new policy to an open issue provided it has adequate reasons for doing so, and providing that the old policy was not unreasonable or unlawful.[60] In that case the record was some four years old and the Commission concluded it should remain closed for reasons of administrative efficiency. In the instant case, however, such an approach is not possible, because the Commission has determined that the proxy group policy applied in Opinion No. 486 was unreasonable.

39. Opinion No. 486 adopted an ROE for Kern River using exactly the same proxy group as was used in *HIOS*, and Opinion No. 486 rejected the inclusion of MLPs in the proxy group based on essentially the same reasoning as in *HIOS*.[61] Based upon an initial review of the requests for rehearing of Opinion No. 486, as well as developments in the gas and oil pipeline industries generally, the Commission concluded that its proxy group arrangements for both gas and oil pipelines must be reexamined, because there are so few reasonably representative corporations available for inclusion the proxy group. Because any change in its proxy group policies would affect the natural gas and oil pipeline industries generally, the Commission determined to address the issue first in a generic proceeding in which all affected parties in both industries could participate. Accordingly, as described above, the Commission issued a proposed policy statement, proposing to change its proxy group policies for both natural gas and oil pipelines. Shortly after issuance of the proposed policy statement, the D.C. Circuit issued its decision in *Petal v. FERC*, vacating and remanding the Commission's proxy group holdings in *HIOS*, and the court expressly observed that Opinion No. 486 had adopted the *HIOS* proxy group.

40. Accordingly, the Policy Statement reviewed the Commission's prior conclusions regarding the inclusion of MLPs in a ROE proxy group in light of the court's decision in

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[57] *See Williston Basin Interstate Pipeline Co.*, 87 FERC ¶ 61,265 (1999).

[58] *Panhandle Eastern Pipeline Co. v. FERC*, 890 F.2d 435 (D.C. Cir. 1989).

[59] *Panhandle Eastern Pipeline Co.*, 52 FERC ¶ 61,127 (1990).

[60] *Consolidated Edison Co. of N.Y. v. FERC*, 315 F.3d (D.C. Cir 2003).

[61] Opinion No. 486, 111 FERC ¶ 61,077 at P 138-140, 142.

Petal v. FERC. While BP is correct that the court left open the possibility that the Commission could continue the *HIOS* proxy arrangements, if it could explain and justify them "in very different terms,"[62] the Commission concluded in the Policy Statement that it must change its proxy group policies in order to address the court's concerns.[63] Among other things, the Commission found that its prior analysis in *HIOS* and Opinion No. 486 of why including MLPs in the proxy group without adjusting their cash distributions would lead to distorted results and was inconsistent with the basic structure of a DCF model and therefore was unreasonable.[64] Because the Commission has found it could not support its proxy group holdings in *HIOS* and Opinion No. 486 and adopted a revised proxy group policy in the Policy Statement, it must apply the new policy in this proceeding.

41. Thus, regarding BP's second argument, it was not inequitable to afford Kern River and the other participants in this case another opportunity to address the ROE issues in light of the Commission's revised proxy group policies, nor should Kern River be required to file a new section 4 rate case as BP urges. While Kern River advanced various theories supporting the inclusion of MLPs in the proxy group in the evidentiary phase of this proceeding and on rehearing, those are subsumed under the Commission's holding that those matters must be revisited. Thus BP's argument that the Commission had previously rejected the use of MLPs in Kern River's proxy group is untenable. BP similarly argues that affording Kern River an opportunity to supplement the record violates the latter's obligation to prove its rates are just and reasonable, to provide all required evidence in its initial case in chief, and is inconsistent with the Commission's rejection of Kern River's earlier efforts to reopen the record. These arguments are specious given *Williston* and the Commission's authority to control its proceedings.

42. BP's third procedural argument is that the Commission acted unlawfully in relying in part on materials outside the record, specifically those included in the record of the Policy Statement. This is incorrect. In an analogous situation the Commission issued a notice of inquiry regarding income tax allowances on December 2, 2004.[65] Following extensive initial and reply comments, the Commission issued its Policy Statement on Income Tax Allowances on May 4, 2005.[66] The Commission then reprised the Income

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[62] *Petal v. FERC*, 496 F.3d at 696.

[63] Policy Statement, 123 FERC ¶ 61,048 at P 47-51.

[64] *Id.* P 47-63.

[65] *Inquiry Regarding Income Tax Allowances* in Docket No. PL05-5-000.

[66] *See Inquiry Regarding Income Tax Allowances*, 111 FERC ¶ 61,139 (2005) (Income Tax Policy Statement).

Tax Policy Statement in detail in *SFPP, L.P.* and made detailed findings expressly grounded in the record of the Income Tax Policy Statement record.[67] On appeal, in *ExxonMobil Oil Corporation v. FERC*,[68] the court upheld the application of the Income Tax Policy Statement based on its review of the record the Commission had developed in the income tax allowance policy proceeding.[69] Opinion No. 486-A used the same approach by addressing certain fundamental issues on an extensive record following that model. Moreover, this complaint is moot because the Commission has afforded a further opportunity for comment on the financial issues discussed in the Policy Statement.

43. BP's fourth criticism is that Opinion No. 486-A erred in holding the MLPs could be included in the Kern River proxy group.[70] However, as BP itself states, the Policy Statement reserved to specific proceedings the determination of which MLPs, if any, were representative of pipeline operations, and as such, are comparable to the risk of the pipeline whose rates are at issue.[71] Thus, the Commission did not conclude that MLPs must always be included in a proxy group, much less that it is appropriate in the instant case. Moreover, the Commission did not exclude from the proxy group all diversified natural gas corporations.[72] The Policy Statement did reconsider the Commission's prior reservations concerning the use of MLPs in a ROE proxy group, and concluded the Commission could reasonably permit the use of MLPs in ROE proxy groups.[73] However,

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[67] *SFPP, L.P.*, 111 FERC ¶ 61,334 (2005) (the Remand Order).

[68] *ExxonMobil Oil Corporation v. FERC*, 487 F.3d 945 (D.C. Cir. 2007) (*ExxonMobil*).

[69] *Id.* at 950-52. The court explicitly stated that:

> "However, in the Remand Order -- which is challenged in the instant case – the Commission expressly relied on the conclusions and reasoning of the Policy Statement....Thus, in determining whether the Remand Order was arbitrary or capricious or contract to *BP West Coast*, we necessarily review the Commission's conclusions and reasoning in the Policy Statement." *Id.* 951.

[70] As discussed below, in its paper hearing filings, BP includes at least three MLPs in its proposed proxy group.

[71] Policy Statement, 123 FERC ¶ 61,048 at P 51 (*citing Petal v. FERC* at P 50).

[72] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 167, 188, 190, Ordering Paragraph (C); *Id.*

[73] *Id.* P 172, 175-76.

the Commission established a paper hearing in this case precisely to determine on a case specific record what entities of any type should be included in the proxy group.

44. The Commission thus rejects BP's contentions that the Commission should decide the ROE issues in this case based on its policies as in effect before the Policy Statement and that the Commission therefore should not have reopened the record. The Commission will address BP's other contentions in its rehearing request contesting certain aspects of proxy group policies adopted in the Policy Statement in the next section of this order.

V. Merits Determinations on the ROE Issues

45. Having disposed of BP's various procedural arguments, we now turn to the merits of the ROE issue. As discussed in the Policy Statement, the Supreme Court has held that "the return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[74] In order to attract capital, "a utility must offer a risk-adjusted expected rate of return sufficient to attract investors."[75] In theory, this requires an evaluation of the regulated firm's needed return compared to other regulated firms of comparable risk.

46. However, most natural gas pipelines are wholly-owned subsidiaries and their common stock is not publicly traded. Therefore, the Commission performs a DCF analysis of publicly-traded proxy firms to determine the return the equity markets require a pipeline to give its investors in order for them to invest their capital in the pipeline. The DCF model is based on the premise that "a stock's price is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk."[76] With simplifying assumptions, the DCF model results in the investor using the following formula to determine share price:

$$P = D/ (r-g)$$

[74] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[75] *CAPP v. FERC*, 254 F.3d 289 at 293.

[76] *Id.*

where P is the price of the stock at the relevant time, D is the current dividend, r is the discount rate or rate of return, and g is the expected constant growth in dividend income to be reflected in capital appreciation.[77]

47. Unlike investors, the Commission uses the DCF model to determine the ROE (the "r" component) to be included in the pipeline's rates, rather than to estimate a stock's value. Therefore, the Commission solves the DCF formula for the discount rate, which represents the rate of return that an investor requires in order to invest in a firm. Under the resulting DCF formula, ROE equals current dividend yield (dividends divided by share price) plus the projected future growth rate of dividends:

$$R = D/P + g$$

48. The Commission uses a two-step procedure for determining the constant growth of dividends: averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group (discussed below), as published by IBES, are used for determining growth for the short term; long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in the GDP.[78] The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[79]

49. The submissions of the parties in the paper hearing focus on the issues of the selection of the proxy group and Kern River's relative risk compared to the potential proxy firms. However, the parties have also addressed various other issues concerning the determination of the ROE to be awarded Kern River. In response, this portion of the order addresses four general topics: (1) the composition of the proxy group; (2) the determination of the dividend yield of the proxy firms; (3) the growth rates of the proxy firms; and (4) the relative position of Kern River within the selected proxy group.

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[77] *National Fuel Gas Supply Corp.*, 51 FERC ¶ 61,122, at 61,337, n.68 (1990); *Ozark Gas Transmission System*, 68 FERC ¶ 61,032, at 61,104, n.16. (1994).

[78] *Northwest Pipeline Company*, 79 FERC ¶ 61,309, at 62,383 (1997) (*Opinion No. 396-B*). *Williston Basin Interstate Pipeline Company*, 79 FERC ¶ 61,311, at 62,389 (1997) (*Williston I*), *aff'd in relevant part*, *Williston v. FERC*, 165 F.3d at 57.

[79] *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶ 61,084 at 61,423-4 (*Opinion No. 414-A*), *reh'g denied*, 85 FERC ¶ 61,323, at 62,266-70 (1998) (*Opinion No. 414-B*), *aff'd*, *CAPP v. FERC*, 254 F.3d 289 (D.C. Cir. 2001).

A. Composition of the Proxy Group

50. As the court explained in *Petal v. FERC*, the purpose of the proxy group is to "provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. Market-determined stock figures reflect a company's risk level and when combined with dividend values, permit calculation of the 'risk-adjusted expected rate of return sufficient to attract investors.'"[80] It is thus crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined. In other words, as the court emphasized in *Petal v. FERC*, the proxy group must be "risk-appropriate."[81]

51. However, given the numerous factors that can vary the risk profile of the individual firm, it is difficult in an individual case to develop a proxy group of sufficient numbers in which the members will have exactly the same risk. In the instant case, 100 percent of Kern River's assets, revenues, and earnings are derived from its interstate gas transmission pipeline function. Given this level of natural gas pipeline activity, it is unlikely there will be complete congruence among the characteristics of all proxy group members. For this reason, as both BP and Staff assert, *Petal* requires a full and complete analysis of the similarities and differences between the business activities of each of the proposed proxy firms and Kern River in order to ensure that the operations presented by the proxy group companies adopted are analogous to Kern River's operations and risks.

52. The paper hearing participants propose a range of proxy group members for both a 2004 and 2007-2008 proxy group. Staff proposes three different groups for the year 2004, one of four members and two of five members. After eliminating a number of firms Staff concluded were inappropriate, Staff's 2004 proxy group included KMI, National Fuel, Northern Border Partners, L.P. (Northern Border), Questar, and TC Pipelines, L.P. (TC Pipelines). For the year 2008 Staff proposed two proxy groups consisting of six and seven members and added the following to the 2004 group: Enterprise Products Partners, L.P. (Enterprise), Equitable, Kinder Morgan Energy Partners, LP (KMEP), Oneok Partners (Oneok, formerly Northern Border), and Southern Union Company (Southern Union), but deleted KMI.[82] BP proposes a nine member group for the year 2004: Equitable, KMEP, KMI, National Fuel, NiSource, Inc. (NiSource), Oneok Partners, L.P. (Oneok, meaning Northern Border in that year),

[80] *Petal v. FERC*, 496 F.3d at 697 (*quoting CAPP v. FERC*, 254 F.3d 289 at 293).

[81] *Id.*

[82] Initial Brief of the Commission Trial Staff (Staff Initial Brief), Ex. S-2 at Schedules 1-3 and 7-9.

Questar, Southern Union, and TC Pipelines.[83] BP also proposes an eleven member group for the year 2008 that added Boardwalk Partners (Boardwalk), Spectra Energy Partners, L.P. (Spectra Partners), Spectra Energy Corporation (Spectra Energy), and deleted KMI.[84] Kern River proposed a four firm sample for the 2004 test year, consisting of Enterprise, KMI, KMEP, and Northern Border, and no proxy group for the year 2008.[85]

53. RCG proposed seven members for the year 2008 consisting of Southern Union, Spectra Energy, TC Pipelines, KMEP, TransCanada Corporation (TransCanada), Oneok, and Boardwalk[86] and later a 2004 group consisting of Equitable, KMI, National Fuel, Questar, TransCanada, Enterprise, and Northern Border. Reliant proposed a three member group for the year 2004 consisting of KMI, Northern Border, and TC Pipelines[87] and a five member sample group for the year 2008 that deleted KMI and added Boardwalk, Southern Union, and Spectra Energy.[88] Staff, Reliant, and BP proposed using a 2004 or 2008 test year with BP favoring 2004, Reliant 2008, and Staff asserting that either was acceptable. Kern River asserted that only the year 2004 is appropriate with RCG first proposing a 2004 test year, but later accepting a 2008 test year as well.

1. The Test Year for This Proceeding

54. This order now addresses the threshold issue of whether the proxy group should be determined based on proxy company data for (1) the 2004 test period upon which Kern River's rates in this rate case are based[89] or (2) updated data for 2008. Opinion No. 486 was based on a 2004 test year. At this juncture, Kern River and Calpine assert that the Commission should retain the 2004 test year. Reliant, BP, and Staff provide proposed proxy groups and DCF analyses for the years 2004 and 2008. RCG first included only a year 2008 proxy group but later devised one for 2004 as well.

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[83] BP Initial Brief at 3.

[84] *Id.* at 4

[85] Supplemental Initial Brief of Kern River Transmission Company in Response to Opinion No. 496-A (Kern River Initial Brief) at 1, 6-10.

[86] RCG Initial Brief at 2, 11-13.

[87] Reply Brief of RCG in Response to Opinion No. 486-A (RCG Reply Brief) at 5.

[88] Reliant Initial Brief at 1, 6-7.

[89] The last twelve months of the test period in this rate case was the year ending on October 31, 2004. For convenience, in this order we shall refer to that period as "the 2004 test year."

55. The parties advancing the use of the 2008 test year argue that nothing in Opinion No. 486-A precludes the use of a 2008 test year, and that in fact the Commission reopened the record in that time frame. Staff further argues that even in gas cases the Commission has a longstanding policy to consider updated financial data beyond the test period when circumstances warrant. While Staff takes no definite position, it suggests that the Commission could establish one equity cost of capital for the period November 1, 2004 through April 17, 2008, and a second thereafter.[90] BP states that there are synchronization and consistency issues if the year 2008 is used and believes that the year 2004 is the better year.[91] Reliant and RCG assert that the year 2008 is the better year because it more accurately reflects economic conditions for the time frame the rates will be in effect. They place particular emphasis on continued growth in Kern River's throughput after 2004, its stronger contractual position in 2008, and the improved prospects for production in the gas basins it serves. They use this evidence to bolster their argument that Kern River is materially less risky than other gas pipelines and should be placed at the lower end of the zone. They argue that the more recent 2008 throughput data establishes that Kern is significantly over recovering its 2004 cost of service.[92]

56. Kern River argues that the year 2008 does not reflect the elements in its cost of service or its risk in that year. It also asserts that many of the firms proposed for the 2008 proxy group did not even exist in 2004 and it is hard to see how the risks of those firms in 2008 could possibly be comparable to the conditions Kern River faced in 2004. Kern River further argues that the additional information regarding volumes and its more recent prospects is wholly inconsistent with the Commission's test period concept. It requests the Commission to exclude all 2008 evidence from the record.[93]

57. The Commission will retain the 2004 test year. All other aspects of Kern River's rates are being established based on data from that time frame, and therefore Kern River's rates should also reflect its capital costs at that time. Kern River's capital cost is the weighted cost of its debt and equity capital structure. The only debt information here is for the year 2004. Thus, if the Commission were to use a 2008 proxy group, it would have to combine a 2004 debt cost with a 2008 equity cost, which distorts the overall weighted cost of capital. Moreover, equity cost is directly related to the cost of debt

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[90] *Citing Williston Basin Interstate Pipeline Company*, 72 FERC ¶ 61,075, at 61,373 (1995).

[91] BP Initial Brief at 4.

[92] RGC Initial Brief at 7-9; Reliant Initial Brief at 5-6 and 15-16.

[93] Reply Brief of Kern River Transmission Company in Response to Opinion No. 486-A (Kern River Reply Brief) at 2-4 and 7-11.

because it reflects in part a markup over debt cost based on the risk of the firm in the same period. Thus, it is internally inconsistent to use debt and equity costs from different periods. Finally, the Commission concludes that RCG and Reliant's use of post-2004 increases in Kern River's throughput to justify a 2008 proxy group is generally inconsistent with the 2004 test period and serves to highlight the lack of synchronization between a cost of service and operating profile grounded in 2004 data and a risk profile based on the year 2008. As Kern River points out, some of the firms relied on for the 2008 proxy group did not even exist in 2004 and as such may not have had a risk profile similar to that of Kern River.[94]

58. This order now turns to an analysis of the firms the parties proposed to include in the proxy group based on data for the year 2004. These firms fall into three categories. These are (1) corporations historically recognized as predominantly engaged in the interstate natural gas transmission business; (2) MLPs owning natural gas transmission companies; and (3) diversified natural gas companies with some interstate natural gas transmission business but with a majority of the business in other natural gas activities such as distribution and exploration and production.

2. Gas Pipeline Transmission Corporations

59. As described above, the Commission historically required that a proxy firm's pipeline business account for, on average, at least 50 percent of the firm's assets or operating income over the most recent three-year period. The possible sample of gas pipeline corporations which satisfy that standard is limited, because El Paso and Williams, two traditional gas transmission companies, are excluded from the 2004 proxy group for the reasons stated in Opinion No. 486. The remaining corporations which satisfy this standard, discussed by the parties, are KMI and TransCanada Corporation. As of the end of 2004, KMI's ownership of Natural Gas Pipeline Company of America (Natural) accounted for 55 percent of its assets.[95] In addition, its investment in KMEP accounted for another 23 percent of its assets. As discussed further below, about 35 percent of KMEP's assets are natural gas pipeline facilities. Thus, KMI's pipeline business accounts for over 60 percent of its assets. All the parties accept KMI as an appropriate interstate gas transmission firm given its predominance of interstate gas pipeline operations. Therefore KMI will be included in the Kern River proxy group.

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[94] Rebuttal Brief of Kern River Transmission Company in Response to Opinion No. 486-A (Kern River Rebuttal Brief) at 8.

[95] Ex. S-3 at 31.

60. Approximately 91 percent of TransCanada's operating income is from its natural gas pipeline business.[96] However, all the parties except RCG oppose its inclusion in the proxy group, because it was involved in a nearly two billion dollar acquisition of Gas Transmission Northwest in 2004, which could distort its stock price and dividend yield.[97] Also, TransCanada's Canadian pipeline is subject to a significantly different regulatory structure that renders it less comparable to domestic pipelines regulated by the Commission.[98] For these reasons, TransCanada will be excluded from the proxy group.

3. MLPs Owning Transmission Companies

61. Various parties suggest four MLPs owning different types of transmission companies for inclusion in the proxy group. The four MLPs are Northern Border, TC Pipelines, KMEP, and Enterprise. Of these, Northern Border and TC Pipelines had gas transmission assets and/or operating income in excess of fifty percent in 2004. The other two MLPs do not satisfy the fifty percent standard, but nevertheless are supported by certain parties. For the reasons discussed below, the Commission includes Northern Border, TC Pipelines, and KMEP in the proxy group, but excludes Enterprise.

a. Northern Border and TC Pipelines

62. During 2004, 91 percent of Northern Border's operating income came from interstate natural gas pipeline operations, with the remainder from gathering and processing.[99] While Northern Border was not followed by Value Line, it was publicly traded and IBES did report on it, including providing a five-year growth projection. All the parties support including Northern Border in the proxy group, and accordingly, the Commission will do so.

63. TC Pipelines is an investment partnership, which in 2004 owned a 30 percent interest in Northern Border Pipeline Co. and a 49.1 percent interest in Tuscarora Gas

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[96] Ex. S-2, Schedule 3.

[97] *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279, at 61,932-33 (2000).

[98] Staff Initial Brief at 8; Staff Reply Brief at 13; Kern River Rebuttal Brief at 14. Value Line recognizes this difference by categorizing TransCanada as among the firms in the "Canadian Energy Industry," and not the firms in the "Natural Gas (Diversified) Industry." Ex. S-3 at 7.

[99] *See* Ex. S-2 at Schedule 2. In 2004, Northern Border held a 70 percent interest in Northern Border Pipeline Co., a 100 percent interest in Viking Gas Transmission Co. and Midwestern Gas Transmission Co., and a 33 percent interest in Guardian Pipeline Co. Ex. BP-150 at 1.

Transmission Co.[100] All of TC Pipeline's 2004 revenue came from dividends paid by those two pipelines. While TC Pipelines is not included in Value Line's list of diversified natural gas companies, it is followed by both Value Line and IBES.

64. Staff, BP, and RCG suggest that TC Pipelines could be a member of a 2004 proxy group. However, Kern River would exclude TC Pipelines from the 2004 proxy group as it has no pipeline operations of its own, is too small to be representative, and was not listed in the major edition of Value Line in 2004 even though all of its revenue derives from gas transmission.

65. The Commission concludes that TC Pipelines is an investment partnership that owned large minority interests in two major interstate natural gas pipelines in 2004 and all of whose revenue came from the dividends of those pipelines. It is true that it owned no pipeline assets of its own, and no credit ratings are included in the record. However, despite its small size, TC Pipelines was a publicly traded company on the New York Stock Exchange, was listed in the secondary or minor Value Line analysis in 2004,[101] and made distributions to its unit holders out of the dividends received from the pipelines in which it invested. Consistent with (1) the premise underlying the DCF methodology that a stock's price is equal to the present value of its future cash flows and (2) the fact that all of the cash flows from an investment in TC Pipelines derive from the gas transmission business, investors in TC Pipelines must view its risk profile as the same as that of the natural gas pipelines in which TC Pipelines invests. Thus, its unit price, cash distributions, and growth prospects are all tied to the health of the gas transmission business. In fact, Kern River's own witness conceded that TC Pipelines "was, and still is, a gas transmission play."[102]

66. Given the small number of firms available for inclusion in the proxy group for the year 2004, the Commission concludes that TC Pipelines should be included due to its predominately natural gas pipeline profile and its publicly traded status. This satisfies two of the Commission's traditional standards, the two more important for performing a representative DCF calculation, and comes close on the third, a listing in Value Line, in 2004. While it was not listed in the major edition of Value Line, it was reported on.[103]

[100] Ex. BP-150 at 1.

[101] Ex. No. RES-16 at 12-14.

[102] Ex. KR-132 at 13.

[103] Reply Brief of Reliant Energy Services (Reliant Rely Brief) at 12, n.9, *citing* Ex. No. RES-16 at 15.

The first assures that the company is representative of the industry and the second that the necessary trading and return information is available. The fact that TC Pipelines is relatively small can be addressed by evaluating its relative risk within the proxy group.

b. Kmep

67. KMEP is an MLP included in Value Line's list of diversified natural gas companies. KMI is its general partner. In 2004, KMEP owned 100 percent interests in two interstate natural gas pipelines, Kinder Morgan Interstate Transmission, Inc., and Trailblazer Pipeline Co.[104] In addition, effective November 1, 2004, KMI transferred its 100 percent ownership interest in TransColorado Gas Transmission Co. to KMEP.[105] According to Standard &Poors Ratings Direct (S&P) data provided by Trial Staff, KMEP's natural gas pipelines accounted for 35 percent of its total assets as of the end of 2004.[106] KMEP also owned oil and product pipelines which accounted for another 35 percent of its assets, CO2 pipelines which accounted for 14 percent of its assets, and terminal facilities which accounted for the remaining 15 percent.[107] The S&P 2004 operating income data for KMEP is distorted by a negative corporate overhead charge of 45 percent. However, similar to the distribution of its assets, KMEP had approximately equal amounts of operating income from its natural gas pipelines and from its oil pipelines and its income from CO2 pipelines and terminals was about half the amount from its gas and oil pipelines.[108] KMEP was not involved in any gas distribution, exploration and production, or trading and marketing activities during 2004.

68. Kern River and BP both propose to include KMEP in the proxy group, but Trial Staff and the other parties do not. Several parties raise two concerns regarding the inclusion of KMEP in the proxy group, one based on its affiliate status with KMI and the second that some 35 percent of its operating income involves oil and product pipelines. Regarding the first concern, Trial Staff asserts that a MLP that has the same assets as a corporation parent should be excluded from the proxy group because including both firms

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[104] BP Ex. No. 178.

[105] Ex. S-3 at 33.

[106] *Id.* at 36.

[107] *Id.*

[108] According to Kern River's analysis of KMEP's 2004 SEC Form 10-K, KMEP obtained 30 percent of its earnings from natural gas pipelines, 31 percent from petroleum pipelines, 20 percent from terminals, and 19 percent from CO2 pipelines. Ex. KR-133 at 2.

double counts the assets and the income. It asserts this would count the cost of capital twice and would overweight the proxy group toward the equity cost of capital of those particular firms. Trial Staff also asserts that the cost of capital for KMI and KMEP is quite close, which indicates they have duplicating assets.[109]

69. In response, Kern River asserts that the two firms have different assets even if they have some similar assets that are owned by different firms. It also argues that the two firms have separately traded public securities and present options to investors. Specifically, KMEP is an MLP that places greater emphasis on distributions and less on growth. KMI is a corporation that places more emphasis on growth and less on current dividends. Thus, they are different firms with different investment profiles despite their interlocking financial interests.[110]

70. The Commission finds that KMI and KMEP represent sufficiently separate investments that both may be included in the proxy group. As of the end of 2004, KMI's investment in KMEP represented only 23 percent of its assets. In addition to its investment in KMEP, KMI also owned 100 percent of Natural, which represented 55 percent of its assets.[111] Thus, KMI's investment in KMEP represented less than one quarter of its assets, and a substantial part of its gas transmission business is unrelated to KMEP. As Kern River points out, KMI and KMEP are separately traded public securities. Given that KMI's business operations include substantial natural gas transmission and other business activities in which KMEP is not involved, the two stocks do not represent investments in the same business. That the investment community views the two stocks as separate and distinct investments is demonstrated by the fact that security analysts surveyed by IBES in 2004 projected significantly greater growth for KMI than for KMEP.

71. Moreover, KMEP's asset and earnings profile includes a products pipeline component equal to its natural gas pipeline component, and secondary CO2 pipeline and terminal components of equal weight. All three of these non-natural gas pipeline components have a somewhat higher risk than the natural gas pipeline component of the firm. As such, Trial Staff's assertion that the two firms have similar risks because they

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[109] Ex. S-6 at 4.

[110] Kern River Reply Brief at 14-15 and Ex. No. KR-138 at 8; Kern River Rebuttal Brief at 14 and Ex. No. KR-139 at 16.

[111] According to Kern River, 39 percent of KMI's 2004 earnings were from Natural and TransColorado (prior to its November 1, 2004 transfer to KMEP), and 7 percent from the gas distribution business of Kinder Morgan Retail, while 53 percent were from KMEP. Ex. KR-133 at 4.

have similar returns may mean that they have similar risks and returns because they have similar assets, not that they have the same assets. In fact, the analysis here would suggest that KMEP's risk is somewhat higher. This would be reflected to a degree in KMI's risk, but KMI would have less risk given its predominance of gas pipeline assets.

72. Thus, while KMEP's risk would be reflected in KMI's return, stock price, and financial ratings, the two firms offer different investment opportunities and ownership characteristics. KMEP and KMI are sufficiently distinct that KMI's partnership interest in KMEP does not require exclusion of KMEP from the proxy group given the instant facts.[112]

73. The second objection to including KMEP in the proxy group is the fact that a significant part of its business in 2004 was the oil pipeline business and therefore it should not be classified as a gas transmission firm because oil and product pipelines have different risks than natural gas pipelines. As Trial Staff notes, the Commission has traditionally considered oil pipelines to be somewhat more risky than natural gas pipelines. The principal reason is that oil pipelines frequently operate in markets where oil can be delivered by competing pipelines, or by barge for longer movements and by trucks from terminals for shorter movements. Oil pipelines must charge common carrier rates that are equal for all customers shipping between the same points. They thus have fewer opportunities to discount within the wider price range available to gas pipelines provided by the latter's ability to contract with individual customers. In contrast, BP asserts here that oil pipelines have no barriers to entry or exit and can recover cost increases through an indexing mechanism that reduces regulatory risk.[113] BP also asserts that the increased demand for the transportation of petroleum products since 2000 may have also reduced the market risk of many petroleum and product pipelines. It therefore concludes that oil pipelines are actually less risky than many, if not most, interstate gas pipelines.

74. As noted, Trial Staff's 2004 analysis concludes that KMEP's operations, based on asset allocations to eliminate accounting distortions, were 35 percent gas transmission, 35 percent oil products, and 30 percent other.[114] The duality of the firm's operations is also reflected by the inclusion of KMEP in that year as part of Value Line's Natural Gas (Diversified) Group. In a later year KMEP became a member of a broad group that included both gas and oil transmission firms. As recently stated by Value Line:

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[112] *See* RCG Initial Brief at 12-13.

[113] Rebuttal Brief of BP Energy Company on Reopened Record Issues (BP Rebuttal Brief) at 19.

[114] Ex. S-3 at 36.

> The Oil/Gas Distribution Industry is unusually homogeneous in its operations as members do little besides distribute hydrocarbons, mostly by pipeline.[115]

This homogeneity reflects the similarities, if somewhat different risks, of a firm owning both types of transmission firms. Thus, it is reasonable to include a firm such as KMEP in the proxy group if the weight of the gas and oil pipelines is similar and the combined transmission function exceeds 50 percent.[116] In fact, all parties did so in 2008, apparently overcoming any reservations regarding KMEP's oil pipeline component they had in 2004.

75. The Commission again concludes that the oil pipeline component of a diversified natural gas company will increase somewhat the firm's overall risk, primarily due to the oil pipeline industry's overall greater exposure to competition. However, this should not preclude the inclusion in a proxy group of a diversified firm having both components where, as here, the combined transmission function of 70 percent is significantly in excess of the 50 percent combined threshold previously discussed and no other one component predominates. Thus, the fact that KMEP has been included in oil pipeline proxy groups does not necessarily preclude its inclusion in a gas pipeline proxy group as the firm has a balanced investment in both businesses.

c. <u>Enterprise</u>

76. Enterprise is another MLP listed in Value Line's list of diversified natural gas companies. In 2004, Enterprise had minority interests in two small offshore NGA regulated pipelines (Nautilus and Venice Gathering System).[117] In addition, in December 2003, it announced a five billion dollar merger with Gulf Terra Energy Partners, L.P. That merger was completed on September 30, 2004, thus giving Enterprise significant onshore intrastate pipeline facilities regulated in part under section 311 of the Natural Gas Policy Act of 1978.[118] As of the end of 2004, after the merger with Gulf Terra, Enterprise's offshore pipeline facilities accounted for 9 percent of its assets and its

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[115] March 14, 2008 Issue; Staff Ex. 3 at 127.

[116] *See* Opinion No. 486, 117 FERC ¶ 61,077 at P 154, n.248, finding that pipelines that primarily transport oil, petroleum products, or natural gas liquids should not be included in a natural gas pipeline proxy group. Opinion No. 486 also excluded firms that were predominately or exclusively electric firms. *Id.* P 129, 138.

[117] Ex. BP-164 at 4.

[118] Ex. BP-164 at 4; Ex. S-1 at 6-7.

onshore natural gas pipelines accounted for 49 percent of its assets. Enterprise also owned natural gas liquids pipelines regulated under the Interstate Commerce Act,[119] which accounted for 36 percent of its assets.[120] Its other assets are related to petrochemical services.

77. Kern River proposes to include Enterprise in its 2004 proxy group. Trial Staff and BP argue that Enterprise should be excluded from any 2004 proxy group because it does not have an investment grade rating. Trial Staff asserts that the Commission now excludes firms from the proxy group that do not have similar credit ratings[121] and that in 2004 Enterprise's rating was BB+, which is one notch below the lowest investment grade rating of BBB-, compared to Kern River's A3 rating.[122] Trial Staff also asserts that El Paso and Williams, the companies the Commission previously excluded from the 2004 proxy group on the grounds of their poor financial condition, also had speculative investment credit ratings in 2004. Trial Staff also states that Enterprise's S&P business profile rating of 6 is riskier than Kern River's rating of 3. Kern River argues that Enterprise was almost of investment grade in 2004 and should therefore be included in the proxy group.

78. The Commission concludes that Enterprise should not be included in the proxy group for several reasons. First, until the Gulf Terra merger was competed near the end of the test period for this rate case, Enterprise was primarily a natural gas liquids pipeline regulated under the ICA, not a gas transmission firm. Enterprise's SEC Form 10-K indicates that during 2004 only 10 percent of its revenues were from the natural gas business, while 73 percent were from its natural gas liquids pipelines.[123] Similarly, natural gas transmission accounted for 19 percent of Enterprise's gross operating margin in that year, while natural gas liquids transportation accounted for 57 percent. Most of the 2004 data which would be used to calculate Enterprise's dividend yield if it were included in the proxy group is for the period before the Gulf Terra merger was completed. As BP states, during that period, Enterprise's natural gas transmission business was "insignificant."[124] BP also presents extensive and convincing evidence that

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[119] Interstate Commerce Act, 49 U.S.C. App. § 1, *et seq*. (1988) (ICA).

[120] Ex. S-3 at 8.

[121] *Citing Southern California Edison Company*, 128 FERC ¶ 61,187, at P 27 (2008) (*SoCal*)

[122] S-1 at 6-7.

[123] Ex. KR-133 at 1.

[124] Ex. BP-143 at 7.

Enterprise's natural gas liquids transmission business is particularly vulnerable to commodity risk due to the pricing mechanism it utilizes to transport natural gas liquids and related interest risk.[125] These points have merit because Enterprise's per barrel rate and margin is dependent on the margins of the underlying commodity transactions, and its tariffs are premised on the regulatory characteristics and risks of oil or petroleum pipeline, which were previously discussed in the context of KMEP.

79. Trial Staff and BP would also exclude Enterprise from the proxy group as a firm that has undertaken mergers or major acquisitions in the test year. Trial Staff asserts that such large scale activity can distort share prices by creating uncertainty (positive and negative) about the impact of change. Such transactions can also influence the stability of the dividend pattern.[126] In *Enbridge Pipelines (KPC)*, the Commission explained another reason for caution.

> [T]he Commission observes that both of Dr. Olson's DCF analyses relied on a proxy group that included the Coastal Corporation (Coastal), El Paso Natural Gas Company (El Paso), Enron Corporation (Enron), Sonat Inc. (Sonat), and The Williams Companies (Williams). But KPC conceded at hearing that it was a mistake to have included Sonat in the proxy group because Sonat was merged with El Paso on March 15, 1999, during the test period and once a company is the subject of an acquisition, the growth rate is based on whatever is expected to happen between that time and when the buyout is completed, which is inconsistent with the Commission's method which seeks to compute a growth rate beyond five years.[127]

80. Kern River argues Enterprise's lack of an investment grade rating was a short term function of a major acquisition with GulfTerra in 2004, a condition which continued until December 2006.[128] However, this simply establishes that Enterprise not only lacked an investment rating, the lack of that rating stemmed from adjustments to a major merger.

81. The Commission therefore concludes that Enterprise should not be included in the proxy group because its commercial characteristics are different from those of interstate gas pipelines and its financial profile was affected by a merger.

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[125] *Id.* at 9-12 and 14.

[126] Ex. Staff S-1 at 6-7 (*citing Southern California Edison Company*, 122 FERC ¶ 61,187 at P 27 (2008) (*SoCal*).

[127] *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 237 (2002) (*Enbridge*).

[128] Kern River Rebuttal Brief at 16-18.

4. <u>The Diversified Natural Gas Corporations</u>

82. In *Williston II*, *HIOS*, and Opinion No. 486, the Commission used the corporations in Value Line's list of diversified natural gas companies as the starting point for developing the proxy group. Such corporations not only have gas transmission operations, but also engage in other aspects of the natural gas business, including exploration and production, gathering and processing, marketing and trading, and distribution to retail customers. A central issue here is whether diversified natural gas companies whose pipeline operations constitute less than 50 percent of their business may nevertheless be included in a natural gas pipeline proxy group, given the court's decision in *Petal v. FERC* and the analyses in the Policy Statement. In the Policy Statement, the Commission did not preclude the use of diversified corporations in the proxy group. However, the Commission did recognize that the probable difference in the risk of the natural gas pipeline business and the risk profile of a diversified gas corporation with substantial local distribution activities was specifically recognized by the court in *Petal v. FERC*.[129]

83. Trial Staff, BP, and RCG continue to include National Fuel, Questar and Equitable from the Value Line list of diversified natural gas companies in their 2004 proxy groups. BP also proposes to include NiSource and Southern Union. While neither of those corporations is on the Value Line diversified natural gas company list, in 2004 they were involved in both the natural gas transmission and distribution businesses, as well as other businesses. In support of their proxy group proposals, Trial Staff, BP, and RCG all assert that the diversified gas corporations they have selected have sufficient gas transmission assets to be included in the proxy group and that the distribution components of the diversified gas companies are only somewhat less risky than their interstate gas transmission assets. In reply, Kern River asserts that both *Petal v. FERC* and the Policy Statement held that local distribution company (LDC)-oriented natural gas corporations are not appropriate for inclusion in a gas pipeline proxy group, nor is this necessary for the year 2004. For the reasons discussed below, the Commission includes National Fuel in the proxy group, but excludes the other four corporations.

a. <u>Whether to Preclude Inclusion in the Proxy Group</u>

84. The Commission first concludes that neither *Petal v. FERC* nor the Policy Statement preclude the use of diversified natural gas companies in a gas pipeline proxy group as matter of law. In fact, in *HIOS* and *Petal v. FERC* the Commission and the court appear to have assumed that National Fuel, Questar, and Equitable were LDCs when evaluating whether these firms could be included in a gas pipeline proxy group. Thus, *Petal v. FERC* does not use the phrase "diversified natural gas corporations." The

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[129] *Id.* at 6-7.

only references to National Fuel, Questar, and Equitable are as distribution companies, which is not how these firms are categorized by Value Line. Accordingly, *Petal v. FERC* appears to have concluded that National Fuel, Questar and Equitable were LDCs, or at least that the Commission's analysis assumed that they were the economic equivalent of LDCs.[130] This apparent factual assumption was incorrect. Moreover, the court stated that on remand it did not require any particular proxy group, but that the overall arrangement must make sense in terms of the relative risk and the statutory command to set just and reasonable rates commensurate with returns on investments in other enterprises having corresponding risks.[131]

85. The Policy Statement likewise states that "[w]hile the Commission is not precluding use of diversified corporations or MLPs in the proxy group, the <u>probable</u> difference in the risk of the natural gas pipeline business and the risk profile of a diversified gas corporation with <u>substantial</u> local distribution activities has been highlighted by the parties and specifically recognized by the court in *Petal*."[132] The Policy Statement did not hold that the difference in risk between the two types of firms is a given. Rather, the issue turns on the whether the components of a diversified natural gas corporation are such that its risk is comparable to a natural gas pipeline. This determination turns on the nature of the firm's components and its business environment.

86. There is little disagreement that the gathering and processing, exploration and production, and trading and marketing activities of a diversified natural gas company are riskier than the gas transmission, oil transmission, or gas distribution components. For example, a report by Moody's Investors Service on how it assigns ratings to North American diversified natural gas transmission and distribution companies describes both the gas pipeline and LDC businesses as relatively low risk because, among other things, "LDCs and pipelines earn regulated rates that lend predictability to their cash flows" and "employ relatively low-tech, long-lived assets and are characterized by low rates of technical innovation."[133] The report then states, "Because these businesses are generally mature and offer limited growth, companies often diversify into other businesses that promise higher return, albeit at higher risk. Generally diversification is into a business

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[130] *Petal v. FERC*, 496 F.3d 695 at 699.

[131] *Id.* at 700.

[132] Policy Statement, 123 FERC ¶ 61,048 at P 51 (*citing Petal v. FERC* at 6-7 in n.64) (emphasis added).

[133] *E.g.*, Staff Ex. S-3 at 76, *reproducing* Moody's Investors Service Rating Methodology, *North American Diversified Natural Gas Transmission and Distribution Companies*, March 2007 (Moody's *North American Diversified*).

within the gas value chain and related to the company's core regulated business. For example, [exploration and production] and [gathering and processing] are the most common areas of diversification."[134] The greater risk of these unregulated activities stems from a relative ease of entry into these markets, the greater exposure to price competition among firms already in the market, and the price volatility of the commodities involved. Within these more market oriented, as opposed to regulated, activities, gathering and processing is the least risky, exploration and production is more risky, and trading and marketing has the highest risk.[135] The presence of these other components leads Trial Staff and BP to argue that if a diversified natural gas company has a significant exploration and production function, the presence of these additional components can offset the lower risk of the LDC component.

87. BP further argues that higher natural gas prices have increased the risk of customer payment defaults and there is now increased regulatory risk because state public utility commissions are reluctant to pass on the higher prices.[136] BP also asserts that LDCs have always faced significant seasonal demand risk and that this risk has been enhanced by the increasingly volatile natural gas prices. It further asserts that LDCs are facing long term declines in gas demand as customers lower their overall demand and increased resulting revenue volatility.[137] BP further asserts that LDCs regularly face competition from other LDCs and now have greater risk than interstate gas pipelines may bypass the LDC to directly serve large end-user loads.[138]

88. In contrast, Kern River argues that the testimony of its expert witness Dr. Olson reviews both the theory of such companies and specific characteristics of each of the diversified natural gas firms Staff and BP suggest.[139] It argues that these firms have integrated production and market storage functions that serve to reduce supply-side and market risk for the enterprise as a whole or that their pipeline revenues are highly dependent on, and supported by storage and transportation contracts of the regulated pipeline component and its distribution affiliates. Kern River further asserts that the integrated, diversified, business profile of such a firm is not comparable to Kern River's

[134] *Id.*

[135] *Id.* at 81.

[136] Ex. No. BP-94 at 65-66; Ex. No. BP-159 at 10, 11-14, 14-16, and 18-20.

[137] Ex. No. BP-94 at 67-68; Ex. No. BP-159 at 6-10, 16-18.

[138] Ex. No. BP-94 at 69-70; Ex. No. BP-159 at 5-6.

[139] Kern River Reply Brief at 15.

midstream transmission-only operations.[140] It further argues that most of the risks cited by BP in particular are offset by regulatory devices designed to stabilize the diversified gas company's local gas distribution operations.

89. The Commission concludes that a diversified natural gas company may not necessarily have "the highly different risk profiles" attributed to such firms by *Petal v. FERC*, or by the Commission in *HIOS* and Opinion No. 486. Staff and BP provide sound arguments why the LDC component of some natural gas distribution companies might have at least as much business and regulatory risk as an interstate natural gas pipeline. Given the record here, the Commission accepts Staff's and BP's general arguments that while LDC operations are less risky than interstate gas pipeline operations, this is not always true to the extent held by *Petal v. FERC* or Opinion No. 486. Thus, a diversified natural gas corporation with a LDC component need not be precluded from inclusion in a proxy group simply because the firm has such distribution operations, particularly if any lower risk of the distribution operations is offset by other higher risk activities.

90. The Commission also concludes BP and Trial Staff overstate the risk generally applicable to the LDC components of diversified natural gas companies. While it is true that the increased reliance on market-based supplies of gas and more volatile retail pricing may have increased the risk of traditional LDCs, this does not change the basic economic structure of the industry. Most LDCs remain local monopolies and often control alternative supplies of gas that help mitigate their gas price risk. Entry remains difficult and the risk of fluctuating gas prices is balanced by the use weighted average gas forms of pricing combined with pass through mechanisms which both shift the risk of changes to the consumer while evening out the worst fluctuations. Similarly, natural gas demand by some customers may have declined due to conservation, but gas is the heating and industrial fuel of choice because of its overall lower BTU cost. Most of these factors advanced by BP are reflected in the Moody's recent evaluation of the relative risk of LDCs and natural gas pipelines. In that evaluation, Moody's continues to consider LDCs to have a lower risk than natural gas pipelines even as it acknowledges that LDCs now face higher risks than when gas prices and entry were more strictly regulated.[141]

91. As Trial Staff and BP also argue, to the extent a diversified natural gas company's distribution business has lower risk than its pipeline business, that lower risk may be offset by the higher risk of the company's exploration and production and other unregulated natural gas activities. On the other hand, given the potential for price volatility in the gas commodity markets and the related higher risk, the more heavily a

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[140] *Id.* 15-17.

[141] Moody's *North American Diversified*, Ex. S-3 at 76-77.

firm is involved in any of the three more risky business groups previously discussed, the harder it may be to evaluate the diversified gas corporation's risk compared to a natural gas pipeline.[142] The potential complexity of such an analysis is why the Commission adopted its historical standard of 50 percent of pipeline income, revenue, or assets for inclusion in a gas pipeline proxy group. This preferred threshold standard reduces the variance of the offsetting factors that may have to be evaluated. For the same reason, if a diversified gas corporation with substantial gathering and processing, exploration and production, and trading and marketing functions is to be included in the proxy group, no one of these components should exceed either of the less risky gas transmission or distribution functions to prevent overweighting the riskier components.[143]

92. Thus, the Commission concludes if the firm has a total of more than 50 percent of gathering and processing, exploration and production, and trading and marketing components, the firm should be excluded from the proxy group. Therefore, it is equally true that if either of a diversified gas corporation's distribution or riskier non-transmission functions <u>substantially</u> outweigh its transmission functions,[144] the Commission would have "to make increasingly difficult determinations of relative risk" by assigning an appropriate weight to less risky distribution and the riskier, more market-oriented components.[145] The framework developed here will reduce the problems of such determinations and therefore will be used to determine which diversified natural gas corporations may be included the proxy group.

93. We now turn to an analysis of each of the diversified natural gas companies proposed for inclusion in the proxy group based on this framework.

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[142] *See.* Opinion No. 486, 117 FERC ¶ 61,077 at P 141, discussing how the losses experienced by El Paso, and similarly Williams, were largely related to their respective energy trading and related risk management operations, rather than to their gas pipeline businesses. These businesses proved to be much more volatile and risky than those of the gas pipeline industry. That was further reason to exclude the firms from the proxy group.

[143] *E.g.,* Staff Initial Brief at 11-12, comparing National Fuel, Northern Borders Partners L.P. and Questar Corporation.

[144] Policy Statement, 123 FERC ¶ 61,048 at P 51.

[145] *Petal v. FERC*, 496 F.3d 695 at 699; *Williston II*, 104 FERC ¶ 61,036 at P 35 n.46.

b. National Fuel

94. In 2004 National Fuel's net income profile was approximately 28 percent distribution, 28 percent natural gas transportation, 32 percent exploration and production, 3 percent trading and marketing, and 8 percent other.[146] Based on these numbers the Commission concludes that National Fuel is not the LDC dominated firm it was characterized as in *Petal v. FERC*, or in *HIOS* or Opinion No. 486. Moreover, the transportation and distribution components exceed 50 percent, are quite well balanced and the 35 percent total of the exploration and production and marketing and trading functions is similar in proportion to the transportation and distribution components. Thus, of the diversified natural gas companies presented here, National Fuel most reasonably conforms to the model in which the less risky distribution function is offset by the riskier exploration and production and marketing and trading functions. While the Commission would prefer to have a sample that consists of firms having at least a 50 percent gas transmission component, National Fuel meets the standards that would support its inclusion in the proxy group if this is necessary to provide an adequate sample size and one that provides a sensible ROE in the 2004 test year.

95. However, as previously noted, Kern River argues that National Fuel is unrepresentative because it is a vertically integrated firm. Thus, it asserts, the transmission and exploration and production functions are less risky because the LDC component provides a stable market for the other three functions. Kern River makes this argument without further supporting analysis or citation to any supporting materials, such as National Fuel's 2004 annual report or related SEC Form 10-K filing. Both of these are available on the company's web site at investor.nationalfuel.com. Given the concern regarding the inclusion of diversified natural gas companies in a proxy group, the Commission downloaded and reviewed National Fuel's 2004 Annual Report and the appended 10-K filing and will include the document in the record through an electronic filing. The report discloses that in 2004 National Fuel's natural gas pipeline operations consisted of 3,013 miles of natural gas pipelines and 32 storage fields. These operations generated $47.7 million in net income and 28.6 percent of National Fuel's total net income, slightly more than National Fuel's$46.7 million net income from its utility operations and representing 28 percent of its total income.[147] The report also states that the pipeline revenues have had the most consistent earnings and that utility income declined by some $10.1 million in 2004 compared to 2003.[148] Both components are

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[146] Ex. S-2, Schedule No. 1.

[147] *National Fuel Gas Company, 2004 Annual Report and Form 10-K* (*National Fuel Annual Report*) at Corporate Profile, 2-3, 9-12, 25-26, 28.

[148] *Id.*

described as being subject to competition with a mild weather and gas price risk being ascribed to the utility component, but that these are accommodated in part by regulatory adjustments that mitigate these risks.[149]

96. Contrary to Kern River's assertions, only 40.6 percent of the gas storage capacity was committed to affiliated firms, and 46.2 percent of the transmission capacity was committed to unaffiliated parties.[150] The gas exploration and production component had net income of $54.3 million, and has proved to be volatile.[151] Moreover, most of the exploration and production was in areas far removed from National Fuel's western New York State distribution business, including the southwest, Gulf of Mexico, and Canada. The report states that most gas and oil is sold to third parties in the area in which it is produced.[152] Thus, contrary to Kern River's unsupported assertions, the greater risk of the gas exploration and production function is not offset by National Fuel's vertically integrated operations. For these reasons, the Commission concludes that National Fuel's natural gas transmission function is not outweighed by its distribution function and that the greater risk exploration and production function reasonably offsets a somewhat less risky distribution function in this case. National Fuel may be included in the proxy group because it is not a predominately LDC diversified natural gas company.

c. **<u>Questar and Equitable</u>**

97. In 2004, Questar had 20 percent gas transmission business and 27 percent distribution business, or almost one third more distribution than transmission assets. It also had 51 percent of the more risky exploration and production business. Thus, its distribution assets substantially exceeded its transmission assets and the riskier production and exploration business exceeded the combined transmission and distribution functions.[153] This same was true of Equitable, whose distribution business of 27 percent was almost three times its natural gas transmission business of 11 percent. Its gathering and processing business exceeded both the other functions at 47 percent.

98. Trial Staff and BP have argued that the riskier components of a natural gas distribution firm can offset the less risky distribution function. Thus both Trial Staff and BP include Questar in their 2004 proxy groups but only BP includes Equitable in its 2004

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[149] *Id.* at 8.

[150] *Id.* at 5-6.

[151] *Id.*, Corporate Profile, 2, 30-31.

[152] *Id.* at 9-10.

[153] Staff Ex. S-2, Schedule No. 2.

proxy group. However, for both Questar and Equitable, the transmission component is relatively small compared to any of remaining components, including the distribution component, and the riskier functions predominate. The Commission concludes that including either firm in the proxy group would require holding that (1) the greater distribution component is not predominantly greater than the gas transmission function, (2) that the greater risk of the gathering and production function only offsets, but does not overwhelm, the distribution function, or (3) that the lesser risk of both the transmission and distribution function, as combined, is not outweighed by the riskier components of these firms. Any such findings would require the Commission to assign an appropriate weight to less risky and riskier components under circumstances where the latter far exceed the gas transmission function.[154] Thus, neither Questar nor Equitable meet the Commission's current standards for inclusion in the proxy group.

d. NiSource and Southern Union

99. Only BP seeks to include NiSource and Southern Union in the 2004 proxy group. The Commission finds that neither should be included in the proxy group. Value Line categorized NiSource as an electric utility in 2004, not a diversified natural gas company. BP contends that this should not matter, because NiSource's gas operations far outweigh its electric operations. It states that in 2004 NiSource owned four interstate natural gas pipelines, Columbia Gas Transmission Corporation, Columbia Gulf Transmission Corp., Crossroads Pipeline Co., and Granite State Gas Transmission, Inc., and that NiSource's gas transmission, storage, and distribution assets represented 55 percent of the company's total assets in 2004, compared to 18 percent for electric operations.[155] However, the exhibit cited by BP shows that NiSource's gas pipelines represented only 18 percent of its assets in 2004, while gas distribution accounted for 37 percent of its assets. Moreover, in 2004, NiSource obtained only about 33 percent of its net operating income from gas pipeline operations, with over 40 percent from gas distribution and 29 percent from electric operations.[156] It is thus clear that NiSource's gas pipeline operations account for only a small proportion of its assets, that its distribution business is substantially greater than its gas pipeline business, and that its electric operations are approximately equal to its gas pipeline business. BP's own testimony indicates that NiSource's electric business is the distribution of electric power to retail customers,[157] which results in a total of 69

[154] *Petal v. FERC*, 496 F.3d 695 at 699; *Williston II*, 104 FERC ¶ 61,036 at P 35 n.46.

[155] Ex. No. BP-164 at 5, *citing* Ex. BP-124, page 1.

[156] Ex. BP-124, page 3 (net income ratios total more than 100 percent due to negative entries in other segment categories).

[157] Ex. BP-136 at 31-32.

percent in the lower risk distribution activities. In these circumstances, we find that BP has failed to show that NiSource is sufficiently comparable to Kern River to be included in the proxy group.

100. Value Line has categorized Southern Union as a gas distribution company, rather than a diversified natural gas company. BP nevertheless contends that it should be included in the proxy group, because it acquired Panhandle Energy on June 11, 2003, thus giving it a 100 percent ownership interest in Panhandle Eastern Pipe Line Co., Trunkline Gas Company, and Sea Robin Pipeline Co.[158] BP has also provided evidence that, as of June 30, 2004, Southern Union's gas pipeline business represented 48 percent of its assets and its gas distribution business accounted for 49 percent of its assets.[159] However, Trial Staff opposes inclusion of Southern Union in the proxy group, because it failed to pay a cash dividend in 2004 and instead issued a stock dividend. Trial Staff asserts that the DCF model is a discounted cash flow model and thus stock dividends should be excluded.

101. In order to justify including a firm that paid a stock dividend in the proxy group, the record must establish that the stock dividend can be considered an equivalent of cash dividend, for example by showing that the investor could convert the stock to a cash value with minimal risk. This might be shown by a demonstration that the stock price remains stable immediately after the distribution period and there is little or no dilution of the equity interest. However, no evidence was presented whether Southern Union's stock dividend was the reasonable equivalent of a cash dividend, and thus the Commission also excludes Southern Union from the proxy group.[160]

5. Size of the Proxy Group

102. Based on the previous analysis the Commission has included five firms in the Kern River proxy group: two corporations, KMI and National Fuel, and three MLPs, Northern Border, TC Pipelines, and KMEP. The parties proposed different sized proxy groups for the 2004 test year. In its request for rehearing of Opinion No. 486-A, BP argued that no MLPs need be included in the proxy group to achieve a sufficiently large proxy group, but in the paper hearing BP proposes a nine member group for the year

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[158] Ex. BP-164 at 4; Ex. BP-168 at 2.

[159] Ex. BP-124 at 5.

[160] *See* Staff Ex. S-4. The other parties do not provide evidence that would establish that the stock dividend was the equivalent of a cash dividend due to a lack of dilution and a stable stock price.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 905
PART B

June 4, 2010

2004 in its comments on the paper hearing.[161] BP's proposed proxy group included six corporations, Equitable, National Fuel, NiSource, KMI, Southern Union, and Questar, and three MLPs, KMEP, Northern Border, and TC Pipelines. For the year 2004, Trial Staff proposed one proxy group of four members and two of five members.[162] RCG proposed a seven member proxy group.[163] Kern River proposed a four firm sample for the 2004 test year.[164] Reliant proposed a three member group for the year 2004.[165] Kern River and Reliant both argue that their relatively small samples should be acceptable for the year 2004. Trial Staff, BP, Calpine, and RCG disagree, asserting that a three or four member proxy group is too small to be reliable or to be consistent with Commission policy.

103. BP argues at length that the larger the sample the more likely that the resulting ROEs will be statistically reliable. The statistical basis for the conclusion that a large proxy group is preferable is discussed by BP's witness Elizabeth Crowe. The greater the number of risk-comparable entities in the proxy group, the higher the probability that the results will be representative of the expected return in the gas pipeline industry. The smaller the number of entities, the higher the probability that some anomalous, unusual, or unrepresentative input will skew the results produced by the mathematical formula. Second, the more entities present in the group, the more likely it is that the addition or subtraction of an entity will not significantly alter the results of the calculation. The testimony contains an example of how the results from Staff's five member 2004 group would change if either of the two members below the median were removed, i.e., the median result would change by 60 basis points. Third, the larger the size of the proxy group, if the entities chosen are equally representative of Kern River's risk and operations, the greater the proportion of total NGA-regulated pipelines will be represented in the sample.[166]

104. The Commission concludes that a proxy group should consist of at least four, and preferably at least five members, if representative members can be found. First, in

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[161] BP Initial Brief at 3-4.

[162] Staff Initial Brief at 9-10.

[163] RCG Reply Brief at 5.

[164] Kern River Initial Brief at 6-10.

[165] Reliant Initial Brief at 6-7.

[166] Supplemental Phase Prepared Reply Testimony of Elizabeth H. Crowe, Ex. No. BP-143 pp. 10-13, *citing* Ex. No. BP-153.

Williston II, the Commission expressly found that three members were too small.[167] In *HIOS*, the Commission reluctantly relaxed the proxy group members in an effort to obtain four members even though a four member gas pipeline proxy group had previously been rejected by the Commission in *Enbridge Pipelines (KPC)*, where the Commission stated:

> The removal of Sonat from the proxy group has the effect of reducing the number of comparable natural gas pipelines to four. In Transcontinental Gas Pipe Line Corporation, we rejected a proxy group containing only four companies because it was determined that four companies are too small a sample and may not be representative of industry conditions. Staff's analysis included five proxy companies. Thus, this is another reason staff's analysis is preferable.[168] (Interior citations omitted).

Utilizing a proxy group of at least five members serves this goal and, as did the Commission's historical practice, will help address BP's statistical concerns. At the same time, the proxy group members must be representative and have reasonably comparable risks under *Petal v. FERC*. Thus, while the Commission agrees that adding more members to the proxy group results in greater statistical accuracy, this is true only if the additional members are appropriately included in the proxy group as representative firms.

105. In the discussion above, the Commission has determined that only two corporations, KMI and National Fuel, are sufficiently representative to be included in the proxy group. The remaining corporations BP sought to include, Equitable, NiSource, Southern Union, and Questar, were not representative for the 2004 test year. Therefore, for the reasons previously discussed, they will not be included in the proxy group, and BP was incorrect in its rehearing request in asserting that a sufficiently large, risk appropriate proxy group could be developed without the inclusion of MLPs. The five firm proxy group, including three MLPs, selected here is sufficient to avoid BP's concerns raised in the paper hearing about a distorted sample.

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[167] *Williston II*, 104 FERC ¶ 61,036 at P 35.

[168] *Enbridge*, 100 FERC ¶ 61,260 at P 237 (*citing* at n.236, *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,427-5 (1998)); *Iroquois Gas Transmission System*, 84 FERC ¶ 61,086, at 61,456 (1998); *Williams Natural Gas Company*, 84 FERC ¶ 61,080, at 61,358 (1998).

B. DCF Analysis of the Selected Proxy Companies

106. This order now turns to the issue of the appropriate DCF analysis of the five firms we have selected for the proxy group. Under the DCF formula used by the Commission, a firm's ROE is the sum of (1) the firm's dividend yield and (2) the projected growth rate. The Commission determines dividend yield by dividing the proxy firm's cash distribution (or dividend) by its current stock price. The Commission uses a two-step procedure for determining the constant growth of dividends: averaging short-term and long-term growth estimates. The Commission uses security analysts' five-year forecasts for each company in the proxy group (discussed below), as published by IBES, to determine growth for the short term; long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in the GDP.[169] The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[170]

107. No party contests the application of this methodology to the two corporations we have included in the proxy group. However, both BP and Kern River raise issues concerning how this methodology should be applied to the three MLPs included in the proxy group. BP asserts that several adjustments must be made to the MLP's cash distribution for purposes of calculating their dividend yield. BP also contends that, absent an adjustment to the MLP's cash distribution, the Commission should not rely on IBES growth projections for an MLP's short-term growth projection. In addition, both BP and Kern River question the Policy Statement's conclusion that an MLP's long term growth projection should be 50 percent of projected long term GDP growth. Kern River also questions the use of the Social Security Administration's GDP growth forecast as one of the three GDP growth projections used for determining the long-term growth projection to be used in the DCF analysis for both corporations and MLPs.

1. Dividend Yield

108. In its request for rehearing of Opinion No. 486-A, BP argues that the Commission erred in finding that an MLP's dividend yield should be calculated based upon the full amount of its distribution. BP asserts two grounds for adjusting the cash distributions used in determining an MLP's dividend yield for purposes of the DCF analysis. First, BP contends that the Commission erred in holding that the MLP's distributions should not be

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[169] *Northwest Pipeline Company*, 79 FERC ¶ 61,309, at 62,383 (1997) (*Opinion No. 396-B*);. *Williston Basin Interstate Pipeline Company*, 79 FERC ¶ 61,311, at 62,389 (1997) (*Williston I*), *aff'd*, *Williston v. FERC*, 165 F.3d 54 at 57.

[170] Opinion No. 414-A*l*, 84 FERC ¶ 61,084 at 61,423-24.

capped at the level of earnings. BP points out that MLPs generally make distributions to unit holders in excess of their reported earnings, and thus the distributions include a return *of* invested capital, as well as a return *on* invested capital. BP states that the Commission provides for the return of a pipeline's invested capital through a separate depreciation allowance included in its cost of service. BP therefore asserts that, as the Commission found in Opinion No. 486, if an MLP's distributions are included in its DCF analysis without being capped at earnings, the resulting ROE will be too high. BP also presented testimony in the paper hearing to the same effect.[171]

109. The Commission thoroughly reviewed this matter in the Policy Statement[172] and Opinion No. 486-A,[173] and concluded that the analysis in Opinion No. 486, upon which BP relies in its instant rehearing request, was fundamentally flawed based on the mechanics of the DCF model. The premise of the DCF model is that a firm's stock price should equal the present value of its future cash flows, discounted at a market rate commensurate with the stock's risk. Under the DCF model, all cash flows, whatever their source, are reflected in the value of stock. On the one hand, large cash flows in excess of earnings add value to the stock by increasing the current dividend yield. On the other hand, such cash flows take value away from the stock by reducing future growth potential.[174]

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[171] Ex. BP-143 at 19.

[172] 123 FERC ¶ 61,259 at P 58-63 and Appendix B.

[173] 123 FERC ¶ 61,056 at P 178-180.

[174] Two shipper exhibits in the instant docket support the conclusion that it is all cash flows, not income, that drives the DFC model. *See* Ex. No. RCG-29, citing Morin, *Regulatory Finance*: *Utilities' Cost of Capital* (1994) at 106-07, and Ex. No. RGC-1 at 29, which quotes Smith Barney as stating in part that earnings are not the basis for the valuation of MLPs because "for most MLPs, distribution levels are more directly related to operating cash flow than to GAAP earnings." While RCG cites this passage for the proposition there should be an adjustment for how a DCF analysis is applied to MLPs, the Commission concludes that it suggests the opposite. The time value of the cash distributions becomes the principal method for valuing an MLP, since those may be accelerated beyond the dividend distributions that would be made by a corporation under Generally Accepted Accounting Principles (GAAP) earnings. This is due principally to distributions of operating cash flows, including the part generated by the depreciation component of a firm's cost structure. That component is a non-cash expense item which affects a firm's income statement but not the net cash flow that may be available for distribution. The tax advantages of MLPs permit this cash to be returned to MLP unit holders more rapidly than to a corporation's shareholders, and the resulting present value

(continued…)

110. If the Commission were to cap the distribution used to determine an MLP's dividend yield at below the market-determined level, but use the actual market price of the MLP's publicly traded units and a growth projection reflecting the actual level of distributions, the DCF analysis would fail to achieve its intended purpose of determining the return the equity market requires in order to justify an investment in the pipeline. That is because there would be a mismatch among the inputs the Commission used for the variables in the DCF formula. The DCF analysis presumes that the market value of an MLP's units is a function of the entire present and future cash flow provided by an investment in those units. Given this interlocking nature of the variables in the DCF formula, adding the artificially reduced dividend yield to a growth projection that properly reflects investors' expectations of the MLP's reduced growth prospects due to its high actual distributions would inevitably result in an ROE lower than that actually required by the market.[175]

111. In addition, use of a proxy MLP's full distribution in determining ROE will not cause a double recovery of the depreciation component included in the pipeline's cost-of-service rates. In a rate case, the Commission determines the dollar amount of the ROE component of the cost-of-service of the pipeline filing the rate case by multiplying (1) the percentage return on equity required by the market by (2) the actual rate base of the pipeline in question. Having found that use of a proxy MLP's full distribution is necessary for the DCF analysis to accurately determine the percentage return on equity required by the equity markets, it necessarily follows that the same percentage should be used in determining the dollar amount of the ROE component of the pipeline's cost of service. Awarding the pipeline an ROE allowance based on that percentage of its own rate base will give the pipeline an opportunity to provide its investors with the return on their investment required by the market. Such an ROE allowance does not implicate the separate depreciation allowance the Commission also includes in a pipeline's cost of service to provide for return of investment. The Commission illustrated these points with a numerical example set forth in Appendix B to the Policy Statement.[176]

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is reflected in the price of the MLP ownership interest. *See also* Policy Statement, 123 FERC ¶ 61,048 at P 58-61.

[175] The earnings cap on the distribution would artificially reduce an MLP's dividend yield below that assumed by the investor in valuing the stock. Adding the artificially reduced dividend yield to a growth projection that reflects the MLP's reduced growth prospects due to its high actual distributions would inevitably result in an ROE lower than that actually required by the market.

[176] Policy Statement, 123 FERC ¶ 61,048, Appendix B.

112. In its rehearing request and its evidence provided at the paper hearing, BP simply reasserts the Commission's findings in Opinion No. 486 were incorrect. It does so without expressly contesting any of the Commission's reasoning in Opinion No. 486-A and the Policy Statement for concluding that Opinion No. 486 reached an incorrect result on this issue. BP does not contest the Commission's explanation why capping the distribution used to determine an MLP's dividend yield at below the market-determined level, while using the actual market price of the MLP's publicly traded units and a growth projection reflecting the actual level of distributions, would lead to distorted results because of a mismatch among the inputs used for the variables in the DCF formula. BP also does not point to any error in the Policy Statement's Appendix B numerical example showing why a DCF analysis using a proxy MLP's full distribution, including any return of equity, does not lead to the award of an excess ROE in a pipeline rate case or the double recovery of depreciation. Accordingly, the Commission denies BP's rehearing request on this issue. The Commission continues to find that the fact an MLP makes distributions in excess of earnings is more appropriately accounted for in the growth component of the DCF analysis by using a growth projection which accurately reflects investor's expectations of reduced growth prospects due to the high level of distributions.

113. Second, in the paper hearing, BP contended that the Commission should adjust the amount of the distribution to be included in the DCF calculation by the amount of the corporate marginal tax rate that would otherwise have been paid on the MLPs income in the absence of its pass through status.[177] BP asserts that this adjustment is necessary to reflect the differences in taxation of a corporation and partnership. BP asserts that a corporation pays taxes on income and then makes a dividend payment to the shareholder, which pays a separate tax. Thus, it argues, the price of the corporate share reflects the after-tax value of the dividend. BP argues that, in contrast, an MLP unit holder does not pay tax on the distributions and therefore the results of the DCF calculation should be adjusted accordingly.

114. The Commission concludes that this argument is fundamentally inconsistent with the court's holding in *ExxonMobil v. FERC*. As the court stated, "the Commission reasonably relied upon evidence that a full income tax allowance is necessary to ensure that corporations and partnerships <u>of like risk</u> will earn <u>comparable</u> <u>after-tax returns.</u>"[178] Inclusion of the projected cash flow from the income tax allowance in the DCF model does just that. While it is true that investors invest on the basis of after-tax returns and price an instrument accordingly, they expect that the cash flow will be available to pay the taxes and thereby maintain a comparable after-tax return to that of a corporation.

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[177] Supplemental Phase Prepared Rebuttal Testimony of Elizabeth H. Crowe dated August 1, 2008, Ex. No. BP-164 at 19 (*citing* Ex. No. BP-158 at 3).

[178] *ExxonMobil Oil Corporation v. FERC*, 487 F.3d 945 at 957 (emphasis added).

Therefore, the Commission's DCF model does not double count the income tax aspects of a MLP partnership instrument.

115. At bottom, BP's argument confuses the investor's application of a DCF model with the Commission's. As discussed in the Policy Statement, the investor prices the instrument based on the perceived risks and the required return. That price necessarily reflects the after-tax cash that will be derived from the dividend component of the model. The Commission does the opposite to derive the cost of capital by looking at the price, the yield, and anticipated growth, and then determining the required return. If the Commission excludes the income tax allowance from the cash available for distribution, the price of the partnership units would drop to reflect the loss of the cash flow necessary to pay the imputed tax cost of the distribution stream. An MLP would have to issue more units to raise the same capital as a corporation of similar risk and its equity cost of capital would be notably higher. This violates the principle that firms of similar risks should have the same equity cost of capital and that this is to be reflected in their allowed returns.

116. Moreover, while the pricing of a MLP instrument may reflect the tax deferral components of such instrument, as the Income Tax Policy Statement explains, this is a matter of timing.[179] The difference in timing of the tax payments may lead the unit holder to pay a higher price for the unit and reduce the equity cost of capital to the firm, although not necessarily the amount of the income tax allowance included in the MLP's rates and borne by the ratepayers.[180] However, in reviewing the profile of firms to be included in a proxy group, the Commission looks only at information on the relative prices and yields of the securities issued by the candidate firms. Thus, for purposes of the Commission's DCF model, tax factors are assumed to be reflected in the unit prices and resulting dividend yields of the MLP.[181] Therefore, there is no requirement to adjust the results to reflect the tax difference between a Subchapter C corporation and a MLP.

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[179] Income Tax Policy Statement, 111 FERC ¶ 61,139 at P 37, n.35. *See also*, *SFPP, L.P.*, 121 FERC ¶ 61,240 at P 29, 31, 52-53.

[180] The Commission has held that the benefits of the any tax deferrals are for the enterprise and should not be credited back to the ratepayers. *See SFPP, L.P.*, 121 FERC ¶ 61,240 at P 29. It should be noted that if the MLP is accorded the income tax allowance, the marginal tax rate for the limited partners is generally restricted to 28 percent. This can reduce the weighted marginal tax rate used to develop the income tax allowance several percentage points below the standard corporate rate of 35 percent.

[181] The price of an MLP interest should reflect the risk of whether the MLP complies with the Commission's income tax allowance policy.

117. Finally, BP asserts that the fact that an investor's capital in an MLP is returned more quickly than capital invested in a corporation means that MLPs are intrinsically less risky and therefore an adjustment should be made to the overall DCF results to reflect this fact. BP would do so by adjusting the amount of the distribution to be included in the DCF calculation. This argument misses the fundamental point that *Petal v. FERC* and the Commission's rate making methodology address the relative risk of enterprises, which need not be determined primarily by their ownership format. As is discussed below, these factors can include the risk associated with the debt to equity ratio of the firm's capital structure, its interest cost and exposure, the stability of its markets and the related stability of its revenue stream, its cost structure, and its operating and managerial efficiency. These factors might be the same for three different firms, one of which is a corporation, the second a MLP, and the third one owned by individuals in their own name or through a general partnership. Assuming similar fundamentals, the equity ownership format may influence the actual or implicit pricing of the equity interest somewhat.

118. Thus, the fact that an MLP owner may recover the equity component more quickly means the instrument has somewhat lower risk and in theory the owner will pay a premium for that factor, which reduces the equity cost of capital to the firm, and hence, to the ratepayer. Conversely, the cost of equity capital to a general partnership, and to the ratepayer, might be a bit higher because the owners are exposed to personal liability. However, within a range of enterprises of similar risk, this should be reflected in the yield of the ownership instrument and would be reflected in the returns generated by the DCF model. Those results are likely to vary somewhat, but this should not preclude developing a proxy group with a reasonable range of returns if the firms' business fundamentals and risk are comparable. Again, any mechanical adjustment by the Commission would most likely be arbitrary, and BP does not explain why a formulaic approach would not be. Therefore, there should be no adjustments to reflect the difference in the distributions of a MLP and corporate dividends.

2. **Short-Term Growth Projection**

119. In both Opinion No. 486-A and the Policy Statement,[182] the Commission held that IBES growth projections are properly used as the short-term growth projection in the Commission's DCF analysis of MLPs. In its request for rehearing of Opinion No. 486-A and its paper hearing testimony, BP asserts that the fact that MLPs' distributions often exceed the firm's book income means that the short term IBES growth forecasts are overstated, and that in any event, it is unclear whether IBES forecasts rely on distribution or income growth as the basis for the projection.

[182] Policy Statement, 123 FERC ¶ 61,048 at P 67, 73-77.

120. In Opinion No. 414-A,[183] the Commission explained that the growth rate to be used in the DCF model is the growth rate expected by the market. Thus, the Commission seeks to base its growth projections on "the best evidence of the growth rates actually expected by the investment community."[184] Moreover, the Commission stated, the growth rate expected by the investment community is not, quoting a Transco witness, "necessarily a correct growth forecast; the market may be wrong. But the cost of common equity to a regulated enterprise depends upon what the market expects not upon precisely what is going to happen."[185]

121. Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[186]

122. While the Commission recognizes that there may be some statistical limitations to the IBES projections, BP has presented no evidence to cause the Commission to modify its previous holding that IBES remains the best and most reliable source of growth information available, including for MLPs. IBES publishes security analysts' five-year growth forecasts for MLPs in the same manner as for corporations. MLPs must publicly report their earnings and distribution levels. Therefore, the security analysts are aware of the degree to which each MLP is making distributions in excess of earnings. The security analysts presumably take that information, together with all other available information concerning the MLP, into account when making their projections. No party questions the Commission's findings in past cases that investors rely on the IBES projections in making investment decisions because they are widely available and generally reflect the input of a number of financial analysts. Also, since IBES projections are company-specific, they should already adjust for any differences among the entities analyzed, including any reduced growth prospects investors expect due to the fact an MLP makes

[183] 85 FERC ¶ 61,323 at 62,268-69.

[184] *Id.* at 62,269.

[185] *Id.*

[186] *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279, at 61,932 (2000).

distributions in excess of earnings. In fact, the 2004 IBES projections for the three MLPs included in the proxy group average 5.33 percent, while the IBES growth projections for the two corporations average 7.5 percent. Thus, those MLP growth projections are about 217 basis points (2.17 percent) below those for the corporations.[187]

123. Thus, using a straight IBES five-year projection without modification presents the best method of estimating an MLP's short-term growth rate. At bottom, the IBES forecasts are what are available for the five year growth time frame. The analysts make whatever assumptions they make regarding the source of funds, the impact of those sources on growth in the shorter time frame, the degree to which certain of those sources may be used for distributions, and whether the growth projections are based on projected income growth or distribution growth. BP asserts that the security analysts' five-year growth forecasts appear generally to be forecasts of growth in earnings, rather than distributions. It argues that the relevant cash flows for the DCF model are the MLP's distributions to the limited partners, and therefore the growth projections used in the DCF analysis should be growth in distributions, not earnings. BP suggests no practical way to go behind the IBES forecasts and adjusting the short term growth component without using an arbitrary adjustment unsupported by a record. Accordingly, regardless of whether financial analysts stated they are reporting projected earnings growth or projected distribution growth for MLPs, the Commission finds the five-year growth rates that IBES reports are acceptable since they closely approximate distribution growth for MLPs, which is the short-term input for the DCF model.

124. In the Policy Statement proceeding, Professor J. Peter Williamson, on behalf of AOPL, reviewed historical IBES five-year growth forecasts for five oil pipeline MLPs since the mid-1990s. IBES had published five to nine growth forecasts for each the MLPs, with a total of 39 forecasts. Williamson compared each of these 39 forecasts to the MLP's actual growth in earnings and distributions during the subsequent five-year period. He found that 29 of the 39 IBES five-year forecasts, or 74 percent, were closer to the actual average distribution growths over that time span than the actual earnings growths. In his study, Williamson also found that historical records fail to support any claims that the IBES forecasts are biased or tend to overstate future growth.[188] In fact, 22

[187] This result is consistent with the Policy Statement, which concluded that the IBES growth rates for MLPs were consistently less than that of corporations. For interstate gas transmission pipelines, the March 2008 average IBES growth rate for corporations was 10.75 percent and 6.86 for MLPs, a difference of 389 basis points or 3.89 percent. Policy Statement, 123 FERC ¶ 61,048 at P 75. The range here is narrower because El Paso and Williams were excluded and the calculation is more conservative than that in the Policy Statement.

[188] AOPL, Post-Technical Conference Comments in Docket No. PL07-2-000, Williamson Aff. at 2-6.

of the 39 forecasts were lower than the actual distribution growth, and 17 were higher. Thus, far from showing a pattern of overestimating actual growth in distributions, the IBES growth projections underestimated growth in distributions 56 percent of the time, a conservative result.

3. Long Term Growth Projection

125. Kern River and BP both argue that limiting the long term growth component to 50 percent of GDP was incorrect, Kern River asserting that the growth factor is too low and BP that it is too high. Again, it should be noted that this is not a matter of comparable risk as that term is generally used in determining whether firms are of similar or comparable risk, and therefore whether they are appropriately included in the proxy group. Rather, as the Policy Statement discusses, the issue is whether MLPs as a class are likely to have a lesser long term growth rate than corporations as a class.[189] Consistent with the same methodology it has previously used to determine the long term growth rate for corporations,[190] the Commission concluded, based on its review of a range of estimates developed by established financial firms, that this was the case.[191]

126. The record here only reinforces the conclusions of the Policy Statement.[192] For example, Trial Staff notes here that Citigroup's long term growth estimates for the three MLPs included in Kern River are 1.0 percent (Enterprise), 0 percent (KMEP) and .5 percent (Oneok Partners), and refers to the figures provided in BP's Supplemental Testimony for the Merrill Lynch and Wachovia long-term growth projections.[193] BP's testimony asserts that Merrill Lynch assigns a terminal growth rate of 1 percent to all MLPs in its analysis and that Wachovia's average long term growth rate for the MLPs in the BP proxy groups is 2.63 percent in 2004. BP asserts this compares to the 2.68 percent long term rate derived for the year 2004 using the Commission's 50 percent of long term

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[189] Policy Statement, 123 FERC ¶ 61,048 at P 85, 88-89.

[190] *Id.* P 88-89.

[191] *Id.* P 89, 90, with references to Kinder Morgan Energy Partners (KMEP). The Value Line analysis of this firm discusses its history of rapid growth through 2003 with less consistent results thereafter and an ambiguous forecast for the period after June 2008. *See* Staff Ex-3 at 153 of 227.

[192] *Id.*

[193] Prepared Reply Affidavit of Commission Staff Witness Douglas M. Green, Ex. S-4 at P 24 and 25.

GDP formula.[194] Trial Staff concludes that the Commission approach is conservative and BP argues that it is too low, arguing the long term rate should be no greater than 1.8 percent.[195]

127. Given the record in the Policy Statement proceeding and the record here, Kern River's general assertions that MLPs have the same long-term growth prospects as Subchapter C corporations are unconvincing. Nothing Kern River presents here contradicts the conclusions of the Policy Statement that MLPs face greater interest rate risk, more restrictive investment opportunities, and a risk of less consistent access to capital than do corporations because the latter can rely more on internally generated funds.[196] The Commission further notes that MLPs tend to have their fastest growth in initial years because of the general partner's efforts to increase its incentive distributions. As discussed in the Policy Statement, this emphasis on incentive distributions is likely to increase the cost of equity capital, which suggests fewer investment opportunities and declining returns in the long term.[197] The Commission therefore again concludes that MLPs should have a lower long term, or terminal, growth rate than that of corporations in the same business.

128. However, the Commission also concludes that the particularly low growth rates accorded MLPs by Merrill Lynch and Citigroup are inconsistent with the fact that many

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[194] Prepared Supplemental Direct Testimony of Elizabeth Crowe, Ex. No. BP-121 at p. 13 and Ex. No. BP-128.

[195] *Id.* The 1.8 percent figure is the average of the Wachovia and Merrill Lynch forecasts for the MLPs included in BP's proxy group. This is a self-selected and narrower sample than the Commission relied on in developing the Policy Statement.

[196] Policy Statement, 123 FERC ¶ 61,048 at P 92-93. *See also* Opinion No. 486, 117 FERC ¶ 61,077 at 151, n.245 (citing Wachovia Securities, Master Limited Partnerships: A Primer (Ex. BP-19 at 11)) for the proposition that:

> Because MLPs pay out virtually all of their cash to unitholders, they must continuously access debt and equity markets to finance growth. If MLPs were unable to access these markets or could not access these markets on favorable terms, this could inhibit long term distribution growth.

The cited Wachovia Securities report issued on November 16, 2003, long before the Commission began to pursue its Policy Statement in July 2007. The greater uncertainty regarding the long term growth prospects of MLPs is a longstanding investor issue.

[197] Policy Statement, 123 FERC ¶ 61,048 at P 92.

MLPs generate substantial returns over time, albeit with long-term growth rates that appear to be declining for even the more aggressive firms.[198] In contrast, the Wachovia studies aré more nuanced with a wider and more discriminating range of terminal growth rates than the other two analyses,[199] which nonetheless serve to emphasize that some reduction in the long-term growth rates for MLPs is appropriate. In fact, the Wachovia forecasts cited by BP for 2004 and 2007 both result in long-term rates of approximately 50 percent of long term GDP,[200] a similar result to the Policy Statement. Moreover, for the firms Trial Staff and BP included in their 2004 and 2008 samples, the application of the Commission's DCF methodology results in overall growth rates for the MLPs that are 22 to 50 percent less than those for the corporations.[201] For these reasons the Commission will retain the 50 percent of long-term GDP formula in this case. This will assure that MLPs receive comparable returns for firms of similar risks with an adjustment to reflect the intrinsic difference in the long-term growth prospects of Subchapter C corporations and the gas pipeline MLPs at issue here.

129. Kern River also objects to the use of the *Social Security Administration's (SSA)* GDP estimates in calculating the long-term growth component of the Commission's DCF model. Kern River asserts that those estimates do not reflect the historic growth of the economy, differ from the *Global Insight* and *Energy Information Administration (EIA)* growth projections, are not relied on by investors unlike *EIA, DRI/McGraw Hill (DRI), Wharton Economic Forecasting Associations (WEFA), and Global Insight*, are biased

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[198] *Id.* P 87, n.118.

[199] For example, Merrill Lynch's terminal rate is a flat 1 percent without regard to the characteristics of the individual firm. The spread for the cited Citigroup firms is from zero to one percent. This is not consistent with the slow but steady growth in sales and distributions demonstrated by Oneok Partners between 2001 and 2004, a period of relatively low economic growth. *See* Ex. S-3 at 185. A similar conclusion could be drawn for TC Pipeline, L.P. (*Id.* at 54 of 227) and Buckeye Partners (*Id.* at 133 of 227).

[200] As discussed above, the Commission is using the 2004 test year to develop the ROE in this proceeding. However, for the sole purpose of testing the Commission's long term methodology under the Policy Statement, it will use the various samples in the record for the period 1994 through mid-2008. This is appropriate given the challenges to the basic methodology of the Policy Statement in the current case by both sides and the evolution of the energy transmission industry over the several years preceding it.

[201] The five year period ended 2004 involved several recession years or years of low growth while the growth rate for the five years ended 2007 was higher. This supports the Commission's conclusion in the Policy Statement that MLPs may be less effective in raising capital when economic activity is lower.

because they result in a better projection of solvency for the social security system, and that the record here does not distinguish between the inflation and real GDP growth factors in the *SSA* model.

130. After review of Trial Staff's testimony,[202] the Commission affirms the use of three sources, *SSA, EIA,* and *Global Insight*, for the long-term growth estimate used in its DCF model. Before 2003, the Commission used GDP estimates by *DRI*, *EIA*, and *WEFA* to calculate the long-term growth projection. However, after the merger of *DRI* and *WEFA* and their acquisition by *Global Insight*, this left only two sources, including *EIA*. Thereafter the Commission accepted the addition of *SSA's* GDP estimates thereby restoring three sources[203] and then confirmed the inclusion of that estimate in the Policy Statement.[204] The Commission further concludes that Kern River's argument about the past correlation of the *SSA, Global Insight,* and *EIA* forecasts is irrelevant because there is no necessary correlation between past forecasts and future forecasts. Trial Staff asserts that the variance between the forecasts had narrowed significantly by 2008, to only about 16 basis points. Moreover, to the extent the *EIA* and *Global Insight* forecasts are similar, this reflects in part the fact that they have overlapping components.[205] There is no evidence here of the extent that investors rely on forecasts other than *SSA's* GDP estimates or that the Commission has disclaimed reliance on any such finding.[206] Regarding Kern River's inflation argument, the Commission's DCF model uses constant dollars and therefore this point is irrelevant.[207] Finally, the Commission has previously affirmed the use of an average of the three long term forecasts in *HIOS*, a contested case, and that ruling was unchallenged.[208]

4. <u>Determination of Proxy Group Range and Median</u>

131. Based upon the above holdings, the Commission holds that the ROEs of the five firms selected for the proxy group are as follows: KMI: 13.00 percent; KMEP: 12.99

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[202] *See* Ex. S-6 at P 11-18.

[203] *See Williston Basin Interstate Pipeline Company*, 104 FERC ¶ 61,036 (2003).

[204] Policy Statement, 123 FERC ¶ 61,048 at P 6, n.7.

[205] Ex. S-6 at P 13.

[206] *See Northwest Pipeline Company*, Opinion No. 396-B, 79 FERC ¶ 61,039 (1997).

[207] Ex. S-6 at P 16.

[208] *HIOS*, 110 FERC ¶ 61,043,at P 153 (2005).

percent; Northern Border: 11.55 percent; TC Pipelines: 10.35 percent; and National Fuel: 8.80 percent. Thus, the range of reasonable returns is 8.8 percent to 13 percent, and the median ROE is Northern Border's ROE of 11.55 percent.[209] The Commission also finds that this distribution of ROEs among the five proxy group firms reinforces our previous conclusion that these firms constitute a risk-appropriate proxy group. All participants have agreed that Northern Border, whose pipeline facilities account for 91 percent of its assets, has a risk profile representative of the gas transmission business and is appropriately included in the proxy group. In addition, while the proxy group includes two firms with less than 50 percent gas transmission business, one (KMEP) has an ROE above the median, while the other (National Fuel) has an ROE below the median. Thus, their presence in the proxy group does not either increase or decrease the median established by Northern Border's ROE.

C. Kern River's Placement within the Range

132. The Commission's rate of return methodology requires an evaluation of Kern River's relative risk within the range of ROEs established by the proxy group. In this regard, the parties' comments raise two distinct issues. The first is the role of credit or business risk ratings in determining the relative risk of the firms included in the proxy group. The second is the actual determination of Kern River's relative risk.

1. The use of credit ratings

133. As part of its determination of whether a firm should be included in the proxy group, Trial Staff reviewed the Investment Credit Rating (ICR) and business risk profiles of several diversified gas corporations with a LDC component to determine if the overall credit and business risk of the firm was considered to be similar or different from firms that were primarily natural gas transmission firms. Trial Staff concluded that some such firms may have credit and business risk ratings indicating risk similar to or higher than a natural gas pipeline.[210]

134. Kern River argues that credit ratings do not reflect business risk, and hence, a firm's equity risk. It argues that a credit rating says nothing about the risk a common stockholder faces concerning the expected cash flows in the form of MLP distributions or corporate dividends.[211] As such, the constituency of the rating agency is the bondholder,

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[209] These ROEs are based on staff's DCF analyses for each proxy member, other than KMEP. The ROE for KMEP is based on BP's calculation.

[210] N. 135, *supra*.

[211] Kern River Reply Brief at 18-19.

not the equity investor. Kern River further asserts that the Commission recognized that debt ratings by credit ratings are of only marginal relevance in assessing a pipeline's equity cost of capital, citing *Northwest Pipeline Corp*:

> The Commission also finds that the parties have ascribed an inordinate amount of significance to Northwest's ranking in the S&P reports. Contrary to the party's intimations, the Commission has never held that an ostensibly favorable ranking in the S&P reports is prima facie evidence of low business risk…[212]

Kern River concludes that the Commission's prior statements mean that assertions that credit ratings can establish that diversified LDC enterprises have the same risk as a transmission pipeline are inconsistent with *Petal v. FERC* and the Policy Statement. It asserts that thus Trial Staff relies unduly on relative credit ratings to support its analysis.

135. BP also argues that credit ratings measure only credit risk stability and do not measure business risk. It argues that, as such, credit ratings do not adequately reflect such factors as growth and the importance of earnings stability to the equity owners. BP also asserts that an emphasis on credit ratings may overstate the relative risk of a firm like Kern River that has strong long-term growth potential and a favorable market position. BP also argues that Trial Staff used credit ratings to expand rather than to narrow the proxy group at issue here.[213] At bottom, it argues that Trial Staff's reliance on credit ratings may understate Kern River's relatively low risk when compared to a diversified natural gas company that has the same credit rating, but whose business risk is higher than Kern River's. BP thus shares some of the Kern River's criticism of Trial Staff's use of credit ratings, but appears to do so in order to reach an opposite conclusion from Kern River.

136. Trial Staff replies that it relied on two measures of relative financial strength and stability. One is the ICR, which ranks the relative credit risk of firms and is described in Appendix B to Mr. Douglas Green's Affidavit Dated June 17, 2008.[214] Trial Staff argues that the greater the risk to the bondholders the greater the risk the equity holders will not receive their payments and required return. Trial Staff also asserts that credit rating agencies such as Moody's do take such factors as revenue stability, growth potential, relative size and competitive position, diversification, and management in making credit

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[212] *Id.* (*quoting Northwest Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,068 (1999)).

[213] *See* Ex. No. BP-136 at 9-53.

[214] Staff Ex. S-1, Appendix B.

evaluations, and as such do consider business risk. It states that it also considered business profile ratings to the extent these were available.[215] Finally, Trial Staff observes that Kern River's own witness routinely relied on credit ratings as an expert witness in state public utility commission rate proceedings.[216] RCG supports the Trial Staff position that credit ratings are relevant to risk evaluation because they reflect the financial soundness of the firm. RCG also argues that Kern River is incorrect that such ratings are irrelevant and that BP's attempt to minimize their value is misplaced.[217]

137. Opinion No. 486 concluded that a pipeline's credit rating is an appropriate part of the risk analysis and is well established by Commission precedent.[218] The Commission again concludes that ICRs, as well as business risk profile ratings, are useful criteria in evaluating relative risk. Trial Staff has established that rating agencies such as Moody's use many factors that would be relevant to an equity investor's analysis of a firm's business prospects. It is correct that a strong credit rating implies a greater ability to provide consistent returns to the firm's stockholders and to raise capital for future growth. Moreover, Trial Staff supplemented its credit analysis with business profile ratings where the information was available. Such analyses are appropriate for determining relative risk within the range of ROEs established by the proxy group. For example, the two financial measures Staff suggests can prove useful for developing a more refined evaluation of the risk of diversified natural gas companies in the proxy group that have a number of different business lines. Thus, the Commission's use of such information would support the detailed analysis required by *Petal v. FERC*, not supplant it.

2. Determination of Kern River's Relative Risk

138. The remaining issue is the relative placement of Kern River within the proxy group. Opinion No. 486 started its analysis by reiterating the Commission's traditional assumption that gas pipelines generally fall into a broad range of average risk absent highly unusual circumstances that indicate an anomalous or low risk as compared to other pipelines. Thus, unless a party makes a very persuasive case in support of the need for an

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[215] Staff Ex. S-3 at p. 94-95 and S-7, reprinting Standard and Poor's *Corporate Ratings Criteria, 2006.*

[216] Staff Rebuttal Brief at 6.

[217] Rebuttal Brief of the Rolled-In Customer Group and Answer in Opposition of Motion to Strike (RCG Rebuttal Brief) at 10-11 and Ex. No. RCG-41 at 4-5.

[218] Opinion No. 486, 117 FERC at P 177 (*citing Transcontinental Pipeline Corp.*, 90 FERC ¶ 61,279, at 61,937 (2000) (*Transcontinental*), Opinion No. 414-A, 84 FERC at 61,427, and *Williston*, 84 FERC at 61,388 (1998).)

adjustment and the level of the adjustment proposed the Commission will set the pipeline's return at the median of the range of reasonable returns.[219] However, Opinion No. 486 continued by recognizing that it had developed this policy at the time when the proxy group was made up entirely of companies that met the historical standards for inclusion in the proxy group, including that pipeline operations were a high proportion of the companies' business. The Commission further recognized that proxy groups had come to have fewer companies that met the historical standards.

139. The Commission therefore concluded where there is a small proxy group that contains companies with a relatively low proportion of pipeline business and substantial distribution operations, an adjustment would be necessary to reflect the difference between pipeline and proxy group members whose LDC operations account for a greater portion of their business than under the traditional standards.[220] Given this framework, Opinion No. 486 held Kern River was a pipeline of average risk, but made an adjustment of 50 basis points to reflect the fact that Kern River faced competitive pressures and market risks that were higher than the LDC oriented firms within the proxy group.[221] This conclusion was contested on rehearing, with Kern River arguing that its ROE should be higher given its extraordinary risk,[222] and several shipper parties asserting that Kern River has significantly less risk than most interstate natural gas pipelines and the adjustment was inappropriate.[223] Opinion No. 486-A did not address these arguments because such issues were set for a paper hearing.

140. On review, the Commission reiterates its existing policy, as announced in *Transcontinental Gas Pipe Line Corp.*, which assumes that pipelines fall into a broad range of average risk, absent highly unusual circumstances that indicate anomalously high or low risk as compared to other pipelines. Thus, unless a party makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's return at the median of the range of reasonable returns.[224] The Policy Statement similarly stated that "the Commission has

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[219] *Id.*

[220] *Id.* at P 171.

[221] *Id.* at P 175.

[222] Request for Rehearing of Kern River at 47-51.

[223] Request for Rehearing and Clarification of BP at 41-45; Request of the RCG for Rehearing and Clarification at 4-11.

[224] *Transcontinental*, 90 FERC ¶ 61,279 at 61,936.

historically assumed the existing pipelines fall within a broad range of average risk" and that a "party has to show highly unusual circumstances that indicate anomalously high or low risk compared to other pipelines to overcome the presumption."[225] *Petal v. FERC* did not reject this historical assumption that most pipelines fall within a broad range of average risk and that, due to the difficulty of making refined adjustments, most are assumed to fall toward the middle of the range absent highly unusual circumstances. However, the court stated that this assumption was valid only if the firms included in the proxy group have comparable risks.[226] Thus, given its concern whether LDC firms were comparable to natural gas pipelines, the court remanded that issue to the Commission.

141. In the prior sections of this order, the Commission analyzed in detail the various firms suggested for inclusion in the proxy group and selected three that consist primarily of gas transmission operations (KMI, Northern Border, and TC Pipelines); an MLP (KMEP) with significant gas and generally comparable oil transmission functions and no distribution or production and exploration functions; and one diversified natural gas company (National Fuel) that had a significant gas transmission function and whose less risky distribution function was offset by its more risky exploration and production functions. The Commission concluded several firms did not have the comparable business characteristics and risk that warranted inclusion in the proxy group, including: El Paso and Williams, whose returns and growth rates were unrepresentative in 2004; Enterprise, which lacked an investment grade rating and whose markets have considerably higher commodity risk; two diversified gas companies, Questar and Equitable, which had too wide a range of business interests and an insufficient percentage of transmission assets to be included in the proxy group; NiSource, whose business was dominated by lower risk gas and electric distribution activities; and Southern Union, which did not pay cash dividend during the relevant period. In doing so, the Commission developed a proxy group dominated by the pipeline transmission firms that the Commission has traditionally used and a fifth diversified natural gas firm that is not dominated by its LDC component. The Commission thereby addressed the court's central concern of comparable risk by selecting a proxy group of firms with sufficiently similar business characteristics to assure a representative proxy group. Firms with characteristics that made them unrepresentative in 2004 were eliminated in the first instance. This makes it unnecessary to consider the adjustment that might be required if a

[225] Policy Statement, 123 FERC ¶ 61,048 at P 7 (*citing id.*)

[226] *Petal v. FERC*, 496 F.3d 695 at 700.

proxy group contains several companies with a relatively low proportion of pipeline business and substantial distribution operations, the concern addressed in Opinion No. 486[227] and as recognized by the Policy Statement.[228]

142. The prior analysis also addresses BP's comment that it is not possible for all pipelines in a sample to fall within an average range since the word "average" necessarily implies that some members of the sample will have higher and lower risk that distinguishes them from the other member of the sample.[229] This argument assumes that all possible firms fall within the proxy group and the broad average range that is appropriate for inclusion in the proxy group. However, this is not the case. As just discussed, the Commission eliminated those firms that might fall at the more extreme ends of the range of potential proxy group members. The firms that are left tend to have certain basic and similar transportation characteristics that cause them to fall toward the middle of the range of potential members. Thus, after assuring an adequate number of proxy firms by including MLPs in the sample, the Commission was able to define a more representative proxy group that reduces the risk that the proxy group might include firms having anomalously high or low risk compared to the natural gas pipeline industry as whole.

143. However, this broadening of the proxy group, however effective, does not eliminate the requirement to evaluate whether the historical presumption has been overcome with respect to Kern River's relative risk as compared to the firms within the proxy group. Turning to the merits, Kern River asserts that it serves fewer LDCs and more independent gas fired generating plants, and as such is faced with less stable demand and greater contract risk, as exemplified by the Mirant bankruptcy and that its actual exposure to contract defaults was growing during the test year 2004. It further asserts that its current natural gas transportation contracts have shorter terms than those of most natural gas pipelines, that a third of its contracts are with shippers that lack investment grade ratings, and that as a result the contracts of those shippers are of lesser value because they are supported by collateral of only 12 months of reservation charges. Kern River also argues that its Rocky Mountain supply basins are vulnerable to displacement by other pipelines and that those gas supplies may be in decline by the year 2015. It further asserts that its levelized rate methodology defers any recovery of its equity, thereby increasing its risk, and that any gains from accelerated depreciation are offset by the requirement to amortize the resulting regulatory obligation. Kern River claims that both these latter points are amplified by the fact its rate design assumes

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[227] Opinion No. 486, 117 FERC ¶ 61,077 at P 171.

[228] Policy Statement, 123 FERC ¶ 61,048 at P 51.

[229] BP Rebuttal Brief at 33.

operations at 100 percent of capacity. It further states that it is more highly leveraged than most interstate gas pipelines due to its 61 percent debt and 39 percent equity capital structure, and that its high percentage of undepreciated plant also exposes it to greater risk. In conclusion, Kern River asserts that due to its credit risk, financial risk and danger of defaults, its ROE should be set at a point mid-way between the median and the high end of the DCF range.[230]

144. In contrast, BP asserts that Kern River has consistently operated at more than 100 percent load factor usage for the last ten years, which indicates the strength of demand for its service when compared to other systems. It further claims that the fact that there is almost no discounting on the Kern River system, except for some very small contracts and certain specialized contracts with affiliate producers, highlights the fact that demand for Kern River's capacity is high. It further asserts that Kern River's contracts had longer terms in 2004 than at present and that its risk was accordingly lower than at the present time. BP further argues that supplies are increasing in Kern River's supply basins and that the pipeline's levelized rate design gives it a pricing advantage over new entrants. BP states that demand for gas fired generation is growing in California for environmental reasons and that this offsets any risk that might come from the higher cost fuel involved in gas fired generation. Furthermore, it states that the rapid recovery of Kern River's rate base over 10 and 15 years means that Kern River's Phase II rates will be lower than its competitors, which gives it a long-term advantage.[231]

145. BP also argues that Kern River had no difficulty reselling the Mirant capacity, that it obtained a favorable settlement in present value terms, and that Opinion No. 486 provided an additional rate factor to cover the same risk. BP also asserts that, in contrast, Northern Border operates at a lower capacity factor than Kern River, that it has a less favorable contract profile, and that this is true if Kern River is compared to gas pipelines as a whole. BP argues that Kern River was acquired in 2002 by an investor known for making low risk investments in firms with stable earnings and good long term growth prospects and that this belies its arguments here. It asserts that Kern River's debt to equity structure has actually less debt than many other pipelines (with Kern River having a weighted average 52 percent debt to equity ratio across its multi-year contract profile). BP further argues that Kern River is building equity through its accelerated depreciation structure, which reduces its capital risk and which permits an accelerated capital recovery. For these reasons, BP concludes that Kern River's ROE should be placed the point mid-way of the median and the low end of the DCF range given that its risk is

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[230] Kern River Initial Brief at 14-19; Kern River Reply Brief at 28-36; Kern River Rebuttal Brief at 39-36.

[231] BP Initial Brief at 6-13; BP Rebuttal Brief at 23-35.

materially less than the other firms that should be included in the proxy group.[232] RCG and Reliant make similar arguments regarding Kern River's market position, reserves, load factor, its excellent credit rating, and the competitive advantage of its levelized rate structure.[233]

146. The Commission affirms its prior conclusion that Kern River falls within the broad range of average risk, but concludes here, in contrast to Opinion No. 486, that no adjustment to the return is required due to the change in the composition of the proxy group.[234] This is because the Commission has excluded any clearly unrepresentative firms from the proxy group. In fact, the effort of the parties to push Kern River toward one end of the range or the other is emblematic of the difficulty of making refined determinations of risk within the proxy group. Thus, Kern River asserts that it has a higher risk of contract default based on its credit profile of its shippers and the fact that it serves fewer LDCs than many pipelines. But many of these shippers signed on for 10 and 15 year contracts that would permit accelerated recovery of Kern River's investment and amortization of its debt.[235] Moreover Kern River has operated at consistently high load factors reflecting demand for its capacity and serves a market were demand for gas fired generation may actually compete for transportation capacity that would otherwise serve the LDC market.[236] While Kern River experienced a number of smaller defaults in 2004, its loss reserves were actually less than its larger competitors in the California market in that year and these defaults do not appear to have affected its credit risk or business risk ratings.[237] Moreover, its default risk is mitigated by Kern River's ability to market its existing capacity with only limited discounting, including the Mirant capacity, its one major default, on advantageous commercial and rate design terms.[238] The decline of coal fired generation in the southwest clearly favors the gas fired generation Kern

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[232] *Id.*; BP Reply Brief at 22.

[233] RCG Initial Brief at 14-17; RCG Reply Brief at 6-7; Reliant Initial Brief at 13-16 and Reliant Reply Brief at 20-22.

[234] Opinion No. 486, 117 FERC ¶ 61,077 at P 177-78.

[235] *Id.* P 10, 16-18, 40, 48.

[236] Ex. No. RES-16 at 25, Table 6; Ex. RCG-35 at 5; BP Rebuttal Brief at 24-25, 35, and Ex. No. BP-162.

[237] Ex. No. RES-16 at 21-22; Ex. No. RES-1 at 22, Table 8; Ex. RCG-35, Schedule 5; RGC Initial Brief at 17.

[238] BP Initial Brief at 7-8; BP Rebuttal Brief at 25; Ex. No. BP-94 at 8, 23-24, 35-36.

River serves and the continued demographic growth in the southwest should serve to mitigate Kern River's contract termination risk and that of entry by competing firms.[239]

147. Moreover, Kern River's assertion that it has an unrepresentative capital structure does not reflect the fact that this is a function of the levelized rate structure that was designed to mitigate financial risk and improve its competitive position. To this end, its capital structure is determined for each contract class based on the debt obligations of each set of levelized contracts, thus spreading that risk by specific shipper class.[240] That debt is recovered on an accelerated basis given that its levelized rates were specifically designed to assure rapid recovery of its debt in no less than 15 years, a fraction of the regulatory useful life and rate base recovery of most interstate gas pipelines.[241] This accelerated depreciation schedule serves to mitigate its risk compared to older pipelines with a longer depreciation schedule but with greater accrued depreciation.

148. It is true that equity recovery may be somewhat deferred, but the present value of that deferral is built into the levelized rate structure and is therefore realized in part as the debt is retired.[242] As the reduced Phase II rates become effective Kern River's competitive position should be enhanced and its equity risk will decline significantly. This will further improve its competitive position regarding firms already in the market, other sources of supply, and new entrants.[243] Thus, while BP and the other shippers understate Kern River's contract risk given its relative dependence on the more competitive generating market, Kern River exaggerates its financial risk given that its levelized rate methodology was specifically designed to mitigate its financial and competitive risks in the first instance.

149. Given the ambiguous nature of the record, the Commission will address with greater specificity the relative risk of the proxy group members, relying in part on the evidence of credit and business risk and the limited information provided on the individual firms. As previously discussed, the Commission held that such information is

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[239] BP Rebuttal Brief at 4 (*citing* Ex. No. BP-94), and 34-35 (*citing* Ex. Nos. BP-94, BP-136, and BP-139). *See Mojave Pipeline Company*, 81 FERC ¶ 61,150, at 61,888-90 (1997), in which the Commission also declined to establish a ROE above the median based on contract risk and competitive pressures in the California market.

[240] Opinion No. 486, 117 FERC ¶ 61,077 at P 120, 176-177, n.291 and 292.

[241] *Id.* P 19-20, 43, 48.

[242] *Id.* P 40; Ex. No. RES-16 at 23;

[243] Opinion No. 486, 117 FERC ¶ 61,077 at P 42, 49.

helpful in making more refined analyses inside the proxy group. The Commission first concludes that KMEP has somewhat more risk than Kern River because 35 percent of its income is from product pipelines and another 30 percent from CO2 pipelines and terminals where income has proven to be less stable.[244] In terms of relative financial risk, in 2004 KMEP's Moody's rating was Baa1,[245] and Kern River's was one notch higher at A3.[246] Similarly, the S&P ratings were BBB+ for KMEP, and A- for Kern River.[247] The comparative business risk ratings were 5 for KMEP, and 3 for Kern River.[248] Both Moody's and S&P reflect a somewhat higher risk profile for KMEP.

150. The Commission also concludes that KMI has somewhat more risk than Kern River based on a review of their relative debt and business ratings. The Moody's bond rating for KMI is Baa2 and for Kern River is A3.[249] The S&P bond ratings of KMI and Kern River are BBB and A-1 respectively and KMI's business risk rating is 5, compared to 3 for Kern River.[250] The somewhat more risky ratings for KMI may be a reflection of its dependence on KMEP's earnings, and the underlying risk of some of KMI's own gas portfolio. This is despite the fact that KMI has a more diverse gas pipeline ownership portfolio for its own account and the presence of some retail utility operations.

151. The Commission further concludes that Northern Border is about the same risk as Kern River given the closeness of their relative financial risk. In 2004 Northern Border's Moody's rating was Baa2 compared to Kern River's A3. The comparative business risk ratings were 4 for Northern Border and 3 for Kern River. These ratings suggest that while Northern Border has a lower load factor and faces competitive and contract term pressures from the large number of interstate gas pipelines converging on the Chicago market,[251] these risks are comparable to the credit, competitive, and contract risk facing

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[244] Ex. S-2, Schedule No. 1;

[245] Moody's rankings are A1, A2, A3, Baa1, Baa2, and Baa3 for investment grade obligations. *See* Ex. S-3 at 80.

[246] Ex. RCG-40, Schedule 2.

[247] The rankings for S&P are AAA, AA, A, and BBB for investment grade obligations. *See* Ex. S-7 at 3. A + or A – is a gradation within the same general ranking. The Fitch Ratings use the same ranking symbols as S&P. *See* Ex. S-5 at 1

[248] Ex. S-2, Schedule Nos. 2 and 3.

[249] Ex. RGC-40, Schedule 2.

[250] Ex. S-2, Schedule Nos. 2 and 3

[251] BP Rebuttal Brief at 33; Ex. No. BP-136 at 19-23.

Kern River in the California market despite its higher load factor.[252] The Commission also concludes that TC Pipelines would be placed at a less risky point in the range as it has about the same risk as Kern River. While it has no debt, it had some financial risk in 2004 due to its minority status and its dependence on the dividends from its pipeline interests.[253]

152. The Commission further concludes that National Fuel has about the same risk as Kern River because National Fuel's pipeline operations have proven to be very stable and its utility operations, while somewhat vulnerable to seasonal fluctuations and prices, are offset by its regulatory environment. Its debt ratings are similar to Kern River's with Moody's giving both companies a rating of A3 in 2004 and S&P giving National Fuel a rating of BBB+ only slightly below Kern River's A rating. National Fuel has a higher business risk rating, perhaps reflecting the more volatile exploration and production business components of its business profile.[254] However, these modest differences in debt ratings are not a basis to conclude that the two firms have materially different financial or business risk, particularly with National Fuel's history of solid, if somewhat fluctuating, earnings.[255] The uncertainty from National Fuel's exploration functions is comparable to Kern River's risk due to the credit risk of some of its shippers or the variation in generator demand on its system.

153. Thus, while there are differences among the proxy group firms with three being somewhat more risky than Kern River, and two having about the same risk, all five proxy group members fall within broad range of average risk. There is no credible evidence in this record to support a finding that Kern River is of anomalously high or low risk compared the other members of the proxy group. To support such a finding a party must make a very persuasive case in support of the need for an adjustment to remove a firm from the broad average range.[256] Nothing presented here meets that standard and except for the financial ratings, much of the evidence is ambiguous or countervailing. The Commission thus concludes that Kern River is of a similar risk to the overall risk of the

[252] Moreover, to the extent Northern Border's lower load factor is built into its rate structure and the current demand upon which those rates are premised is stable, this neutralized the difference in load factor difference between the firms. This observation demonstrates how simple numerical comparisons can be quite misleading.

[253] *See e.g.,* Ex. S-1 at 19.

[254] Ex. Staff S-2, Schedule No. 3; Ex. RGC-40, Schedule 2.

[255] *National Fuel Annual Report* at 1.

[256] *Transcontinental*, 90 FERC ¶ 61,279 at 61,936.

proxy group. Therefore there are no reasonable grounds here to adjust Kern River's ROE to a point above or below the median ROE of the proxy group selected here and the Commission holds that Kern River's ROE for the 2004 test year is 11.55 percent. Therefore the 12.50 percent ROE embedded in the September 30 Settlement is not just and reasonable and neither are the settlement rates in which it is embedded.

VI. Ruling on the Settlement

154. The 2008 Settlement is contested by BP and Southwest Gas and opposed by the Staff. Article 12 provides that the Settlement "shall not become effective and shall be void if the Commission chooses to approve it only as to the consenting parties rather than as to all parties,"[257] thus precluding severance of any party to the proceeding. Trial Staff opposition stems from this provision on the grounds that it cannot reasonably be imposed on a contesting party.

155. In *Trailblazer Pipeline Co.*,[258] discussing the Commission's standards for approving contested settlements, the Commission stated:

> The Supreme Court has held that where a settlement is contested, the Commission must make "an independent finding supported by 'substantial evidence on the record as a whole' that the proposal will establish 'just and reasonable' rates." Consistent with this requirement, Rule 602(h)(1)(i) of the Commission's settlement rules provides that the Commission may decide the merits of contested settlement issues only if the record contains substantial evidence upon which to base a reasoned decision or the Commission determines that there is no genuine issue of material fact. If the Commission finds that the record lacks substantial evidence, or finds that contesting parties or issues cannot be severed, Rule 602(h)(1)(ii) provides for the Commission either (A) to establish procedures for the purpose of receiving additional evidence on the contested issues or (B) to "take other action which the Commission determines to be appropriate."[259] (Interior citations in n. 263).

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[257] Reply Comments of Trial Staff on Offer or Settlement and Stipulation at 1, *citing*, Article 12, Sections 1 and 2 of the Proposed Settlement.

[258] *Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345 (1998), *order on reh'g*, 87 FERC ¶ 61,110 (1999).

[259] *Id.*, 87 FERC ¶ 61,110 at 61,438 (*citing Mobil Oil Corp. v. FERC*, 417 U.S. 283, 314 (1974) (*Mobil*), *United Municipal Distributors Group v. FERC*, 732 F.2d 202, 207 n.8 (D.C. Cir. 1984), and 18 C.F.R. § 385.602(h)(1)(i), respectively).

The Commission also pointed out that the courts have reversed Commission orders approving contested settlements where the court found that the Commission did not give sufficient consideration to the interests of contesting parties, even if the settlement had wide support and there were only one or very few contesting parties.[260]

156. In light of this court precedent, *Trailblazer* explained four approaches for approving contested settlements that are consistent with the courts' requirements. As summarized in that case, these are: Approach No. 1, where the Commission renders a binding merits decision on each of the contested issues; Approach No. 2, where approval of the contested settlement is based on a finding that the overall settlement as a package provides a just and reasonable result; Approach No. 3, where the Commission determines whether the benefits of the settlement outbalance the nature of the objections, in light of the limited interest of the contesting party in the outcome of the case; and Approach No. 4, where the Commission approves the settlement as uncontested for the consenting parties, and severs the contesting parties to litigate the issues.[261]

157. The parties concede that in this case the Commission may not use Approach No. 4 and sever the contesting parties under the explicit terms of the Settlement, nor can it use Approach No. 3 given that BP and Southwest Gas are both major shippers on the system. Thus, the Commission must utilize Approach No. 1 or Approach No. 2 if the Settlement is to be approved.

158. Under Approach No. 1, the Commission can approve a contested settlement, if there is an adequate record and the Commission can find that each of the contesting parties' contentions lack merit. BP comments raise four points that it considers to be genuine material issues of fact. These are: (1) mixed issues of law and material facts concerning the determination of Kern River's ROE; (2) whether Kern River is really experiencing negative Accumulated Deferred Income Tax balances; (3) related allocation issues; and (4) whether the billing determinants used in allocations of costs consistently reflect seasonal units of service for the 15-year rolled-in rates.[262] Southwest also objects to the 12.50 percent ROE embedded in the Settlement rates, as well asserting that the Settlement improperly limits the availability of the Periods Two and Three rates. Kern River and the supporting parties assert that a full factual record has been developed here,

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[260] In *Trailblazer,* 85 FERC ¶ 61,345 at 62,340-41,the Commission cited *Tejas Power Corp. v. FERC*, 908 F.2d 998 (D.C. Cir. 1990), *LaClede Gas Company v. FERC*, 997 F.2d 936 (D.C. Cir. 1993), *NorAm Gas Transmission v. FERC*, 148 F.3d 1158 (D.C. Cir. 1998),and *Southern California Edison Co. v. FERC*, 162 F.3d 116 (D.C. Cir. 1998)

[261] *Trailblazer*, 87 FERC ¶ 61,110 at 61,439.

[262] Initial Comments of BP dated October 28, 2008 at 9 (BP Initial Comments).

that the Settlement conforms to the Commission's merits findings in Opinion Nos. 486 and 486-A, and that the ROE embedded in the Settlement is within the range of reasonable equitable returns developed on the extensive record of this proceeding. In particular, Kern River asserts that the Commission should distinguish between legitimate disputes raised by the Settlement itself and new or untimely issues that are grounded in a party's objections to the levelized rate methodology that was litigated at hearing.[263] RCG further argues that the material issues of fact raised by BP are embedded in a black box settlement whose components are within the bounds of the Commission's rulings in Opinion Nos. 486 and 486-A and therefore they need not be pursued further.[264]

159. The Commission concludes that it cannot impose the Settlement on the contesting parties under Approach No. 1, because it cannot find that each of the contesting parties' contentions lack merit. For purposes of the analysis here, the Commission accepts the supporting parties' representations that on all issues other than ROE, the Settlement is consistent with the Commission's merits determinations in Opinion Nos. 486 and 486-A. However, the contesting parties also assert that the 12.50 percent ROE embedded in the Settlement rates is too high. As fully discussed above, the Commission has held, based upon the paper hearing record, that Kern River should be awarded an ROE of only 11.55 percent, some 95 basis points lower than the Settlement ROE. Accordingly, the Commission cannot find that the contesting parties' contention that the Settlement is ROE is too high lacks merit.

160. Approach No. 2 provides for approval of the contested settlement based on a finding that the overall settlement as a package provides a just and reasonable result. Kern River asserts that this standard will be met if the rate resulting from the Settlement will be less than that which would be determined by the Commission on the merits.[265] In particular, it asserts that the pre-tax return of 11.63 percent embedded in the settlement rates is well within the range of plausible litigation and is only 80 basis points higher than 10.82 percent pre-tax rate of return that would result from the rulings in Opinion No. 486.[266] RCG argues more expansively that the benefits from approving the Settlement include: (1) the Settlement rates are less than the filed rates and in some cases close to or less than the pre-existing rates; (2) the Settlement provides for early implementation of

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263 Reply Comments of Kern River in Support of Offer of Settlement and Stipulation at 5-6;

264 Reply Comments of RCG Requesting Prompt Approval of the Settlement at 7-9.

265 Kern River Reply Comments at 6.

266 Initial Comments of Kern River in Support of Offer of Settlement at 6-8.

the lower rates; (3) the Settlement avoids the need to rule on complex issues involving the compliance filing and ends four years of protracted litigation; (4) the Settlement provides for rate stability for four years; and (5) it provides for early resolution of issues related to the Period Two rates with full participation by the parties.

161. In contrast, Trial Staff asserts that the Settlement results in rates that are unreasonably high, that the Commission does not use the composite return cited by Kern River to establish rates, and the Settlement unduly constrains a shipper's right to challenge the settlement rates in the future.[267] BP asserts that the Settlement may not be imposed on a contesting party for similar reasons.[268] Southwest makes similar assertions and notes that the 80 basis points cited by Kern River add approximately $14.5 million to its cost of service with a corresponding impact on its rates.[269] Therefore, they conclude, the Settlement will not result in the just and reasonable rates required by *Mobile, supra*.

162. The Commission concludes that it cannot find that the overall settlement as a package provides a just and reasonable result, as required by Approach No. 2. Approach No. 2 does not require a merits finding on each of the issues raised by the contesting party. However, as the Commission explained in *Trailblazer*, under Approach No. 2 the Commission must find "that the contesting party would be in no worse position under the terms of the settlement than if the case were litigated."[270] This entails an analysis of the Settlement's resolution of specific issues so as to determine whether a litigated result on some of the issues would have would have been more favorable to the pipeline than under the Settlement, thereby offsetting the fact that some of the contesting parties' objections may have merit. In such a situation, the Commission could find that "the result under the settlement is no worse for the contesting party than the likely result of continued litigation."[271] The Commission can make no such finding here.

163. As discussed above, the parties supporting the settlement state that it resolves all non-ROE issues consistent with the Commission's merits holdings in Opinion Nos. 486 and 486-A. Thus, the Commission cannot find that the Settlement resolves any issues in a manner that is more favorable to Kern River than a litigated result on those issues

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[267] Staff Rely Comments, *passim*.

[268] BP Initial Comments at 12-13, 31-32, and 77-78.

[269] Reply Comments of Southwest in Opposition to Offer of Settlement and Stipulation at 5-7.

[270] 87 FERC ¶ 61,110 at 61,439.

[271] *Id.*

would have been. Rather, at best the Settlement resolves all issues consistent with the litigated result in this case, except for ROE as to which the Settlement reaches a result higher than the ROE the Commission has found to be just and reasonable. It follows that the Settlement rates are higher than the just and reasonable rates determined pursuant to the litigation in this proceeding.

164. Moreover, the Settlement does not appear to provide any other benefit sufficient to offset the fact the overall Settlement rates are higher than the just and reasonable rates determined in this proceeding. It does not appear that the Settlement will result in a significant reduction in litigation for several reasons. As the parties note, the record is virtually complete and the Commission has made merits findings at this point on all issues that are necessary to support a revised compliance filing and the underlying cost elements that would be used to develop that compliance filing. Those findings include the findings on ROE in this order and various rulings in Opinion Nos. 486, 486-A, and this order regarding the determination of Kern River's Period One rates. The Settlement itself provides for further litigation concerning Kern River's Period Two rates, and the Commission is also ruling here that further review of the Period Three rates would be administratively wasteful. Moreover, nothing in the Settlement precludes a judicial appeal by BP and Southwest on the merits of a Commission order approving the Settlement.

165. For the same reasons, the proposed settlement will not result in rate certainty and administrative efficiency, either retrospectively or prospectively. Even if the Commission were to approve the Settlement, that decision would likely be appealed and the rates and refunds the Settlement provides to all parties would be subject to the risk of reversal on appeal. These uncertainties could be reduced if the Settlement permitted the Commission to sever the contesting parties under Approach No. 4. However, the Settlement clearly removes that possibility from the Commission's hands.

166. Given these conclusions and the Commission's prior holding that the rate of return of 12.50 percent embedded in the Settlement rates cannot be found to be just and reasonable under either Approach No. 1 or Approach No. 2, the Commission need not reach the other objections raised by Trial Staff and the contesting parties BP and Southwest. Finally, the Commission notes that the result here is consistent with the recent decision in *Petal v. FERC*, where the court emphasized that "the Commission may adopt an uncontested settlement *only* "after finding it is fair and reasonable and in the public interest."[272] It necessarily follows that the Commission must make the same finding for a contested settlement, which it cannot do here given that there is no justification on the record for approving a ROE that is in excess of the median ROE adopted by this order. Therefore the Settlement is rejected.

[272] *Petal v. FERC*, 496 F.3d 695 at 700.

VII. BP's Rehearing Request Concerning Periods Two and Three Levelized Rates

167. In its June 16, 2008 request for rehearing of Opinion No. 486-A, BP requests clarification, or in the alternative, rehearing of several issues related to Kern River's levelized rate structure. BP's requested clarifications focus on the three rate periods set forth in Opinion No. 486,[273] as reaffirmed by Opinion No. 486-A.[274]

168. In order to address these issues it is necessary to briefly review Kern River's initial rate proposal. Kern River proposed to continue its levelized rate methodology which was first approved in the certificate authorizing its Original System.[275] That methodology includes separate rates for three different periods: (1) the 15-year term of the firm shippers' initial contracts (Period One), (2) the period from the proposed expiration of those contracts to the end of Kern River's depreciable life (Period Two), and (3) the period thereafter (Period Three). The levelized rates for Period One were designed to permit Kern River to recover approximately 70 percent of its original investment, an amount approximately equal to the portion of its invested capital funded through debt. Since this would allow Kern River to recover more invested capital during Period One than it would under ordinary straight-line depreciation for the depreciable life of the project, the rates for Period Two and Period Three were lower than the Period One rates.[276] In Opinion Nos. 486 and 486-A, the Commission accepted the use of these rate periods by Kern River and, in order to increase the assurance that Kern River's shippers will obtain the benefit of the lower Period Two rates if such shippers continue service beyond the terms of their existing contracts, the Commission directed that Kern River

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[273] Opinion No. 486, 117 FERC ¶ 61,077.

[274] Opinion No. 486-A, 123 FERC ¶ 61,056 (2008).

[275] Kern River proposed to continue using the rate levelization methodology and cost of service rate principles as approved in the original Kern River certificate proceeding, *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990), its extended term (ET) rate settlement proceeding, *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000), *reh'g denied,* 94 FERC ¶ 61,115 (2001), its 2003 Expansion certificate proceeding, *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056 (2002), and prior Kern River rate case settlements, *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995); *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124, *order on reh'g,* 91 FERC ¶ 61,103 (2000).

[276] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 2.

include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire.[277]

169. In its rehearing request, BP argues that the Commission should clarify that if Kern River retains debt during the effectiveness of the Period Two rates, the level of such rates must be adjusted to provide any resulting benefits to Shippers. Secondly, BP argues that the Commission should clarify that the excess depreciation recovered by Kern River from certain capacity during Period One will, during Period Two, be used only to derive rates for the same capacity. Third, BP argues that the Commission should clarify that Kern River's shippers will continue to get the benefit of their bargain in Period Three. Lastly, BP asserts that it requests rehearing regarding any issue for which its requested clarification is not granted. The Commission will address these issues in turn.

A. Period Two Debt Rate Adjustment

170. BP asserts that Opinion No. 486 states that "the Commission did not [in Kern River's initial certification proceeding] mandate the recovery of debt in any particular timeframe."[278] BP also asserts that in implementing Kern River's ET program, the Commission stated that "after the debt attributable to the original system construction is repaid, [Kern River's] transportation rates will step-down to a lower level."[279] BP states that on rehearing of Opinion No. 486 it expressed concern that these statements, taken together, might allow Kern River to argue that Period Two step-down rates could not be implemented until all its debt is repaid.

171. BP argues that in Opinion No. 486-A, the Commission clarified that "if Kern River refinances its debt, and the debt, therefore, is not extinguished before the implementation of the Period Two rates, the level of the Period Two rates may be adjusted to reflect any benefits to shippers from such action but not any detriment to shippers."[280] It asserts that this clarification did not fully clarify the issue because the use of the word "may" creates additional uncertainty regarding whether the level of Kern River's Period Two rates must be adjusted to reflect the benefit to shippers if Kern River refinances its debt before the implementation of Period Two rates. Therefore, BP requests that the Commission clarify that if Kern River retains debt in its capital structure

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[277] *Id.* P 11.

[278] BP Request at 28 (*citing* Opinion No. 486 at n. 90.

[279] *Id.* (*citing Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061, at 61,159 (2000)).

[280] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 46.

during the time Period Two rates are being collected, the level of Period Two rates must be adjusted to reflect any benefits to shippers from such action but not any detriment to shippers.

172. In Opinion No. 486-A, the Commission, in discussing the composition of Kern River's Period Two Rates, determined that the Period Two rates must be filed with the effective dates linked to the expiration of the 10 or 15 year contracts currently held by Kern River's shippers, and that the Period Two rates must be based upon no more than 30 percent of Kern River's current rate base, which is an amount corresponding to the amount of equity under Kern River's capital structure. In addition to this finding, the Commission also stated that

> [I]f Kern River refinances its debt, and the debt, therefore, is not extinguished before the implementation of the Period Two rates, the level of the Period Two rates may be adjusted to reflect any benefits to shippers from such action but not any detriment to shippers.[281]

173. The Commission reasoned that in determining the Period Two rates refinancing would not change the level of the remaining rate base at the end of the levelization[282] and pointed out that, as Kern River had stated:

> if Kern River refinances its debt and/or debt is not fully extinguished at the end of the respective shipper contracts, Kern River's Period Two rates cannot be higher than if it had used all the depreciation collected during Period One to pay off its debt. The entire depreciation allowance reflected in Kern River's Period One rates must be subtracted from rate base in calculating the Period Two rates regardless of Kern River's actual use of these funds. Thus, the rate base used to design Kern River's Period Two rates may not reflect

[281] *Id.*

[282] The Commission also cited to Kern River's Brief Opposing Exceptions which stated:

> The only effect of a refinancing would be that the remaining rate base after levelization would be capitalized partly with debt and partly with equity, rather than entirely with equity. Moreover, because debt capital costs less than equity capital, Kern River's post levelization shippers *would be better off* under refinancing than if Kern River maintained the nearly 100 percent equity capital structure that would otherwise exist. Ex. Nos. KR-23 at 20, KR-29 (emphasis in original).

> more than 30 percent of its original invested capital no matter what the level of its outstanding debts. However, as Kern River states, if some of that rate base is, contrary to current expectations, financed by debt rather than equity, that fact will be reflected in the calculation of the Period Two rates. Since debt is cheaper than equity, this would reduce the Period Two rates below what they would be otherwise. Thus, there is no way that the shippers could be harmed by Kern River's failure to pay off all of its debt during Period One.[283]

174. BP requests that the Commission clarify that if Kern River retains debt in its capital structure during the time the Period Two rates are being collected, the level of Period Two rates must be adjusted to reflect any benefits to shippers from such action but not any detriment to shippers. The Commission grants the requested clarification consistent with the above discussion, subject to one caveat. As required by the NGA, any change in the Period Two rates after they are approved in the compliance phase of this proceeding can only be implemented pursuant to a section 4 rate filing by Kern River or a section 5 action by the Commission.

B. <u>Use of Depreciation in the Derivation of Period Two Rates</u>

175. BP asserts that the Commission should clarify that excess depreciation recovered by Kern River from certain capacity during Period One will be used only to derive rates for the same capacity during Period Two.

176. BP states that Opinion No. 486-A does not explicitly provide that the excess depreciation recovered by Kern River during Period One will be flowed back, during Period Two, to the same capacity from which the excess recovery was obtained. Therefore, BP requests that the Commission clarify that the same capacity that over-funded depreciation will be charged a rate during Period Two that reflects the full benefit of that overfunded amount, presuming the same shipper(s) have retained the capacity in Period Two. BP also asserts that if the same shippers do not retain capacity in Period Two the Commission must specify how Kern River's over-recovery will be returned and explain how Kern River will be prevented from retaining the excess revenue.

177. BP argues that Opinion No. 486-A claims to protect the parties' bargained-for benefits but that a failure to accurately track the over-collection for purposes of deriving a Period Two rate for the shipper who has paid the excess depreciation would violate the parties' bargain. BP asserts that it would be inconsistent with cost based ratemaking by failing to credit to the over-contributing shipper the value of the over collection, or to

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[283] *Id.* (*citing* Kern River Brief Opposing Exceptions at 33).

allow Kern River to retain such over-collection. BP asserts that this would result in subsidization and violation of the Commission's 1999 Pricing Policy Statement,[284] which requires that existing shippers not subsidize shippers using a subsequent and more costly expansion.

178. In Opinion No. 486, the Commission recognized that Kern River's levelization methodology would levelize Kern River's rates over several different periods, so that Kern River can recover 70 percent of its invested capital through the Period One levelized rates in effect during the terms of the shippers' current contracts. The Commission noted that, as a result, unlike the usual situation with levelized rates, Kern River's levelized rates will recover less of its costs during the early years of Period One than under traditional rates. However, the Commission continued to state that by the end of Period One those rates will have recovered more costs than traditional rates would have recovered at that stage of Kern River's life. The Commission stated that, "Kern River will then return this excess recovery to its shippers during Period Two, through the step-down rates to be implemented at the start of Period Two."[285]

179. The Commission, as it explained in Opinion No. 486,[286] required that Kern River keep track of its recovered depreciation from ratepayers in a separate account. The Commission directed that Kern River record annual book depreciation as an addition to Account No. 108 (Accumulated Depreciation Expense), and a regulatory asset or liability is booked for the difference between the annual regulatory depreciation expense it recovers in rates and the book depreciation expense it records in Account No. 108. The Commission also stated that, "[a]t the end of Period One, the regulatory liability, which BP asserts will amount to $500 million, will be reflected in the Period Two rates and thereby returned to Kern River's shippers."[287]

180. Lastly, in Opinion No. 486-A, the Commission found that Kern River's proposal to file Period One rates that would collect approximately 70 percent of its original costs from its shippers over either a ten or fifteen year period (depending on the length of their contracts) which would then be followed by Period Two rates that would be based upon the remaining 30 percent at the expiration of the original ten or fifteen year term was unjust and unreasonable because it did not provide adequate assurances that its shippers

[284] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999).

[285] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 26.

[286] Opinion No. 486, 117 FERC ¶ 61,077 at P 47-48.

[287] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 28.

would obtain the benefit of the lower Period Two rates if they continued service beyond the terms of their existing contracts. Therefore, the Commission directed Kern River to file revised tariff sheets setting forth its currently proposed rates based upon the instant cost of service as well as the rates and effective date of the step-down Period Two rates to be available to its 10 and 15 year shippers.[288]

181. Therefore, the Commission has found that Kern River must record this excess recovery (as opposed to straight line depreciation) and return it to its shippers during Period Two, through the step-down rates filed in Kern River's tariff and based upon the instant cost of service. BP requests that the Commission also add that the excess depreciation recovered by Kern River during Period One will be flowed back, during Period Two, to the same capacity from which the excess recovery was obtained. BP also asserts that if the same shippers do not retain capacity in Period Two the Commission must specify how Kern River's over-recovery will be returned and explain how Kern River will be prevented from retaining the excess revenue.

182. The Commission declines to grant BP's requested clarification. The Commission has required that the excess depreciation amounts be recorded and that the Period Two rates be calculated to return any excess amounts to the shippers during Period Two. Kern River is required to place these Period Two rates in its tariff. BP is free, in the compliance phase of this proceeding, to object to Kern River's proposed Period Two rates if it believes that the rates set forth by Kern River do not correctly return any overfunded depreciation amounts from Period One. This would include any issue concerning whether Kern River has properly allocated the returned depreciation amounts among the relevant customer groups.

183. The Commission will not specify that shippers that do not retain capacity in Period Two will derive any benefit from Kern River's rate methodology. The bargain in this proceeding is based upon continued use of the facilities. If a shipper determines that it is in its best interests to terminate service at the end of its current contract and thereby forego the benefit of Period Two rates, the Commission will not require any special modification of the Period Two or Period Three rates to reflect this fact other than the usual change in rate design volumes that would occur in a pipeline's next rate proceeding.

C. <u>Period Three Rates</u>

184. BP argues that the Commission has only directed Kern River to include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire. However, BP asserts that the Commission has not provided a mechanism to

[288] Opinion No. 486, 117 FERC ¶ 61,077 at P 61-62.

ensure that Period Three rates continue to provide Kern River's shippers with the benefit of the levelization bargain. BP requests that the Commission clarify that Kern River's Period Three rates will continue to be based on the principles articulated in the orders certificating Kern River and otherwise will continue to reflect the benefit of their bargain. Also, BP requests that Period Three rates be restated now consistent with the practice commenced in the original certificate order, and derived using the same principles used in the certificate orders governing the Original System.

185. BP argues that there is no assurance that Kern River will file another rate case before step down Period Two rates would take effect in 2011 for Original System 10 year shippers.[289] Therefore, in order to retain capacity during Period Two, pursuant to ROFR procedures, BP may have to match bids at the maximum rate not just for Period Two, but also those in effect during Period Three for such capacity. BP argues that without stated maximum Period Three rates, the ROFR process will be needlessly contentious.

186. The Commission will grant the requested clarification in part. First, BP states that the Commission should clarify that Kern River's Period Three rates will continue to be based on the principles articulated in the orders certificating Kern River and otherwise will continue to reflect the benefit of their bargain. The Commission so clarifies its orders. Throughout this proceeding, the Commission has been consistent in finding that the parties will retain the benefit of their bargain and that the levelized methodology will be maintained in absence of an overarching policy reason.[290] In Opinion No.486-A, the

[289] The Commission stated in Opinion No. 486 that as a result of the contractual options presented to the shippers through the various expansions of Kern River's system, the contract expiration profiles as of November 1, 2004, the end of the adjustment period in the instant proceeding, were as follows:

> Original system – 10-year contracts (remaining term of 6 years, 11 months); Original system – 15-year contracts (remaining term of 11 years, 11 months); 2002 Expansion – 10-year contracts (remaining term 7 years, 6 months); 2002 Expansion – 15-year contracts (remaining term 12 years, 6 months); 2003 Expansion – 10-year contracts (remaining term 8 years, 6 months); 2003 Expansion – 15-year contracts (remaining term 13 years, 6 months); and Big Horn Lateral contracts (remaining term 13 years, 2 months). Negotiated rate contracts pertaining to the High Desert Lateral under a traditional depreciation methodology also have a remaining term of 13 years, 2 months.

Opinion No. 486, 117 FERC ¶ 61,077, at n.46 (*citing* Ex. KR-45 at 4, 7).

[290] For example, Opinion No. 486, 117 FERC ¶ 61,077 at P 39 ("we hold that in Kern River's instant rate case, it may and should continue the levelized rate model agreed

(continued…)

Commission, in discussing the allocation of risks that parties had agreed to in this proceeding stated "once the Commission has issued the certificate, 'the Commission will not lightly change the allocation of risk inherent in the optional certificate as granted,' absent some 'overarching policy reason.'"[291] Therefore, the Commission clarifies that that the Period Three rates will be designed in manner consistent with the principles set forth in the instant proceeding.[292]

187. Secondly, BP requests that the Period Three rates be restated now consistent with the practice commenced in the original certificate order, and derived using the same principles used in the certificate orders governing the Kern River Original System. BP argues that under Kern River's ROFR procedures, BP may have to match bids at the maximum rate not just for Period Two, but also those in effect during Period Three for such capacity. BP argues that without stated maximum Period Three rates, the ROFR process will be needlessly contentious.

188. The Commission declines to grant BP's request. As stated the Period Three rates are to commence at the end of the depreciable life of the Kern River facilities, in approximately another 30 years.[293] The Commission finds that given its findings above

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to in its certificate proceeding and subsequent proceedings"); at P 42 ("In the Commission's view, the depreciation recovery under levelized rates is, by necessity, a long term proposition. . . . it is inherent in any such plan that the levelized rate will remain in effect for the entire agreed upon period."); at P 44 ("Therefore, the Commission finds that the levelization methodology must remain in place for shippers to realize the benefits bargained for as a part of the refinancing settlement.")

[291] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 19 (*citing Mojave Pipeline Co.*, 81 FERC ¶ 61,150 at 61,682-83 (footnote omitted)).

[292] This is consistent with the Commission's determination in Opinion No. 486-A, that:

> BP, and all the other parties who agreed Kern River's levelized rate methodology, should have reasonably anticipated from the beginning that [the levelized]methodology would continue in effect throughout Kern River's life, absent agreement by all parties to modify or eliminate that rate design. Nor should it come as any surprise to the parties that the Commission would hold the parties to their agreement.

Opinion No. 486-A, 123 FERC ¶ 61,056 P 19.

[293] The Commission uses the economic life of the pipeline in determining depreciation. In this proceeding, the Commission affirmed the holdings of the ALJ

(continued...)

that the Period Three rates will be designed in a manner consistent with the principles set forth in the instant proceeding, it is unnecessary and burdensome to require that rates which are to begin as far in the future as the Period Three rates be incorporated into the Kern River's tariff at this time.

189. Currently, shippers pay rates in Period One until the end of their respective contracts upon which Period Two rates commence. While the Period Two rates are yet to take effect, such rates will commence for the 10 and 15 year shippers when current contracts terminate within two to eight years. The Commission found that Kern River's rate proposal did not provide adequate assurances that its shippers would obtain the benefit of the lower Period Two rates if they continued service beyond the terms of their existing contracts. Because the Commission viewed the opportunity for shippers to obtain the lower Period Two rates upon the expiration of their existing contracts as a vital component of the levelization methodology proposed by Kern River,[294] and because the Commission concluded that the makeup of the Period Two rates would be more transparent, the Commission concluded that the implementation of the Period One rates without the benefit of the stepdown Period Two rates being included in Kern River's tariff was unjust and unreasonable.[295]

190. The circumstances faced by the Commission with regard to the Period Three rates differ from those surrounding its decision to include the Period Two rates in Kern River's tariff. First, in the prior decision the Period Two rates were the next set of rates to take effect and were directly affected by decisions taken for calculation of the Period One rates. Here, the Period Three rates will take effect only after Period Two is completed.

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concerning the 35-year remaining economic life of the rolled-in transmission system (calculated from the October 31, 2004, end of the test period in this proceeding). The Commission also adopted recommendations resulting from a finding of a 35-year economic life including an average remaining economic life of 30.6 years for the original system and 27.0 years for the 2002 expansion. Opinion No. 486 at P 410-443.

[294] The Commission stated that its:

> original and subsequent approvals of the levelized methodology for Kern River were premised on the eventual availability of the step-down of rates bargained for by the shippers. In the instant proceeding, this step-down benefit of the lower Period Two rate remains an essential component of Kern River's proposal.

Opinion No. 486, 117 FERC ¶ 61,077 at P 54.

[295] Opinion No. 486-A, 123 FERC ¶ 61,056,at P 62.

Therefore, the Period Three rates are not the next set of rates to be imposed upon the shippers. In the Commission's view, forecasting the rates as far in the future as required to include Period Three rates in the tariff (approximately 30 years) does not yield the benefits it saw in requiring that the Period Two rates be included in the tariff. The Commission finds that under these circumstances, inclusion of the Period Three rate requires far too much speculation such as, for example, whether a management fee will be necessary at the end of Kern River's depreciable life.

191. Accordingly, the Commission finds that it is not necessary to include the future Period Three rates in Kern River's tariff. Moreover, the Commission finds that BP's argument that it is necessary to know rates far in the future in order that the ROFR process will not be needlessly contentious is not persuasive. First, any ROFR process may include time periods for which rates are not currently known. It is the Net Present Value based on the maximum rate currently in effect that controls the allocation of capacity. Secondly, given the speculation in forecasting rates as far into the future as necessary as for the Period Three rates, in the Commission's view, such action could hardly be less contentious than the ROFR process foreseen by BP.

VIII. Conclusion and Further Filing Requirements

192. The Commission holds that the 12.50 ROE embedded in the rates filed as part Kern River's September 30, 2008 settlement proposal is not just and reasonable. Therefore, the rates at issue are not just and reasonable and the settlement is rejected. BP's request for clarification and rehearing is granted in part and denied in part for the reasons stated in the body of this order. Kern River is therefore, directed to cancel the interim rates filed with the settlement effective October 1, 2008 and to make a revised compliance filing within 45 days after this order issues using a ROE of 11.55 percent to design its compliance filing rates. Comments thereon will be due 75 days after this order issues with reply comments due 90 days after this order issues. Kern River is further directed to recapture the interim refunds previously made at the earliest practical date after this order issues as required by the settlement.

The Commission orders:

(A) The settlement proposal dated September 30, 2008 is rejected as unjust and unreasonable for the reasons stated in the body of this order.

(B) BP's request for clarification and rehearing is granted in part and denied in part.

(C) Kern River shall make a revised compliance filing within 45 days after this order issues conforming to the findings of this order.

(D) Comments on the revised compliance filing are due 75 days after this order issues and reply comments are due 90 days after this order issues.

(E) Kern River shall recapture the refunds previously made under terms of the settlement at the earliest practical date after this order issues.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 906

Exhibits in Support
Of Opening Testimony

June 4, 2010

Analytical Perspectives

Budget of the U.S. Government

Fiscal Year 2011

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Budget of the United States Government, Fiscal Year 2011 contains the Budget Message of the President, information on the President's priorities, budget overviews organized by agency, and summary tables.

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Historical Tables, Budget of the United States Government, Fiscal Year 2011 provides data on budget receipts, outlays, surpluses or deficits, Federal debt, and Federal employment over an extended time period, generally from 1940 or earlier to 2011 or 2015.

To the extent feasible, the data have been adjusted to provide consistency with the 2011 Budget and to provide comparability over time.

Appendix, Budget of the United States Government, Fiscal Year 2011 contains detailed information on the various appropriations and funds that constitute the budget and is designed primarily for the use of the Appropriations Committees. The *Appendix* contains more detailed financial information on individual programs and appropriation accounts than any of the other budget documents. It includes for each agency: the proposed text of appropriations language; budget schedules for each account; legislative proposals; explanations of the work to be performed and the funds needed; and proposed general provisions applicable to the appropriations of entire agencies or group of agencies. Information is also provided on certain activities whose transactions are not part of the budget totals.

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GENERAL NOTES

1. All years referenced for budget data are fiscal years unless otherwise noted. All years referenced for economic data are calendar years unless otherwise noted.

2. Detail in this document may not add to the totals due to rounding.

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TABLE OF CONTENTS

ECONOMIC AND BUDGET ANALYSES

2. ECONOMIC ASSUMPTIONS

When the President took office in January 2009, the economy was in the midst of an economic crisis. The recession, which began in December 2007, became more severe toward the end of 2008, and, in the three quarters ending in the first quarter of 2009, real GDP fell at an annual rate of 4.8 percent, the steepest three-quarter decline since 1947. Meanwhile, the unemployment rate surged 1.2 percentage points in the first quarter of 2009, the largest increase since 1975.[1]

The first order of business for the new Administration was to arrest the rapid decline in economic activity. The President and Congress took unprecedented actions to restore demand, stabilize financial markets, and put people back to work. These steps included passage of the American Recovery and Reinvestment Act (ARRA), signed by the President just 28 days after taking office. They also included the Financial Stability Plan, announced in February, which encompassed wide-ranging measures to strengthen the banking system, increase consumer and business lending, and stem foreclosures and support the housing market. These and a host of other actions walked the economy back from the brink.

While current data suggest that production bottomed out during the summer of 2009, American businesses were still shedding jobs in the third and four quarters. The unemployment rate was 10.0 percent in December 2009 (the most recent month of data), and the number of long-term unemployed was 6.1 million. The recovery is projected to gain momentum slowly in 2010 and to strengthen in 2011-2013. Unfortunately, even with healthy economic growth there is likely to be an extended period of higher-than-normal unemployment lasting for several years.

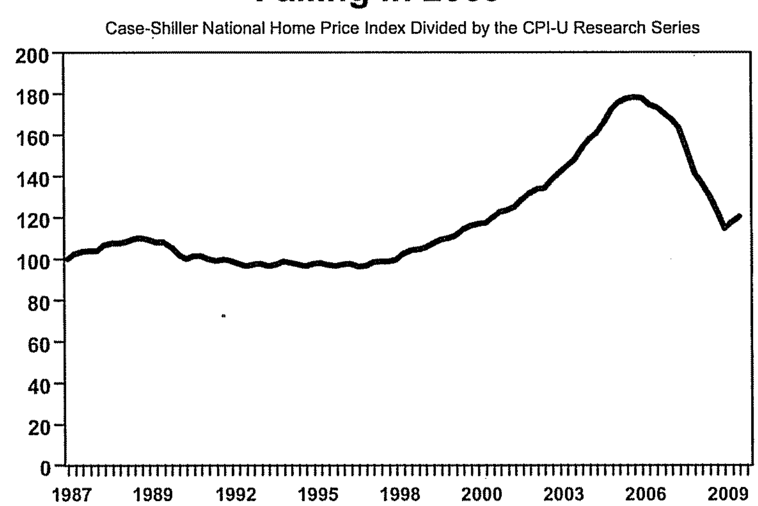
Recent Economic Performance

The accumulated stresses from a contracting housing market and strains on financial markets brought the previous expansion to an end in December 2007. In its early stages, the 2008-2009 recession was relatively mild, but financial conditions worsened sharply in the fall of 2008, and from that point forward the recession became much more severe. Production began rising in the second half of 2009, but the labor market has not yet begun to recover, although it is expected to begin to recover in 2010. The strength of the recovery is one of the key issues for the forecast.

Housing Markets.—The downturn had its origin in the housing market. In hindsight, it is clear that by the early years of this decade, housing prices had become caught up in a speculative bubble that finally burst. Housing prices fell sharply from 2006 until 2009, but in recent months the market has shown signs of stabilizing (see Chart 2–1). As prices fell, investment in housing plummeted, reducing the rate of real GDP growth by an average of 1 percentage point per quarter. With the stabilization of house prices in the second half of 2009, housing

[1] In the Budget, economic performance is discussed in terms of calendar years. Budget figures are discussed in terms of fiscal years.

Chart 2-1. Relative House Prices Stopped Falling in 2009



investment also began to recover, adding 0.4 percentage points to real GDP growth in the third quarter.

At the low point for residential building in April 2009, monthly housing starts fell to an annual rate of just 479,000 units. This was the lowest level ever recorded for this series, which dates from 1959. In normal times, at least 1.5 million starts a year are needed to accommodate the needs of an expanding population and to replace older units as they wear out. Since April, housing starts have been trending up, although they experienced a sharp drop in October as builders paused to see whether the homebuyers' tax credit would be extended. A bill extending the credit was signed by President Obama on November 6, 2009, and starts rebounded in November. A large overhang of vacant homes exists currently, however, which must be reduced before a robust housing recovery can become established. The foreclosure rate in the third quarter of 2009 was 1.4 percent, which is the highest since records have been kept going back to 1972. With foreclosures adding to the stock of vacant homes, housing prices are likely to remain subdued. Although residential building is likely to remain modest for some time, the forecast assumes a gradual recovery in housing activity, which contributes to GDP growth in 2010-2012.

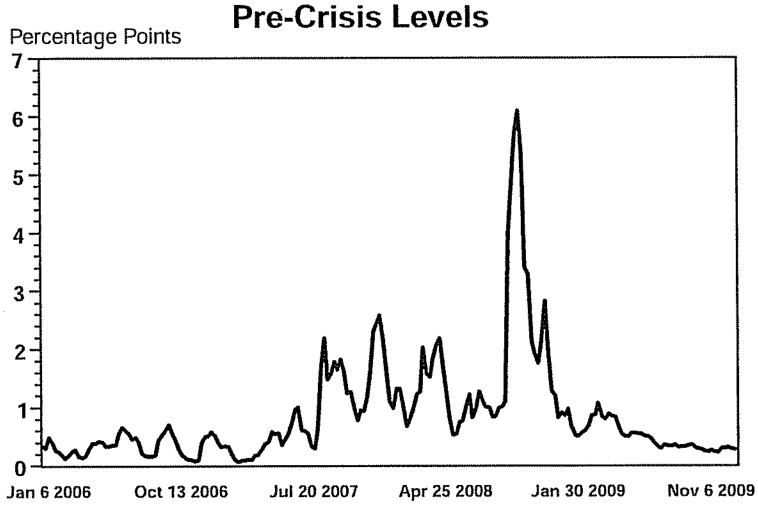
The Financial Crisis.—In August 2007, the United States subprime mortgage market became the focal point for a worldwide reduction in risk tolerance. Subprime mortgages are mortgages provided to borrowers who do not meet the standard criteria for borrowing at the lowest prevailing interest rate, either because of low income, a poor credit history, lack of a down payment, or other reasons. In the spring of 2007, there was over $1 trillion outstanding in such mortgages, and with house prices falling, many of these mortgages were on the brink of default.

As banks and other investors lost confidence in the value of these high-risk mortgages and the securities based on them, banks became much less willing to lend to each other. Money market participants outside the banks became unwilling to lend to one another as well. Financial market participants of all kinds were uncertain of the degree to which other participants' balance sheets had been contaminated. The heightened uncertainty was reflected in unprecedented spreads between interest rates on Treasury securities and those on various types of financial market debt.

One especially telling differential is the spread between the yield on short-term U.S. Treasury securities, and the London interbank lending rate (LIBOR) which banks trading in the London money market charge one another for short-term lending in dollars. Historically, this differential has amounted to only 30 or 40 basis points. In August 2007, it shot up to over 200 basis points, and it spiked again, most dramatically, in September 2008 following the bankruptcy of Lehman Brothers (see Chart 2-2). Gradually, over the course of this year the LIBOR spread and other measures of credit risk have declined. In recent months these spreads have regained their pre-crisis levels. This is the clearest evidence that the financial crisis has eased. Although financial institutions have easier access to funds, they remain reluctant to lend.

The policy response following the Lehman Brothers bankruptcy was crucial in restoring confidence and limiting the financial panic. Over the course of the following three months, the Federal Reserve lowered its short-term interest rate target to near zero, while creating new programs to provide credit to markets where banks were no longer lending. The Troubled Asset Relief Program (TARP) provided the Treasury with the financial resources to bolster banks' capital position and to remove troubled assets from banks' balance sheets. In the spring of 2009, the Treasury and bank regulators conducted the Supervisory Capital Assessment Program, a stress test to determine the health of the nineteen largest U.S. banks. The test provided more transparency than had existed

Chart 2-2. The One-Month LIBOR Spread over the One-Month Treasury Yield has Returned to Pre-Crisis Levels



before concerning the banks financial position, and this reassured investors. Consequently, the banks have been able to raise private capital, providing further evidence that the credit crisis has eased.

Negative Wealth Effects and Consumption.—Between the third quarter of 2007 and the first quarter of 2009, the net worth of American households declined by $17.5 trillion, or 26.5 percent – the equivalent of more than one year's GDP. A precipitous decline in the stock market and falling house prices over this period were the main reasons for the drop in household wealth. Since then wealth has partially recovered as the stock market has rallied, and house prices have stopped falling, but even so, household wealth remains well below its peak levels prior to the recession.

Americans have reacted to this massive loss of wealth by saving more. The household saving rate had been declining since the 1980s, and it reached a low point of 0.8 percent in April 2008. Since then it has increased sharply, rising to a temporary high point of 6.4 percent last May following a distribution of special $250 payments to Social Security and Supplemental Security Income recipients and the implementation of other Recovery Act provisions. In November, the saving rate was still 4.7 percent (see Chart 2–3). In the long-run, increased saving is essential for raising future living standards. However, a sudden increase in the desire to save implies a corresponding reduction in consumer demand, and that fall-off in consumption had a negative effect on the economy in the second half of 2008. During that period, real consumer spending fell at an annual rate of 3.3 percent, the steepest two-quarter decline since 1980. In 2009, consumption has started to rise again, but it has not yet regained its peak reached in 2007.

The Labor Market.—The unemployment rate continued to rise in the second half of 2009 despite the turnaround in economic production. The increase in unemployment has had devastating effects on American families, and the recovery will not be real for most Americans until the job market also turns around. The good news is that historically, when the economy grows so does employment, although there is usually a lag of one to two quarters before unemployment declines after the resumption of real GDP growth. The normal sequence of events around a business cycle trough is for aggregate demand to revive, which pulls up sales. Initially, firms respond to the pickup in demand by increasing work hours of the existing work force and hiring temporary workers, but eventually as the higher level of demand is recognized, firms begin to hire permanent employees again, and employment revives. At that point, labor force participation is also likely to increase as discouraged workers return to the market place. Finally, the unemployment rate declines as the recovery takes hold (see Chart 2–4).

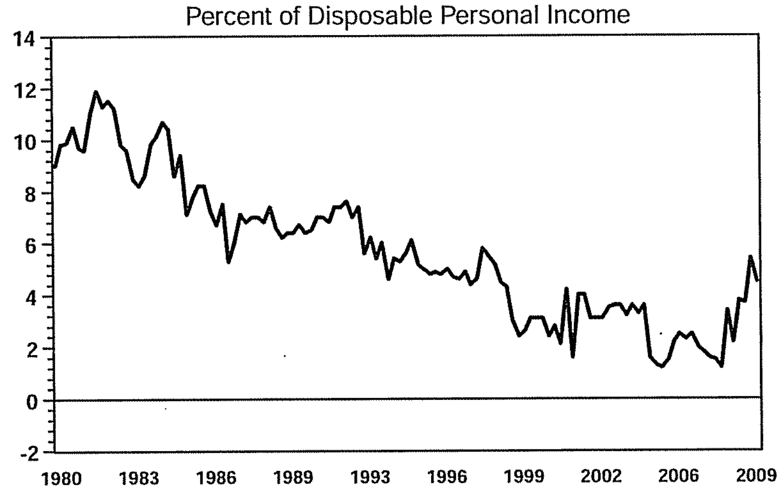
Following the recessions in 1991 and 2001, however, the lag between increased output and the decline in unemployment was much longer than one or two quarters, mainly because the recovery in production was slower and more hesitant. Unfortunately, because of the lingering effects of the credit crisis and the accompanying loss of household wealth, the recovery from the current recession is also expected to begin more slowly than in some recoveries in the past. The expected growth rate should be rapid enough to reduce the unemployment rate in 2010, but the improvement could be slow at first.

Policy Background

Over the last 12 months, the Administration and the Federal Reserve have taken a series of actions to end the recession and bolster the economy. On the fiscal side, the passage of ARRA was a crucial step. Meanwhile, the Federal Reserve has kept its target interest rate near zero

Chart 2-3. The Personal Saving Rate has Risen Sharply Since 2008

Percent of Disposable Personal Income



in order to stimulate growth, and it has also taken several novel measures to unfreeze the Nation's credit markets.

Fiscal Policy.—The Federal budget affects the economy through many channels. For an economy coming out of a deep recession, the most important of these is the budget's effect on total demand. In a slumping economy, the level of demand is the main determinant of how much is produced and how many workers will be employed. Government spending on goods and services can substitute for missing private spending while changes in taxes and transfers can contribute to demand by enabling people to spend more than they otherwise would. ARRA bolstered aggregate demand in several ways which have helped spark the recovery. It increased spending on goods and services at the Federal level; it provided assistance to State governments; it included large tax reductions for middle-class families; and it extended unemployment insurance and other benefits which have allowed people to maintain spending at levels higher than would otherwise have occurred.

The fiscal stimulus in ARRA was intended to provide a significant boost to demand in both 2009 and 2010. So far the stimulus has proceeded as intended. Although the economy has continued to lose jobs, the loss would have been much larger without the benefits of ARRA. In the first quarter of 2009, payroll employment was falling at an average rate of 691 thousand jobs per month. By the fourth quarter, the rate of job loss had declined to 69 thousand per month. It is not possible to judge the effectiveness of a macroeconomic policy without some idea of the alternative. Critics of ARRA have tended to argue that continued job losses are evidence of ineffectiveness. However, the only way to know that is through a macroeconomic model that can be used to project the employment outcome under an alternative policy. In fact, results from a range of models imply that employment was increased through the fourth quarter of 2009 by between 1.0 million and 2.1 million jobs thanks to ARRA.

The economic recovery efforts have, intentionally, increased the deficit. The increase in the deficit has been extraordinary, but it was the necessary response to the crisis the Administration inherited. It is also temporary. The Budget provides a path to lower medium-term deficits.

Over the long term, deficits tend to have some combination of two macroeconomic effects. First, they can raise interest rates and decrease investment, as the Federal Government goes into the credit markets and competes with private investors for limited capital. Second, deficits can increase the amount that the United States borrows from abroad, as foreigners step in to finance our consumption. Either way, deficits reduce future standards of living. If interest rates rise and investment falls, that makes American workers less productive and reduces our incomes. If we borrow more from abroad as a result of our deficits, that means that more of our future incomes will be mortgaged to pay back foreign creditors. Persistent large deficits would also limit the Government's maneuvering room to handle future crises.

Monetary Policy.—The Federal Reserve is responsible for monetary policy. Traditionally, it has relied on a relatively narrow range of instruments to achieve its policy goals, but in the recent crisis the Federal Reserve is using a broader set of approaches. The reason for departing from past practice is that the traditional tool of monetary policy—adjusting short-term interest rates—has proved insufficient. In addressing the economic crisis, the Federal Reserve has created facilities to provide credit to the commercial paper market directly and to provide backup liquidity for money market mutual funds. The Federal Reserve together with Treasury has expanded a facility to lend against AAA-rated asset-backed securities collateralized by student loans, auto loans, credit card loans, and business loans guaranteed by the Small Business Administration (SBA). The Federal Reserve has also bought longer-term securities for its portfolio.

Chart 2-4. The Lag between the Turnaround in Real GDP and the Turning Point for Payroll Employment and the Unemployment Rate

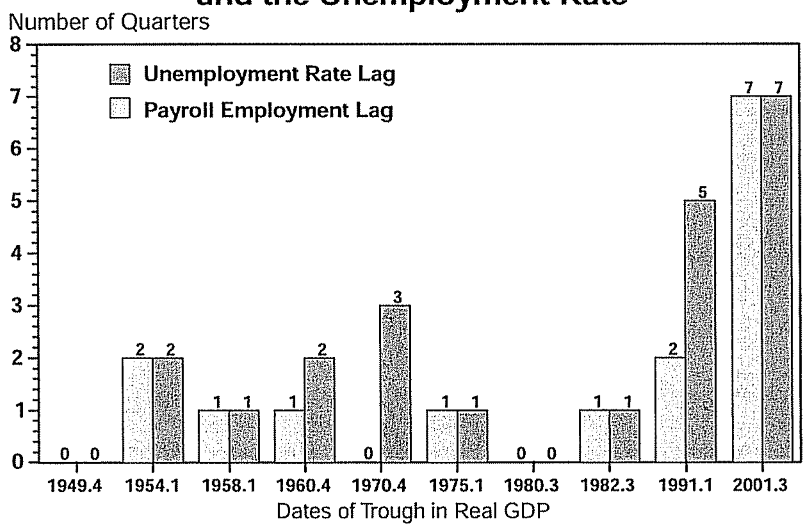


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Table 2–1. ECONOMIC ASSUMPTIONS[1]
(Calendar years; dollar amounts in billions)

	2008 Actual	2009	Projections 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gross Domestic Product (GDP):													
Levels, dollar amounts in billions:													
Current dollars	14,441	14,252	14,768	15,514	16,444	17,433	18,446	19,433	20,408	21,373	22,329	23,312	24,323
Real, chained (2005) dollars	13,312	12,973	13,317	13,823	14,416	15,027	15,633	16,194	16,714	17,190	17,643	18,091	18,543
Chained price index (2005 = 100), annual average	108.5	109.8	110.8	112.2	114.0	116.0	117.9	120.0	122.0	124.3	126.5	128.8	131.1
Percent change, fourth quarter over fourth quarter:													
Current dollars	0.1	0.4	4.0	5.7	6.1	6.0	5.7	5.2	5.0	4.5	4.5	4.4	4.3
Real, chained (2005) dollars	–1.9	–0.5	3.0	4.3	4.3	4.2	3.9	3.4	3.1	2.7	2.6	2.5	2.5
Chained price index (2005 = 100)	1.9	0.9	1.0	1.4	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
Percent change, year over year:													
Current dollars	2.6	–1.3	3.6	5.1	6.0	6.0	5.8	5.3	5.0	4.7	4.5	4.4	4.3
Real, chained (2005) dollars	0.4	–2.5	2.7	3.8	4.3	4.2	4.0	3.6	3.2	2.8	2.6	2.5	2.5
Chained price index (2005 = 100)	2.1	1.2	0.9	1.2	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
Incomes, billions of current dollars:													
Corporate profits before tax	1,463	1,418	1,816	1,933	1,918	1,915	1,924	1,998	2,031	2,058	2,076	2,087	2,150
Employee Compensation	8,037	7,762	8,040	8,499	9,041	9,626	10,247	10,855	11,447	12,024	12,612	13,197	13,792
Wages and salaries	6,546	6,259	6,468	6,825	7,293	7,776	8,288	8,783	9,263	9,733	10,198	10,667	11,134
Other taxable income[2]	3,311	3,081	3,204	3,327	3,591	3,830	4,049	4,218	4,434	4,662	4,857	5,073	5,305
Consumer Price Index (all urban):[3]													
Level (1982–84 = 100), annual average	215.2	214.5	218.7	222.0	226.3	230.8	235.5	240.2	245.1	250.3	255.5	260.9	266.4
Percent change, fourth quarter over fourth quarter	1.5	1.4	1.3	1.7	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1
Percent change, year over year	3.8	–0.3	1.9	1.5	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1
Unemployment rate, civilian, percent:													
Fourth quarter level	6.9	10.3	9.8	8.9	7.9	7.0	6.2	5.7	5.4	5.3	5.2	5.2	5.2
Annual average	5.8	9.3	10.0	9.2	8.2	7.3	6.5	5.9	5.5	5.3	5.2	5.2	5.2
Federal pay raises, January, percent:													
Military[4]	3.5	3.9	3.4	1.4	NA	NA	NA	NA	NA	NA	NA	NA	NA
Civilian[5]	3.5	3.9	2.0	1.4	NA	NA	NA	NA	NA	NA	NA	NA	NA
Interest rates, percent:													
91-day Treasury bills[6]	1.4	0.2	0.4	1.6	3.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1
10-year Treasury notes	3.7	3.3	3.9	4.5	5.0	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3

NA = Not Available
[1] Based on information available as of mid-November 2009.
[2] Rent, interest, dividend, and proprietors' income components of personal income.
[3] Seasonally adjusted CPI for all urban consumers.
[4] Percentages apply to basic pay only; percentages to be proposed for years after 2011 have not yet been determined.
[5] Overall average increase, including locality pay adjustments. Percentages to be proposed for years after 2011 have not yet been determined.
[6] Average rate, secondary market (bank discount basis).

The Federal Reserve's actions helped ease the credit crisis as evidenced by a decline in the interest rate spread between U.S. Treasuries and other securities. The expanded credit facilities have also caused a large increase in the Federal Reserve's balance sheet. Federal Reserve assets have increased from under $1 trillion to over $2 trillion. Because much of the increase in Federal Reserve liabilities has gone into idle reserves of banks, and because of the considerable slack in the economy, current inflation risks are low. The Federal Reserve is prepared to reduce the assets on its balance sheet promptly as the economy recovers from the current recession and the crisis in the financial sector eases. Indeed, continued improvements in financial market conditions have been accompanied by further declines in credit extended through many of the Federal Reserve's liquidity programs.

Financial Stabilization Policies.—Over the course of the last 12 months, the U.S. financial system has been pulled back from the brink of a catastrophic collapse. The very real danger that the system would disintegrate in a cascade of failing institutions and collapsing asset prices has been averted. The Administration's Financial Stability Plan played a key role in cleaning up and strengthening the nation's banking system. This plan began with a forward-looking capital assessment exercise for the 19 U.S. banking institutions with assets in excess of $100 billion. This was the so-called "stress test" aimed at determining whether these institutions had sufficient capital to withstand stressful deterioration in economic conditions. The resulting transparency and resolution of uncertainty regarding banks' potential losses boosted confidence and allowed banks to raise substantial funds in private markets and repay tens of billions of dollars in taxpayer investments.

The second component of the Financial Stability Plan was aimed at establishing a market for the troubled real-estate assets that were at the center of the crisis. The plan included provisions for the Federal Government to join private investors in buying mortgage-backed securities. Removing these assets from the banks' balance sheets is a key step to restoring the financial system to normal functioning.

The Financial Stability Plan also aimed to unfreeze secondary markets for loans to consumers and businesses. The Administration has undertaken the Making Home Affordable plan to help distressed homeowners, encourage access to home financing credit and avoid foreclosures and stabilize neighborhoods. The Home Affordable Modification Program has over 850 thousand mortgage modifications underway. In 2009 millions of American took advantage of low interest rates to refinance their mortgages at lower interest rates. The Administration has launched several initiatives through the SBA to increase loans from small and community banks to small businesses, and it is continuing a joint Treasury-Federal Reserve program that expands credit to small businesses and consumers by lending against securities backed by business and consumer loans.

Economic Projections

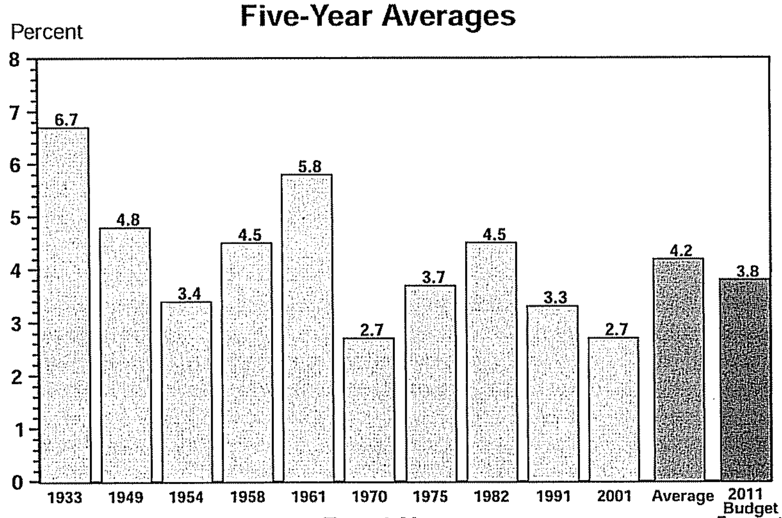
The economic projections underlying the 2011 Budget estimates are summarized in Table 2–1. The assumptions are based on information available as of mid-November 2009. This section discusses the Administration's projections and the next section compares the projections with those of the Blue Chip Consensus of outside forecasters.

Real GDP.—The Administration projects the economic recovery that began in the second half of 2009 will continue in 2010 with real GDP growing at an annual rate of 3.0 percent (fourth quarter over fourth quarter). In 2011-2013, growth is projected to increase to around 4-1/4 percent annually as underutilized economic capacity returns to productive uses.

As shown in Chart 2–5, the Administration's projections for real GDP growth over the next five years imply a recovery that is a bit below the historical average. It is true that recent recoveries have been somewhat weaker, but the last two expansions were preceded by relatively mild recessions, which left less pent-up demand when conditions improved. Because of the depth of the recent recession, there is much more room for a rebound in spending and production than was true either in 1991 or 2001. On the other hand, continued weakness in the financial sector may limit the pace of the recovery. Thus, on net, the Administration is forecasting a recovery over the next five years that is slightly below historical averages.

Longer-Term Growth.—The Administration forecast does not attempt to project cyclical developments beyond the next few years. The long-run projection for real economic growth and unemployment assumes that they will maintain trend values in the years following the return to full employment. In the nonfarm business sector, produc-

Chart 2-5. Real GDP Growth Following a Recession: Five-Year Averages



tivity growth is assumed to grow at 2.3 percent per year, while nonfarm labor supply grows at a rate of around 0.7 percent per year, so nonfarm business output grows approximately 3.0 percent per year. Real GDP growth, reflecting the slower measured growth in activity outside the nonfarm business sector, proceeds at a rate of 2.5 percent. That is markedly slower than the average growth rate of real GDP since 1947—3.3 percent per year. In the 21st Century, real GDP growth in the United States is likely to be permanently slower than it was in earlier eras because of the slowdown in labor force growth that is expected beginning with the retirement of the post-World War II "baby boom" generation.

Unemployment.—Although production began to increase last summer, the unemployment rate remains highly elevated. In October, the overall unemployment rate rose above 10.0 percent for the first time since 1983, and it was at 10.0 percent in both November and December. The broadest measure of underutilized labor published by the Bureau of Labor Statistics—the U-6 measure which includes discouraged workers and those working part-time for economic reasons—reached 17.4 percent in October, and was at 17.3 percent in December. The overall unemployment rate is projected to begin to decline slightly over the course of 2010, although it may increase slightly before finally turning around. Because growth in 2010 is projected to be relatively slow for the early stages of a recovery, unemployment is projected to remain high for a prolonged period. The unemployment rate is projected to decline to 7.0 percent by the end of 2013.

Inflation.—Inflation declined in 2009. Over the four quarters ending in 2009:3, the price index for GDP rose only 0.6 percent compared with an increase of 2.5 percent over the previous four quarters. The Consumer Price Index for all urban consumers (CPI-U) has been more volatile. For the 12 months ending in July the overall CPI-U fell by 1.9 percent. Over the previous 12 months it had increased by 5.4 percent. Since July the CPI has risen at an annual rate of 3.9 percent. Most of these swings have been due to sharp movements in food and energy prices over the last two years. The so-called "core" CPI, excluding both food and energy, was up 1.6 percent through the 12 months ending in July compared with 2.5 percent during the previous 12 months. While the rate of inflation in the overall CPI has increased since July, the core inflation rate has averaged only 1.4 percent. The weak demand resulting from the recession has held down prices increases for a wide range of goods and services. Continued high unemployment is expected to preserve a low inflation rate for the next several years. Eventually, as the economy recovers and the unemployment rate declines, the rate of inflation should rise again, returning to rates around 2 percent per year—similar to the rates that existed pre-recession. With the recovery path assumed in the Administration forecast, the risk of outright deflation appears minimal. In the long-run, the Administration assumes that the rate of change in the CPI will average 2.1 percent and that the GDP price index will increase at a 1.8 percent annual rate.

Interest Rates.—Interest rates on Treasury securities fell sharply in late 2008, as both short-term and long-term rates declined to their lowest levels in decades. In 2009, short-term Treasury rates remained near zero, and the monthly average 10-year yield fluctuated within a range of 2-1/2 percent to 3-3/4 percent. Investors have sought the security of Treasury debt during the heightened financial uncertainty of the last few years, which has reduced yields. In the Administration projections, interest rates are expected to rise as financial concerns are alleviated and the economy recovers from recession. The 91-day Treasury bill rate is projected to reach 4.1 percent and the 10-year rate 5.3 percent by 2013. These forecast rates are historically low, reflecting lower inflation in the forecast than for most of the post-World War II period. After adjusting for inflation, the projected real interest rates are close to their historical averages.

Income Shares.—The share of labor compensation in GDP was extremely low by historical standards in 2009. It is expected to rise over the forecast period to more normal levels. As a share of GDP, employee compensation was 54.5 percent in 2009 and it is expected to rise over the course of the 10-year forecast. In the expansion that ended in 2007, labor compensation tended to lag behind the growth in productivity, and that has also been true for the recent surge in productivity growth.

While the overall share of labor compensation is expected to increase, the share of taxable wages is expected to remain roughly flat. Rising health insurance costs are projected to put upward pressure on the share of fringe benefits. The Administration economic projections do not account for the effects of health reform on compensation shares.

The share of corporate profits before taxes was 13.9 percent of GDP in the third quarter of 2006 prior to the recession, which was near an all-time high. Since then profits before tax have dropped sharply. They are expected to be only 9.9 percent of GDP in 2009. As the economy recovers, the profit share is projected to rebound. In the forecast, the ratio of pretax profits to GDP reaches 12.5 percent in 2011 and then falls to around 9 percent by the end of the 10-year projection period as the share of employee compensation slowly recovers to approach its long-run historical average.

Comparison with Private-Sector Forecasts

Table 2–2 compares the economic assumptions for the 2011 Budget with projections by the Blue Chip Consensus, an average of about 50 private-sector economic forecasts. These other economic projections differ in some respects from the Administration's projections, but the forecast differences are relatively small over the next two years, especially when compared with the margin of error in all economic forecasts. Like the Administration, the private forecasters believe that real GDP growth resumed in mid-2009 and that the economy will continue to recover showing positive growth in 2010 and 2011. They also agree that inflation will be at a low rate in 2010-2011, while outright deflation is avoided, and that after peaking at a relatively high level, the unemployment rate gradually declines and interest rates rise.

There are some conceptual differences between the Administration forecast and the private economic forecasts. The Administration forecast assumes that the President's Budget proposals will be enacted. The 50 or so private forecasters in the Blue Chip Consensus make differing policy assumptions, but none would necessarily assume that the Budget is adopted in full. In addition, the forecasts were not made at the same time. The Administration forecast was completed in mid-November. The almost three-month lag between the forecast date and Budget release occurs because the budget process requires agencies to receive the forecast's assumptions in time to use them in making the budget estimates for agency programs that are incorporated in the Budget. Forecasts made at different dates will differ if there is economic news between the two dates that alters the economic outlook. The Blue Chip consensus displayed in this table was the latest available at the time the Budget went to print—and was completed in early January, about six weeks after the Administration forecast was finalized.

Real GDP Growth.—The Administration's real GDP projections are very similar to those of the Blue Chip consensus in 2010 while exceeding the consensus view in 2011. In its August 2009 projections (the most recent available) the Congressional Budget Office (CBO) projected long-run growth of 2.2 percent per year. Most of the difference between the Administration and CBO's long-run growth comes from a difference in the expected rate of growth of the labor force. Both forecasts assume that the labor force will grow more slowly than in the past because of population aging, but the Administration bases its population projections on the Census Bureau's projections, which tend to run higher than the CBO projections. The Administration also believes that labor force participation could be somewhat stronger in the future. The net difference in the two forecasts is only a few tenths of a percentage point.

All economic forecasts are subject to error, and the forecast errors are usually much larger than the forecast differences discussed above. As discussed in chapter 3, past forecast errors among the Administration, CBO, and the Blue Chip have been similar.

Unemployment, Inflation, and Interest Rates.—The Administration forecast has an unemployment rate of 10.0 percent in 2010 and 9.2 percent in 2011. The January Blue Chip consensus is identical to the Administration forecast in both years. Both the Administration and the Blue Chip consensus anticipate a moderate rate of inflation over the next two years. The forecasts are also similar in their projections for the path of interest rates.

Table 2–2. COMPARISON OF ECONOMIC ASSUMPTIONS
(Calendar years)

	2009	2010	2011
Nominal GDP (in billions of dollars):			
2011 Budget	14,252	14,768	15,514
Blue Chip	14,254	14,827	15,530
Real GDP (year-over-year):			
2011 Budget	–2.5	2.7	3.8
Blue Chip	–2.5	2.8	3.1
Real GDP (fourth-quarter-over-fourth-quarter):			
2011 Budget	–0.5	3.0	4.3
Blue Chip	–0.3	2.9	3.2
GDP Price Index:[1]			
2011 Budget	1.2	0.9	1.2
Blue Chip	1.2	1.2	1.6
Consumer Price Index (CPI-U):[1]			
2011 Budget	–0.3	1.9	1.5
Blue Chip	–0.3	2.1	2.0
Unemployment Rate:[2]			
2011 Budget	9.3	10.0	9.2
Blue Chip	9.2	10.0	9.2
Interest Rates:[2]			
91-Day Treasury Bills (discount basis):			
2011 Budget	0.2	0.4	1.6
Blue Chip	0.2	0.4	1.8
10-Year Treasury Notes:			
2011 Budget	3.3	3.9	4.5
Blue Chip	3.3	3.9	4.6

Sources: Administration, January 2010 Blue Chip Economic Indicators, Aspen Publishers, Inc.
[1] Year-over-year percent change.
[2] Annual averages, percent.

Short-term rates are expected to be near zero in 2009, but then to increase in 2010 and 2011. The interest rate on 10-year Treasury notes is projected to rise from 3.3 percent to about 4-1/2 percent in 2011 in both forecasts.

Changes in Economic Assumptions

Although some of the economic assumptions underlying this Budget have changed compared with those used for the 2010 Budget, most of the forecast values are similar, especially in the long run (see Table 2–3). The previous Budget did not fully anticipate the severity of the 2008-2009 recession, especially in the labor market. Consequently, the unemployment rate projected for 2009-2010 turned out to be too low. So far the forecast of 2009 real GDP growth appears to have been closer to the mark. The economic recovery projected for 2010 has been reduced slightly in view of the relatively modest start to the recovery so far in 2009. Finally, the long-run growth trend was pegged at 2.6 percent per year in the previous Budget and that has been reduced slightly to 2.5 percent per year in the current Budget in view of continuing revisions to the historical data that suggest a slower rate of trend productivity growth.

Table 2–3. COMPARISON OF ECONOMIC ASSUMPTIONS IN THE 2010 AND 2011 BUDGETS
(Calendar years; dollar amounts in billions)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Nominal GDP:											
2010 Budget Assumptions[1]	14,374	14,989	15,820	16,828	17,842	18,695	19,528	20,397	21,304	22,252	23,242
2011 Budget Assumptions	14,252	14,768	15,514	16,444	17,433	18,446	19,433	20,408	21,373	22,329	23,312
Real GDP (2005 dollars):											
2010 Budget Assumptions[1]	13,060	13,474	14,017	14,658	15,266	15,714	16,123	16,543	16,974	17,415	17,868
2011 Budget Assumptions	12,973	13,317	13,823	14,416	15,027	15,633	16,194	16,714	17,190	17,643	18,091
Real GDP (percent change):[2]											
2010 Budget Assumptions[1]	–1.9	3.2	4.0	4.6	4.2	2.9	2.6	2.6	2.6	2.6	2.6
2011 Budget Assumptions	–2.5	2.7	3.8	4.3	4.2	4.0	3.6	3.2	2.8	2.6	2.5
GDP Price Index (percent change):[2]											
2010 Budget Assumptions[1]	1.3	1.1	1.5	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
2011 Budget Assumptions	1.2	0.9	1.2	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8
Consumer Price Index (all-urban; percent change):[2]											
2010 Budget Assumptions[1]	–0.6	1.6	1.8	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1
2011 Budget Assumptions	–0.3	1.9	1.5	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1
Civilian Unemployment Rate (percent):[3]											
2010 Budget Assumptions[1]	8.1	7.9	7.1	6.0	5.2	5.0	5.0	5.0	5.0	5.0	5.0
2011 Budget Assumptions	9.3	10.0	9.2	8.2	7.3	6.5	5.9	5.5	5.3	5.2	5.2
91-day Treasury bill rate (percent):[3]											
2010 Budget Assumptions[1]	0.2	1.6	3.4	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0
2011 Budget Assumptions	0.2	0.4	1.6	3.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1
10-year Treasury note rate (percent):[3]											
2010 Budget Assumptions[1]	2.8	4.0	4.8	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2011 Budget Assumptions	3.3	3.9	4.5	5.0	5.2	5.3	5.3	5.3	5.3	5.3	5.3

[1] Adjusted for July 2009 comprehensive NIPA revisions.
[2] Year-over-year.
[3] Calendar year average.

5. LONG TERM BUDGET OUTLOOK

The horizon for most numbers in this budget is 10 years. In particular, the account-level estimates in the 2011 Budget extend to 2020. This 10-year horizon reflects a balance between the importance of considering both the current and future implications of budget decisions made today and a practical limit on the construction of detailed budget projections for years in the future.

Nonetheless, many decisions made today will have important repercussions beyond the 10-year horizon, and it is important to anticipate what future budgetary requirements beyond the 10-year horizon might flow from current laws and policies despite the uncertainty surrounding the assumptions needed for such estimates. Long-run budget projections can be useful in drawing attention to potential problems. Imbalances that may be manageable in the 10-year time frame can become unmanageable if allowed to grow.

To this end, the budget projections in this chapter extend the policies proposed in the 2011 Budget for 75 years. Because of the uncertainties involved in making long-run projections, results are presented for a base case and for several alternative scenarios.

Although the Budget offers major initiatives in many areas, the Administration recognizes that not all of the policy initiatives needed to stabilize the country's long-run fiscal situation have been formulated. The projections in this chapter reflect the fact that until these reforms are enacted, simply extending current laws and policies leaves the budget in an unsustainable position. Reforms are needed to make sure that programs like Medicare Part A and Social Security, which are expected to be financed from dedicated revenue sources, remain self-sustaining, and that overall budgetary resources are large enough to support future spending. One of the reasons why the Administration made health care reform a first-year priority is that there is no way to achieve long-run fiscal sustainability without slowing the growth rate of health expenditures. The Administration intends to work with Congress to develop additional policies that will prevent the outcomes shown in many of the charts below from occurring.

The key drivers of the long-range deficit are the Government's major health and retirement programs: Medicare, Medicaid and Social Security.

- Medicare finances health insurance for most of the Nation's seniors and many individuals with disabilities. Medicare's growth has exceeded that of other Federal spending for decades tracking the rapid growth in overall health care costs.
- Medicaid provides medical assistance, including acute and long-term care, to low-income persons including families with dependent children as well as aged, blind or disabled individuals. It has grown more rapidly than the economy for several decades.
- Social Security provides retirement benefits, disability benefits, and survivors' insurance for the Nation's workers. Outlays for Social Security benefits will begin to exceed its dedicated revenue stream over the next quarter century putting pressure on the overall budget.

Long-range projections for Social Security and Medicare have been prepared for decades, and the actuaries at the Centers for Medicare and Medicaid Services plan to produce such projections for Medicaid in the near future. Budget projections for individual programs, however, even important ones such as Medicare and Social Security, cannot reveal the Government's overall budgetary position, which is why the projections in this chapter offer a useful complement to the long-run projections for the individual programs.

Future budget outcomes depend on a host of unknowns—changing economic conditions, unforeseen international developments, unexpected demographic shifts, the unpredictable forces of technological advance, and evolving political preferences to name a few. These uncertainties make even short-run budget forecasting quite difficult, and the uncertainties increase the further into the future projections are extended. While uncertainty makes forecast accuracy difficult to achieve, it does not detract from the importance of long-run budget projections, because future problems are often best addressed in the present. A full treatment of all the relevant risks is beyond the scope of this chapter, but the chapter does show how long-run budget projections respond to changes in some of key economic and demographic assumptions.

An Unsustainable Path

The deficit is projected to fall from its recent peak levels as the economy recovers from the recession and the worldwide financial crisis eases. By the end of the 10-year budget window, the deficit has returned to a lower level, and the debt held by the public is no longer rising rapidly relative to GDP. However, the fiscal position is not sustainable in the long run without further policy changes.

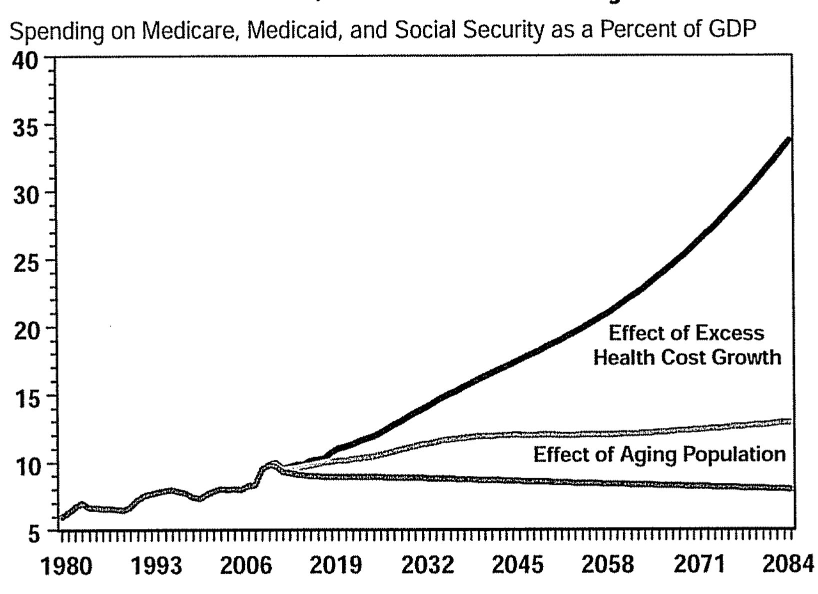
Beyond the 10-year budget window, increasing health costs and population aging will place the budget on an unsustainable course unless policy changes are made to address these challenges. Medicare and Medicaid have grown faster than the economy for decades, and if they continue to do so their growth will exert tremendous pressures on the budget. Additionally, the first members of the huge generation born after World War II, the so-called baby boomers, reached age 62 in 2008 and became eligible for Social Security retirement benefits. In 2011, they will turn 65 and become eligible for Medicare. In the years that follow, the elderly population will steadily increase, putting serious strains on the budget.

Sources of Increased Spending for Medicare, Medicaid, and Social Security.—The most important single factor driving the long-run budget outlook is the growth of health care expenditures. For decades, health care spending has outpaced the growth in total output (detailed national health expenditure data extend back to 1960). This excess cost growth must eventually be addressed if the budget is to reach a sustainable long-run position. The Administration's approach to health care reform has focused on bringing these costs under control. In the long-run projections in this chapter, different assumptions about the growth rate of health care costs are made. In the base case, a continuation of the historical trend would see the per beneficiary cost of health care spending for Medicare, Medicaid, and private health care rising 2 percent per year faster than GDP per capita.

The alternatives assume that the historical trend of rising costs is reduced. The health care legislation being considered in Congress is designed to be deficit neutral (or better) over the next 10 years based on hard, scoreable savings and to slow the growth rate of health care spending over the longer term. There are three broad reforms in the legislation under consideration in Congress that experts believe will produce significant savings relative to the historical trend: an excise tax on the highest-cost insurance plans will encourage substitution of more efficient plans with lower costs, while raising take-home pay; an independent payment advisory board will be empowered to suggest changes in Medicare and the health care system to improve the quality and value of its services; and an array of other delivery system reforms will gradually reduce costs. With 10-year deficit neutrality and the other three components in place, it is reasonable to expect a break in the trend of future health care costs, but the baseline does not include these savings because the final form of the legislation was not resolved in time for the Administration to produce detailed estimates of its long-run effects.

Of the many possible alternative projections, two are chosen here for examination. The first alternative is consistent with the projections made by the Medicare actuaries in the 2009 Trustees' Report, which assumes that health care costs will gradually stabilize as a share of GDP over the next 75 years. The actuaries base this conclusion on a stylized model that makes assumptions about (i) continuing improvements in medical technology, (ii) the extent to which new technology raises or lowers health care costs, and (iii) society's preferences for health care compared with other goods and services. It is more likely this stabilization will occur with the passage of health reform. In the actuaries' projections, health care costs grow rapidly over the next 25 years, as excess cost growth is assumed to be 1.4 percent per year in 2033. By 2083, it has slowed to less than 0.2 percent per year. The average excess cost growth over the entire 75-year projection period is 1 percent per year. The second alternative assumes more savings will be generated by health reform. More effective cost discipline over the long run could lower excess cost growth on average to 0.5 percent per year, a reduction of 1-1/2 percentage points compared with the historical trend. This still allows for some increase in medical costs relative to GDP, which seems likely given the value people place on good health and increased lifespans, but with such a large reduction in the trend, the problems connected with rising costs would become much more manageable.

Chart 5-1. Sources of Projected Growth in Medicare, Medicaid, and Social Security



Population aging also poses a serious long-run budgetary challenge. Because of lower expected fertility and improved longevity, the Social Security actuaries project that the ratio of workers to Social Security beneficiaries will fall from around 3.3 currently to a little over 2 by the time most of the baby boomers have retired. From that point forward, the ratio of workers to beneficiaries is expected to continue to decline slowly. With fewer workers to pay the taxes needed to support the retired population, budgetary pressures will steadily mount without reforms.

Chart 5-1 decomposes the projected growth in Medicare, Medicaid, and Social Security into the portion due to health costs per beneficiary growing faster than GDP per capita and the portion due to population aging. The projections are based on the Budget for the first 10 years and then the historical rate of excess health cost growth for years after 2020. For the next 20 years both increasing numbers of beneficiaries and rapid health cost growth contribute to the increase in the share of GDP devoted to these programs, but after 2030 health cost growth is the primary driver of spending growth.

Long-Run Budget Projections.—In 2009, the three major entitlement programs—Medicare, Medicaid, and Social Security—accounted for 41 percent of non-interest Federal spending, up from 30 percent in 1980. By 2030, when the surviving baby boomers will all be 65 or older, these three programs could account for 60 percent of non-interest Federal spending unless there is a break in the trend of health care costs or other major reforms to the programs. At the end of the projection period, in 2085, the figure could rise to nearly 80 percent of non-interest spending, again assuming current trends were to continue. In other words without reforms, most of the budget, aside from interest, would go to these three programs alone. That would severely reduce the flexibility of the budget, and the Government's ability to respond to new challenges.

The overall budget cannot sustain the projected increase in these major programs indefinitely. The budget projections shown in Table 5–1 illustrate that point. Without further adjustments to spending and revenue in the current decade and changes in entitlement programs in the longer term, the deficit will rise steadily relative to the overall economy during coming decades. These rising deficits would drive publicly held Federal debt as a ratio to GDP to levels well above its previous peak level reached at the end of World War II. Timely reforms, especially those that would lower the trend of health care costs, are needed to avoid such a development. The policies included in current health care legislation are important steps in this direction, though achieving fiscal sustainability will require both effective implementation of these policies and additional policy changes in the future. The Administration aims to work with Congress so that the ratio of debt-to-GDP stabilizes at an acceptable level once the economy has recovered.

Revenues.—Projected revenues in these long-run budget projections start with the estimated receipts under the Administration's proposals in the 2011 Budget. In the absence of further policy changes, the ratio of taxes to GDP is projected to remain roughly constant over most of the period from 2020 to 2085. The tax code is indexed for inflation, but not for increases in real income, so there is a tendency for individual income taxes to increase relative to incomes when real incomes are rising. With rising real incomes, a larger percentage of taxpayers will be in higher tax brackets and this will raise the ratio of taxes to GDP. Offsetting this trend is the decline in taxable wages as a share of overall compensation. Fringe benefits, especially private health insurance, have grown faster than overall compensation for decades, and, unless there are major cost saving reforms to private health insurance, that trend is projected to continue. The result is that the higher average marginal tax rates that result from rising real incomes apply to a declining share of total income.

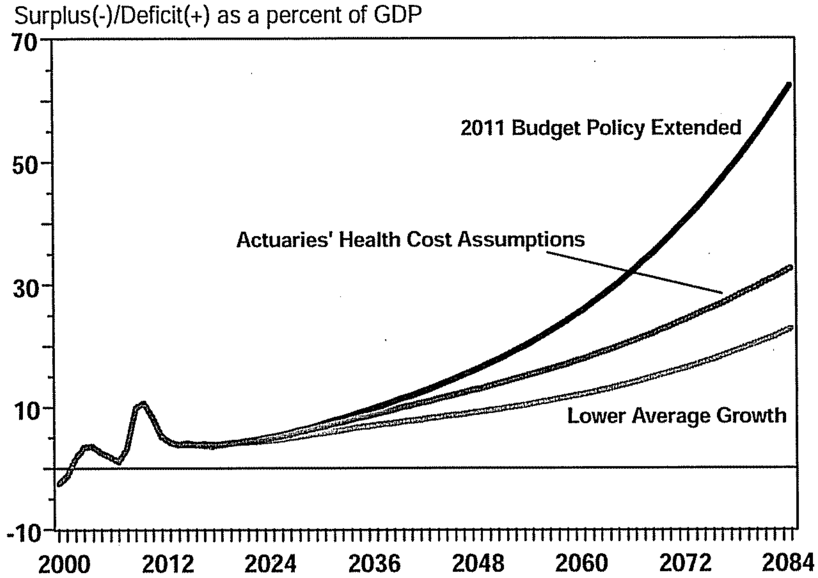
The projections assume that the Alternative Minimum Tax (AMT) will be effectively indexed, so the AMT does not raise the ratio of receipts to GDP. Some Federal tax-

Table 5–1. LONG-RUN BUDGET PROJECTIONS
(Receipts, Outlays, Surplus or Deficit, and Debt as a Percent of GDP)

	1980	1990	2000	2010	2020	2030	2050	2060	2085
Receipts	19.0	18.0	20.6	14.8	19.6	19.8	20.0	19.9	18.7
Outlays:									
Discretionary	10.1	8.7	6.3	9.6	6.2	6.1	6.1	6.1	6.1
Mandatory:									
Social Security	4.3	4.3	4.1	4.9	5.0	5.6	5.4	5.3	5.1
Medicare	1.1	1.7	2.0	3.1	4.0	5.3	9.6	11.9	22.0
Medicaid	0.5	0.7	1.2	1.9	2.0	2.4	3.5	4.1	6.6
Other	3.7	3.2	2.4	4.7	3.1	2.8	2.6	2.6	3.1
Subtotal, mandatory	9.6	9.9	9.7	14.5	14.1	16.1	21.1	24.0	36.9
Net Interest	1.9	3.2	2.3	1.3	3.5	4.5	10.0	14.8	38.0
Total outlays	21.7	21.9	18.2	25.4	23.7	26.8	37.2	44.9	81.0
Surplus or Deficit (–)	–2.7	–3.9	2.4	–10.6	–4.2	–6.9	–17.1	–25.0	–62.3
Primary Surplus or Deficit (–)	–0.8	–0.6	4.7	–9.4	–0.7	–2.4	–7.2	–10.2	–24.3
Federal Debt Held by the Public	26.1	42.1	34.7	63.6	77.2	98.8	218.1	323.7	829.7

Note: The figures shown in this table for 2030 and beyond are the product of a long-range forecasting model maintained by the Office of Management and Budget. This model is separate from the models and capabilities that produce detailed programmatic estimates in the Budget. It was designed to produce long-range forecasts based on additional assumptions regarding growth of the economy, the long-range evolution of specific programs, and the demographic and economic forces affecting those programs. The model, its assumptions, and sensitivity testing of those assumptions are presented in this chapter.

Chart 5-2. Health Care Cost Alternatives



es tend to decline in real terms in the absence of policy changes. For example, many excise taxes are set in nominal terms, so collections decline as a share of GDP when there is inflation. But such taxes are a relatively small fraction of total revenue. Income taxes and payroll taxes account for most of Federal revenue.

Discretionary Outlays.— Because discretionary spending is determined annually through the legislative process, there is no simple natural assumption for projecting its future path. The budget provides a specific path for discretionary spending over the next 10 years. Beyond that time frame, there are several different plausible assumptions for the path of future discretionary spending. One possibility would be to assume that discretionary spending will be held constant in inflation adjusted terms. That would allow discretionary programs to increase with wage costs and other prices, but would not allow the programs to expand with population or real growth in the economy. Extending this assumption over many decades is not realistic. When the population and economy grow, as assumed in these projections, the demand for public services is likely to expand as well. The current base projection, therefore, assumes that discretionary spending keeps pace with the growth in GDP in the long run, so that spending increases in inflation-adjusted terms whenever there is real economic growth. This chapter also shows outcomes under alternative assumptions.

Table 5-1 shows how the budget would evolve without further changes in policy under the base assumptions described above. The key assumption is the continued excess health care cost growth of around 2 percent per year, which dramatically increases the share of the budget devoted to Medicare and Medicaid. Other parts of the budget show much less growth. Social Security benefits rise relative to the economy over the next 25 years, but beyond that point decline slightly as slower wage growth, the result of rapid health care cost growth, reduces future benefit payments. Other mandatory programs do not increase relative to the size of the economy, and discretionary programs are held to a constant share of GDP by assumption. On the revenue side, once tax revenues recover from the economic downturn, there is little change in revenues relative to GDP through 2060, as the forces pushing up taxes are roughly balanced by those limiting their growth. After 2060, the continuing rise in health costs lowers taxable incomes sufficiently to reduce total revenues relative to GDP. With total outlays increasing much more rapidly than taxes, the deficit rises, and publicly held debt greatly exceeds historical levels.

Alternative Policy, Economic, and Technical Assumptions

The quantitative results discussed above are sensitive to changes in underlying policy, economic, and technical assumptions. Some of the most important of these assumptions and their effects on the budget outlook are discussed below. Increasing deficits result for most plausible projections of the long run trends.

Health Spending.—The base projections for Medicare and Medicaid over the next 75 years assume an extension of historical trends in health care spending. On average, Medicare and Medicaid costs per beneficiary have risen about 2 percent faster than GDP per capita since the programs were established in the 1960s. Continuing this trend would push costs steadily higher and is one of the main reasons the long-run projections show an unsustainable fiscal path.

Chart 5-3. Alternative Discretionary Projections

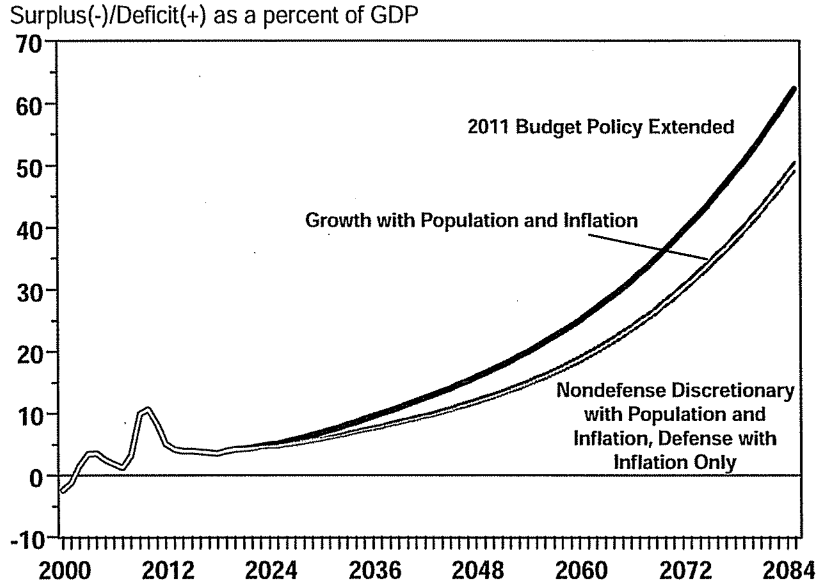


Chart 5-2 shows budget outcomes under the base assumptions and under two other scenarios. In the first, per capita health care costs grow at the rates assumed in the 2009 Medicare Trustees' Report. Specifically, this alternative assumes that the excess growth of health care costs above growth in GDP per capita growth averages about 1 percent per year for the next 75 years, falling from the historical value of over 2.0 percent to 1.4 percent in 2033 and to about 0.2 percent per year in 2083. In the second scenario, excess cost growth is reduced to 0.5 percent per year on average over the next 75 years.

Discretionary Spending.— The current base projection for discretionary spending assumes that after 2020, discretionary spending keeps pace with the growth in GDP (see Chart 5-3). An alternative assumption would be to allow discretionary spending to increase for inflation and population growth only. In this case, discretionary spending would remain constant in inflation adjusted per

Chart 5-4. Alternative Revenue Projections

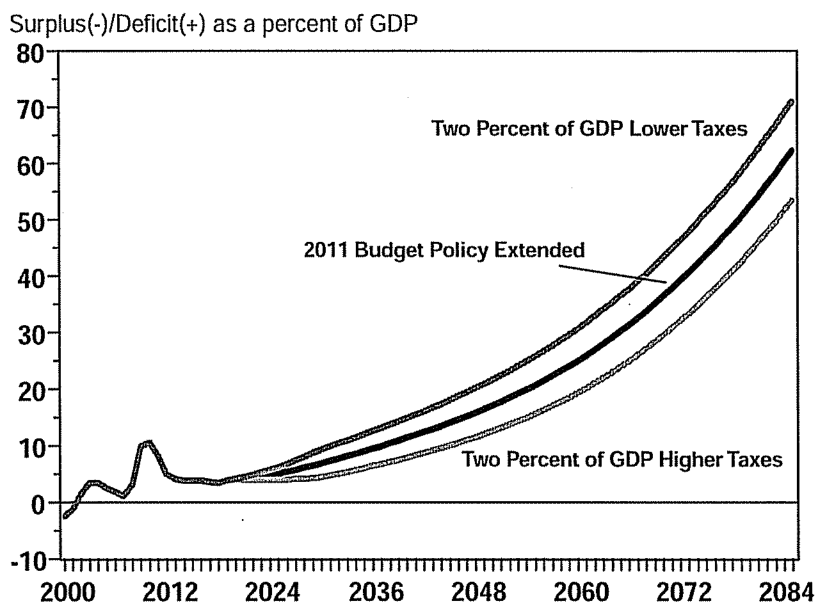
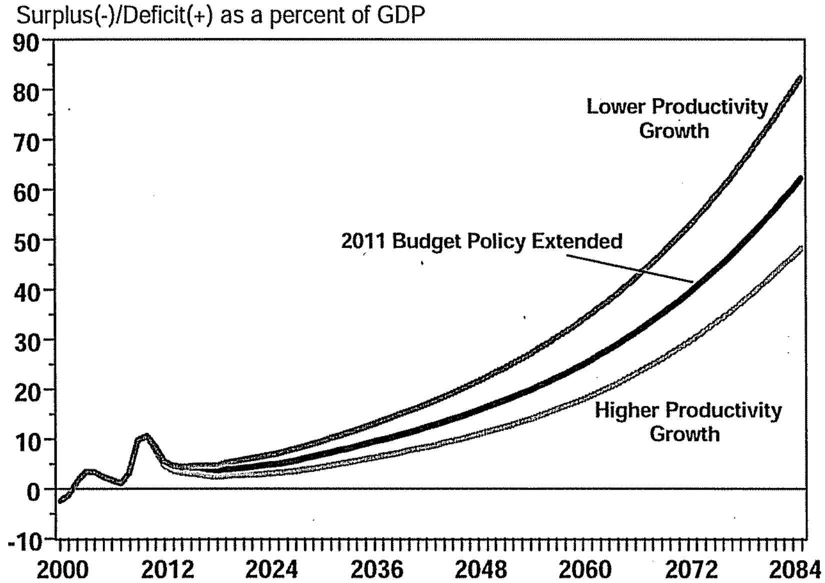


Chart 5-5. Alternative Productivity Assumptions

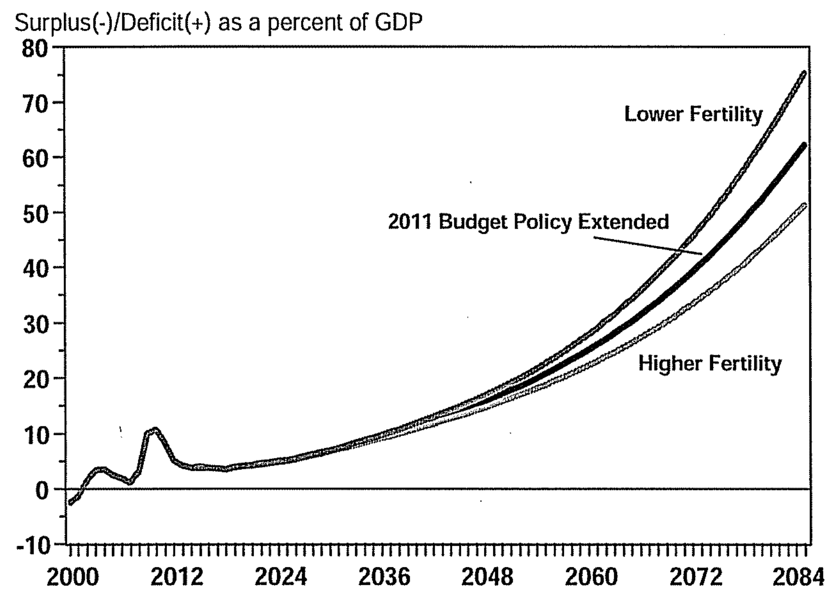


capita terms. Yet another possible assumption is to allow nondefense discretionary spending to grow with inflation plus population, but to increase defense spending only for inflation.

Alternative Revenue Projections.— In the base projection, tax receipts are roughly stable relative to GDP from 2020 through 2060, before declining thereafter. Chart 5-4 shows alternative receipts assumptions. Allowing receipts to rise over time by 2 percentage points of GDP more than in the base case would lower the long-run budget deficit, but not by enough to establish a sustainable path for future policy. Reducing taxes by 2 percentage points of GDP would bring the projected rise in the deficit and the publicly held debt forward in time.

Productivity.—The rate of future productivity growth has a major effect on the long-run budget outlook (see Chart 5-5). It is also highly uncertain. Over the next few decades, an increase in productivity growth

Chart 5-6. Alternative Fertility Assumptions



would reduce projected budget deficits. Higher productivity growth adds directly to the growth of the major tax bases, while it has a smaller immediate effect on outlay growth even assuming that discretionary spending rises with GDP. For much of the last century, output per hour in nonfarm business grew at an average rate of around 2-1/4 percent per year. Growth was not always steady. In the 25 years following 1948, productivity grew at an average rate of 2.7 percent per year, but this was followed by a period of much slower growth. From 1973 to 1995, output per hour in nonfarm business grew at an average annual rate of just 1.4 percent per year. In the latter half of the 1990s, however, the rate of productivity growth increased again and it has remained higher albeit with some fluctuations since then. Indeed, the average growth rate of productivity in nonfarm business has averaged 2.7 percent per year since the fourth quarter of 1995, the same as the average growth rate in the earlier postwar period.

The base projections assume that output per hour in nonfarm business will increase at an average annual rate of around 2.3 percent per year, close to its long-run average and slightly below its average growth since 1995. This implies that real GDP per hour worked will grow at an average annual rate of 2.0 percent per year. The difference is accounted for by the fact that the sectors of the economy that are counted in GDP outside of the nonfarm business sector tend to have lower productivity growth than nonfarm business does. The alternatives highlight the effect of raising and lowering the projected productivity growth rate by 1/2 percentage point.

Population.—The key assumptions for projecting long-run demographic developments are fertility, immigration, and mortality.

- The demographic projections assume that fertility will average about 2.0 total lifetime births per woman in the future, just slightly below the replacement rate needed to maintain a constant population in the absence of immigration—2.1 births per woman (see Chart 5-6). The alternatives are those in the latest Social Security trustees' report (1.7 and 2.3 births per woman).
- The rate of immigration is assumed to average around 1 million immigrants per year in these projections (see Chart 5-7). Higher immigration relieves some of the downward pressure on population growth from low fertility and allows total population to expand throughout the projection period, although at a much slower rate than has prevailed historically. The alternatives are taken from the Social Security Trustees' Report (1.3 million total immigrants per year in the high alternative and 0.8 million in the low alternative).
- Mortality is projected to decline as people live longer in the future (see Chart 5-8). These assumptions parallel those in the latest Social Security Trustees' Report. The average period life expectancy for women is projected to rise from 80.0 years in 2008 to 86.3 years in 2085, and the average period life expectancy for men is expected to increase from 75.4 years in 2007 to 83.1 years in 2085. A technical panel advising the Social Security trustees has reported that the improvement in longevity might be even greater than assumed here. The variations show the high and low alternatives from the latest Trustees' report (average female and male life expectancy reaching 82.7 and 79.1 in the low cost alternative and 89.9 and 87.2 in the high cost alternative).

Chart 5-7. Alternative Immigration Assumptions

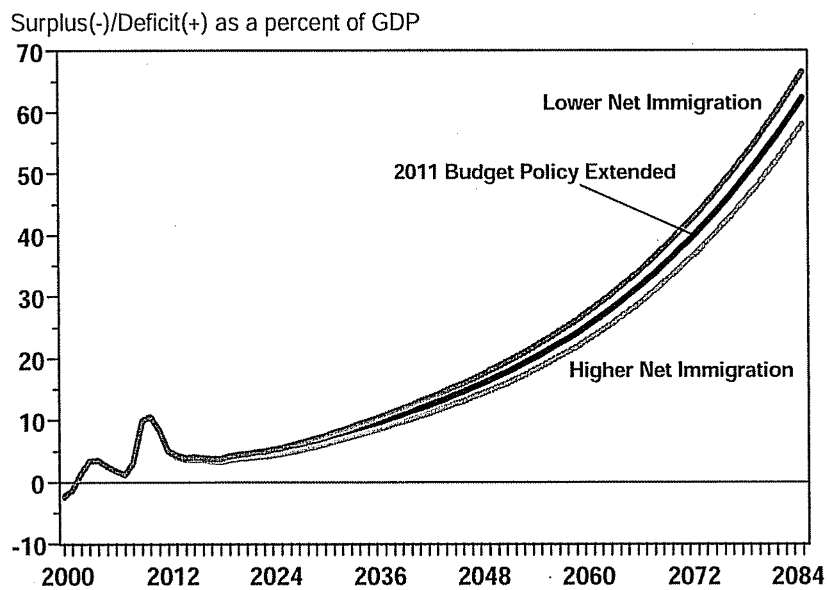
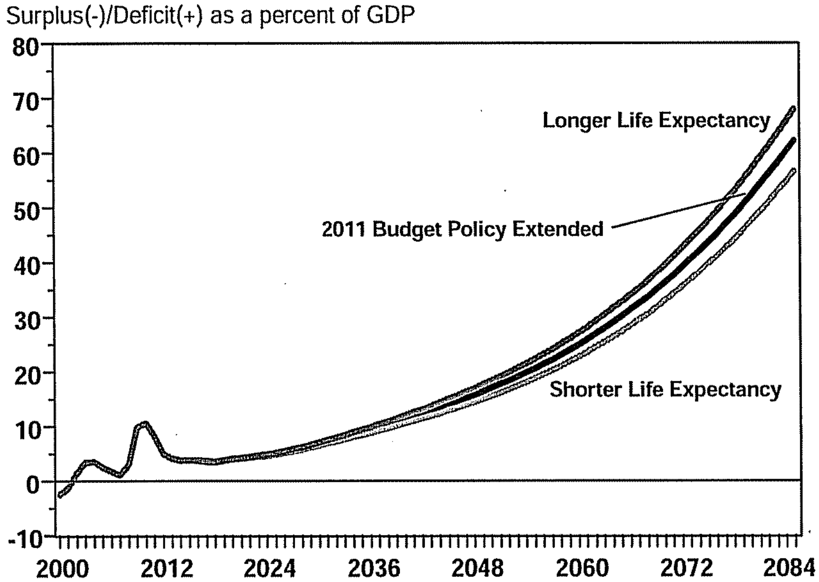


Chart 5-8. Alternative Mortality Assumptions



The long-run budget outlook is highly uncertain. With pessimistic assumptions, the fiscal picture deteriorates even sooner than in the base projection. More optimistic assumptions imply a longer period before the pressures of rising spending overwhelm the budget. But despite the uncertainty, these projections show under a wide range of forecasting assumptions that overall budgetary resources will not be sufficient to support all future projected commitments. These projections highlight the commitments for future policy action to address the main drivers of future budgetary costs, especially health costs.

The Fiscal Gap

The fiscal gap is one measure of the size of the adjustment needed to preserve fiscal sustainability in the long run.[1] It is defined as the increase in taxes or reduction in non-interest expenditures required to keep the long-run ratio of government debt to GDP at its current level if implemented immediately. The gap is usually measured as a percentage of GDP. The fiscal gap is calculated over a finite time period, and therefore it may understate the adjustment needed to achieve longer-run sustainability.

Table 5-2 shows fiscal gap calculations for the base case calculated over a 75-year horizon and for the various alternative scenarios described above. The fiscal gap in the base case is 8.0 percent of GDP, and it ranges in the alternative scenarios from 2.8 percent of GDP to 9.6 percent of GDP. In all cases, significant fiscal adjustments would be needed to achieve long-run sustainability.

[1] Alan J. Auerbach, "The U.S. Fiscal Problem: Where We Are, How We Got Here, and Where We're Going," *NBER: Macroeconomics Annual 1994*, pp 141 – 175.

Table 5–2. FISCAL GAP UNDER ALTERNATIVE BUDGET SCENARIOS
(Percent of GDP)

Baseline	8.0
Health:	
Excess cost growth averages 1 percent	4.5
Excess cost growth averages 1/2 percent	2.8
Discretionary Outlays:	
Grow with inflation plus population	6.2
Defense grows with inflation; nondefense grows with inflation plus population	5.9
Revenues:	
Revenues exceed baseline by 2 percent of GDP	6.4
Revenues fall short of baseline by 2 percent of GDP	9.6
Productivity:	
Productivity grows by 0.5 percent per year faster than the baseline	6.6
Productivity grows by 0.5 percent per year slower than the baseline	9.6
Population:	
Fertility:	
2.3 births per woman	7.1
1.7 births per woman	8.8
Immigration:	
1.3 million immigrants per year	7.5
0.7 million immigrants per year	8.4
Mortality:	
Female life expectancy 82.7 years; male life expectancy 79.1 years in 2085	7.2
Female life expectancy 89.9 years; male life expectancy 87.2 years in 2085	8.8

Table 5–3. INTERMEDIATE ACTUARIAL PROJECTIONS FOR OASDI AND HI

	2010	2020	2030	2050	2085
	(Percent of Payroll)				
Medicare Hospital Insurance (HI)					
Income Rate	3.2	3.3	3.4	3.4	3.5
Cost Rate	3.6	4.4	6.0	8.7	12.2
Annual Balance	–0.4	–1.1	–2.6	–5.3	–8.7
Projection Interval:			25 years	50 years	75 years
Actuarial Deficiency 2008 - 2083			–1.4	–2.8	–3.9
	(Percent of Payroll)				
Old Age Survivors and Disability Insurance (OASDI)					
Income Rate	12.9	13.0	13.2	13.3	13.4
Cost Rate	12.5	14.5	16.8	16.6	17.8
Annual Balance	0.4	–1.5	–3.6	–3.4	–4.4
Projection Interval:			25 years	50 years	75 years
Actuarial Balance			–0.2	–1.5	–2.0

Actuarial Projections for Social Security and Medicare

The Trustees for the Hospital Insurance and Social Security trust funds issue annual reports that include projections of income and outgo for these funds over a 75-year period. These projections are based on different methods and assumptions than the long-run budget projections presented above. Even with these differences, the message is similar: the growth in per capita health care costs and the retirement of the baby-boom generation will exhaust the trust funds unless further remedial action is taken.

The Trustees' reports feature the actuarial balance of the trust funds as a summary measure of their financial status. For each trust fund, the balance is calculated as the change in receipts or program benefits (expressed as a percentage of taxable payroll) that would be needed to preserve a small positive balance in the trust fund at the end of a specified time period. The estimates cover periods ranging in length from 10 to 75 years. These balance calculations show what it would take to achieve a positive trust fund balance at the end of a specified period of time, not what it would take to maintain a positive balance indefinitely. To maintain a positive balance forever requires a larger adjustment than is needed to maintain a positive balance over 75 years when the annual balance in the program is negative at the end of the 75-year projection period as it is expected to be for Social Security and Medicare without future programmatic reforms.

Table 5–3 shows the projected income rate, cost rate, and annual balance for the Medicare Part A and OASDI Trust Funds at selected dates under the Trustees' intermediate assumptions.

For the Medicare HI trust fund, costs as a percentage of Medicare covered payroll are projected to rise from 3.6 percent today to 6.0 percent of projected payroll in 2030 and 12.2 percent of payroll in 2085. Income excluding interest rises only slightly from 3.2 percent of payroll today to 3.5 percent of payroll in 2085. Thus the annual balance moves from a relatively small 0.4 percent of payroll deficit today to 2.6 percent deficit in 2030 and 8.7 percent in 2085. On a 75-year basis, the HI actuarial deficit is 3.9 percent of payroll, roughly twice that of Social Security.

As a result of reforms legislated in 1983, Social Security is currently running a small surplus with income exceeding costs. Over time, as the ratio of workers to retirees falls, costs are projected to rise from 12.5 percent of Social Security covered payroll today to 14.5 percent of payroll in 2020, 16.8 percent of payroll in 2030 and 17.8 percent of payroll in 2085. Revenues excluding interest are projected to rise only slightly from 12.9 percent of payroll today to 13.4 percent in 2085. Thus the annual balance is projected to switch from surplus to deficit, with the deficit rising to 1.5 percent of payroll in 2020, 3.6 percent of payroll in 2030, and 4.4 percent of payroll in 2085. On a 75-year basis, the actuarial deficit is projected to be 2.0 percent of payroll.

TECHNICAL NOTE: SOURCES OF DATA AND METHODS OF ESTIMATING

The long-range budget projections are based on demographic and economic assumptions. A simplified model of the Federal budget, developed at OMB, is used to compute the budgetary implications of these assumptions.

Demographic and Economic Assumptions.—For the years 2010–2020, the assumptions are drawn from the Administration's economic projections used for the 2011 Budget. These budget assumptions reflect the President's policy proposals. The economic assumptions are extended beyond this interval by holding inflation, interest rates, and the unemployment rate constant at the levels assumed in the final year of the budget forecast.

Population growth and labor force growth are extended using the intermediate assumptions from the 2009 Social Security Trustees' report. The projected rate of growth for real GDP is built up from the labor force assumptions and an assumed rate of productivity growth. Productivity growth, measured as real GDP per hour, is assumed to equal its average rate of growth over the next 10 years in the Budget's economic assumptions.

CPI inflation holds stable at 2.1 percent per year; the unemployment rate is constant at 5.2 percent; and the yield on 10-year Treasury notes is steady at 5.3 percent.

Real GDP per hour, grows at the same average rate as in the Administration's 10-year projections—2.0 percent per year.

Consistent with the demographic assumptions in the Trustees' reports, U.S. population growth slows from around 1 percent per year to about two-thirds that rate by 2030, and slower rates of growth beyond that point. By the end of the projection period it is as low as 0.4 percent per year.

Real GDP growth is less than its historical average of around 3.2 percent per year because the slowdown in population growth and the increase in the population over age 65 reduce labor supply growth. In these projections, average real GDP growth declines to around 2.5 percent per year.

The economic and demographic projections described above are set by assumption and do not automatically change in response to changes in the budget outlook. This is unrealistic, but it simplifies comparisons of alternative policies.

Budget Projections: For the period through 2020, receipts follow the 2011 Budget's policy projections. After 2020, income tax receipts are assumed to rise relative to wages and salaries as real income growth pushes more people into higher tax brackets. However, this tendency is largely offset by the projected rise in nontaxed fringe benefits, mainly because health insurance costs are rising faster than wages. Other taxes generally hold close to the averages reached by 2020 in the Budget projections. Discretionary spending follows the policies in the Budget over the next 10 years and grows at the rate of growth in nominal GDP afterwards. Other spending also aligns with the Budget through the budget horizon. Long-run Social Security spending is projected by the Social Security actuaries using this chapter's long-range assumptions. Medicare benefits are projected based on a projection of excess health care cost growth of 2 percent per year, the assumptions for the growth in the beneficiary population from the 2009 Medicare Trustees' report, and the general inflation assumptions described above. Medicaid outlays are based on the economic and demographic projections in the model. Other entitlement programs are projected based on rules of thumb linking program spending to elements of the economic and demographic projections such as the poverty rate.

6. FEDERAL BORROWING AND DEBT

Debt is the largest legally binding obligation of the Federal Government. At the end of 2009, the Government owed $7,545 billion of principal to the individuals and institutions who had loaned it the money to fund past deficits. During that year, the Government paid the public approximately $202 billion of interest on this debt. In addition to the Government's debt obligation, at the end of 2009, the Government held financial assets, net of other liabilities, of $898 billion. Therefore, the Government's debt net of financial assets was $6,647 billion, or 46.7 percent of GDP.

The deficit was $1,413 billion in 2009. This $1,413 billion deficit and other financing transactions totaling $329 billion required the Government to increase its borrowing from the public by $1,742 billion last year. Meanwhile, as-

Table 6–1. TRENDS IN FEDERAL DEBT HELD BY THE PUBLIC
(Dollar amounts in billions)

Fiscal Year	Debt held by the public:		Debt held by the public as a percent of:		Interest on the debt held by the public as a percent of:[3]	
	Current dollars	FY 2009 dollars[1]	GDP	Credit market debt[2]	Total outlays	GDP
1946	241.9	2,261.5	108.7	N/A	7.4	1.8
1950	219.0	1,666.3	80.2	53.3	11.4	1.8
1955	226.6	1,514.9	57.2	43.2	7.6	1.3
1960	236.8	1,405.6	45.6	33.7	8.5	1.5
1965	260.8	1,447.3	37.9	26.9	8.1	1.4
1970	283.2	1,306.9	28.0	20.8	7.9	1.5
1975	394.7	1,340.3	25.3	18.4	7.5	1.6
1980	711.9	1,671.9	26.1	18.5	10.6	2.3
1985	1,507.3	2,698.3	36.4	22.3	16.2	3.7
1990	2,411.6	3,697.3	42.1	22.6	16.2	3.5
1995	3,604.4	4,868.5	49.1	26.7	15.8	3.3
2000	3,409.8	4,240.1	34.7	19.1	13.0	2.4
2001	3,319.6	4,032.7	32.5	17.5	11.6	2.1
2002	3,540.4	4,231.3	33.6	17.5	8.9	1.7
2003	3,913.4	4,581.6	35.6	17.8	7.5	1.5
2004	4,295.5	4,903.1	36.8	18.0	7.3	1.4
2005	4,592.2	5,076.1	36.9	17.6	7.7	1.5
2006	4,829.0	5,161.2	36.5	16.9	8.9	1.8
2007	5,035.1	5,229.5	36.2	16.2	9.2	1.8
2008	5,803.1	5,890.4	40.2	17.6	8.7	1.8
2009	7,544.7	7,544.7	53.0	21.9	5.7	1.4
2010 estimate	9,297.7	9,215.1	63.6	N/A	6.3	1.6
2011 estimate	10,498.3	10,291.4	68.6	N/A	8.0	2.0
2012 estimate	11,472.1	11,073.1	70.8	N/A	10.9	2.5
2013 estimate	12,325.7	11,697.4	71.7	N/A	13.0	3.0
2014 estimate	13,139.3	12,260.2	72.2	N/A	14.2	3.2
2015 estimate	13,988.4	12,833.6	72.9	N/A	14.9	3.4

N/A = Not available.

[1] Debt in current dollars deflated by the GDP chain-type price index with fiscal year 2009 equal to 100.

[2] Total credit market debt owed by domestic nonfinancial sectors, modified in some years to be consistent with budget concepts for the measurement of Federal debt. Financial sectors are omitted to avoid double counting, since financial intermediaries borrow in the credit market primarily in order to finance lending in the credit market. Source: Federal Reserve Board flow of funds accounts. Projections are not available.

[3] Interest on debt held by the public is estimated as the interest on Treasury debt securities less the "interest received by trust funds" (subfunction 901 less subfunctions 902 and 903). The estimate of interest on debt held by the public does not include the comparatively small amount of interest paid on agency debt or the offsets for interest on Treasury debt received by other Government accounts (revolving funds and special funds).

sets net of liabilities rose by $382 billion in 2009. Debt held by the public net of financial assets increased from 36.6 percent of Gross Domestic Product (GDP) at the end of 2008 to 46.7 percent of GDP at the end of 2009. The deficit is estimated to increase to $1,556 billion in 2010, largely as a result of the Government's continued actions to restore economic growth, and then begin to fall. Declining deficits are estimated to significantly reduce growth in debt as a percentage of GDP; debt net of financial assets is projected to reach 61.6 percent of GDP at the end of 2011 and then to grow much more gradually in subsequent years.

Trends in Debt Since World War II

Table 6–1 depicts trends in Federal debt held by the public from World War II to the present and estimates from the present through 2015. (It is supplemented for earlier years by Tables 7.1–7.3 in *Historical Tables*, which is published as a separate volume of the Budget.) Federal debt peaked at 108.7 percent of GDP in 1946, just after the end of the war. From then until the 1970s, Federal debt as a percentage of GDP decreased almost every year because of relatively small deficits, an expanding economy, and inflation. With households borrowing large amounts to buy homes and consumer durables, and with businesses borrowing large amounts to buy plant and equipment, Federal debt also decreased almost every year as a percentage of total credit market debt outstanding. The cumulative effect was impressive. From 1950 to 1975, debt held by the public declined from 80.2 percent of GDP to 25.3 percent, and from 53.3 percent of credit market debt to 18.4 percent. Despite rising interest rates, interest outlays became a smaller share of the budget and were roughly stable as a percentage of GDP.

Federal debt relative to GDP is a function of the Nation's fiscal policy as well as overall economic conditions. During the 1970s, large budget deficits emerged as spending grew and as the economy was disrupted by oil shocks and rising inflation. The nominal amount of Federal debt more than doubled, and Federal debt relative to GDP and credit market debt stopped declining after the middle of the decade. The growth of Federal debt accelerated at the beginning of the 1980s, due in large part to a deep recession, and the ratio of Federal debt to GDP grew sharply. It continued to grow throughout the 1980s as large tax cuts, enacted in 1981, and substantial increases in defense spending were only partially offset by reductions in domestic spending. The resulting deficits increased the debt to almost 50 percent of GDP by 1993. The ratio of Federal debt to credit market debt also rose, though to a lesser extent. Interest outlays on debt held by the public, calculated as a percentage of either total Federal outlays or GDP, increased as well.

The growth of Federal debt held by the public was slowing by the mid-1990s, however, as a growing economy and two major budget agreements enacting spending cuts and revenue increases reduced deficits significantly. The debt declined markedly relative to both GDP and total credit market debt, from 1997 to 2001, as surpluses emerged. Debt fell from 49.3 percent of the GDP in 1993 to 32.5 percent in 2001. Interest as a share of outlays peaked at 16.5 percent in 1989 and then fell to 8.9 percent by 2002; interest as a percentage of GDP fell by a similar proportion.

The impressive progress in reducing the debt burden stopped and then reversed course beginning in 2002. A decline in the stock market, a recession, and the initially slow recovery from that recession all reduced tax receipts. The tax cuts of 2001 and 2003 had a similarly large and longer-lasting effect, as did the growing costs of the wars in Iraq and Afghanistan. Deficits ensued and debt began to rise, both in nominal terms and as a percentage of GDP. There was a small temporary improvement in 2006 and 2007 as economic growth led to a revival of receipt growth.

As a result of the most recent recession, which began in December 2007, and the massive financial and economic challenges it imposed on the Nation, the deficit began increasing rapidly in 2008. The deficit increased more substantially in 2009 as the Government continued to take aggressive steps to restore the health of the Nation's economy and financial markets. This Budget begins the difficult work of restoring fiscal discipline and returning the country to a more sustainable fiscal path. Deficits are projected to continue at an unusually high level in 2010 but then recede thereafter as the improving economy begins to translate into lower outlays and higher receipts. Debt net of financial assets as a percent of GDP is estimated to grow to 55.8 percent at the end of 2010 and 61.6 percent at the end of 2011 and then to grow much more slowly in subsequent years.

Debt Held by the Public and Gross Federal Debt

The Federal Government issues debt securities for two principal purposes. First, it borrows from the public to finance the Federal deficit.[1] Second, it issues debt to Federal Government accounts, primarily trust funds, which accumulate surpluses. By law, trust fund surpluses must generally be invested in Federal securities. The gross Federal debt is defined to consist of both the debt held by the public and the debt held by Government accounts. Nearly all the Federal debt has been issued by the Treasury and is sometimes called "public debt," but a small portion has been issued by other Government agencies and is called "agency debt." [2]

Borrowing from the public, whether by the Treasury or by some other Federal agency, is important because it represents the Federal demand on credit markets. Regardless of whether the proceeds are used for tangible or intangible investments or to finance current consumption, the Federal demand on credit markets has to be financed out of the

[1] For the purposes of the Budget, "debt held by the public" is defined as debt held by investors outside of the Federal Government, both domestic and foreign, including U.S. State and local governments and foreign governments. It also includes debt held by the Federal Reserve.

[2] The term "agency debt" is defined more narrowly in the budget than customarily in the securities market, where it includes not only the debt of the Federal agencies listed in Table 6–4, but also the debt of the Government-Sponsored Enterprises listed in Table 22–9 at the end of Chapter 22 of this volume and certain Government-guaranteed securities.

saving of households and businesses, the State and local sector, or the rest of the world. Federal borrowing thereby competes with the borrowing of other sectors of the economy for financial resources in the credit market. Borrowing from the public thus affects the size and composition of assets held by the private sector and the amount of saving imported from abroad. It also increases the amount of future resources required to pay interest to the public on Federal debt. Borrowing from the public is therefore an important concern of Federal fiscal policy.[3] Borrowing from the public, however, is an incomplete measure of the Federal impact on credit markets. Different types of Federal activities can affect the credit markets in different ways. For example, with the Federal Government's recent extraordinary efforts to stabilize credit markets, the Government has used the borrowed funds to acquire financial assets that would otherwise have required financing in the credit markets directly. (For more information on other ways in which Federal activities impact the credit market, see the discussion at the end of this chapter.)

Issuing debt securities to Government accounts performs an essential function in accounting for the operation of these funds. The balances of debt represent the cumulative surpluses of these funds due to the excess of their tax receipts, interest receipts, and other collections over their spending. The interest on the debt that is credited to these funds accounts for the fact that some earmarked taxes and user charges will be spent at a later time than when the funds receive the monies. The debt securities are assets of those funds but are a liability of the general fund to the fund that holds the securities, and are a mechanism for crediting interest to that fund on its recorded balances. These balances generally provide the fund with authority to draw upon the U.S. Treasury in later years to make future payments on its behalf to the public. Public policy may result in the Government's running surpluses and accumulating debt in trust funds and other Government accounts in anticipation of future spending.

However, issuing debt to Government accounts does not have any of the credit market effects of borrowing from the public. It is an internal transaction of the Government, made between two accounts that are both within the Government itself. Issuing debt to a Government account is not a current transaction of the Government with the public; it is not financed by private saving and does not compete with the private sector for available funds in the credit market. While such issuance provides the account with assets—a binding claim against the Treasury—those assets are fully offset by the increased liability of the Treasury to pay the claims, which will ultimately be covered by taxation or borrowing. Similarly, the current interest earned by the Government account on its Treasury securities does not need to be financed by other resources.

Furthermore, the debt held by Government accounts does not represent the estimated amount of the account's obligations or responsibilities to make future payments to the public. For example, if the account records the transactions of a social insurance program, the debt that it holds does not necessarily represent the actuarial present value of estimated future benefits (or future benefits less taxes) for the current participants in the program; nor does it necessarily represent the actuarial present value of estimated future benefits (or future benefits less taxes) for the current participants plus the estimated future participants over some stated time period. The future transactions of Federal social insurance and employee retirement programs, which own 93 percent of the debt held by Government accounts, are important in their own right and need to be analyzed separately. This can be done through information published in the actuarial and financial reports for these programs.[4]

This Budget uses a variety of information sources to analyze the condition of Social Security and Medicare, the Government's two largest social insurance programs. Chapter 5 of this volume, "Long-Term Budget Outlook," projects Social Security and Medicare outlays to the year 2085 relative to GDP. The excess of future Social Security and Medicare benefits relative to their dedicated income is very different in concept and much larger in size than the amount of Treasury securities that these programs hold.

For all these reasons, debt held by the public and debt net of financial assets are both better gauges of the effect of the budget on the credit markets than gross Federal debt.

Government Deficits or Surpluses and the Change in Debt

Table 6–2 summarizes Federal borrowing and debt from 2009 through 2020. In 2009 the Government borrowed $1,742 billion, increasing the debt held by the public from $5,803 billion at the end of 2008 to $7,545 billion at the end of 2009. The debt held by Government accounts increased $148 billion, and gross Federal debt increased by $1,890 billion to $11,876 billion.

Debt held by the public.—The Federal Government primarily finances deficits by borrowing from the public, and it primarily uses surpluses to repay debt held by the public.[5] Table 6–2 shows the relationship between the

[3] The Federal subsector of the national income and product accounts provides a measure of "net government saving" (based on current expenditures and current receipts) that can be used to analyze the effect of Federal fiscal policy on national saving within the framework of an integrated set of measures of aggregate U.S. economic activity. The Federal subsector and its differences from the budget are discussed in Chapter 28 of this volume, "National Income and Product Accounts."

[4] Extensive actuarial analyses of the Social Security and Medicare programs are published in the annual reports of the boards of trustees of these funds. The actuarial estimates for Social Security, Medicare, and the major Federal employee retirement programs are summarized in the *Financial Report of the United States Government*, prepared annually by the Treasury Department in coordination with the Office of Management and Budget.

[5] Treasury debt held by the public is measured as the sales price plus the amortized discount (or less the amortized premium). At the time of sale, the book value equals the sales price. Subsequently, it equals the sales price plus the amount of the discount that has been amortized up to that time. In equivalent terms, the book value of the debt equals the principal amount due at maturity (par or face value) less the unamortized discount. (For a security sold at a premium, the definition is symmetrical.) For inflation-indexed notes and bonds, the book value includes a periodic adjustment for inflation. Agency debt is generally recorded at par.

Table 6–2. FEDERAL GOVERNMENT FINANCING AND DEBT

(In billions of dollars)

	Actual 2009	Estimate 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Financing:												
Unified budget deficit	1,412.7	1,555.6	1,266.7	828.5	727.3	705.8	751.9	777.7	778.0	785.1	908.4	1,002.9
Other transactions affecting borrowing from the public:												
Changes in financial assets and liabilities:[1]												
Change in Treasury operating cash balance[2]	–96.3	–5.3	–200.0	....	....	....	....	....	....	....	....	....
Net disbursements of credit financing accounts:												
Direct loan accounts	293.5	210.4	142.6	135.1	117.9	108.5	99.2	70.4	84.9	78.8	90.8	91.3
Guaranteed loan accounts	7.5	–6.8	8.1	11.8	11.8	6.0	4.2	3.2	1.2	–2.2	–4.0	–5.6
Troubled Asset Relief Program equity purchase accounts	105.4	0.6	–15.2	–*	–1.9	–4.9	–4.5	–4.8	–9.2	–10.7	–25.9	–15.8
Subtotal, net disbursements	406.4	204.1	135.5	147.0	127.9	109.6	98.9	68.9	76.8	65.9	60.9	69.8
Net purchases of non-Federal securities by the National Railroad Retirement Investment Trust	–2.9	–1.3	–1.0	–0.9	–1.0	–1.0	–1.0	–1.4	–1.1	–1.3	–1.3	–1.2
Net change in other financial assets and liabilities[3]	22.2	....	....	....	....	....	....	....	....	....	....	....
Subtotal, changes in financial assets and liabilities	329.4	197.6	–65.5	146.1	126.9	108.6	97.9	67.4	75.7	64.6	59.6	68.7
Seigniorage on coins	–0.4	–0.2	–0.5	–0.8	–0.7	–0.7	–0.7	–0.7	–0.7	–0.7	–0.7	–0.7
Total, other transactions affecting borrowing from the public	329.0	197.4	–66.0	145.3	126.2	107.9	97.2	66.7	75.0	63.9	59.0	68.0
Total, requirement to borrow from the public (equals change in debt held by the public)	1,741.7	1,752.9	1,200.7	973.8	853.5	813.7	849.0	844.5	853.0	849.0	967.4	1,070.9
Changes in Debt Subject to Statutory Limitation:												
Change in debt held by the public	1,741.7	1,752.9	1,200.7	973.8	853.5	813.7	849.0	844.5	853.0	849.0	967.4	1,070.9
Change in debt held by Government accounts	148.1	157.8	156.7	217.8	264.3	265.1	302.0	309.2	321.3	337.2	285.3	256.4
Less: change in debt not subject to limit and other adjustments	3.5	–1.7	–0.5	1.3	1.3	0.6	0.9	1.2	1.2	1.0	0.7	–0.5
Total, change in debt subject to statutory limitation	1,893.3	1,909.1	1,356.9	1,192.9	1,119.1	1,079.4	1,151.8	1,154.9	1,175.6	1,187.2	1,253.4	1,326.8
Debt Subject to Statutory Limitation, End of Year:												
Debt issued by Treasury	11,850.3	13,760.1	15,116.8	16,308.4	17,426.3	18,504.5	19,655.6	20,809.4	21,984.4	23,171.3	24,424.2	25,751.2
Less: Treasury debt not subject to limitation (–)[4]	–12.9	–13.6	–13.4	–12.1	–10.9	–9.7	–8.9	–7.9	–7.3	–7.0	–6.5	–6.8
Agency debt subject to limitation	*	*	*	*	*	*	*	*	*	*	*	*
Adjustment for discount and premium[5]	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7
Total, debt subject to statutory limitation[6]	11,853.1	13,762.2	15,119.1	16,312.0	17,431.1	18,510.5	19,662.4	20,817.2	21,992.8	23,180.0	24,433.4	25,760.1
Debt Outstanding, End of Year:												
Gross Federal debt:[7]												
Debt issued by Treasury	11,850.3	13,760.1	15,116.8	16,308.4	17,426.3	18,504.5	19,655.6	20,809.4	21,984.4	23,171.3	24,424.2	25,751.2
Debt issued by other agencies	25.5	26.5	27.3	27.2	27.2	27.8	27.7	27.6	26.9	26.2	26.0	26.2
Total, gross Federal debt	11,875.9	13,786.6	15,144.0	16,335.7	17,453.5	18,532.3	19,683.3	20,836.9	22,011.3	23,197.5	24,450.1	25,777.4
Held by:												
Debt held by Government accounts	4,331.1	4,489.0	4,645.7	4,863.6	5,127.8	5,393.0	5,694.9	6,004.1	6,325.5	6,662.7	6,948.0	7,204.3
Debt held by the public[8]	7,544.7	9,297.7	10,498.3	11,472.1	12,325.7	13,139.3	13,988.4	14,832.8	15,685.8	16,534.8	17,502.2	18,573.1

*$50 million or less.

[1]A decrease in the Treasury operating cash balance (which is an asset) is a means of financing a deficit and therefore has a negative sign. An increase in checks outstanding (which is a liability) is also a means of financing a deficit and therefore also has a negative sign.

[2]Includes assumed Supplementary Financing Program balance of $200 billion on September 30, 2010, and zero on September 30, 2011, and beyond.

[3]Besides checks outstanding, includes accrued interest payable on Treasury debt, uninvested deposit fund balances, allocations of special drawing rights, and other liability accounts; and, as an offset, cash and monetary assets (other than the Treasury operating cash balance), other asset accounts, and profit on sale of gold.

[4]Consists primarily of debt issued by or held by the Federal Financing Bank.

[5]Consists mainly of unamortized discount (less premium) on public issues of Treasury notes and bonds (other than zero-coupon bonds) and unrealized discount on Government account series securities.

[6]The statutory debt limit is $12,394 billion, as enacted on December 28, 2009.

[7]Treasury securities held by the public and zero-coupon bonds held by Government accounts are almost all measured at sales price plus amortized discount or less amortized premium. Agency debt securities are almost all measured at face value. Treasury securities in the Government account series are otherwise measured at face value less unrealized discount (if any).

[8]At the end of 2009, the Federal Reserve Banks held $769.2 billion of Federal securities and the rest of the public held $6,775.5 billion. Debt held by the Federal Reserve Banks is not estimated for future years.

Federal deficit or surplus and the change in debt held by the public. The borrowing or debt repayment depends on the Federal Government's expenditure programs and tax laws, on the economic conditions that influence tax receipts and outlays, and on debt management policy. The sensitivity of the budget to economic conditions is analyzed in Chapter 3 of this volume, "Interactions Between the Economy and the Budget."

The total or unified budget surplus consists of two parts: the on-budget surplus or deficit; and the surplus of the off-budget Federal entities, which have been excluded from the budget by law. Under present law, the off-budget Federal entities are the Social Security trust funds (Old-Age and Survivors Insurance and Disability Insurance) and the Postal Service fund. [6] The on-budget and off-budget surpluses or deficits are added together to determine the Government's financing needs.

Over the long run, it is a good approximation to say that "the deficit is financed by borrowing from the public" or "the surplus is used to repay debt held by the public." However, the Government's need to borrow in any given year has always depended on several other factors besides the unified budget surplus or deficit, such as the change in the Treasury operating cash balance. These other factors—"other transactions affecting borrowing from the public"—can either increase or decrease the Government's need to borrow and can vary considerably in size from year to year. As a result of the Government's recent extraordinary efforts to stabilize the Nation's credit markets, these other factors have significantly increased borrowing from the public. The other transactions affecting borrowing from the public are presented in Table 6–2 (an increase in the need to borrow is represented by a positive sign, like the deficit).

In 2009 the deficit was $1,413 billion while these other factors—primarily the net disbursements of credit financing accounts—increased the need to borrow by $329 billion. As a result, the Government borrowed $1,742 billion from the public. The other factors are estimated to increase borrowing by $197 billion in 2010 and reduce borrowing by $66 billion in 2011. In 2012–2020, these other factors are expected to increase borrowing by annual amounts ranging from $59 billion to $145 billion.

Prior to 2008, the effect of these other transactions had been much smaller. In the 20 years between 1988 and 2007, the cumulative deficit was $2,956 billion, the increase in debt held by the public was $3,145 billion, and other factors added a total of $190 billion of borrowing, 6 percent of total borrowing over this period. By contrast, the other factors resulted in more than 40 percent of the total increase in borrowing from the public for 2008 and nearly 20 percent of the increase for 2009.

Three specific factors presented in Table 6–2 are especially important.

Change in Treasury operating cash balance.—The cash balance increased by a record $296 billion in 2008, primarily as a result of Treasury's creation of the Supplementary Financing Program (SFP). Under this temporary program, Treasury issues short-term debt and deposits the cash proceeds with the Federal Reserve for use by the Federal Reserve in its actions to stabilize the financial markets. In 2009, the cash balance decreased by $96 billion, due to a $135 billion reduction in the SFP balance offset by a $38 billion increase in the non-SFP cash balance. In the preceding 10 years, changes in the cash balance had been much smaller, ranging from a decrease of $26 billion in 2003 to an increase of $23 billion in 2007. The operating cash balance is projected to decrease by $5 billion in 2010, to $270 billion, including an assumed SFP balance of $200 billion and a non-SFP balance of $70 billion. In 2011, the operating cash balance is projected to decrease by $200 billion due to an assumed end-of-year SFP balance of zero. Changes in the operating cash balance, while occasionally large, are inherently limited over time. Decreases in cash—a means of financing the Government—are limited by the amount of past accumulations, which themselves required financing when they were built up. Increases are limited because it is generally more efficient to repay debt.

Net financing disbursements of the direct loan and guaranteed loan financing accounts.—Under the Federal Credit Reform Act of 1990 (FCRA), budget outlays for direct loans and loan guarantees consist of the estimated subsidy cost of the loans or guarantees at the time when the direct loans are disbursed or the guaranteed loans are made. The cash flows to and from the public resulting from these loans and guarantees—the disbursement and repayment of loans, the default payments on loan guarantees, the collections of interest and fees, and so forth—are not costs (or offsets to costs) to the Government except for their subsidy costs (the present value of the estimated net losses), which are already included in budget outlays. Therefore, they are non-budgetary in nature and are recorded as transactions of the non-budgetary financing account for each credit program. [7]

The financing accounts also include several types of intragovernmental transactions. In particular, they receive payment from the credit program accounts for the costs of new direct loans and loan guarantees; they also receive payment for any upward reestimate of the costs of direct loans and loan guarantees outstanding. These collections are offset against the gross disbursements of the financing accounts in determining the accounts' total net cash flows. The gross disbursements include outflows to the public—such as of loan funds or default payments—as well as the payment of any downward reestimate of costs to budgetary receipt accounts. The total net cash flows of the financing accounts, consisting of transactions with both the public and the budgetary accounts, are called "net financing disbursements." They occur in the same way as the "outlays" of a budgetary account, even though they do not represent budgetary costs, and therefore af-

[6] For further explanation of the off-budget Federal entities, see Chapter 12 of this volume, "Coverage of the Budget."

[7] The Federal Credit Reform Act of 1990 (sec. 505(b)) requires that the financing accounts be non-budgetary. As explained in Chapter 12 of this volume, "Coverage of the Budget," they are non-budgetary in concept because they do not measure cost. For additional discussion of credit programs, see Chapter 22 of this volume, "Credit and Insurance," and Chapter 11, "Budget Concepts."

fect the requirement for borrowing from the public in the same way as the deficit.

The intragovernmental transactions of the financing accounts do not affect Federal borrowing from the public. Although the deficit changes because of the budget's outlay to, or receipt from, a financing account, the net financing disbursement changes in an equal amount with the opposite sign, so the effects are cancelled out. On the other hand, financing account disbursements to the public increase the requirement for borrowing from the public in the same way as an increase in budget outlays that are disbursed to the public in cash. Likewise, financing account receipts from the public can be used to finance the payment of the Government's obligations, and therefore they reduce the requirement for Federal borrowing from the public in the same way as an increase in budget receipts.

In some years, large net upward or downward reestimates in the cost of outstanding direct and guaranteed loans may cause large swings in the net financing disbursements. In 2009, the downward reestimates in some accounts largely cancelled out the upward reestimates in other accounts, for a net upward reestimate of $0.4 billion. In 2010, due primarily to the Troubled Asset Relief Program (TARP), downward reestimates are significantly larger than upward reestimates, resulting in a net downward reestimate of $115 billion.

The impact of the net financing disbursements on borrowing grew significantly in 2009, largely as a result of Government actions to address the Nation's financial and economic challenges including through TARP, purchases of mortgage-backed securities issued or guaranteed by the Government-Sponsored Enterprises (GSEs), and the Temporary Student Loan Purchase Program. Net financing disbursements increased from $33 billion in 2008 to a record $406 billion in 2009. Borrowing due to financing accounts is estimated to fall by nearly half, to $204 billion in 2010, primarily due to large repayments of TARP assistance. After 2010, the credit financing accounts are expected to increase borrowing by amounts ranging from $61 billion to $147 billion over the next 10 years.

Net purchases of non-Federal securities by the National Railroad Retirement Investment Trust (NRRIT).—This trust fund was established by the Railroad Retirement and Survivors' Improvement Act of 2001. In 2003, most of the assets in the Railroad Retirement Board trust funds were transferred to the NRRIT trust fund, which invests its assets primarily in private stocks and bonds. The Act required special treatment of the purchase or sale of non-Federal assets by this trust fund, treating such purchases as a means of financing rather than an outlay. Therefore, the increased need to borrow from the public to finance the purchase of non-Federal assets is part of the "other transactions affecting borrowing from the public" rather than included as an increase in the deficit. While net purchases and redemptions affect borrowing from the public, unrealized gains and losses on NRRIT's portfolio are included in both the other factors and, with the opposite sign, in NRRIT's net outlays in the deficit, for no net impact on borrowing from the public. The increased borrowing associated with the initial transfer expanded publicly held debt by $20 billion in 2003. Net transactions in subsequent years have been much smaller. In 2009, net reductions, including losses, were $3 billion. Net reductions are expected to be roughly $1 billion annually for 2010 through 2020. [8]

Debt held by Government accounts.—The amount of Federal debt issued to Government accounts depends largely on the surpluses of the trust funds, both on-budget and off-budget, which owned 93 percent of the total Federal debt held by Government accounts at the end of 2009. In 2009, the total trust fund surplus was $127 billion, and trust funds invested $131 billion in Federal securities. Investment may differ somewhat from the surplus due to changes in the amount of cash assets not currently invested. The remainder of debt issued to Government accounts is owned by a number of special funds and revolving funds. The debt held in major accounts and the annual investments are shown in Table 6–5.

Debt Held by the Public Net of Financial Assets and Liabilities

While debt held by the public is a key measure for examining the role and impact of the Federal Government in the U.S. and international credit markets and for other purposes, it provides incomplete information on the Government's financial condition. The U.S. Government holds significant financial assets, which must be offset against debt held by the public and other financial liabilities to achieve a more complete understanding of the Government's financial condition. The acquisition of those financial assets represents a transaction with the credit markets, broadening those markets in a way that is analogous to the demand on credit markets that borrowing entails. For this reason, debt held by the public is also an incomplete measure of the impact of the Federal Government in the U.S. and international credit markets.

One transaction that can increase both borrowing and assets is an increase to the Treasury operating cash balance. For example, in 2008, under the Supplementary Financing Program (discussed above), the Government borrowed nearly $300 billion to increase the Treasury operating cash balance held with the Federal Reserve; the cash balance created by the program represents an asset that is available to the Federal Government. Looking at both sides of this transaction—the borrowing to obtain the cash and the asset of the cash holdings—provides much more complete information about the Government's financial condition than looking at only the borrowing from the public. Another example of a transaction that simultaneously increases borrowing from the public and Federal assets is Government borrowing to issue direct loans to the public. When the direct loan is made, the Government is also acquiring an asset in the form of future payments of principal and interest, net of the Government's expected losses on the loans. Similarly, when the National Railroad Retirement Investment Trust increases its holdings of non-Federal securities, the borrowing to purchase those securities is offset by the value of the asset holdings.

[8] The budget treatment of this fund is further discussed in Chapter 11 of this volume, "Budget Concepts."

CASE: UE 215
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Staff/907
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CONGRESS OF THE UNITED STATES
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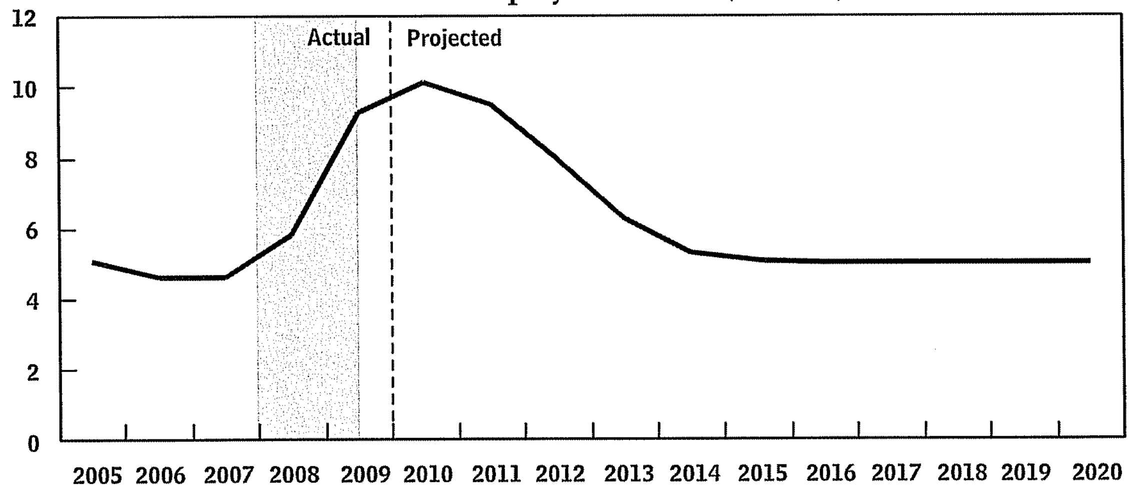
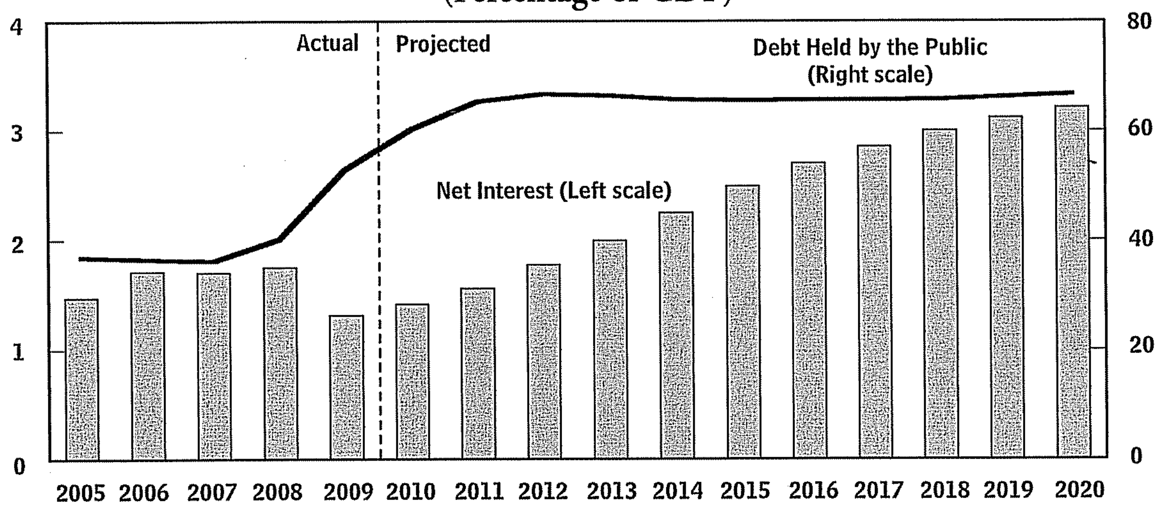
The Budget and Economic Outlook: Fiscal Years 2010 to 2020

The Unemployment Rate (Percent)



Debt Held by the Public and Net Interest Payments (Percentage of GDP)



JANUARY 2010

Staff/907
Storm/2

Pub. No. 4095

Staff/907
Storm/3

CBO

The Budget and Economic Outlook: Fiscal Years 2010 to 2020

January 2010

The Congress of the United States ■ Congressional Budget Office

Notes

The economic forecast was completed on December 8, 2009, and estimates of 2009 values shown in the text and tables are based on information that was available by that date.

Numbers in the text and tables may not add up to totals because of rounding.

Unless otherwise indicated, years referred to in describing the economic outlook are calendar years, and years referred to in describing the budget outlook are federal fiscal years (which run from October 1 to September 30).

Some of the figures have shaded bars that indicate the duration of recessions. The National Bureau of Economic Research establishes the dates on which recessions begin and end but has not yet done so for the end of the most recent recession, which is shown as having ended in the second quarter of calendar year 2009.

Supplemental data for this analysis are available on the Congressional Budget Office's Web site (www.cbo.gov).

Preface

This volume is one of a series of reports on the state of the budget and the economy that the Congressional Budget Office (CBO) issues each year. It satisfies the requirement of section 202(e) of the Congressional Budget Act of 1974 that CBO submit to the Committees on the Budget periodic reports about fiscal policy and its baseline projections of the federal budget. In accordance with CBO's mandate to provide impartial analysis, the report makes no recommendations.

The baseline spending projections were prepared by the staff of CBO's Budget Analysis Division under the supervision of Peter Fontaine, Theresa Gullo, Holly Harvey, Janet Airis, Tom Bradley, Kim Cawley, Jeffrey Holland, Sarah Jennings, Leo Lex, Kate Massey, and Sam Papenfuss. The revenue estimates were prepared by the staff of the Tax Analysis Division under the supervision of Frank Sammartino, David Weiner, and Mark Booth, with assistance from the Joint Committee on Taxation. (A detailed list of contributors to the spending and revenue projections appears in Appendix G.)

The economic outlook presented in Chapter 2 was prepared by CBO's Macroeconomic Analysis Division under the direction of Robert Dennis, Kim Kowalewski, and John Peterson. Robert Arnold and Christopher Williams produced the economic forecast and projections. David Brauer, Juan Contreras, Naomi Griffin, Juann Hung, Mark Lasky, Joe Mattey, Benjamin Page, Frank Russek, David Torregrosa, Steven Weinberg, and Susan Yang contributed to the analysis. Holly Battelle and Priscila Hammett provided research assistance.

An early version of CBO's economic forecast was discussed at a meeting of the agency's Panel of Economic Advisers. At that time, members of the panel were Henry J. Aaron, Martin N. Baily, Richard Berner, Martin Feldstein, Kristin J. Forbes, Robert J. Gordon, Robert E. Hall, Jan Hatzius, Douglas Holtz-Eakin, Simon Johnson, Anil Kashyap, Lawrence Katz, Laurence H. Meyer, William D. Nordhaus, Rudolph G. Penner, Adam S. Posen, James Poterba, Alice Rivlin, Nouriel Roubini, Diane C. Swonk, and Stephen P. Zeldes. John Haltiwanger and Aysegul Sahin attended the panel's meeting as guests. Although CBO's outside advisers provided considerable assistance, they are not responsible for the contents of this report.

Jeffrey Holland wrote the summary. Barry Blom wrote Chapter 1, with assistance from Jared Brewster, Jeffrey Holland, and David Newman. Robert Arnold wrote Chapter 2, with assistance from Kim Kowalewski, John Peterson, and David Torregrosa. Christina Hawley Anthony wrote Chapter 3, with assistance from Santiago Vallinas and Jared Brewster.

Mark Booth wrote Chapter 4, with assistance from Grant Driessen, Barbara Edwards, Zachary Epstein, Pamela Greene, and Joshua Shakin. Christina Hawley Anthony and Jeffrey Holland wrote Appendix A. Amber Marcellino wrote Appendix B, with assistance from Mark Booth. Santiago Vallinas wrote Appendix C. Jared Brewster wrote Appendix D. Holly Battelle compiled Appendix E, and Amber Marcellino compiled Appendix F. Santiago Vallinas and Chayim Rosito produced the glossary.

Christine Bogusz, Chris Howlett, Kate Kelly, Loretta Lettner, and John Skeen edited the report, with assistance from Leah Mazade and Sherry Snyder. Maureen Costantino designed the cover and prepared the report for publication, with assistance from Jeanine Rees. Lenny Skutnik printed the initial copies, Linda Schimmel handled the print distribution, and Simone Thomas and Annette Kalicki prepared the electronic version for CBO's Web site (www.cbo.gov).

Douglas W. Elmendorf

Douglas W. Elmendorf
Director

January 2010

Contents

Staff/907
Storm/8

Tables

Staff/907
Storm/10

Tables (Continued)

Tables (Continued)

Figures

Figures (Continued)

Boxes

Summary

The Congressional Budget Office (CBO) projects that if current laws and policies remained unchanged, the federal budget would show a deficit of about $1.3 trillion for fiscal year 2010 (see Summary Table 1). At 9.2 percent of gross domestic product (GDP), that deficit would be slightly smaller than the shortfall of 9.9 percent of GDP ($1.4 trillion) posted in 2009. Last year's deficit was the largest as a share of GDP since the end of World War II, and the deficit expected for 2010 would be the second largest. Moreover, if legislation is enacted in the next several months that either boosts spending or reduces revenues, the 2010 deficit could equal or exceed last year's shortfall.

The large 2009 and 2010 deficits reflect a combination of factors: an imbalance between revenues and spending that predates the recession and turmoil in financial markets, sharply lower revenues and elevated spending associated with those economic conditions, and the costs of various federal policies implemented in response to those conditions.

The deep recession that began two years ago appears to have ended in mid-2009. Economic activity picked up during the second half of last year, with inflation-adjusted GDP and industrial production both showing gains. Still, GDP remains roughly 6½ percent below CBO's estimate of the output that could be produced if all labor and capital were fully employed (that difference is called the output gap), and the unemployment rate, at 10 percent, is twice what it was two years ago.

Economic growth in the next few years will probably be muted in the aftermath of the financial and economic turmoil. Experience in the United States and in other countries suggests that recovery from recessions triggered by financial crises and large declines in asset prices tends to be protracted. Also, although aggressive action on the part of the Federal Reserve and the fiscal stimulus package enacted in early 2009 helped moderate the severity of the recession and shorten its duration, the support coming from those sources is expected to wane. Furthermore, spending by households is likely to be constrained by slow growth of income, lost wealth, and limits on their ability to borrow, and investment spending will be slowed by the large number of vacant homes and offices.

Under current law, the federal fiscal outlook beyond this year is daunting: Projected deficits average about $600 billion per year over the 2011–2020 period. As a share of GDP, deficits drop markedly in the next few years but remain high—at 6.5 percent of GDP in 2011 and 4.1 percent in 2012, the first full fiscal year after certain tax provisions originally enacted in 2001, 2003, and 2009 are scheduled to expire. Thereafter, deficits are projected to range between 2.6 percent and 3.2 percent of GDP through 2020.

Those accumulating deficits will push federal debt held by the public to significantly higher levels. At the end of 2009, debt held by the public was $7.5 trillion, or 53 percent of GDP; by the end of 2020, debt is projected to climb to $15 trillion, or 67 percent of GDP. With such a large increase in debt, plus an expected increase in interest rates as the economic recovery strengthens, interest payments on the debt are poised to skyrocket. CBO projects that the government's annual spending on net interest will more than triple between 2010 and 2020 in nominal terms, from $207 billion to $723 billion, and will more than double as a share of GDP, from 1.4 percent to 3.2 percent (see Summary Figure 1).

Moreover, CBO's baseline projections understate the budget deficits that would arise under many observers' interpretation of current policy, as opposed to current law. In particular, the projections assume that major provisions of the tax cuts enacted in 2001, 2003, and 2009 will expire as scheduled and that temporary changes that have kept the alternative minimum tax (AMT) from affecting many more taxpayers will not be extended. The

Summary Table 1.

CBO's Baseline Budget Outlook

	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total, 2011-2015	Total, 2011-2020
							In Billions of Dollars							
Total Revenues	2,105	2,175	2,670	2,964	3,218	3,465	3,625	3,814	3,996	4,170	4,352	4,563	15,941	36,836
Total Outlays	3,518	3,524	3,650	3,613	3,756	3,940	4,105	4,335	4,521	4,712	5,000	5,250	19,065	42,883
Total Deficit (-) or Surplus	**-1,414**	**-1,349**	**-980**	**-650**	**-539**	**-475**	**-480**	**-521**	**-525**	**-542**	**-649**	**-687**	**-3,124**	**-6,047**
On-budget	-1,551	-1,434	-1,076	-757	-659	-608	-619	-659	-659	-669	-765	-793	-3,719	-7,263
Off-budget[a]	137	86	96	108	120	133	139	138	134	127	116	107	595	1,216
Debt Held by the Public at the End of the Year	7,544	8,797	9,785	10,479	11,056	11,556	12,055	12,595	13,133	13,678	14,329	15,027	n.a.	n.a.
							As a Percentage of Gross Domestic Product							
Total Revenues	14.8	14.9	17.8	18.8	19.3	19.7	19.7	19.8	19.9	20.0	20.1	20.2	19.1	19.6
Total Outlays	24.7	24.1	24.3	23.0	22.5	22.4	22.3	22.6	22.6	22.6	23.1	23.3	22.9	22.8
Total Deficit	**-9.9**	**-9.2**	**-6.5**	**-4.1**	**-3.2**	**-2.7**	**-2.6**	**-2.7**	**-2.6**	**-2.6**	**-3.0**	**-3.0**	**-3.7**	**-3.2**
Debt Held by the Public at the End of the Year	53.0	60.3	65.3	66.6	66.3	65.6	65.4	65.5	65.5	65.7	66.1	66.7	n.a.	n.a.
Memorandum:														
Gross Domestic Product (Billions of dollars)	14,236	14,595	14,992	15,730	16,676	17,606	18,421	19,223	20,036	20,823	21,667	22,544	83,425	187,719

Source: Congressional Budget Office.

Note: n.a. = not applicable.

a. Off-budget surpluses comprise surpluses in the Social Security trust funds and the net cash flow of the Postal Service.

baseline projections also assume that annual appropriations rise only with inflation, which would leave discretionary spending very low relative to GDP by historical standards. If the tax cuts were made permanent, the AMT was indexed for inflation, and annual appropriations kept pace with GDP, the deficit in 2020 would be nearly the same, historically large, share of GDP that it is today, and debt held by the public would equal nearly 100 percent of GDP.

The Budget Outlook

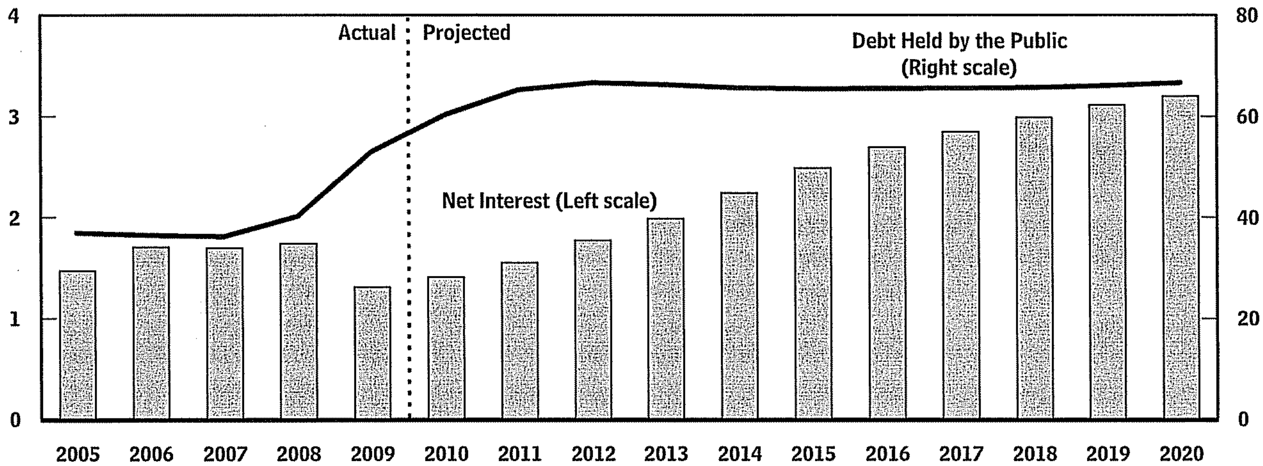
In 2010, under an assumption that no legislative changes occur, CBO estimates that federal spending will total $3.5 trillion and revenues will total $2.2 trillion. The resulting deficit of about $1.3 trillion would be just $65 billion less than last year's shortfall and more than three times the size of the deficit recorded in 2008. Total outlays are projected to increase by just $5 billion, while revenues are projected to rise by $70 billion. The deficit for this year is on track to be about as large as last year's because an expected decline in federal aid to the financial sector will be offset by increases in other outlays, particularly spending from last year's stimulus legislation and outlays for income support programs, health care programs, Social Security, and net interest. At the same time, revenues are projected to increase only modestly primarily because of the slow pace of economic recovery forecast by CBO and the lagged effect of the recession on tax receipts.

In 2011, according to CBO's baseline projections, the deficit falls to $980 billion, or 6.5 percent of GDP, as the economy improves, certain tax provisions expire as scheduled, and spending related to the economic downturn abates. Revenues are projected to rise by about $500 billion, an increase of 23 percent, while outlays are projected to increase by $126 billion, or 4 percent.

Summary Figure 1.

Debt Held by the Public and Net Interest

(Percentage of gross domestic product) (Percentage of gross domestic product)

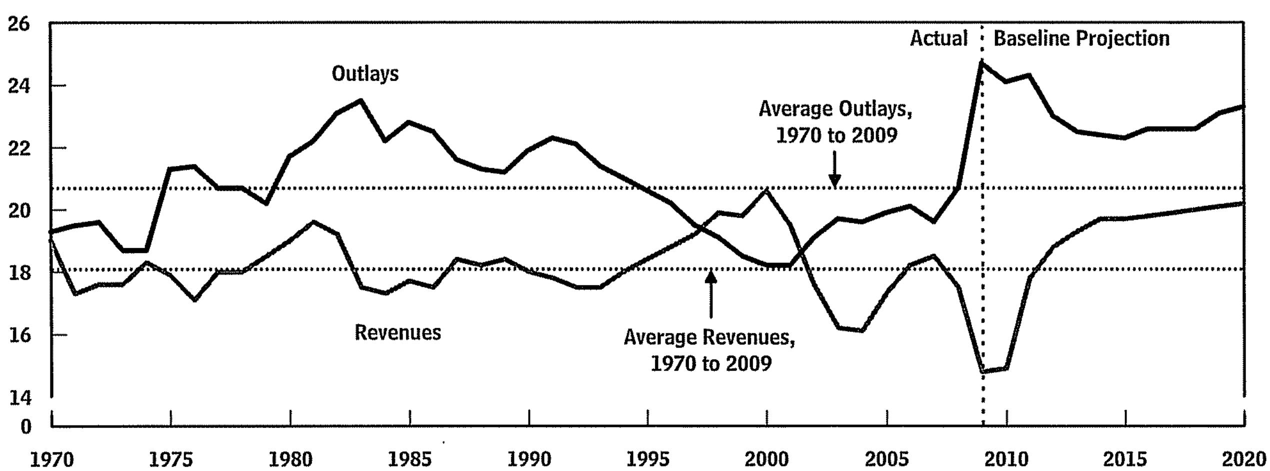


Source: Congressional Budget Office.

Summary Figure 2.

Total Revenues and Outlays

(Percentage of gross domestic product)



Source: Congressional Budget Office.

Looking beyond 2011, CBO's baseline projections show outlays remaining between 22.3 percent and 23.3 percent of GDP (compared with 24.1 percent in 2010) (see Summary Figure 2). Continued economic growth will allow payments for unemployment compensation and other benefit programs to subside, and discretionary spending is assumed to increase slowly. However, the retirement of more members of the baby-boom generation and rising health care spending per person will cause outlays for Medicare, Medicaid, and Social Security to continue to grow fairly rapidly.

The baseline projections show revenues rising to 20.2 percent of GDP by 2020 (compared with 14.9 percent in 2010), with most of the increase stemming from individual income tax receipts. Almost half of the increase in those receipts relative to the size of the economy can be attributed to the expiration of provisions originally enacted in the Economic Growth and Tax Relief Reconciliation Act of 2001, the Jobs and Growth Tax Relief Reconciliation Act of 2003, and the American Recovery and Reinvestment Act (ARRA), as well as other expiring tax provisions; the remainder is due to the economic recovery and structural features of the individual income tax system.

The Economic Outlook

Severe economic downturns often sow the seeds of robust recoveries. During a slump in economic activity, consumers defer purchases, especially for housing and durable goods, and businesses postpone capital spending and try to cut inventories. Once demand in the economy picks up, the disparity between the desired and actual stocks of capital assets and consumer durable goods widens quickly, and spending by consumers and businesses can accelerate rapidly. Although CBO expects that the current recovery will be spurred by that dynamic, in all likelihood, the recovery will also be dampened by a number of factors. Those factors include the continuing fragility of some financial markets and institutions; declining support from fiscal policy as the effects of ARRA wane and tax rates increase because of the scheduled expiration of key tax provisions; and slow wage and employment growth, as well as a large excess of vacant houses.

In CBO's forecast, real GDP increases by 2.1 percent between the fourth quarter of 2009 and the fourth quarter of 2010 and by 2.4 percent in 2011 (see Summary Table 2). Given CBO's estimate of growth in potential output, those GDP growth rates will narrow the difference between actual output and potential output (the output gap) only slightly. Growth of real GDP will accelerate after 2011, spurred by stronger business investment and residential construction. For 2012 through 2014, CBO projects that real GDP will increase by an average of 4.4 percent per year, which would close the output gap completely by the end of 2014.

Even though economic activity began to increase again during the second half of 2009, the unemployment rate continued to rise, finishing the year at 10.0 percent. Hiring usually lags behind output during the initial stages of a recovery because firms tend to increase output first by boosting productivity and by raising the number of hours that existing employees work; adding employees tends to occur later. CBO expects that the unemployment rate will average slightly above 10 percent in the first half of 2010 and then turn downward in the second half of the year (see Summary Figure 3). As the economy expands further, the rate of unemployment is projected to continue declining until, in 2016, it reaches 5 percent, which is equal to CBO's estimate of the rate of unemployment consistent with the usual rate of job turnover in U.S. labor markets.

Reflecting the large amount of slack in the economy, inflation will decrease further from its already low level in 2009, CBO forecasts. The core price index for personal consumption expenditures (that is, the PCE price index excluding the prices of food and energy) will rise by about 1 percent (on a fourth-quarter-to-fourth-quarter basis) in 2010 and by 0.9 percent in 2011. The overall PCE price index will rise by 1.4 percent in 2010 and 1.1 percent in 2011.

CBO's forecast anticipates slower growth in 2010 and 2011 than does the forecast of the *Blue Chip* consensus (reflecting the views of about 50 private-sector economists). Most private forecasters probably assume that the Congress will not allow previous tax cuts to expire as scheduled. If CBO assumed, in contrast with the assumption of its baseline, that all of the expiring tax provisions were extended beyond 2010, the agency's forecast of the level of real GDP at the end of 2011 would be in line with the forecast of the *Blue Chip* consensus (although real GDP in later years would be diminished relative to the baseline projection by the greater accumulation of government debt). CBO's forecast for inflation is roughly in line with that of the *Blue Chip* consensus in 2010 but significantly lower in 2011.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 908

Exhibits in Support
Of Opening Testimony

June 4, 2010

Staff/908
Storm/1

Annual Energy Outlook 2010
Early Release Overview

December 2009

AEO2010 Early Release Overview

Energy Trends to 2035

In preparing the *Annual Energy Outlook 2010* (*AEO-2010*), the Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview focuses primarily on one case, the *AEO2010* reference case, which is presented and compared with the updated *Annual Energy Outlook 2009* (updated *AEO2009*) reference case released in April 2009[1] (see Table 1). Because of the uncertainties inherent in any energy market projection, particularly in periods of high price volatility, rapid market transformation, or active changes in legislation, the reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2010* publication is released in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the *AEO2010* reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates). EIA considers this practice to be a prudent approach to addressing the impact of legislation and regulations. Currently, there are many pieces of legislation and regulation that appear to have a high probability of being enacted in the not-too-distant future, and some laws include sunset provisions that may be extended; however, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions are not exercised consistently.

As in past *AEO* editions, the complete *AEO2010* will include many additional cases. The standard set of cases in the complete *AEO* will be expanded to include additional cases that reflect the impact of extending a variety of current energy programs beyond their current expiration or the permanent retention of a broad set of current programs that are currently subject to sunset provisions, among others. In addition to the alternative cases prepared for *AEO2010*, EIA has examined many proposed policies at the request of Congress in 2009, and reports describing the results of those analyses are available on EIA's web site.[2]

Key updates in the *AEO2010* reference case include:

- This year, for the first time, a projection period that extends through 2035
- Revised handling of corporate average fuel economy (CAFE) standards to reflect the standards proposed jointly by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Transportation's National Highway Traffic Safety Administration (NHTSA) for light-duty vehicles (LDVs) in model years 2012 through 2016
- Updated projections of investment costs for many categories of capital-intensive energy projects
- Recognition of changes in environmental rules at both the Federal and State levels
- Implementation of a new lower 48 onshore oil and natural gas supply submodule that improves EIA's ability to address issues related to changes and improvements in technology, access to land for exploration and production, and legislative policies
- Updated characterization of natural gas shale plays, reflecting the continued evolution of "shale gas" resources and extraction technologies.

Economic Growth

- Real gross domestic product (GDP) grows by 2.5 percent per year from 2008 to 2030 in the *AEO-2010* reference case (similar to the GDP growth rate in the updated *AEO2009* reference case) and by 2.4 percent per year from 2008 to 2035. The Nation's population, labor force, and productivity grow at annual rates of 0.9 percent, 0.6 percent, and 2.0 percent, respectively, from 2008 to 2035.
- Beyond 2011, the economic assumptions underlying the *AEO2010* reference case reflect trend projections that do not include short-term fluctuations. The near-term scenario for economic growth is consistent with that in EIA's September 2009 *Short-Term Energy Outlook*.

[1]The *AEO2009* reference case, originally released in December 2008, was updated to reflect the provisions of the American Recovery and Reinvestment Act (ARRA), enacted in mid-February 2009.
[2]See "Responses to Congressional and Other Requests," at www.eia.doe.gov/oiaf/service_rpts.htm.

Energy Prices

Crude Oil

- World oil prices declined sharply from their mid-2008 peak in the latter half of 2008 but have generally risen throughout 2009. Prices continue to rise gradually in the reference case (Figure 1), as the world economy rebounds and global demand grows more rapidly than liquids supplies from producers outside of the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil in the reference case is $133 per barrel in 2008 dollars, or about $224 per barrel in nominal dollars. Alternative cases in the complete *AEO2010* will address the impacts that higher and lower world crude oil prices have on U.S. energy markets.
- The *AEO2010* reference case assumes that limitations on access to energy resources restrain the growth of non-OPEC conventional liquids production between 2008 and 2035 and that OPEC targets a relatively constant market share of 41 percent of total world liquids production.
- Contributing to world oil price uncertainty is the degree to which non-OPEC countries and countries outside the Organization for Economic Cooperation and Development (OECD), such as Russia and Brazil, restrict economic access to potentially productive resources. Other factors causing uncertainty include OPEC investment decisions, which will affect future world oil prices and the economic viability of unconventional liquids.
- The *AEO2010* reference case also includes significant long-term potential for supply from non-OPEC producers. In several resource-rich regions (including Brazil, Russia, and Kazakhstan), high oil prices, expanded infrastructure, and further investment in exploration and drilling contribute to additional non-OPEC oil production (Figure 2). Also, with the economic viability of Canada's oil sands enhanced by higher world oil prices and advances in production technology, production from oil sands reaches 4.5 million barrels per day in 2035.

Liquid Products

- Real prices (in 2008 dollars) for motor gasoline and diesel in the *AEO2010* reference case are $3.68 per gallon and $3.83 per gallon in 2030, lower than in the updated *AEO2009* reference case, largely due to the lower crude oil prices in the *AEO2010* reference case. In 2035, real gasoline and diesel prices reach $3.91 per gallon and $4.11 per gallon. Diesel prices are higher than gasoline prices throughout the projection because of stronger growth in demand for diesel than for motor gasoline.
- Retail prices for E85 (a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) are projected to shift from a volumetric basis to an energy-equivalent basis relative to motor gasoline, in order to meet the renewable fuels standard (RFS) legislated in Public Law 110-140, the Energy Independence and Security Act of 2007 (EISA2007). In 2022, the retail price of gasoline is $3.41 per gallon while the price of E85 is $2.63 per gallon, reflecting the higher energy content of gasoline versus E85 and delivering a similar cost for the two fuels per mile traveled.

Natural Gas

- The price of natural gas at the wellhead is lower in the *AEO2010* reference case than in the updated *AEO2009* reference case due to a more rapid

Figure 1. Energy prices, 1980-2035 (2008 dollars per million Btu)

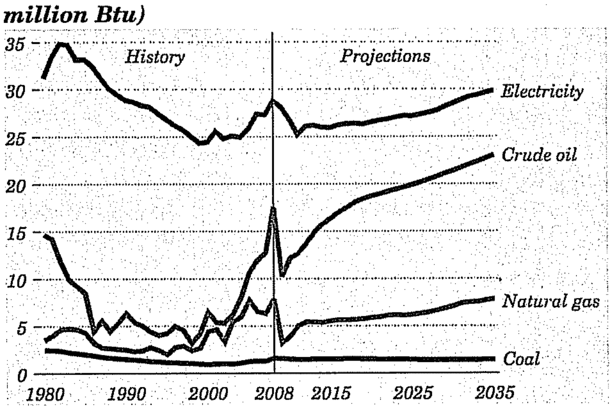
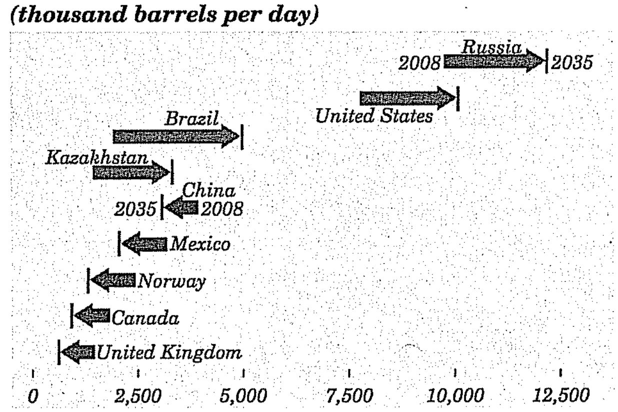


Figure 2. Change in conventional liquids production by top non-OPEC producers, 2008-2035 (thousand barrels per day)



ramping up of shale gas production, particularly after 2015. *AEO2010* assumes a larger resource base for natural gas, based on a reevaluation of shale gas and other resources, and a more rapid rate for bringing new resources into production, based on observations of the industry's current capability.

- In the *AEO2010* reference case (as in the updated *AEO2009* reference case), natural gas prices increase in the short term from the low prices observed in 2009 that resulted from the sharp economic downturn. After 2012, prices continue to rise in the *AEO2010* reference case, but more slowly, as additional resources are brought into production to meet demand growth. Natural gas wellhead prices reach $8.06 per thousand cubic feet (2008 dollars) in 2035.

Coal

- Coal prices are expected to moderate through 2029 from their recent high levels because of a continuing shift to lower cost production west of the Mississippi River; however, they remain slightly above the price projections in the updated *AEO2009* reference case through 2025. In the *AEO2010* reference case, the share of total coal production from west of the Mississippi River, on a Btu basis, grows from 50 percent in 2008 to 60 percent in 2029 and remains at that level through 2035.
- In the *AEO2010* reference case, average real minemouth coal prices (in 2008 dollars) fall from $1.55 per million Btu ($31.26 per short ton) in 2008 to $1.41 per million Btu ($27.37 per short ton) in 2029, then begin rising slightly to $1.44 per million Btu ($28.10 per short ton) in 2035 as demand increases and the share of lower cost western production remains steady at 60 percent.

Electricity

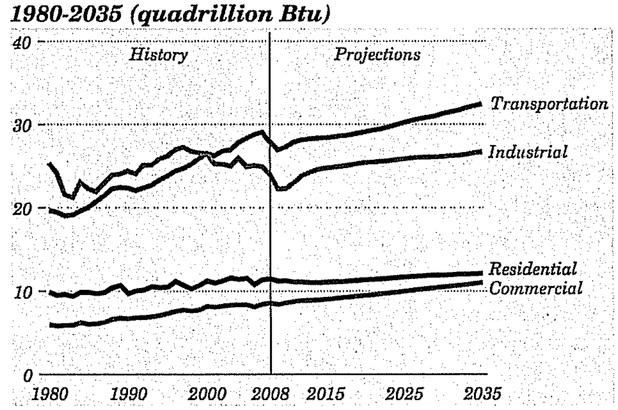
- Following the recent rapid decline in natural gas prices, real average delivered electricity prices in the *AEO2010* reference case fall sharply from 9.8 cents per kilowatthour in 2008 to 8.6 cents per kilowatthour in 2011 and remain below 9.0 cents per kilowatthour through 2020. Electricity prices tend to reflect trends in fuel prices—particularly natural gas prices, because natural-gas-fired plants often are the marginal generators. There can be lags in the timing of price impacts, however, because fuel price contracts may affect the fuel costs passed through to electricity consumers.
- Throughout the projection, electricity prices are linked to natural gas prices. Once natural gas prices begin to rise steadily, electricity prices also begin to increase, reaching an average of 10.2 cents per kilowatthour in 2035. Over the longer term, real electricity prices rise as demand grows and the prices of delivered fuels increase, leading to higher production costs.
- Relatively lower costs for fuel through most of the projection period lead to lower electricity prices in the *AEO2010* reference case than in the updated *AEO2009* reference case. Electricity prices in 2030 (in 2008 dollars) are 9.7 cents per kilowatthour in the *AEO2010* reference case compared with 10.3 cents per kilowatthour in the updated *AEO2009* reference case.

Energy Consumption by Sector

Residential

- Residential delivered energy consumption in the *AEO2010* reference case grows from 11.3 quadrillion Btu in 2008 to 11.9 quadrillion Btu in 2030, 0.3 quadrillion Btu less than in the updated *AEO2009* reference case (Figure 3). Contributing to the lower level of residential energy use is the recent adoption of regional standards for heating and cooling equipment, which require a 90-percent efficiency rating for natural gas furnaces in the northern tier of the country.
- Recently enacted efficiency standards for residential lighting products and incandescent lighting in EISA2007 significantly reduce electricity demand for lighting in the residential sector.
- Shipments of ground-source (geothermal) heat pumps to the residential market increased 40 percent in 2008, as tax credits specified in the Energy

Figure 3. Delivered energy consumption by sector, 1980-2035 (quadrillion Btu)



Improvement and Extension Act of 2008 (EIEA-2008) and greater consumer awareness have fostered significant growth in this emerging technology. The stock of ground-source geothermal heat pumps reaches 2.25 million units in 2030 in the *AEO2010* reference case, 44 percent more than projected in the updated *AEO2009* reference case. Even with the relatively large increase in the number of ground-source heat pump installations, the 2.25 million units represent only 2.2 percent of the heating market for single-family homes in 2030.

Commercial

- Despite lower energy prices after 2015, efficiency gains lead to slower growth in commercial energy consumption in the *AEO2010* reference case than in the updated *AEO2009* reference case. Delivered commercial energy consumption grows from 8.6 quadrillion Btu in 2008 to 10.5 quadrillion Btu in 2030, about 147 trillion Btu less than in the updated *AEO2009* reference case.
- New lighting and refrigeration standards and Federal and State efficiency programs help offset increasing demand for electricity to power electronic equipment, holding growth in commercial electricity use to 1.3 percent per year from 2008 to 2035—the same as growth in commercial floorspace.
- Higher near-term electricity prices combine with the 30-percent Federal investment tax credit to foster increased adoption of commercial photovoltaic systems and small wind turbines in the *AEO2010* reference case relative to the updated *AEO2009* reference case.

Industrial

- Slightly more than one-third of delivered energy consumption in the United States occurs in the industrial sector. The largest users of energy in this sector are the bulk chemical, refining, mining, and paper industries. Those four industries together account for more than 60 percent of total industrial delivered energy consumption. Although the largest current user of energy is the bulk chemicals industry, the refining industry, which also uses energy for coal-to-liquids (CTL), natural gas-to-liquids (GTL), and biofuel production, becomes the largest energy-consuming industry starting in 2028 in the *AEO2010* reference case.
- Collectively, the energy-intensive manufacturing industries—bulk chemicals, refining, paper products, iron and steel, aluminum, food, glass, and cement—produce about one-fifth of the dollar value of industrial shipments while accounting for two-thirds of industrial delivered energy consumption. Strong growth in fuel use for refining results from higher industrial demand for lighter feedstocks, a shift by refineries from lighter to heavier crudes, and growth in biofuel production. As a result, the share of industrial energy use by the energy-intensive industries grows slightly, from 67 percent in 2008 to 70 percent in 2035, despite declines in energy consumption for several other industries.
- Industrial shipments increase 44 percent from 2008 to 2035 in the *AEO2010* reference case, while growth in the energy-intensive manufacturing industries, which drive total industrial energy consumption, is much slower (25 percent). As a result, industrial delivered energy consumption increases only 8 percent. Most significant is a decline of nearly 10 percent in shipments from the bulk chemical industry from 2008 to 2035, leading to a decline of nearly 7 percent in this industry's energy consumption, including feedstock usage.
- Energy consumption in the refining industry—including petroleum, biofuels, and CTL—drives the growth in total industrial delivered energy consumption. While total shipments from the refining industry are largely unchanged from those in the updated *AEO2009* reference case projections, the industry becomes more energy-intensive as a result of growth in energy-intensive biofuels and CTL production.

Transportation

- Delivered energy consumption in the transportation sector grows to 31.3 quadrillion Btu in 2030 (only slightly higher than the 31.2 quadrillion Btu in the updated *AEO2009* reference case) and 32.5 quadrillion Btu in 2035 in the *AEO2010* reference case.
- Energy consumption for LDVs grows to 17.2 quadrillion Btu in 2030, 0.7 quadrillion Btu higher than in the updated *AEO2009* reference case, and to 17.7 quadrillion Btu in 2035 in the *AEO2010* reference case. Lower fuel prices in *AEO2010* and slightly higher total real disposable personal income combine to increase total vehicle miles traveled in 2030 relative to the updated

AEO2009 reference case, offsetting the impact of slightly higher efficiency for new LDVs resulting from revised CAFE standards.

- Energy demand for heavy trucks increases to 6.3 quadrillion Btu (3.2 million barrels per day) in 2030—compared with 6.6 quadrillion Btu in the updated *AEO2009* reference case—and 6.8 quadrillion Btu (3.5 million barrels per day) in 2035 in the *AEO2010* reference case. Fuel use by heavy trucks is lower in the *AEO2010* reference case as a result of the incorporation of updated historical data, which includes a decrease in heavy truck travel.
- *AEO2010* assumes the adoption of CAFE standards jointly proposed by the EPA and NHTSA for LDVs in model years 2012 through 2016. The proposed fuel economy standards for model year 2016 then modestly increase through the 2020 model year to meet the requirements of EISA2007. CAFE standards beyond 2020 are similar to those used in the updated *AEO2009* reference case. To attain the mandated fuel economy levels, the *AEO2010* reference case includes a rapid increase in sales of unconventional vehicle technologies,[3] such as flex-fuel, hybrid, and diesel vehicles, as well as slower growth in sales of new light trucks. Sales of hybrid vehicles, including plug-in hybrid electric vehicles (PHEVs), increase from 2.6 percent of new LDV sales in 2008 to 24.6 percent in 2035. PHEV sales grow rapidly as a result of the EIEA2008 tax credits, increasing to about 90,000 vehicles annually in 2015. In 2035, PHEVs account for 2.6 percent of new LDV sales and 1.7 percent of the total LDV stock.

Energy Consumption by Primary Fuel

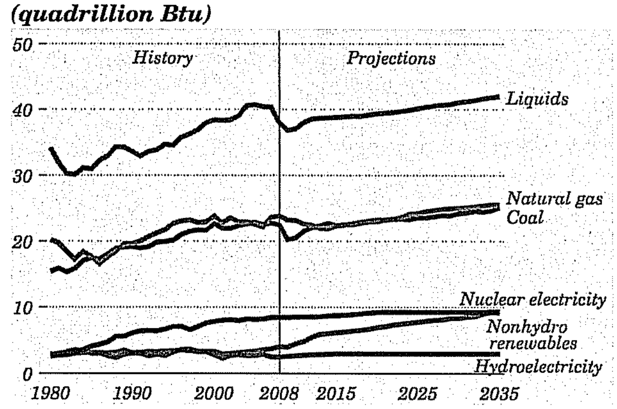
- The fossil fuel share of energy consumption falls from 84 percent of total U.S. energy demand in 2008 to 78 percent in 2035, reflecting the impact of the new CAFE, ARRA, EIEA2008, EISA2007, and State provisions.
- Biofuel consumption accounts for most of the growth in total U.S. liquids consumption, as consumption of petroleum-based liquids is essentially flat.
- Rapid growth in the consumption of renewable fuels results mainly from the implementation of the Federal RFS for transportation fuels and State renewable portfolio standard (RPS) programs for electricity generation.
- Increased renewable energy consumption in the electric power sector, excluding hydropower, accounts for 41 percent of the growth in electricity generation from 2008 to 2035.

Total primary energy consumption in the *AEO2010* reference case grows 14.4 percent, from 100.1 quadrillion Btu in 2008 to 114.5 quadrillion Btu in 2035. Among the most important factors leading to lower total energy demand in the *AEO2010* reference case than was projected in the updated *AEO2009* reference case are greater use of more efficient appliances and vehicles in response to CAFE, EISA2007, and EIEA2008 requirements.

Total U.S. consumption of liquid fuels, including both fossil liquids and biofuels, grows from 38.4 quadrillion Btu (19.5 million barrels per day) in 2008 to 42.0 quadrillion Btu (22.1 million barrels per day) in 2035 in the *AEO2010* reference case (Figure 4). Biofuel consumption accounts for most of the growth, as consumption of petroleum-based liquids is essentially flat. The transportation sector dominates demand for liquid fuels, and its share (as measured by energy content) grows from 71 percent of total liquids consumption in 2008 to 75 percent in 2035.

In the *AEO2010* reference case, natural gas consumption falls to 21.3 trillion cubic feet in 2014 before increasing gradually to 24.3 trillion cubic feet in 2030, 0.8 trillion cubic feet higher than projected in the updated *AEO2009* reference case, as a result of lower natural gas prices (especially when compared with oil prices) in the *AEO2010* reference case. Natural gas consumption reaches 24.9 trillion cubic feet in 2035 in the *AEO2010* reference case.

Figure 4. Energy consumption by fuel, 1980-2035 (quadrillion Btu)



[3]Vehicles that can use alternative fuels or employ electric motors and advanced electricity storage, advanced engine controls, or other new technologies.

Total coal consumption increases from 22.4 quadrillion Btu (1,122 million short tons) in 2008 to 25.6 quadrillion Btu (1,319 million short tons) in 2035 in the *AEO2010* reference case. Coal consumption, mostly for electric power generation, grows gradually throughout the projection period, as existing plants are used more intensively, and new plants, which are already under construction, are completed and enter service. Coal consumption in the electric power sector in 2030 in the *AEO2010* reference case is more than 1 quadrillion Btu lower than in the updated *AEO2009* reference case, however, as a result of higher levels of natural gas use for electric power generation due to relatively lower natural gas prices in the *AEO2010* reference case.

The moderate increase in coal consumption from 2008 to 2035 also reflects coal use at CTL plants, a new industry projected to start up over the coming years, stimulated by rising oil prices and assuming current policies. In 2035, CTL accounts for approximately 1 quadrillion Btu of coal use, despite concerns about potential GHG regulations.

Total consumption of marketed renewable fuels grows 2.8 percent per year in the *AEO2010* reference case. Marketed renewable fuels include wood, municipal waste, and biomass in the end-use sectors; hydroelectricity, geothermal, municipal waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 3.9 quadrillion Btu is included with liquids fuel consumption in 2035.

Although the situation is uncertain, the current state of the industry and EIA's present view of the projected rates of technology development and market penetration of cellulosic biofuel technologies suggest that available quantities of cellulosic biofuels will be insufficient to meet the new RFS targets for cellulosic biofuels before 2022, triggering both waivers and a modification of applicable volumes, as provided in Section 211(o) of the Clean Air Act as amended in EISA2007. The modification of volumes reduces the overall target in 2022 from 36.0 to 25.8 billion gallons in the *AEO2010* reference case.[4]

Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.2 quadrillion Btu in 2008 to 4.3 quadrillion Btu in 2035. The projected consumption of nonhydroelectric renewable energy in the *AEO2010* reference case is predominantly a result of an expansion of Federal tax credits for renewable generation and capacity, as well as State RPS programs that require specific and generally increasing shares of electricity sales to be supplied by renewable resources, such as wind, solar, geothermal, and, in some States, biomass or hydropower. Rising fossil fuel prices also contribute to the growth in consumption of renewables in the later years of the projection. The largest sources of growth in renewable energy use in the *AEO2010* reference case are biomass and wind, both of which benefit from concerns about the possible enactment of future GHG regulations that dampen investment in carbon-intensive technologies.

Energy Intensity

- The energy intensity of the U.S. economy, measured as primary energy use (in thousand Btu) per dollar of GDP (in 2000 dollars), declines 40 percent from 2008 to 2035 in the *AEO2010* reference case as the result of a continued shift from energy-intensive manufacturing to services, rising energy prices, and the adoption of policies that promote energy efficiency.
- The reference case reflects observed historical relationships between energy prices and energy conservation. To the extent that consumer preferences change, the improvement in energy intensity or energy consumption per capita could be greater or smaller.

Since 1992, the energy intensity of the U.S. economy has declined an average of 1.9 percent per year, in large part because the economic output of the service sectors, which use relatively less energy per dollar of output, has grown at a pace 2.5 times that of the industrial sector (in constant dollar terms). As a result, the share of total shipments accounted for by the industrial sectors fell from 28 percent in 1992 to 22 percent in 2008. In the *AEO2010* reference case, the industrial share of total shipments continues to decline, to 18 percent in 2035 (Figure 5).

Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. The U.S. population increases 28 percent from 2008 to 2035 in the *AEO-2010* reference case, and energy consumption grows

[4]The accounting of RFS volumes is based on ethanol-equivalent gallons and not necessarily on actual physical volumes. Other RFS-qualifying fuels are assigned an "equivalence value multiplier," which largely reflects the differential between each fuel's energy content and the energy content of ethanol. The volumes of individual qualifying fuels are discussed on a physical volume basis and, therefore, do not sum to the total RFS volume cited.

14 percent over the same period. Energy consumption per capita declines 0.4 percent per year from 2008 to 2030 in the *AEO2010* reference case, similar to the decline in the updated *AEO2009* reference case.

With rising energy prices and growing concern about the environment, interest in energy conservation has increased. Although additional energy conservation is induced by higher energy prices in the *AEO2010* reference case, no further policy-induced conservation measures are assumed beyond those in existing legislation and regulation, nor does the reference case assume behavioral changes beyond those observed in the past.

Energy Production and Imports

Net imports of energy meet a major, but declining, share of total U.S. energy demand in the *AEO2010* reference case (Figure 6). The projected growth in energy imports is moderated by increased use of biofuels (much of which are produced domestically), demand reductions resulting from new efficiency standards, rapid improvement in the efficiency of appliances, and higher energy prices. Higher fuel prices also spur domestic energy production across all fuels, further tempering import growth. The net import share of total U.S. energy consumption in 2035 is 20 percent, compared with 26 percent in 2008. (The share was 29 percent in 2007, but it has dropped considerably during the current recession.)

Liquids

- U.S. dependence on imported liquids, measured as a share of total U.S. liquids use, is expected to continue declining over the projection period, from the high-water mark of 60 percent, attained in 2005 and 2006, to 45 percent in 2035.
- Cumulatively, lower 48 oil production in the *AEO2010* reference case is approximately the same as in the updated *AEO2009* reference case, but the pattern differs in that more oil is produced earlier in *AEO2010* and less is produced later. In the *AEO2010* reference case, crude oil production increases from 5 million barrels per day in 2008 to 6.3 million barrels per day in 2027 and remains at just over 6 million barrels per day through 2035 (Figure 7). Production increases are expected from the deep waters of the Gulf of Mexico and from onshore enhanced oil recovery (EOR) projects.
- Offshore oil production in *AEO2010* is lower than in *AEO2009* throughout most of the projection period, because prices for natural gas co-produced with crude oil in associated fields are lower and because of expected delays in near-term projects (based on a reevaluation of the history of development in current fields).

Although world oil prices in the *AEO2010* reference case are lower than in the updated *AEO2009* reference case, they remain high enough to have the same impact on the initiation of oil shale production as in the *AEO2009* reference case. In both projections, oil shale production is initiated in 2023 and grows rapidly thereafter, assuming current policies. The long-term potential for oil shale production is one of the more uncertain areas of the projection for domestic oil production because production costs are relatively high and improvements in extraction technologies are expected to be needed, and also because of uncertainty about potential changes in controlling legislation.

Figure 5. Output in industrial and service sectors, 1990-2035 (trillion 2000 dollars)

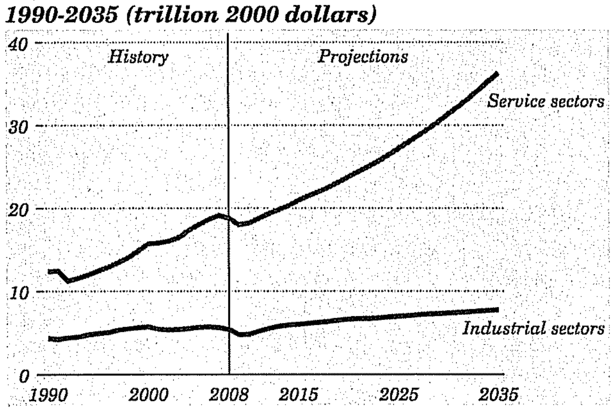
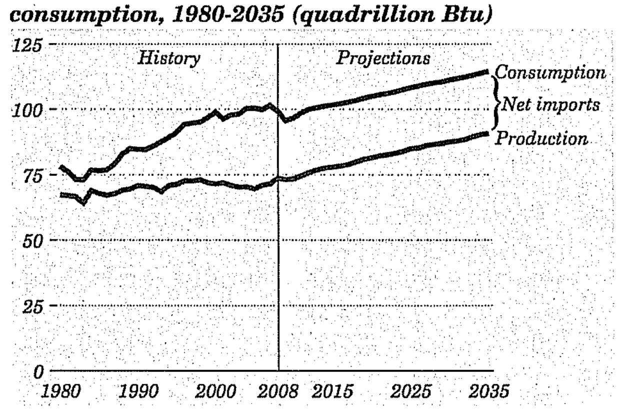


Figure 6. Total energy production and consumption, 1980-2035 (quadrillion Btu)

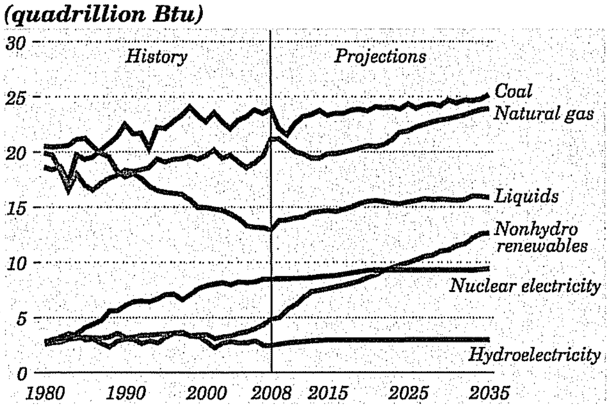


Natural Gas

- A larger resource base of shale gas results in higher shale gas production overall and a higher rate of development in the *AEO2010* reference case than in the updated *AEO2009* reference case. As a result, production from gas shale plays in 2030 is 50 percent higher in the *AEO2010* reference case, than in the updated *AEO2009* reference case.
- Increased production from gas shale plays takes production shares from other higher-cost sources—particularly, offshore production. Lower natural gas prices induced by growth in gas shales make offshore production less economical and slows its development.
- Net pipeline imports are considerably higher in the *AEO2010* reference case than projected in the updated *AEO2009* reference case. Although Canada's conventional natural gas production continues to decline, its unconventional production increases more rapidly than in *AEO2009*, reflecting the penetration of shale gas extraction technologies beyond U.S. borders.

Cumulative lower 48 natural gas production in the *AEO2010* reference case is slightly higher than in the updated *AEO2009* reference case as a result of greater supply availability, particularly from gas shale plays. In the updated *AEO2009* reference case, technically recoverable shale gas resources were estimated at 267 trillion feet; in the *AEO2010* reference case they are estimated at 347 trillion cubic feet. Given the rapid development in recent plays, including the Marcellus and Haynesville, it is assumed that newer shale gas plays can be brought into production faster than assumed in the updated *AEO2009* reference case. As a result, shale gas production grows at a much faster pace.

Figure 7. Energy production by fuel, 1980-2035 (quadrillion Btu)



An Alaska natural gas pipeline is expected to be completed in 2023 in the *AEO2010* reference case, 1 year later than in the updated *AEO2009* reference case. The later timing is a result of lower natural gas wellhead prices. Of course, there are many factors that could alter the timeline for the opening of the Alaskan natural gas pipeline, and this is a major uncertainty in the natural gas supply projection.

Total net pipeline imports of natural gas from Canada and Mexico decline from 2.7 trillion cubic feet in 2008 to 0.9 trillion cubic feet in 2030 in the *AEO2010* reference case, as compared with net exports of 0.4 trillion cubic feet in 2030 in the updated *AEO2009* reference case. Net pipeline imports continue to fall in the *AEO2010* reference case, reaching 0.6 trillion cubic feet in 2035. The much higher level of net pipeline imports in *AEO2010* results largely from projected increases in production of shale gas in Canada. The assumed Canadian shale gas resource base is approximately 100 trillion cubic feet higher in the *AEO2010* reference case than in the updated *AEO2009* reference case. The largest increase in production occurs toward the end of the *AEO2010* projection period.

Total U.S. net imports of LNG in the *AEO2010* reference case peak slightly later than in the updated *AEO2009* reference case, based on a revised worldwide outlook for liquefaction supply. Because of delays in liquefaction projects, LNG imports peak at 1.5 trillion cubic feet in 2021 in the *AEO2010* reference case, as compared with a peak of 1.4 trillion cubic feet in 2018 in the updated *AEO2009* reference case.

Coal

- Although coal remains the most important fuel for U.S. electricity generation, its share of total electricity generation is slightly lower in the *AEO2010* reference case than in the updated *AEO2009* reference case, and total coal-fired generation also is lower. As a consequence, total coal production is slightly lower in the *AEO2010* reference case than in the updated *AEO2009* reference case.

As U.S. coal use grows in the *AEO2010* reference case, domestic coal production increases at an average rate of 0.2 percent per year, from 23.9 quadrillion Btu (1,172 million short tons) in 2008 to 25.2 quadrillion Btu (1,285 million short tons) in 2035. Production from mines west of the Mississippi River trends upward over the entire projection period. Following substantial declines in output in 2009 and 2010, coal production east of the Mississippi River remains relatively constant from 2010 through 2035. On a Btu basis, 60 percent of domestic coal production originates from States west of the Mississippi River in 2035, up from 50 percent in 2008.

Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 92 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2010* reference case (22.2 quadrillion Btu in 2030) is less than in the updated *AEO2009* reference case (23.4 quadrillion Btu in 2030). For the most part, the reduced outlook for coal consumption in the electricity sector is the result of increased generation from natural gas and renewable energy in the *AEO2010* reference case.

Another emerging market for coal is CTL plants. In the *AEO2010* reference case, coal use at CTL plants grows from 0.5 quadrillion Btu (32 million short tons) in 2020 to 1.0 quadrillion Btu (68 million short tons) in 2035.

Electricity Generation

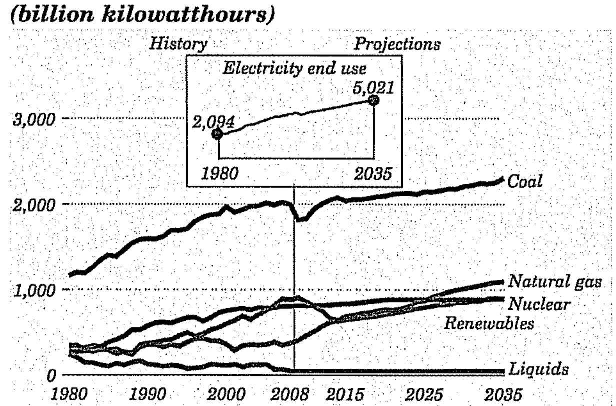
- Total electricity consumption, including both purchases from electric power producers and on-site generation, increases at an average annual rate of 1.0 percent from 2008 to 2035 in the *AEO2010* reference case.
- Although the mix of investments in new power plants includes fewer coal-fired plants than other fuel technologies, coal remains the dominant energy source for electricity generation (Figure 8) because of continued reliance on existing coal-fired plants and the addition of some new ones in the absence of an explicit Federal policy to reduce GHG emissions.
- Natural gas plays a larger role in the *AEO2010* reference case than in earlier *AEO*s because growing concerns about GHG emissions make it more attractive than coal and because new natural-gas-fired plants are much cheaper to build than new renewable or nuclear plants.
- Generation from renewable resources increases in response to the extension of key Federal tax credits and the loan guarantee program in ARRA, which greatly increase renewable generation relative to the projections in earlier outlooks. Additional growth is also supported by State requirements for renewable generation.

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,873 billion kilowatthours in 2008 to 5,021 billion kilowatthours in 2035 in the *AEO2010* reference case, increasing at an average annual rate of 1.0 percent. The growth rate in the *AEO2010* projection is the same as in the updated *AEO2009* reference case.

A total of 24 gigawatts of coal-fired generating capacity are added from 2008 to 2030 in the *AEO2010* reference case, less than the 32 gigawatts added in the updated *AEO2009* reference case. Concerns about GHG emissions continue to slow the expansion of coal-fired capacity in the *AEO2010* reference case, even under current laws and policies. Lower projected fuel prices for new natural-gas-fired plants also affect the relative economics of coal-fired capacity. Total coal-fired generating capacity grows to 337 gigawatts in 2035 in the *AEO2010* reference case. Compared with the updated *AEO2009* reference case, electricity generation from natural gas in 2030 is 4 percent higher in the *AEO2010* reference case. Generation from natural gas continues to grow through 2035.

Nuclear generating capacity in the *AEO2010* reference case increases from 100.6 gigawatts in 2008 to 112.9 gigawatts in 2035. The increase includes 8.4 gigawatts of capacity at new plants and 4.0 gigawatts from uprates at existing plants. There are no projected nuclear plant retirements through 2035 in the *AEO2010* reference case because it is assumed that plant owners will apply for, and be granted, license extensions beyond the current 20-year extensions of operating licenses (that originally were granted for a 40-year period) as long as it is economical to continue the operation of existing plants. Clearly, the future of existing nuclear plants is a major uncertainty in the *AEO2010* projections, as the possibility of license extensions beyond 60 years is likely to be significantly

Figure 8: Electricity generation by fuel, 1980-2035 (billion kilowatthours)



affected by information developed over the next 2 decades.

Electricity generation from nuclear power plants grows from 806 billion kilowatthours in 2008 to 898 billion kilowatthours in 2035 in the *AEO2010* reference case, accounting for about 17 percent of total generation in 2035 compared with 20 percent in 2008. Higher construction costs for new nuclear plants, along with lower projected natural gas prices, make new nuclear capacity slightly less attractive than was projected in the updated *AEO2009* reference case.

Generation from renewable resources grows in response to the extension of key Federal tax credits and the loan guarantee program in ARRA, which greatly increases renewable generation relative to the projections in earlier outlooks. Additional growth is also supported by the many State requirements for renewable generation. The share of generation coming from renewable fuels grows from 9 percent in 2008 to 17 percent in 2035. In the *AEO2010* reference case, Federal subsidies for renewable generation are assumed to expire as enacted. Their extension could have a large impact on renewable generation.

Energy-Related Carbon Dioxide Emissions

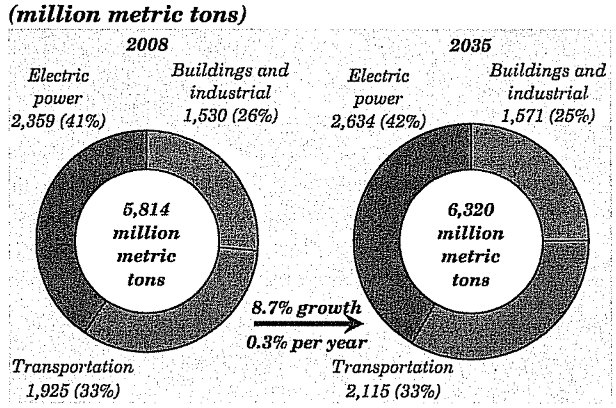
- Total U.S. primary energy-related emissions of carbon dioxide (CO_2) increase 8.7 percent in the *AEO2010* reference case, from 5,814 million metric tons in 2008 to 6,320 million metric tons in 2035, or an average of 0.3 percent per year (Figure 9).
- Emissions per capita fall an average of 0.6 percent per year, as demand growth for electricity and transportation fuels is moderated by higher energy prices, efficiency standards, State RPS requirements, and Federal CAFE standards.

In the *AEO2010* reference case, total primary energy-related CO_2 emissions increase 6 percent from 2008 to 2030, matching the percentage growth projected in the updated *AEO2009* reference case. Following a decline from 2008 to 2009 as a result of the current economic recession, CO_2 emissions return to their 2008 level in 2019 and then gradually rise to 6,320 million metric tons in 2035.

Energy-related CO_2 emissions reflect the quantities of fossil fuels consumed and, because of their different carbon contents, the mix of coal, petroleum, natural gas, and other fuels consumed. Given the high carbon content of coal and its use currently to generate more than one-half of the U.S. electricity supply, prospects for CO_2 emissions depend in part on growth in electricity demand. Electricity sales growth in the *AEO2010* reference case slows as a result of a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, housing patterns, and economic activity. With slower electricity demand growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related CO_2 emissions grow only 0.4 percent per year from 2008 to 2035. Growth in CO_2 emissions from transportation activity also slows in comparison with recent experience, as Federal CAFE standards increase the efficiency of the vehicle fleet, and higher fuel prices moderate growth in travel.

Taken together, all these factors tend to slow the growth in primary energy consumption and CO_2 emissions. As a result, energy-related emissions of CO_2 grow 9 percent from 2008 to 2035—lower than the 14-percent increase in total energy use. Over the same period the economy becomes less carbon-intensive, as CO_2 emissions per dollar of GDP decline 40 percent.

Figure 9. U.S. primary energy-related carbon dioxide emissions by sector and fuel, 2008 and 2035 (million metric tons)



AEO2010 Early Release Overview

Table 1. Comparison of projections in the *AEO2010* and Updated *AEO2009* reference cases, 2008-2035

Energy and economic factors	2008	2020 *AEO2010*	2020 *AEO2009*	2030 *AEO2010*	2030 *AEO2009*	2035 *AEO2010*
Primary energy production (quadrillion Btu)						
Petroleum	13.08	15.51	15.01	15.68	18.00	15.87
Dry natural gas	21.14	20.54	20.13	23.00	23.67	23.92
Coal	23.86	23.71	24.56	24.68	25.42	25.19
Nuclear power	8.46	9.26	9.14	9.29	9.29	9.41
Hydropower	2.46	2.96	2.95	2.98	2.96	2.99
Biomass	3.97	5.63	6.19	7.93	8.58	9.27
Other renewable energy	1.17	3.01	2.97	3.17	3.08	3.36
Other	0.10	0.89	0.93	0.92	1.01	0.81
Total	**74.23**	**81.51**	**81.88**	**87.63**	**92.02**	**90.83**
Net imports (quadrillion Btu)						
Petroleum	24.06	20.83	20.35	21.23	17.90	21.30
Natural gas	3.04	2.66	1.92	1.91	0.42	1.53
Coal/other (- indicates export)	-1.11	-0.37	0.11	0.08	0.47	0.53
Total	**25.99**	**23.11**	**22.37**	**23.22**	**18.78**	**23.36**
Consumption (quadrillion Btu)						
Liquid fuels	38.35	39.36	38.67	41.08	40.30	42.02
Natural gas	23.91	23.27	22.13	25.01	24.15	25.56
Coal	22.41	23.01	24.36	24.25	25.42	25.11
Nuclear power	8.46	9.26	9.14	9.29	9.29	9.41
Hydropower	2.46	2.96	2.95	2.98	2.96	2.99
Biomass	3.10	3.93	4.28	5.19	5.60	5.83
Other renewable energy	1.17	3.01	2.97	3.17	3.08	3.36
Net electricity imports	0.24	0.20	0.18	0.20	0.16	0.22
Total	**100.09**	**105.00**	**104.67**	**111.18**	**110.96**	**114.51**
Liquid fuels (million barrels per day)						
Domestic crude oil production	4.96	6.13	5.79	6.20	7.14	6.27
Other domestic production	3.38	4.58	4.58	5.26	5.35	5.73
Net imports	11.19	9.72	9.51	9.91	8.38	10.00
Consumption	19.53	20.56	20.05	21.48	20.92	22.06
Natural gas (trillion cubic feet)						
Production	20.62	20.04	19.65	22.44	23.09	23.34
Net imports	2.95	2.57	1.85	1.84	0.38	1.46
Consumption	23.25	22.63	21.53	24.33	23.50	24.86
Coal (million short tons)						
Production	1,172	1,183	1,223	1,260	1,272	1,285
Net imports	-49	-15	7	2	22	20
Consumption	1,122	1,183	1,240	1,276	1,305	1,319
Prices (2008 dollars)						
Imported low-sulfur, light crude oil (dollars per barrel)	99.57	108.28	119.36	123.50	133.80	133.22
Imported crude oil (dollars per barrel)	92.61	98.14	117.02	111.49	127.09	121.37
Domestic natural gas at wellhead (dollars per thousand cubic feet)	8.07	6.03	6.94	7.31	8.19	8.06
Domestic coal at minemouth (dollars per short ton)	31.26	30.01	27.99	27.43	28.48	28.10
Average electricity price (cents per kilowatthour)	9.8	9.0	9.5	9.7	10.3	10.2
Economic indicators						
Real gross domestic product (billion 2000 dollars)	11,652	15,416	15,398	19,883	19,875	22,362
GDP chain-type price index (2000=1.000)	1.225	1.497	1.521	1.849	1.896	2.059
Real disposable personal income (billion 2000 dollars)	8,753	11,967	11,903	16,069	16,014	18,168
Value of manufacturing shipments (billion 2000 dollars)	4,014	5,006	5,019	5,680	5,631	6,010
Primary energy intensity (thousand Btu per 2000 dollar of GDP)	**8.59**	**6.81**	**6.80**	**5.59**	**5.58**	**5.12**
Energy-related carbon dioxide emissions (million metric tons)	**5,814**	**5,852**	**5,905**	**6,176**	**6,207**	**6,320**

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Coal consumption includes waste coal consumed in the electric power and industrial sectors, which is not included in coal production.

Sources: AEO2010 National Energy Modeling System, run AEO2010R.D111809A; and AEO2009 National Energy Modeling System, run STIMULUS.D041409A.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 909

Exhibits in Support
Of Opening Testimony

June 4, 2010

Minutes of the Federal Open Market Committee
January 26-27, 2010

A joint meeting of the Federal Open Market Committee and the Board of Governors of the Federal Reserve System was held in the offices of the Board of Governors in Washington, D.C., on Tuesday, January 26, 2010, at 2:00 p.m. and continued on Wednesday, January 27, 2010, at 8:30 a.m.

PRESENT:

Ben Bernanke, Chairman
William C. Dudley, Vice Chairman
James Bullard
Elizabeth Duke
Thomas M. Hoenig
Donald L. Kohn
Sandra Pianalto
Eric Rosengren
Daniel K. Tarullo
Kevin Warsh

Christine Cumming, Charles L. Evans, Richard Fisher, Narayana Kocherlakota, and Charles I. Plosser, Alternate Members of the Federal Open Market Committee

Jeffrey M. Lacker, Dennis P. Lockhart, and Janet L. Yellen, Presidents of the Federal Reserve Banks of Richmond, Atlanta, and San Francisco, respectively

Brian F. Madigan, Secretary and Economist
Matthew M. Luecke, Assistant Secretary
David W. Skidmore, Assistant Secretary
Michelle A. Smith, Assistant Secretary
Scott G. Alvarez, General Counsel
Nathan Sheets, Economist
David J. Stockton, Economist

Alan D. Barkema, Thomas A. Connors, William B. English, Jeff Fuhrer, Steven B. Kamin, Simon Potter, Lawrence Slifman, Mark S. Sniderman, Christopher J. Waller, and David W. Wilcox, Associate Economists

Brian Sack, Manager, System Open Market Account

Jennifer J. Johnson, Secretary of the Board, Office of the Secretary, Board of Governors

Patrick M. Parkinson, Director, Division of Bank Supervision and Regulation, Board of Governors

Robert deV. Frierson,[1] Deputy Secretary, Office of the Secretary, Board of Governors

Charles S. Struckmeyer, Deputy Staff Director, Office of the Staff Director for Management, Board of Governors

James A. Clouse, Deputy Director, Division of Monetary Affairs, Board of Governors

Linda Robertson,[2] Assistant to the Board, Office of Board Members, Board of Governors

Sherry Edwards, Andrew T. Levin, and William R. Nelson, Senior Associate Directors, Division of Monetary Affairs, Board of Governors; David Reifschneider and William Wascher, Senior Associate Directors, Division of Research and Statistics, Board of Governors

Stephen A. Meyer, Senior Adviser, Division of Monetary Affairs, Board of Governors; Stephen D. Oliner, Senior Adviser, Division of Research and Statistics, Board of Governors

Michael Leahy, Associate Director, Division of International Finance, Board of Governors; Daniel E. Sichel, Associate Director, Division of Research and Statistics, Board of Governors

Michael G. Palumbo, Deputy Associate Director, Division of Research and Statistics, Board of Governors; Egon Zakrajsek, Deputy Associate Director, Division of Monetary Affairs, Board of Governors

David H. Small, Project Manager, Division of Monetary Affairs, Board of Governors

[1] Attended Tuesday's session only.
[2] Attended Wednesday's session only.

Carol C. Bertaut, Senior Economist, Division of International Finance, Board of Governors; Louise Sheiner, Senior Economist, Division of Research and Statistics, Board of Governors

Mark A. Carlson and Kurt F. Lewis, Economists, Division of Monetary Affairs, Board of Governors

Penelope A. Beattie, Assistant to the Secretary, Office of the Secretary, Board of Governors

Carol Low, Open Market Secretariat Specialist, Division of Monetary Affairs, Board of Governors

Randall A. Williams, Records Management Analyst, Division of Monetary Affairs, Board of Governors

Harvey Rosenblum, Executive Vice President, Federal Reserve Bank of Dallas

David Altig, Spence Hilton, Loretta J. Mester, and Glenn D. Rudebusch, Senior Vice Presidents, Federal Reserve Banks of Atlanta, New York, Philadelphia, and San Francisco, respectively

Warren Weber, Senior Research Officer, Federal Reserve Bank of Minneapolis

David C. Wheelock, Vice President, Federal Reserve Bank of St. Louis

Julie Ann Remache, Assistant Vice President, Federal Reserve Bank of New York

Hesna Genay, Economic Advisor, Federal Reserve Bank of Chicago

Robert L. Hetzel, Senior Economist, Federal Reserve Bank of Richmond

Annual Organizational Matters
In the agenda for this meeting, it was reported that advices of the election of the following members and alternate members of the Federal Open Market Committee for a term beginning January 26, 2010, had been received and that these individuals had executed their oaths of office.

The elected members and alternate members were as follows:

William C. Dudley, President of the Federal Reserve Bank of New York, with Christine Cumming, First Vice President of the Federal Reserve Bank of New York, as alternate.

Eric Rosengren, President of the Federal Reserve Bank of Boston, with Charles I. Plosser, President of the Federal Reserve Bank of Philadelphia, as alternate.

Sandra Pianalto, President of the Federal Reserve Bank of Cleveland, with Charles L. Evans, President of the Federal Reserve Bank of Chicago, as alternate.

James Bullard, President of the Federal Reserve Bank of St. Louis, with Richard Fisher, President of the Federal Reserve Bank of Dallas, as alternate.

Thomas M. Hoenig, President of the Federal Reserve Bank of Kansas City, with Narayana Kocherlakota, President of the Federal Reserve Bank of Minneapolis, as alternate.

By unanimous vote, the following officers of the Federal Open Market Committee were selected to serve until the selection of their successors at the first regularly scheduled meeting of the Committee in 2011, with the understanding that in the event of the discontinuance of their official connection with the Board of Governors or with a Federal Reserve Bank, they would cease to have any official connection with the Federal Open Market Committee:

Ben Bernanke	Chairman
William C. Dudley	Vice Chairman
Brian F. Madigan	Secretary and Economist
Matthew M. Luecke	Assistant Secretary
David W. Skidmore	Assistant Secretary
Michelle A. Smith	Assistant Secretary
Scott G. Alvarez	General Counsel
Thomas Baxter	Deputy General Counsel
Richard M. Ashton	Assistant General Counsel
Nathan Sheets	Economist
David J. Stockton	Economist

Alan D. Barkema
Thomas A. Connors
William B. English
Jeff Fuhrer
Steven B. Kamin
Simon Potter
Lawrence Slifman
Mark S. Sniderman
Christopher J. Waller
David W. Wilcox — Associate Economists

By unanimous vote, the Committee amended its Program for Security of FOMC Information with the addition of a summary of the rule that governs noncitizen access to FOMC information.

By unanimous vote, the Federal Reserve Bank of New York was selected to execute transactions for the System Open Market Account.

By unanimous vote, Brian Sack was selected to serve at the pleasure of the Committee as Manager, System Open Market Account, with the understanding that his selection was subject to being satisfactory to the Federal Reserve Bank of New York.

In his annual review of the Committee's authorizations for domestic open market operations and foreign currency transactions, the Manager noted that the Desk recommended continuing to use dollar roll transactions in the process of settling agency mortgage-backed securities (MBS) purchases, and that staff proposed adding a sentence to the directive to authorize using dollar roll transactions after March 31 for the purpose of settling MBS purchases executed by that date. He also noted that the Desk intended to conduct reverse repurchase agreements (RRPs) over the course of the coming year to ensure the readiness of the Federal Reserve's tools for absorbing bank reserves. Such transactions were authorized by the Committee's resolution of November 24, 2009. Finally, he indicated that the Desk was developing the capability to conduct agency MBS administration, trading, and settlement using internal resources, but it would continue to use agents to conduct these tasks until that capability was fully developed.

By unanimous vote, the Committee approved the Authorization for Domestic Open Market Operations (shown below) with amendments to paragraph 4 that allow the use of "securities that are direct obligations of, or fully guaranteed as to principal and interest by, any agency of the United States" in temporary short-term investment transactions with foreign and international accounts and fiscal agency accounts. The Guidelines for the Conduct of System Open Market Operations in Federal-Agency Issues remained suspended.

AUTHORIZATION FOR DOMESTIC OPEN MARKET OPERATIONS
(Amended January 26, 2010)

1. The Federal Open Market Committee authorizes and directs the Federal Reserve Bank of New York, to the extent necessary to carry out the most recent domestic policy directive adopted at a meeting of the Committee:

A. To buy or sell U.S. government securities, including securities of the Federal Financing Bank, and securities that are direct obligations of, or fully guaranteed as to principal and interest by, any agency of the United States in the open market, from or to securities dealers and foreign and international accounts maintained at the Federal Reserve Bank of New York, on a cash, regular, or deferred delivery basis, for the System Open Market Account at market prices, and, for such Account, to exchange maturing U.S. government and federal agency securities with the Treasury or the individual agencies or to allow them to mature without replacement; and

B. To buy or sell in the open market U.S. government securities, and securities that are direct obligations of, or fully guaranteed as to principal and interest by, any agency of the United States, for the System Open Market Account under agreements to resell or repurchase such securities or obligations (including such transactions as are commonly referred to as repo and reverse repo transactions) in 65 business days or less, at rates that, unless otherwise expressly authorized by the Committee, shall be determined by competitive bidding, after applying reasonable limitations on the volume of agreements with individual counterparties.

2. In order to ensure the effective conduct of open market operations, the Federal Open Market Committee authorizes the Federal Reserve Bank of New York to use agents in agency MBS-related transactions.

3. In order to ensure the effective conduct of open market operations, the Federal Open Market Committee authorizes the Federal Reserve Bank of New York to lend on an overnight basis U.S. government securities and securities that are direct obligations of any agency of the United States, held in the System Open

Market Account, to dealers at rates that shall be determined by competitive bidding. The Federal Reserve Bank of New York shall set a minimum lending fee consistent with the objectives of the program and apply reasonable limitations on the total amount of a specific issue that may be auctioned and on the amount of securities that each dealer may borrow. The Federal Reserve Bank of New York may reject bids that could facilitate a dealer's ability to control a single issue as determined solely by the Federal Reserve Bank of New York.

4. In order to ensure the effective conduct of open market operations, while assisting in the provision of short-term investments for foreign and international accounts maintained at the Federal Reserve Bank of New York and accounts maintained at the Federal Reserve Bank of New York as fiscal agent of the United States pursuant to section 15 of the Federal Reserve Act, the Federal Open Market Committee authorizes and directs the Federal Reserve Bank of New York:

A. For the System Open Market Account, to sell U.S. government securities, and securities that are direct obligations of, or fully guaranteed as to principal and interest by, any agency of the United States, to such accounts on the bases set forth in paragraph 1.A under agreements providing for the resale by such accounts of those securities in 65 business days or less on terms comparable to those available on such transactions in the market; and

B. For the New York Bank account, when appropriate, to undertake with dealers, subject to the conditions imposed on purchases and sales of securities in paragraph 1.B, repurchase agreements in U.S. government securities, and securities that are direct obligations of, or fully guaranteed as to principal and interest by, any agency of the United States, and to arrange corresponding sale and repurchase agreements between its own account and such foreign, international, and fiscal agency accounts maintained at the Bank.

Transactions undertaken with such accounts under the provisions of this paragraph may provide for a service fee when appropriate.

5. In the execution of the Committee's decision regarding policy during any intermeeting period, the Committee authorizes and directs the Federal Reserve Bank of New York, upon the instruction of the Chairman of the Committee, to adjust somewhat in exceptional circumstances the degree of pressure on reserve positions and hence the intended federal funds rate and to take actions that result in material changes in the composition and size of the assets in the System Open Market Account other than those anticipated by the Committee at its most recent meeting. Any such adjustment shall be made in the context of the Committee's discussion and decision at its most recent meeting and the Committee's long-run objectives for price stability and sustainable economic growth, and shall be based on economic, financial, and monetary developments during the intermeeting period. Consistent with Committee practice, the Chairman, if feasible, will consult with the Committee before making any adjustment.

By unanimous vote, the Authorization for Foreign Currency Operations, the Foreign Currency Directive, and the Procedural Instructions with Respect to Foreign Currency Operations were reaffirmed in the form shown below. The vote to reaffirm these documents included approval of the System's warehousing agreement with the U.S. Treasury.

AUTHORIZATION FOR FOREIGN CURRENCY OPERATIONS
(Reaffirmed January 26, 2010)

1. The Federal Open Market Committee authorizes and directs the Federal Reserve Bank of New York, for the System Open Market Account, to the extent necessary to carry out the Committee's foreign currency directive and express authorizations by the Committee pursuant thereto, and in conformity with such procedural instructions as the Committee may issue from time to time:

A. To purchase and sell the following foreign currencies in the form of cable transfers through spot or forward transactions on the open market at home and abroad, including transactions with the U.S. Treasury, with the U.S. Exchange Stabilization Fund established by section 10 of the Gold Reserve Act of 1934, with foreign monetary authorities, with the Bank for International Settlements, and with other international financial institutions:

Australian dollars
Brazilian reais
Canadian dollars
Danish kroner
euro
Japanese yen
Korean won
Mexican pesos
New Zealand dollars
Norwegian kroner
Pounds sterling

Singapore dollars
Swedish kronor
Swiss francs

B. To hold balances of, and to have outstanding forward contracts to receive or to deliver, the foreign currencies listed in paragraph A above.

C. To draw foreign currencies and to permit foreign banks to draw dollars under the reciprocal currency arrangements listed in paragraph 2 below, provided that drawings by either party to any such arrangement shall be fully liquidated within 12 months after any amount outstanding at that time was first drawn, unless the Committee, because of exceptional circumstances, specifically authorizes a delay.

D. To maintain an overall open position in all foreign currencies not exceeding $25.0 billion. For this purpose, the overall open position in all foreign currencies is defined as the sum (disregarding signs) of net positions in individual currencies, excluding changes in dollar value due to foreign exchange rate movements and interest accruals. The net position in a single foreign currency is defined as holdings of balances in that currency, plus outstanding contracts for future receipt, minus outstanding contracts for future delivery of that currency, i.e., as the sum of these elements with due regard to sign.

2. The Federal Open Market Committee directs the Federal Reserve Bank of New York to maintain reciprocal currency arrangements ("swap" arrangements) for the System Open Market Account for periods up to a maximum of 12 months with the following foreign banks, which are among those designated by the Board of Governors of the Federal Reserve System under section 214.5 of Regulation N, Relations with Foreign Banks and Bankers, and with the approval of the Committee to renew such arrangements on maturity:

Foreign bank	Amount of arrangement (millions of dollars equivalent)
Bank of Canada	2,000
Bank of Mexico	3,000

Any changes in the terms of existing swap arrangements, and the proposed terms of any new arrangements that may be authorized, shall be referred for review and approval to the Committee.

3. All transactions in foreign currencies undertaken under paragraph 1.A above shall, unless otherwise expressly authorized by the Committee, be at prevailing market rates. For the purpose of providing an investment return on System holdings of foreign currencies or for the purpose of adjusting interest rates paid or received in connection with swap drawings, transactions with foreign central banks may be undertaken at nonmarket exchange rates.

4. It shall be the normal practice to arrange with foreign central banks for the coordination of foreign currency transactions. In making operating arrangements with foreign central banks on System holdings of foreign currencies, the Federal Reserve Bank of New York shall not commit itself to maintain any specific balance, unless authorized by the Federal Open Market Committee. Any agreements or understandings concerning the administration of the accounts maintained by the Federal Reserve Bank of New York with the foreign banks designated by the Board of Governors under section 214.5 of Regulation N shall be referred for review and approval to the Committee.

5. Foreign currency holdings shall be invested to ensure that adequate liquidity is maintained to meet anticipated needs and so that each currency portfolio shall generally have an average duration of no more than 18 months (calculated as Macaulay duration). Such investments may include buying or selling outright obligations of, or fully guaranteed as to principal and interest by, a foreign government or agency thereof; buying such securities under agreements for repurchase of such securities; selling such securities under agreements for the resale of such securities; and holding various time and other deposit accounts at foreign institutions. In addition, when appropriate in connection with arrangements to provide investment facilities for foreign currency holdings, U.S. government securities may be purchased from foreign central banks under agreements for repurchase of such securities within 30 calendar days.

6. All operations undertaken pursuant to the preceding paragraphs shall be reported promptly to the Foreign Currency Subcommittee and the Committee. The Foreign Currency Subcommittee consists of the Chairman and Vice Chairman of the Committee, the Vice Chairman of the Board of Governors, and such other member of the Board as the Chairman may designate (or in the absence of members of the Board serving on the Subcommittee, other Board members designated by the Chairman as alternates, and in the absence of the Vice Chairman of the Committee, the Vice Chairman's alternate). Meetings of the Subcommittee shall be called at the request of any member, or at the request of the Manager, System Open Market Account ("Manager"), for the purposes of reviewing recent or contemplated operations and of consulting

with the Manager on other matters relating to the Manager's responsibilities. At the request of any member of the Subcommittee, questions arising from such reviews and consultations shall be referred for determination to the Federal Open Market Committee.

7. The Chairman is authorized:
   A. With the approval of the Committee, to enter into any needed agreement or understanding with the Secretary of the Treasury about the division of responsibility for foreign currency operations between the System and the Treasury;
   B. To keep the Secretary of the Treasury fully advised concerning System foreign currency operations, and to consult with the Secretary on policy matters relating to foreign currency operations;
   C. From time to time, to transmit appropriate reports and information to the National Advisory Council on International Monetary and Financial Policies.
8. Staff officers of the Committee are authorized to transmit pertinent information on System foreign currency operations to appropriate officials of the Treasury Department.
9. All Federal Reserve Banks shall participate in the foreign currency operations for System Account in accordance with paragraph 3G(1) of the Board of Governors' Statement of Procedure with Respect to Foreign Relationships of Federal Reserve Banks dated January 1, 1944.

FOREIGN CURRENCY DIRECTIVE
(Reaffirmed January 26, 2010)

1. System operations in foreign currencies shall generally be directed at countering disorderly market conditions, provided that market exchange rates for the U.S. dollar reflect actions and behavior consistent with IMF Article IV, Section 1.
2. To achieve this end the System shall:
   A. Undertake spot and forward purchases and sales of foreign exchange.
   B. Maintain reciprocal currency ("swap") arrangements with selected foreign central banks.
   C. Cooperate in other respects with central banks of other countries and with international monetary institutions.
3. Transactions may also be undertaken:
   A. To adjust System balances in light of probable future needs for currencies.
   B. To provide means for meeting System and Treasury commitments in particular currencies, and to facilitate operations of the Exchange Stabilization Fund.
   C. For such other purposes as may be expressly authorized by the Committee.
4. System foreign currency operations shall be conducted:
   A. In close and continuous consultation and cooperation with the United States Treasury;
   B. In cooperation, as appropriate, with foreign monetary authorities; and
   C. In a manner consistent with the obligations of the United States in the International Monetary Fund regarding exchange arrangements under IMF Article IV.

PROCEDURAL INSTRUCTIONS WITH RESPECT TO FOREIGN CURRENCY OPERATIONS
(Reaffirmed January 26, 2010)

In conducting operations pursuant to the authorization and direction of the Federal Open Market Committee as set forth in the Authorization for Foreign Currency Operations and the Foreign Currency Directive, the Federal Reserve Bank of New York, through the Manager, System Open Market Account ("Manager"), shall be guided by the following procedural understandings with respect to consultations and clearances with the Committee, the Foreign Currency Subcommittee, and the Chairman of the Committee, unless otherwise directed by the Committee. All operations undertaken pursuant to such clearances shall be reported promptly to the Committee.

1. The Manager shall clear with the Subcommittee (or with the Chairman, if the Chairman believes that consultation with the Subcommittee is not feasible in the time available):
   A. Any operation that would result in a change in the System's overall open position in foreign currencies exceeding $300 million on any day or $600 million since the most recent regular meeting of the Committee.
   B. Any operation that would result in a change on any day in the System's net position in a single foreign currency exceeding $150 million, or $300 million when the operation is associated with repayment of swap drawings.
   C. Any operation that might generate a substantial volume of trading in a particular currency by the System, even though the change in the System's net position in that currency might be less than the limits specified in 1.B.

D. Any swap drawing proposed by a foreign bank not exceeding the larger of (i) $200 million or (ii) 15 percent of the size of the swap arrangement.

2. The Manager shall clear with the Committee (or with the Subcommittee, if the Subcommittee believes that consultation with the full Committee is not feasible in the time available, or with the Chairman, if the Chairman believes that consultation with the Subcommittee is not feasible in the time available):

A. Any operation that would result in a change in the System's overall open position in foreign currencies exceeding $1.5 billion since the most recent regular meeting of the Committee.

B. Any swap drawing proposed by a foreign bank exceeding the larger of (i) $200 million or (ii) 15 percent of the size of the swap arrangement.

3. The Manager shall also consult with the Subcommittee or the Chairman about proposed swap drawings by the System and about any operations that are not of a routine character.

Developments in Financial Markets and the Federal Reserve's Balance Sheet

The Manager of the System Open Market Account reported on developments in domestic and foreign financial markets during the period since the Committee met on December 15-16, 2009. Financial market conditions remained supportive of economic growth, though volatility in securities markets increased notably toward the end of the intermeeting period. Year-end funding pressures were minimal. No market strains had appeared as a result of the imminent closing, on February 1, of most of the Federal Reserve's special liquidity facilities. The Manager also reported on System open market operations in agency debt and agency MBS during the intermeeting period. The Desk continued to gradually slow the pace of its purchases of these securities as it moved toward completing the Committee's program of asset purchases by March 31. The Desk also continued to engage in dollar roll transactions in agency MBS securities to facilitate settlement of its outright purchases. The Federal Reserve's total assets remained a bit above $2.2 trillion, as the increase in the System's holdings of securities was almost entirely offset by a further decline in usage of the System's credit and liquidity facilities. By unanimous vote, the Committee ratified the Desk's transactions. Participants agreed that the Desk should continue the interim approach of not reinvesting the proceeds of maturing or prepaid agency securities and MBS held by the Federal Reserve. The Desk had continued to reinvest the proceeds of maturing Treasury securities by acquiring newly auctioned Treasury securities issued on the same day its existing holdings matured; participants agreed that the Desk should continue this practice for now, but the Committee would consider further its policy for redeeming or reinvesting maturing Treasury securities. There were no open market operations in foreign currencies for the System's account during the intermeeting period.

Staff briefed the Committee on current usage of the discount window and other liquidity facilities and suggested additional steps policymakers could take to normalize the Federal Reserve's liquidity provision. These steps included continuing to scale back amounts offered through the Term Auction Facility (TAF); returning to the pre-crisis standard of one-day maturity for primary credit loans to all but the smallest depository institutions; and increasing, initially to 50 basis points from 25 basis points, the spread between the primary credit rate and the upper end of the Committee's target range for the federal funds rate. Setting the spread reflects a balance between two objectives: encouraging depository institutions to use the discount window as a backup source of liquidity when they are faced with temporary liquidity shortfalls or when funding markets are disrupted, and discouraging depository institutions from relying on the discount window as a routine source of funds when other funding is generally available. The spread was 100 basis points before the financial crisis emerged; the Federal Reserve narrowed the spread to 50 basis points and then to 25 basis points as part of its response to the financial crisis. Participants judged that improvements in bank funding markets warranted reducing amounts offered at TAF auctions toward zero in three steps over the next few months, while noting that they would be prepared to modify that plan if necessary to support financial stability and economic growth. They agreed that it would soon be appropriate to return the maturity of primary credit loans to overnight and to widen the spread between the primary credit rate and the top of the Committee's target range for the federal funds rate. Several participants noted that the optimal spread could depend, in part, on the Committee's eventual decisions about the most suitable approach to implementing U.S. monetary policy over the longer term. Participants generally agreed that such steps to return the Federal Reserve's liquidity provision to a normal footing would be technical adjustments to reflect the notable diminution of the market strains that had made the creation of new liquidity facilities and expansion of existing facilities necessary and emphasized that such steps would not indicate a change in the Committee's assessment of the appropriate stance of monetary policy or the proper time to begin moving to a less accommodative policy stance.

> Secretary's note: After the FOMC meeting, the Chairman, acting under authority delegated by the Board of Governors, directed that TAF auction amounts be reduced to $50 billion for the February 8 auction and to $25 billion for the final TAF auction, to be held on March 8.

Staff also briefed policymakers about tools and strategies for an eventual withdrawal of policy accommodation and summarized linkages between these tools and strategies and alternative frameworks for implementing monetary policy in the longer run. The tools for moving to a less accommodative policy stance encompassed (1) raising the interest rate paid on excess reserve balances (the IOER rate); (2) executing term reverse repurchase agreements with the primary dealers; (3) executing term RRPs with a broader range of counterparties; (4) using a term deposit facility (TDF) to absorb excess reserves; (5) redeeming maturing and prepaid securities held by the Federal Reserve without reinvesting the proceeds; and (6) selling securities held by the Federal Reserve before they mature. All but the first of these tools would shrink the supply of reserve balances; the last two would also shrink the Federal Reserve's balance sheet. The Desk already had successfully tested its ability to conduct term RRPs with primary dealers by arranging several small-scale transactions using Treasury securities and agency debt as collateral; staff anticipated that the Federal Reserve would be able to execute term RRPs against MBS early this spring and would have the capability to conduct RRPs with an expanded set of counterparties soon after. In coming weeks, staff would analyze comments received in response to a *Federal Register* notice, published in late December, requesting the public's input on the TDF proposal. Staff would then prepare a final proposal for the Board's consideration. A TDF could be operational as soon as May.

Staff described several feasible strategies for using these six tools to support a gradual return toward a more normal stance of monetary policy: (1) using one or more of the tools to progressively reduce the supply of reserve balances—which rose to an exceptionally high level as a consequence of the expansion of the Federal Reserve's liquidity and lending facilities and subsequent large-scale asset purchases during the financial crisis—before raising the IOER rate and the target for the federal funds rate; (2) increasing the IOER rate in line with an increase in the federal funds rate target and concurrently using one or more tools to reduce the supply of reserve balances; and (3) raising the IOER rate and the target for the federal funds rate and using reserve draining tools only if the federal funds rate did not increase in line with the Committee's target.

Participants expressed a range of views about the tools and strategies for removing policy accommodation when that step becomes appropriate. All agreed that raising the IOER rate and the target for the federal funds rate would be a key element of a move to less accommodative monetary policy. Most thought that it likely would be appropriate to reduce the supply of reserve balances, to some extent, before the eventual increase in the IOER rate and in the target for the federal funds rate, in part because doing so would tighten the link between short-term market rates and the IOER rate; however, several noted that draining operations might be seen as a precursor to tightening and should only be undertaken when the Committee judged that an increase in its target for the federal funds rate would soon be appropriate. For the same reason, a few judged that it would be better to drain reserves concurrently with the eventual increase in the IOER and target rates.

With respect to longer-run approaches to implementing monetary policy, most policymakers saw benefits in continuing to use the federal funds rate as the operating target for implementing monetary policy, so long as other money market rates remained closely linked to the federal funds rate. Many thought that an approach in which the primary credit rate was set above the Committee's target for the federal funds rate and the IOER rate was set below that target—a corridor system—would be beneficial. Participants recognized, however, that the supply of reserve balances would need to be reduced considerably to lift the funds rate above the IOER rate. Several saw advantages to using the IOER rate, rather than a target for a market rate, to indicate the stance of policy. Participants noted that their judgments were tentative, that they would continue to discuss the ultimate operating regime, and that they might well gain useful information about longer-run approaches during the eventual withdrawal of policy accommodation.

Finally, staff noted that the Committee might want to address both the eventual size of the Federal Reserve's balance sheet and its composition. Policymakers were unanimous in the view that it will be appropriate to shrink the supply of reserve balances and the size of the Federal Reserve's balance sheet substantially over time. Moreover, they agreed that it will eventually be appropriate for the System Open Market Account to return to holding only securities issued by the U.S. Treasury, as it did before the financial crisis. Several thought the Federal Reserve should hold, eventually, a portfolio composed largely of shorter-term Treasury securities. Participants agreed that a policy of redeeming and not replacing agency debt and MBS as those securities mature or are prepaid would contribute to achieving both goals and thus would be appropriate. Many thought it would also be desirable to redeem some or all of the Treasury securities owned by the Federal Reserve as they mature, recognizing that at some point in the future the Federal Reserve would need to resume purchases of Treasury securities to offset reductions in other assets and to accommodate growth in the public's demand for U.S. currency. Participants expressed a range of views about asset sales. Most judged that a future program of gradual asset sales could be helpful in shrinking the size of the Federal Reserve's balance sheet, reducing reserve balances, and shifting the composition of securities holdings back toward Treasury securities; however, many were concerned that such transactions could cause market disruptions and have adverse implications for the economic recovery, particularly if they were to begin before the recovery had become self-sustaining and before the Committee had determined that a tightening of financial conditions was appropriate and had begun to raise short-term interest rates. Several thought it important to begin a program of asset sales in the near future to ensure that the Federal Reserve's balance sheet shrinks more quickly and in a more predictable manner than could be achieved solely by redeeming maturing securities and not reinvesting prepayments; they judged that a program of asset sales spread over a number of years would underscore the Committee's determination to exit from the period of exceptionally accommodative monetary policy in a manner and at a pace that would keep inflation contained without having large effects on asset prices or market interest rates. A few suggested that the pace of asset sales, and potentially of purchases, could be adjusted over time in response to developments in the economy and the evolution of the economic outlook. The Committee made no decisions about asset sales at this meeting.

Staff Review of the Economic Situation

The information reviewed at the January 26-27 meeting suggested that economic activity continued to strengthen in recent months. Consumer spending was well maintained in the fourth quarter, and business expenditures on equipment and software appeared to expand substantially. However, the improvement in the housing market slowed, and spending on nonresidential structures continued to fall. Recent data suggested that the pace of inventory liquidation diminished considerably last quarter, providing a sizable boost to economic activity. Indeed, industrial production advanced at a solid pace in the fourth quarter. In the labor market, layoffs subsided noticeably in the final months of last year, but the unemployment rate remained elevated and hiring stayed weak. Meanwhile, increases in energy prices pushed up headline consumer price inflation even as core consumer price inflation remained subdued.

Some indicators suggested that the deterioration in the labor market was abating. The pace of job losses continued to moderate: The three-month change in private nonfarm payrolls had become progressively less negative since early 2009; that pattern was widespread across industries. The unemployment rate was essentially unchanged from October through December. The labor force participation rate, however, had declined steeply since the spring, likely reflecting, at least in part, adverse labor market conditions. Moreover, hiring remained weak, the total number of individuals receiving unemployment insurance—including extended and emergency benefits—continued to climb, the average length of ongoing unemployment spells rose steeply, and joblessness became increasingly concentrated among the long-term unemployed.

Total industrial production (IP) rose in December, the sixth consecutive increase since its trough. The gain in December primarily resulted from a jump in output at electric and natural gas utilities caused by unseasonably cold weather. Manufacturing IP edged down after large and widespread gains in November. For the fourth quarter as a whole, the solid increase in manufacturing IP reflected a recovery in motor vehicle output, rising export demand, and a slower pace of business inventory liquidation. Output of consumer goods, business equipment, and materials all rose in the fourth quarter, though the average monthly gains in these categories were a little smaller than in the third quarter. The available near-term indicators of production suggested that IP would increase further in coming months.

Consumer spending continued to trend up late last year but remained well below its pre-recession level. After a strong increase in November, real personal consumption expenditures appeared to drop back some in December. Retail sales may have been held down by unusually bad weather, but purchases of new light motor vehicles continued to increase. The fundamental determinants of household spending—including real disposable income and wealth—strengthened modestly, on balance, near the end of the year but were still relatively weak. Despite the improvement from early last year, measures of consumer sentiment remained low relative to historical norms, and terms and standards on consumer loans, particularly credit card loans, stayed very tight.

The recovery in the housing market slowed in the second half of 2009, even though a number of factors supported housing demand. Interest rates for conforming 30-year fixed-rate mortgages remained historically low. In addition, the Reuters/University of Michigan Surveys of Consumers reported that the number of respondents who expected house prices to increase continued to exceed the number who expected prices to decrease. Sales of existing single-family homes rose strongly from July to November but fell in December, a pattern that suggested sales were pulled ahead in anticipation of the originally scheduled expiration of the first-time homebuyer credit on November 30. Still, existing home sales remained above their level in earlier quarters. Sales of new homes also turned down in November and December, retracing part of their recovery earlier in the year. Similarly, starts of single-family homes retreated a little from June to December after advancing briskly last spring. The pace of construction was slow enough that even the modest pace of new home sales was sufficient to further reduce the overhang of unsold new single-family houses.

Real spending on equipment and software apparently rose robustly in the fourth quarter following a slight increase in the previous quarter. Spending on high-tech equipment, in particular, appeared to increase at a considerably more rapid clip in the fourth quarter than in the third; both orders and shipments of high-tech equipment rose markedly, on net, in October and November. Business purchases of motor vehicles likely also climbed in the fourth quarter. Outside of the transportation and high-tech sectors, business outlays on equipment and software appeared to change little in the fourth quarter. Conditions in the nonresidential construction sector generally remained poor. Real spending on structures outside of the drilling and mining sector dropped in the third quarter; data on nominal expenditures through November pointed to an even faster rate of decline in the fourth quarter. The pace of real business inventory liquidation appeared to decrease considerably in the fourth quarter. After three quarters of sizable declines, real nonfarm inventories shrank at a more modest pace in October, and book-value data for this category suggested that inventories may have increased in real terms in November. Available data suggested that the change in inventory investment—including a sizable accumulation in wholesale stocks of farm products—made an appreciable contribution to the increase in real gross domestic product (GDP) in the fourth quarter.

Consumer price inflation was modest in December after being boosted in the preceding two months by increases in energy prices. Core consumer price inflation remained subdued. Price increases for non-energy services slowed early last year and remained modest throughout 2009, reflecting declining prices for housing services and perhaps the deceleration in labor costs. Price increases for core goods were quite modest during the second half of 2009. According to survey results, households' expectations of near-term inflation increased in January; in addition, median longer-term inflation expectations edged up, though they remained near the lower end of the narrow range that has prevailed over the past few years.

The U.S. international trade deficit widened in November, as a sharp rise in nominal imports outpaced an increase in exports. The rise in exports was driven primarily by a large gain in agricultural exports, which was partially offset by a decline in exports of consumer goods that followed robust growth in October. Imports of oil accounted for roughly one-third of the increase in total imports, though most other categories of imports also recorded gains.

Incoming data suggested that activity in advanced foreign economies continued to expand in the fourth quarter, though at a moderate pace. However, unemployment rates remained elevated and consumption indicators were mixed. Credit conditions improved further, as lending to the private sector expanded in some economies. Increases in export and import volumes pointed to a gradual recovery in international trade. Economic activity in emerging market economies continued to expand in the fourth quarter, although at a pace slower than that of the third quarter. Within emerging Asia, growth appeared to have remained robust in China and to have slowed elsewhere.

In Latin America, indicators pointed to a continuation of growth in much of the region, although growth in Mexico appeared to slow significantly following the third quarter's outsized gain. Amid rising energy prices, 12-month headline inflation for December picked up in all advanced foreign economies except Japan, where deflation moderated only mildly. Headline inflation continued to rise in emerging Asia, driven by energy and food prices. In Latin America, headline inflation remained below its earlier elevated pace.

Staff Review of the Financial Situation

The decision by the FOMC to keep the target range for the federal funds rate unchanged at the December meeting and its retention of the "extended period" language in the statement were widely anticipated by market participants and elicited little price response. Later in the intermeeting period, the expected path of the federal funds rate implied by federal funds and Eurodollar futures quotes shifted down slightly as investors apparently interpreted Federal Reserve communications, including the discussion of large-scale asset purchases in the FOMC minutes, as pointing to a more protracted period of accommodative monetary policy than had been anticipated. By contrast, yields on 2- and 10-year nominal Treasury securities were about unchanged on net. Inflation compensation based on 5-year Treasury inflation-protected securities (TIPS) increased; the increase likely reflected higher inflation risk premiums and a further improvement in TIPS market liquidity, along with some rise in inflation expectations owing, in part, to increases in oil prices. Inflation compensation 5 to 10 years ahead declined slightly.

Financial market conditions remained supportive of economic growth over the intermeeting period, and short-term funding markets were generally stable. Spreads between London interbank offered rates (Libor) and overnight index swap (OIS) rates at one- and three-month maturities remained low, while spreads at the six-month maturity continued to edge down. Spreads on A2/P2-rated commercial paper (CP) and AA-rated asset-backed CP held steady at the low end of the range that has prevailed since mid-2007. Strong demand for Treasury bills in the cash and repurchase agreement (repo) market, together with a seasonal decline in bills outstanding, put downward pressure on both bill yields and short-term repo rates. Although year-end pressures in short-term funding markets were generally modest amid ample liquidity, the repo market experienced some year-end dislocations, with a few transactions reportedly occurring at negative interest rates. Use of Federal Reserve credit facilities edged lower over the intermeeting period, and market commentary suggested little concern about the impending expiration of a number of the facilities.

After trending higher for most of the intermeeting period, broad stock price indexes subsequently reversed course amid elevated volatility, ending the period little changed on balance. The gap between the staff's estimate of the expected real equity return over the next 10 years for S&P 500 firms and the real 10-year Treasury yield—a rough gauge of the equity risk premium—stayed about the same and remained well above its average level during the past decade. Over the intermeeting period, yields on both investment-grade and speculative-grade corporate bonds edged down, while those on comparable-maturity Treasury securities held steady. Estimates of bid-asked spreads for corporate bonds—a measure of liquidity in the corporate bond market—remained steady. In the leveraged loan market, average bid prices rose further and bid-asked spreads were little changed.

Overall, net debt financing by nonfinancial businesses was near zero in the fourth quarter after declining in the third, consistent with weak demand for credit and still tight credit standards and terms at banks. In December, gross public equity issuance by nonfinancial firms maintained its solid pace and issuance by financial firms increased noticeably, as several large banks issued shares and used the proceeds to repay capital injections they had received from the Troubled Asset Relief Program. Financing conditions for commercial real estate, however, remained strained. Moody's index of commercial property prices showed another drop in October, bringing the index back to its 2002 level. Delinquency rates on loans in commercial mortgage-backed securities pools increased further in December. The average interest rate on 30-year conforming fixed-rate residential mortgages increased slightly over the intermeeting period but remained within the narrow range of values over recent months. Consumer credit contracted for the 10th consecutive month in November, owing to a further steep decline in revolving credit. Credit card interest rate spreads continued to increase in November. In contrast, spreads on new auto loans extended their downtrend through early January. Delinquency rates on consumer loans remained high in recent months. Issuance of credit card asset-backed securities was minimal in October and November but picked up in December after the Federal Deposit Insurance Corporation announced a temporary extension of safe-harbor rules for its handling of securitized assets should a sponsoring bank be taken into receivership.

Commercial bank credit continued to contract in December, as an increase in banks' securities holdings was more than offset by a large drop in total loans. Commercial and industrial loans and commercial real estate loans again fell markedly. Although a substantial fraction of banks continued to tighten their credit policies on commercial real estate loans in the fourth quarter, lending standards for most other types of loans were little changed, according to the January Senior Loan Officer Opinion Survey on Bank Lending Practices. Nonetheless, standards and terms on all major loan types remained tight, and the demand for loans reportedly weakened further.

M2 continued to expand sluggishly in December. Growth of liquid deposits remained robust, but small time deposits and retail money market mutual funds again contracted at a rapid pace in response to the low yields on those assets. The monetary base and total bank reserves were roughly flat, as the contraction in credit outstanding from the Federal Reserve's liquidity and credit facilities was about offset by the Desk's purchases of agency debt and MBS.

Over the intermeeting period, benchmark sovereign yields in most advanced foreign economies displayed some volatility but ended little changed on net. Global sovereign bond offerings since the start of the year had been reasonably well received, although mounting fiscal concerns made investors more reluctant to hold debt issued by the Greek government; sovereign yields rose in Greece and, to a lesser extent, in several other countries where fiscal issues have raised concerns among investors. All major foreign central banks kept their policy rates unchanged. Foreign equity prices generally ended the intermeeting period down. European financial stocks declined substantially, as early profit reports for the fourth quarter from a few banks rekindled some concerns about the health of the banking system. The broad nominal index of the foreign exchange value of the dollar rose, reportedly reflecting a growing perception that U.S. growth prospects were better than those in Europe and Japan. Concerns that policy tightening by China might restrain the global recovery also may have contributed to the dollar's appreciation against many currencies late in the period.

Staff Economic Outlook

In the forecast prepared for the January FOMC meeting, the staff revised up its estimate of the increase in real GDP in the fourth quarter of 2009. The upward revision was in inventory investment; the staff's projection of the increase in final demand was unchanged. Nonfarm businesses apparently moved earlier to stem the pace of inventory liquidation than the staff had anticipated. As a result, the economy likely entered 2010 with production in closer alignment with sales than the staff had expected in mid-December. Apart from the fluctuations in inventories, economic developments largely were as the staff had anticipated. The incoming information on the labor market and industrial production was broadly consistent with staff expectations, and, though housing activity seemed to be on a lower-than-anticipated trajectory, recent data on business capital spending were slightly above expectations. The staff continued to project a moderate recovery in economic activity over the next two years, with economic growth supported by the accommodative stance of monetary policy and by a further waning of the factors that weighed on spending and production over the past two years. The staff also continued to expect that resource slack would be taken up only gradually over the forecast period.

The staff's forecasts for some slowing of core and headline inflation over the next two years were little changed. There were no significant surprises in the incoming price data, substantial slack in resource utilization was still expected to put downward pressure on costs, and longer-term inflation expectations remained relatively stable. Given staff projections for consumer energy prices, headline inflation was projected to run somewhat above core inflation in 2010 but to slow to the same subdued rate as core inflation in 2011.

Participants' Views on Current Conditions and the Economic Outlook

In conjunction with this FOMC meeting, all meeting participants—the five members of the Board of Governors and the presidents of the 12 Federal Reserve Banks—provided projections for economic growth, the unemployment rate, and consumer price inflation for each year from 2010 through 2012 and over a longer horizon. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge over time under appropriate monetary policy and in the absence of further shocks. Participants' forecasts through 2012 and over the longer run are described in the Summary of Economic Projections, which is attached as an addendum to these minutes.

In their discussion of the economic situation and outlook, participants agreed that the incoming data and information received from business contacts, though mixed, indicated that economic growth had strengthened in the fourth quarter, that firms were reducing payrolls at a less rapid pace, and that downside risks to the outlook for economic growth had diminished a bit further. Participants saw the economic news as broadly in line with the expectations for moderate growth and subdued inflation in 2010 that they held when the Committee met in mid-December; moreover, financial conditions were much the same, on balance, as when the FOMC last met. Accordingly, participants' views about the economic outlook had not changed appreciably. Many noted the evidence that the pace of inventory decumulation slowed quite substantially in the fourth quarter of 2009 as firms increased output to bring production into closer alignment with sales. Participants saw the slower pace of inventory reductions as a welcome indication that, in general, firms no longer had large inventory overhangs. But they observed that business contacts continued to report great reluctance to build inventories, increase payrolls, and expand capacity. Participants expected the economic recovery to continue, but most anticipated that the pickup in output and employment growth would be rather slow relative to past recoveries from deep recessions. A moderate pace of expansion would imply slow improvement in the labor market this year, with unemployment declining only gradually. Most participants again projected that the economy would grow somewhat more rapidly in 2011 and 2012, generating a more pronounced decline in the unemployment rate, as financial conditions and the availability of credit continue to improve. In general, participants saw the upside and downside risks to the outlook for economic growth as roughly balanced. Participants agreed that underlying inflation currently was subdued and was likely to remain so for some time. Some noted the risk that, with output well below potential over the next couple of years, inflation could edge further below the rates they judged most consistent with the Federal Reserve's dual mandate for maximum employment and price stability; others, focusing on risks to inflation expectations and the challenge of removing monetary accommodation in a timely manner, saw inflation risks as tilted toward the upside, especially in the medium term.

The weakness in labor markets continued to be an important concern for the FOMC; moreover, the prospects for job growth remained an important source of uncertainty in the economic outlook, particularly in the outlook for consumer spending. While the average pace of layoffs diminished substantially in recent months, few firms were hiring. The unusually large fraction of individuals who were working part time for economic reasons, as well as the uncommonly low level of the average workweek, pointed to a gradual increase in payrolls for some time even if hours worked were to increase substantially as the economic recovery proceeded. Indeed, many business contacts again reported that they would be cautious in hiring, saying they expected to meet any near-term increase in demand by raising existing employees' hours and boosting productivity, thus delaying the need to add employees. If businesses were able to continue generating large productivity gains, as in recent quarters, then firms would need to hire fewer workers in the near term to meet rising demands for their products. But if the unusually rapid productivity growth seen in recent quarters was not sustained, then job growth could pick up significantly as productivity returned to sustainable levels. The rise in employment of temporary workers in recent months appeared to be continuing; historical experience suggested that increased use of temporary help could presage a broader increase in job growth.

Participants generally saw the data and anecdotal evidence as indicating moderate growth in demands for goods and services, although with substantial variation across sectors. Consumer spending appeared to be increasing modestly. Reports on holiday sales were mixed. Retailers indicated that consumers appeared more willing to buy but that they remained unusually sensitive to pricing. Business contacts continued to report that they were limiting investment outlays pending resolution of uncertainty about sales prospects and future tax and regulatory policies; moreover, they had substantial excess capacity and thus little need to expand production facilities. Even so, the data indicated solid growth in business spending on high-tech equipment in recent months. Anecdotal evidence suggested that such spending was being driven by opportunities to reduce costs and by replacement investment that firms had deferred during the downturn. By and large, participants judged that residential investment had stabilized but did not expect housing construction to make a sizable contribution to economic growth during the next year or two. Commercial construction continued to trend down, primarily reflecting weak fundamentals, though financing constraints probably were also playing a role. Stronger economic growth abroad was contributing to growth in U.S. exports, thus helping support the recovery in industrial production in the United States.

Policymakers judged that financial conditions were, on balance, about as supportive of growth as when the Committee met in December. Though volatility in equity prices increased late in the intermeeting period, broad equity price indexes were about unchanged overall, private credit spreads narrowed somewhat, and financial markets generally continued to function significantly better than early last year. All categories of bank loans, however, continued to contract sharply. Survey evidence suggested that banks had ceased tightening standards on most types of business and consumer loans, though commercial real estate loans were a notable exception. Anecdotal evidence suggested that some banks were starting to look for opportunities to expand lending.

Though headline inflation had been variable, largely reflecting swings in energy prices, core measures of inflation were subdued and were expected to remain so. One participant noted that core inflation had been held down in recent quarters by unusually slow increases in the price index for shelter, and that the recent behavior of core inflation might be a misleading signal of the underlying inflation trend. Reports from business contacts suggested less price discounting, but pricing power remained limited. Wage growth continued to be restrained, and unit labor costs were still falling. Energy prices had dropped back in recent weeks, but many participants saw upward pressures on commodity prices associated with expanding global economic activity as an inflation risk. However, some noted that the high degree of slack in resource utilization posed a downside risk to inflation. Survey measures of expected future inflation were fairly stable, but some market-based measures of inflation expectations and inflation risk suggested continuing concern among market participants about the risk of higher medium-term inflation, perhaps reflecting large fiscal deficits and the size of the Federal Reserve's balance sheet.

Though participants agreed there was considerable slack in resource utilization, their judgments about the degree of slack varied. The several extensions of emergency unemployment insurance benefits appeared to have raised the measured unemployment rate, relative to levels recorded in past downturns, by encouraging some who have lost their jobs to remain in the labor force. If that effect were large—some estimates suggested it could account for 1 percentage point or more of the increase in the unemployment rate during this recession—then the reported unemployment rate might be overstating the amount of slack in resource utilization relative to past periods of high unemployment. Several participants observed that the necessity of reallocating labor across sectors as the recovery proceeds, as well as the loss of skills caused by high levels of long-term unemployment and permanent separations, could reduce the economy's potential output, at least temporarily; historical experience following large adverse financial shocks suggests such an effect. On the other hand, if recent productivity gains were to be sustained, as some business contacts indicated they would be, potential output currently could be higher than standard measures suggested, and the high level of the unemployment rate could be a more accurate indication of slack in resource utilization than usual measures of the output gap.

Committee Policy Action

In their discussion of monetary policy for the period ahead, members agreed that no changes to the Committee's large-scale asset purchase programs or to its target range for the federal funds rate were warranted at this meeting, inasmuch as the asset purchase programs were nearing completion and neither the economic outlook nor financial conditions had changed appreciably since the December meeting. Accordingly, the Committee affirmed its intention to purchase a total of $1.25 trillion of agency MBS and about $175 billion of agency debt by the end of the current quarter and to gradually slow the pace of these purchases to promote a smooth transition in markets. The Committee emphasized that it would continue to evaluate its purchases of securities in light of the evolving economic outlook and conditions in financial markets. Members recognized that references to "purchases" of securities would need to be modified as the completion of the asset purchase programs draws near. One member recommended that the FOMC replace the portion of the statement that indicates the Committee will evaluate its "purchases" of securities with an indication that the Committee will evaluate its "holdings" of securities. The change in wording would encompass the possibility that the Committee might decide, at some point, either to sell securities or to purchase additional securities. Other members judged that it would be premature to make such a change in the statement before observing economic and financial conditions as the Committee's current asset purchase program comes to a close. Accordingly, the Committee decided to retain the reference to securities "purchases" for the time being. The Committee also affirmed its 0 to ¼ percent target range for the federal funds rate and, based on the outlook for a gradual economic recovery, decided to reiterate its anticipation that economic conditions, including low levels of resource utilization, subdued inflation trends, and stable inflation expectations, were likely to warrant exceptionally low rates for an extended period. Members agreed that the path of short-term rates going forward would depend on the evolution of the economic outlook.

Committee members and Board members agreed that, with few exceptions, the functioning of most financial markets, including interbank markets, no longer showed significant impairment. Accordingly they agreed that the statement to be released following the meeting would indicate that the Federal Reserve would be closing the Asset-Backed Commercial Paper Money Market Mutual Fund Liquidity Facility, the Commercial Paper Funding Facility, the Primary Dealer Credit Facility, and the Term Securities Lending Facility on February 1, 2010. Committee members also agreed to announce that temporary liquidity swap arrangements between the Federal Reserve and other central banks would expire on February 1. In addition, the statement would say that amounts available through the Term Auction Facility would be scaled back further, with \$50 billion of 28-day credit to be offered on February 8 and \$25 billion of 28-day credit to be offered at the final auction of March 8. The statement also would note that the anticipated expiration dates for the Term Asset-Backed Securities Loan Facility remained June 30, 2010, for loans backed by new-issue commercial mortgage-backed securities, and March 31, 2010, for loans backed by all other types of collateral. Members emphasized that they were prepared to modify these plans if necessary to support financial stability and economic growth.

At the conclusion of the discussion, the Committee voted to authorize and direct the Federal Reserve Bank of New York, until it was instructed otherwise, to execute transactions in the System Account in accordance with the following domestic policy directive:

> "The Federal Open Market Committee seeks monetary and financial conditions that will foster price stability and promote sustainable growth in output. To further its long-run objectives, the Committee seeks conditions in reserve markets consistent with federal funds trading in a range from 0 to ¼ percent. The Committee directs the Desk to purchase agency debt and agency MBS during the intermeeting period with the aim of providing support to private credit markets and economic activity. The timing and pace of these purchases should depend on conditions in the markets for such securities and on a broader assessment of private credit market conditions. The Desk is expected to execute purchases of about \$175 billion in housing-related agency debt and about \$1.25 trillion of agency MBS by the end of the first quarter. The Desk is expected to gradually slow the pace of these purchases as they near completion. The Committee anticipates that outright purchases of securities will cause the size of the Federal Reserve's balance sheet to expand significantly in coming months. The Committee directs the Desk to engage in dollar roll transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions to be conducted through the end of the first quarter, as directed above. The System Open Market Account Manager and the Secretary will keep the Committee informed of ongoing developments regarding the System's balance sheet that could affect the attainment over time of the Committee's objectives of maximum employment and price stability."

The vote encompassed approval of the statement below to be released at 2:15 p.m.:

> "Information received since the Federal Open Market Committee met in December suggests that economic activity has continued to strengthen and that the deterioration in the labor market is abating. Household spending is expanding at a moderate rate but remains constrained by a weak labor market, modest income growth, lower housing wealth, and tight credit. Business spending on equipment and software appears to be picking up, but investment in structures is still contracting and employers remain reluctant to add to payrolls. Firms have brought inventory stocks into better alignment with sales. While bank lending continues to contract, financial market conditions remain supportive of economic growth. Although the pace of economic recovery is likely to be moderate for a time, the Committee anticipates a gradual return to higher levels of resource utilization in a context of price stability.

With substantial resource slack continuing to restrain cost pressures and with longer-term inflation expectations stable, inflation is likely to be subdued for some time.

The Committee will maintain the target range for the federal funds rate at 0 to ¼ percent and continues to anticipate that economic conditions, including low rates of resource utilization, subdued inflation trends, and stable inflation expectations, are likely to warrant exceptionally low levels of the federal funds rate for an extended period. To provide support to mortgage lending and housing markets and to improve overall conditions in private credit markets, the Federal Reserve is in the process of purchasing $1.25 trillion of agency mortgage-backed securities and about $175 billion of agency debt. In order to promote a smooth transition in markets, the Committee is gradually slowing the pace of these purchases, and it anticipates that these transactions will be executed by the end of the first quarter. The Committee will continue to evaluate its purchases of securities in light of the evolving economic outlook and conditions in financial markets.

In light of improved functioning of financial markets, the Federal Reserve will be closing the Asset-Backed Commercial Paper Money Market Mutual Fund Liquidity Facility, the Commercial Paper Funding Facility, the Primary Dealer Credit Facility, and the Term Securities Lending Facility on February 1, as previously announced. In addition, the temporary liquidity swap arrangements between the Federal Reserve and other central banks will expire on February 1. The Federal Reserve is in the process of winding down its Term Auction Facility: $50 billion in 28-day credit will be offered on February 8 and $25 billion in 28-day credit will be offered at the final auction on March 8. The anticipated expiration dates for the Term Asset-Backed Securities Loan Facility remain set at June 30 for loans backed by new-issue commercial mortgage-backed securities and March 31 for loans backed by all other types of collateral. The Federal Reserve is prepared to modify these plans if necessary to support financial stability and economic growth."

Voting for this action: Ben Bernanke, William C. Dudley, James Bullard, Elizabeth Duke, Donald L. Kohn, Sandra Pianalto, Eric Rosengren, Daniel K. Tarullo, and Kevin Warsh.

Voting against this action: Thomas M. Hoenig.

Mr. Hoenig dissented because he believed it was no longer advisable to indicate that economic and financial conditions were likely to "warrant exceptionally low levels of the federal funds rate for an extended period." In recent months, economic and financial conditions improved steadily, and Mr. Hoenig was concerned that, under these improving conditions, maintaining short-term interest rates near zero for an extended period of time would lay the groundwork for future financial imbalances and risk an increase in inflation expectations. Accordingly, Mr. Hoenig believed that it would be more appropriate for the Committee to express an expectation that the federal funds rate would be low for some time—rather than exceptionally low for an extended period. Such a change in communication would provide the Committee flexibility to begin raising rates modestly. He further believed that moving to a modestly higher federal funds rate soon would lower the risks of longer-run imbalances and an increase in long-run inflation expectations, while continuing to provide needed support to the economic recovery.

It was agreed that the next meeting of the Committee would be held on Tuesday, March 16, 2010. The meeting adjourned at 1:20 p.m. on January 27, 2010.

Notation Vote

By notation vote completed on January 5, 2010, the Committee unanimously approved the minutes of the FOMC meeting held on December 15-16, 2009.

Brian F. Madigan
Secretary

Summary of Economic Projections

In conjunction with the January 26–27, 2010, FOMC meeting, the members of the Board of Governors and the presidents of the Federal Reserve Banks, all of whom participate in deliberations of the FOMC, submitted projections for output growth, unemployment, and inflation for the years 2010 to 2012 and over the longer run. The projections were based on information available through the end of the meeting and on each participant's assumptions about factors likely to affect economic outcomes, including his or her assessment of appropriate monetary policy. "Appropriate monetary policy" is defined as the future path of policy that the participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her interpretation of the Federal Reserve's dual objectives of maximum employment and stable prices. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge over time under appropriate monetary policy and in the absence of further shocks.

FOMC participants' forecasts for economic activity and inflation were broadly similar to their previous projections, which were made in conjunction with the November 2009 FOMC meeting. As depicted in figure 1, the economic recovery from the recent recession was expected to be gradual, with real gross domestic product (GDP) expanding at a rate that was only moderately above participants' assessment of its longer-run sustainable growth rate and the unemployment rate declining slowly over the next few years. Most participants also anticipated that inflation would remain subdued over this period. As indicated in table 1, a few participants made modest upward revisions to their projections for real GDP growth in 2010. Beyond 2010, however, the contours of participants' projections for economic activity and inflation were little changed, with participants continuing to expect that the pace of the economic recovery will be restrained by household and business uncertainty, only gradual improvement in labor market conditions, and slow easing of credit conditions in the banking sector. Participants generally expected that it would take some time for the economy to converge fully to its longer-run path—characterized by a sustainable rate of output growth and by rates of employment and inflation consistent with their interpretation of the Federal Reserve's dual objectives—with a sizable minority of the view that the convergence process could take more than five to six years. As in November, nearly all participants judged the risks to their growth outlook as generally balanced, and most also saw roughly balanced risks surrounding their inflation projections. Participants continued to judge the uncertainty surrounding their projections for economic activity and inflation as unusually high relative to historical norms.

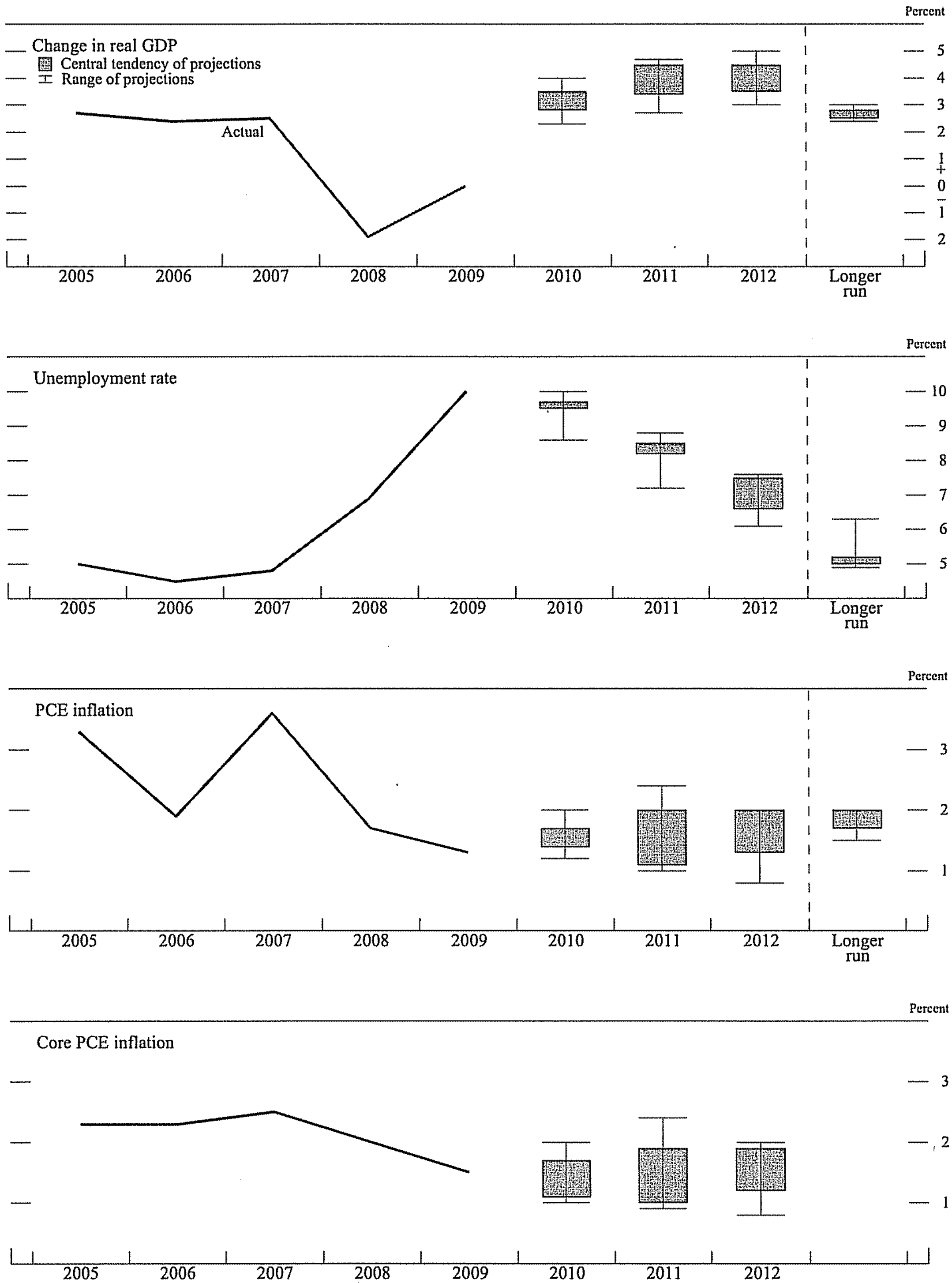
Table 1. Economic projections of Federal Reserve Governors and Reserve Bank presidents, January 2010
Percent

Variable	Central tendency[1]				Range[2]			
	2010	2011	2012	Longer run	2010	2011	2012	Longer run
Change in real GDP	2.8 to 3.5	3.4 to 4.5	3.5 to 4.5	2.5 to 2.8	2.3 to 4.0	2.7 to 4.7	3.0 to 5.0	2.4 to 3.0
November projection	2.5 to 3.5	3.4 to 4.5	3.5 to 4.8	2.5 to 2.8	2.0 to 4.0	2.5 to 4.6	2.8 to 5.0	2.4 to 3.0
Unemployment rate	9.5 to 9.7	8.2 to 8.5	6.6 to 7.5	5.0 to 5.2	8.6 to 10.0	7.2 to 8.8	6.1 to 7.6	4.9 to 6.3
November projection	9.3 to 9.7	8.2 to 8.6	6.8 to 7.5	5.0 to 5.2	8.6 to 10.2	7.2 to 8.7	6.1 to 7.6	4.8 to 6.3
PCE inflation	1.4 to 1.7	1.1 to 2.0	1.3 to 2.0	1.7 to 2.0	1.2 to 2.0	1.0 to 2.4	0.8 to 2.0	1.5 to 2.0
November projection	1.3 to 1.6	1.0 to 1.9	1.2 to 1.9	1.7 to 2.0	1.1 to 2.0	0.6 to 2.4	0.2 to 2.3	1.5 to 2.0
Core PCE inflation[3]	1.1 to 1.7	1.0 to 1.9	1.2 to 1.9		1.0 to 2.0	0.9 to 2.4	0.8 to 2.0	
November projection	1.0 to 1.5	1.0 to 1.6	1.0 to 1.7		0.9 to 2.0	0.5 to 2.4	0.2 to 2.3	

NOTE: Projections of change in real gross domestic product (GDP) and in inflation are from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The November projections were made in conjunction with the meeting of the Federal Open Market Committee on November 3–4, 2009.

1. The central tendency excludes the three highest and three lowest projections for each variable in each year.
2. The range for a variable in a given year consists of all participants' projections, from lowest to highest, for that variable in that year.
3. Longer-run projections for core PCE inflation are not collected.

Figure 1. Central tendencies and ranges of economic projections, 2010–12 and over the longer run



NOTE: Definitions of variables are in the notes to table 1. The data for the actual values of the variables are annual. The data for the change in real GDP, PCE inflation, and core PCE inflation shown for 2009 incorporate the advance estimate of GDP for the fourth quarter of 2009, which the Bureau of Economic Analysis released on January 29, 2010; this information was not available to FOMC meeting participants at the time of their meeting.

The Outlook

Participants' projections for real GDP growth in 2010 had a central tendency of 2.8 to 3.5 percent, a somewhat narrower interval than in November. Recent readings on consumer spending, industrial production, and business outlays on equipment and software were seen as broadly consistent with the view that economic recovery was under way, albeit at a moderate pace. Businesses had apparently made progress in bringing their inventory stocks into closer alignment with sales and hence would be likely to raise production as spending gained further momentum. Participants pointed to a number of factors that would support the continued expansion of economic activity, including accommodative monetary policy, ongoing improvements in the conditions of financial markets and institutions, and a pickup in global economic growth, especially in emerging market economies. Several participants also noted that fiscal policy was currently providing substantial support to real activity, but said that they expected less impetus to GDP growth from this factor later in the year. Many participants indicated that the expansion was likely to be restrained not only by firms' caution in hiring and spending in light of the considerable uncertainty regarding the economic outlook and general business conditions, but also by limited access to credit by small businesses and consumers dependent on bank-intermediated finance.

Looking further ahead, participants' projections were for real GDP growth to pick up in 2011 and 2012; the projections for growth in both years had a central tendency of about 3½ to 4½ percent. As in November, participants generally expected that the continued repair of household balance sheets and gradual improvements in credit availability would bolster consumer spending. Responding to an improved sales outlook and readier access to bank credit, businesses were likely to increase production to rebuild their inventory stocks and increase their outlays on equipment and software. In addition, improved foreign economic conditions were viewed as supporting robust growth in U.S. exports. However, participants also indicated that elevated uncertainty on the part of households and businesses and the very slow recovery of labor markets would likely restrain the pace of expansion. Moreover, although conditions in the banking system appeared to have stabilized, distress in commercial real estate markets was expected to pose risks to the balance sheets of banking institutions for some time, thereby contributing to only gradual easing of credit conditions for many households and smaller firms. In the absence of further shocks, participants generally anticipated that real GDP growth would converge over time to an annual rate of 2.5 to 2.8 percent, the longer-run pace that appeared to be sustainable in view of expected demographic trends and improvements in labor productivity.

Participants anticipated that labor market conditions would improve only slowly over the next several years. Their projections for the average unemployment rate in the fourth quarter of 2010 had a central tendency of 9.5 to 9.7 percent, only a little below the levels of about 10 percent that prevailed late last year. Consistent with their outlook for moderate output growth, participants generally expected that the unemployment rate would decline only about 2½ percentage points by the end of 2012 and would still be well above its longer-run sustainable rate. Some participants also noted that considerable uncertainty surrounded their estimates of the productive potential of the economy and the sustainable rate of employment, owing partly to substantial ongoing structural adjustments in product and labor markets. Nonetheless, participants' longer-run unemployment projections had a central tendency of 5.0 to 5.2 percent, the same as in November.

Most participants anticipated that inflation would remain subdued over the next several years. The central tendency of their projections for personal consumption expenditures (PCE) inflation was 1.4 to 1.7 percent for 2010, 1.1 to 2.0 percent for 2011, and 1.3 to 2.0 percent for 2012. Many participants anticipated that global economic growth would spur increases in energy prices, and hence that headline PCE inflation would run slightly above core PCE inflation over the next year or two. Most expected that substantial resource slack would continue to restrain cost pressures, but that inflation would rise gradually toward their individual assessments of the measured rate of inflation judged to be most consistent with the Federal Reserve's dual mandate. As in November, the central tendency of projections of the longer-run inflation rate was 1.7 to 2.0 percent. A majority of participants anticipated that inflation in 2012 would still be below their assessments of the mandate-consistent inflation rate, while the remainder expected that inflation would be at or slightly above its longer-run value by that time.

Uncertainty and Risks

Nearly all participants shared the judgment that their projections of future economic activity and unemployment continued to be subject to greater-than-average uncertainty.[1] Participants generally saw the risks to these projections as roughly balanced, although a few indicated that the risks to the unemployment outlook remained tilted to the upside. As in November, many participants highlighted the difficulties inherent in predicting macroeconomic outcomes in the wake of a financial crisis and a severe recession. In addition, some pointed to uncertainties regarding the extent to which the recent run-up in labor productivity would prove to be persistent, while others noted the risk that the deteriorating performance of commercial real estate could adversely affect the still-fragile state of the banking system and restrain the growth of output and employment over coming quarters.

As in November, most participants continued to see the uncertainty surrounding their inflation projections as higher than historical norms. However, a few judged that uncertainty in the outlook for inflation was about in line with typical levels, and one viewed the uncertainty surrounding the inflation outlook as lower than average. Nearly all participants judged the risks to the inflation outlook as roughly balanced; however, two saw these risks as tilted to the upside, while one regarded the risks as weighted to the downside. Some participants noted that inflation expectations could drift downward in response to persistently low inflation and continued slack in resource utilization. Others pointed to the possibility of an upward shift in expected and actual inflation, especially if extraordinarily accommodative monetary policy measures were not unwound in a timely fashion. Participants also noted that an acceleration in global economic activity could induce a surge in the prices of energy and other commodities that would place upward pressure on overall inflation.

Diversity of Views

Figures 2.A and 2.B provide further details on the diversity of participants' views regarding the likely outcomes for real GDP growth and the unemployment rate in 2010, 2011, 2012, and over the longer run. The distribution of participants' projections for real GDP growth this year was slightly narrower than the distribution of their projections last November, but the distributions of the projections for real GDP growth in 2011 and in 2012 were little changed. The dispersion in participants' output growth projections reflected, among other factors, the diversity of their assessments regarding the current degree of underlying momentum in economic activity, the evolution of consumer and business sentiment, and the likely pace of easing of bank lending standards and terms. Regarding participants' unemployment rate projections, the distribution for 2010 narrowed slightly, but the distributions of their unemployment rate projections for 2011 and 2012 did not change appreciably. The distributions of participants' estimates of the longer-run sustainable rates of output growth and unemployment were essentially the same as in November.

Figures 2.C and 2.D provide corresponding information about the diversity of participants' views regarding the inflation outlook. For overall and core PCE inflation, the distributions of participants' projections for 2010 were nearly the same as in November. The distributions of overall and core inflation for 2011 and 2012, however, were noticeably more tightly concentrated than in November, reflecting the absence of forecasts of especially low inflation. The dispersion in participants' projections over the next few years was mainly due to differences in their judgments regarding the determinants of inflation, including their estimates of prevailing resource slack and their assessments of the extent to which such slack affects actual and expected inflation. In contrast, the relatively tight distribution of participants' projections for longer-run infla-

Table 2. Average historical projection error ranges
Percentage points

Variable	2010	2011	2012
Change in real GDP[1]	±1.3	±1.5	±1.6
Unemployment rate[1]	±0.6	±0.8	±1.0
Total consumer prices[2]	±0.9	±1.0	±1.0

NOTE: Error ranges shown are measured as plus or minus the root mean squared error of projections for 1989 through 2008 that were released in the winter by various private and government forecasters. As described in the box "Forecast Uncertainty," under certain assumptions, there is about a 70 percent probability that actual outcomes for real GDP, unemployment, and consumer prices will be in ranges implied by the average size of projection errors made in the past. Further information is in David Reifschneider and Peter Tulip (2007), "Gauging the Uncertainty of the Economic Outlook from Historical Forecasting Errors," Finance and Economics Discussion Series 2007-60 (Washington: Board of Governors of the Federal Reserve System, November).

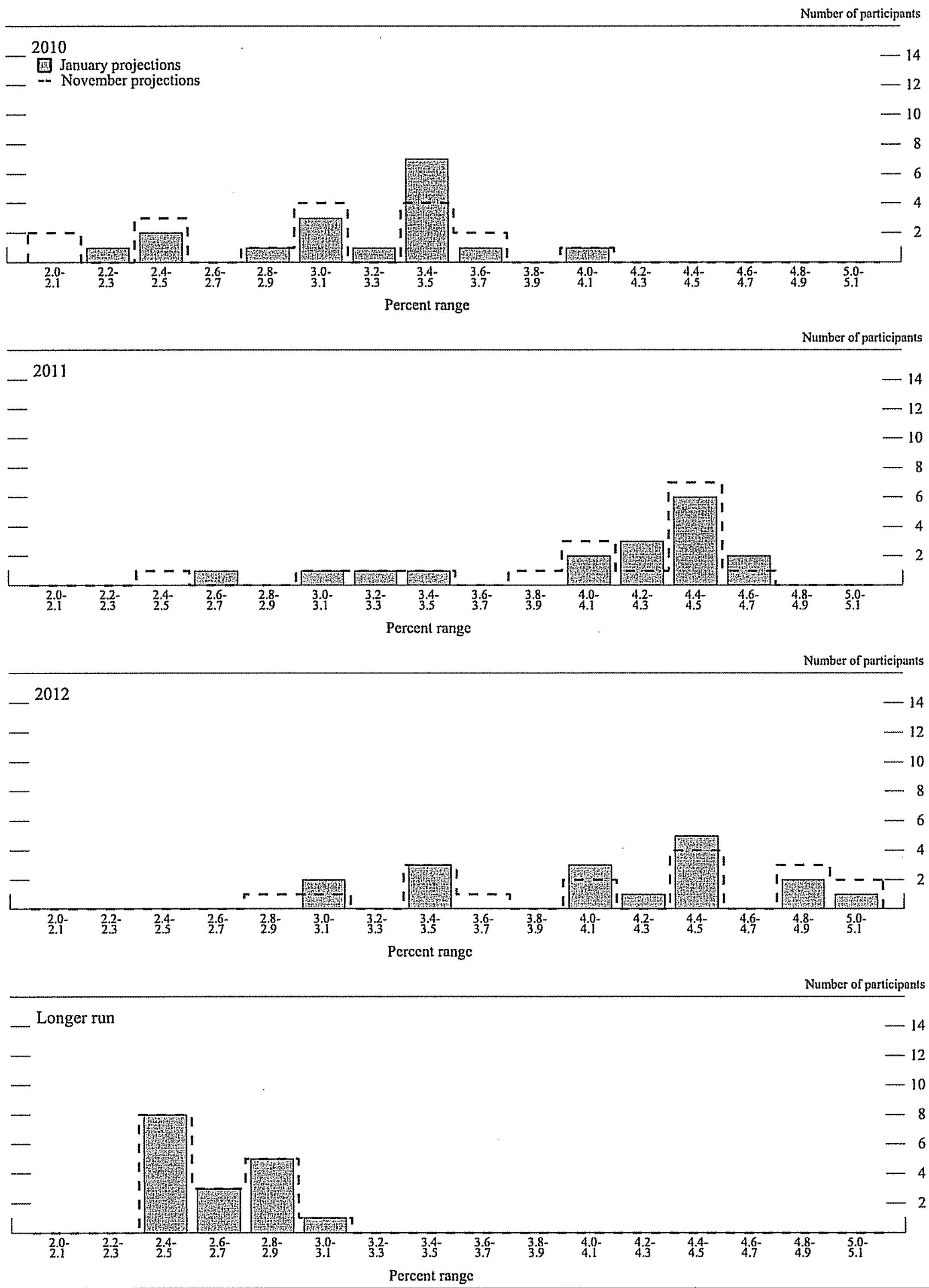
1. For definitions, refer to general note in table 1.

2. Measure is the overall consumer price index, the price measure that has been most widely used in government and private economic forecasts. Projection is percent change, fourth quarter of the previous year to the fourth quarter of the year indicated.

[1] Table 2 provides estimates of forecast uncertainty for the change in real GDP, the unemployment rate, and total consumer price inflation over the period from 1989 to 2008. At the end of this summary, the box "Forecast Uncertainty" discusses the sources and interpretation of uncertainty in economic forecasts and explains the approach used to assess the uncertainty and risk attending participants' projections.

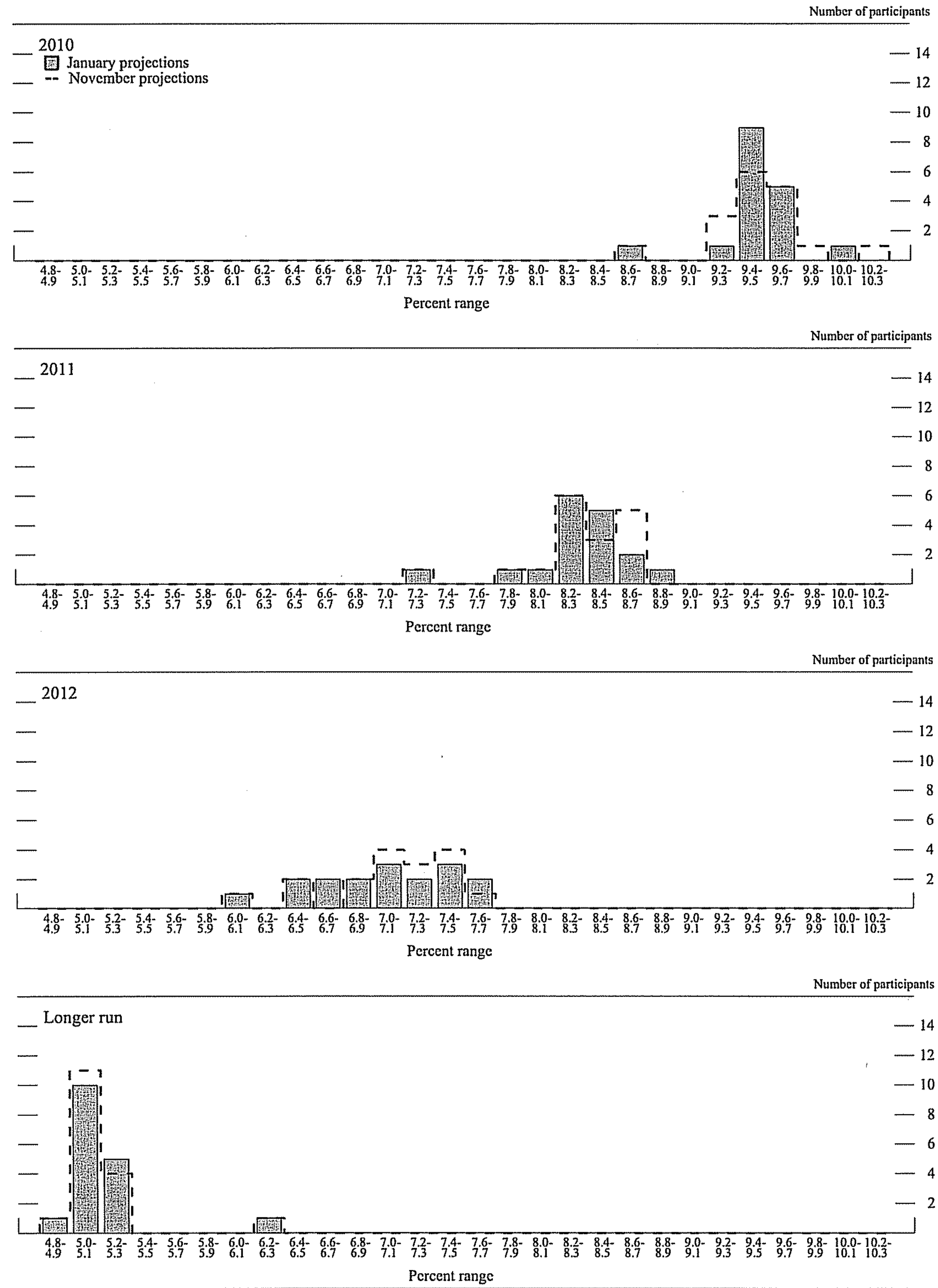
tion illustrates their substantial agreement about the measured rate of inflation that is most consistent with the Federal Reserve's dual objectives of maximum employment and stable prices.

Figure 2.A. Distribution of participants' projections for the change in real GDP, 2010–12 and over the longer run



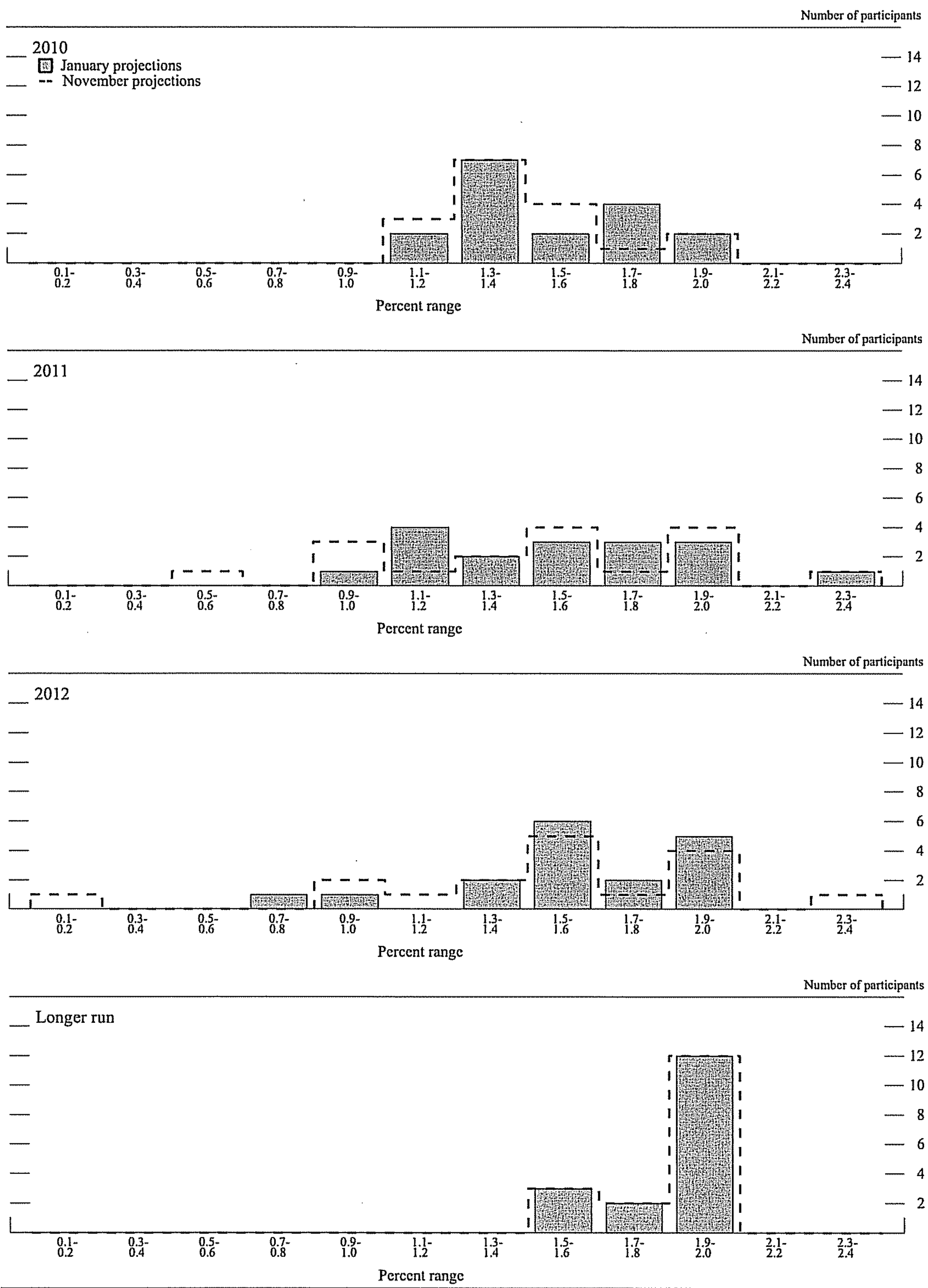
NOTE: Definitions of variables are in the general note to table 1.

Figure 2.B. Distribution of participants' projections for the unemployment rate, 2010–12 and over the longer run



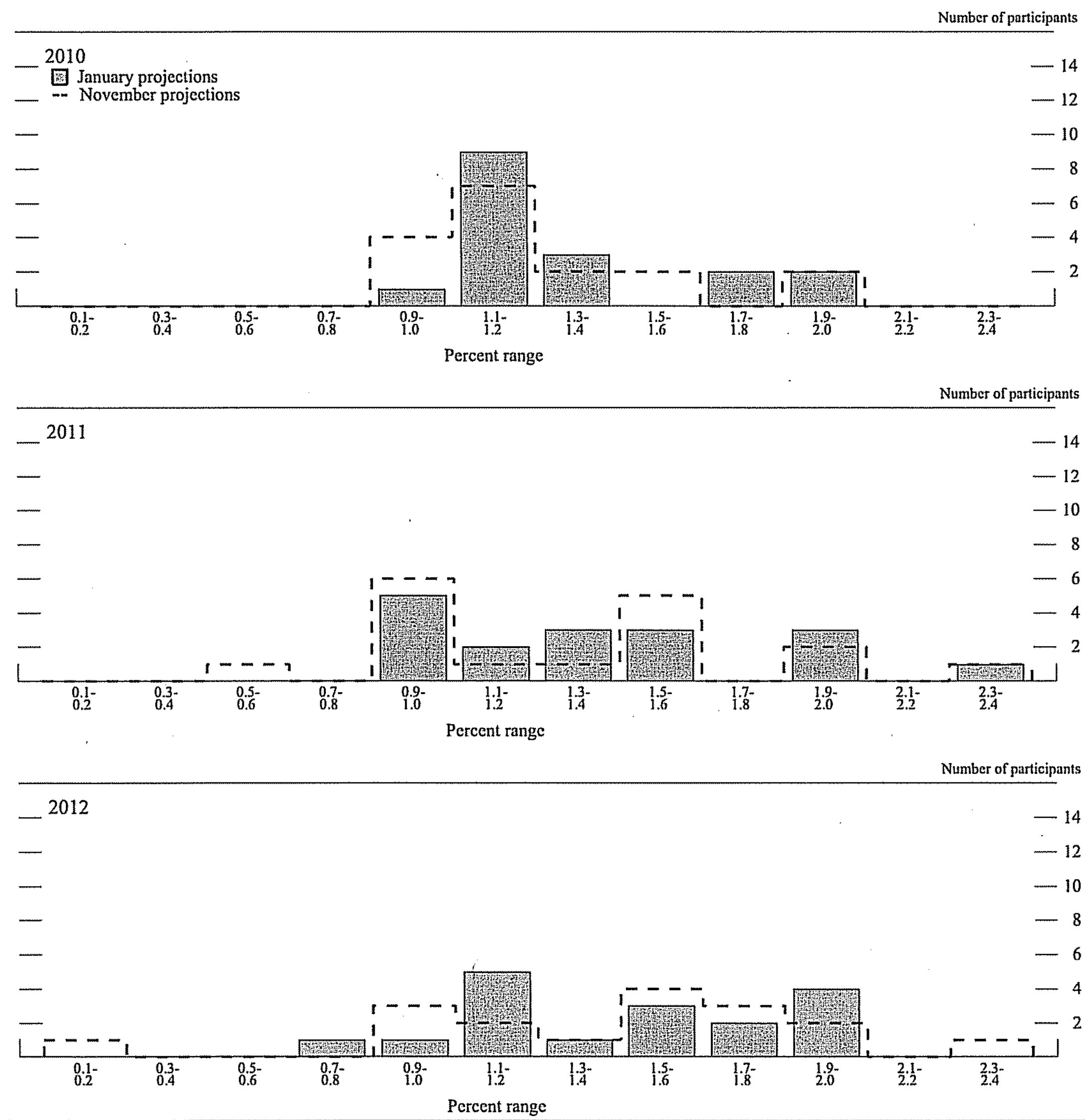
NOTE: Definitions of variables are in the general note to table 1.

Figure 2.C. Distribution of participants' projections for PCE inflation, 2010–12 and over the longer run



NOTE: Definitions of variables are in the general note to table 1.

Figure 2.D. Distribution of participants' projections for core PCE inflation, 2010–12



NOTE: Definitions of variables are in the general note to table 1.

Forecast Uncertainty

The economic projections provided by the members of the Board of Governors and the presidents of the Federal Reserve Banks inform discussions of monetary policy among policymakers and can aid public understanding of the basis for policy actions. Considerable uncertainty attends these projections, however. The economic and statistical models and relationships used to help produce economic forecasts are necessarily imperfect descriptions of the real world. And the future path of the economy can be affected by myriad unforeseen developments and events. Thus, in setting the stance of monetary policy, participants consider not only what appears to be the most likely economic outcome as embodied in their projections, but also the range of alternative possibilities, the likelihood of their occurring, and the potential costs to the economy should they occur.

Table 2 summarizes the average historical accuracy of a range of forecasts, including those reported in past *Monetary Policy Reports* and those prepared by Federal Reserve Board staff in advance of meetings of the Federal Open Market Committee. The projection error ranges shown in the table illustrate the considerable uncertainty associated with economic forecasts. For example, suppose a participant projects that real gross domestic product (GDP) and total consumer prices will rise steadily at annual rates of, respectively, 3 percent and 2 percent. If the uncertainty attending those projections is similar to that experienced in the past and the risks around the projections are broadly balanced, the numbers reported in table 2 would imply a probability of about 70 percent that actual GDP would expand within a range of 1.7 to 4.3 percent in the current year, 1.5 to 4.5 percent in the second year, and 1.4 to 4.6 percent in the third year. The corresponding 70 percent confidence intervals for overall inflation would be 1.1 to 2.9 percent in the current year and 1.0 to 3.0 percent in the second and third years.

Because current conditions may differ from those that prevailed, on average, over history, participants provide judgments as to whether the uncertainty attached to their projections of each variable is greater than, smaller than, or broadly similar to typical levels of forecast uncertainty in the past as shown in table 2. Participants also provide judgments as to whether the risks to their projections are weighted to the upside, are weighted to the downside, or are broadly balanced. That is, participants judge whether each variable is more likely to be above or below their projections of the most likely outcome. These judgments about the uncertainty and the risks attending each participant's projections are distinct from the diversity of participants' views about the most likely outcomes. Forecast uncertainty is concerned with the risks associated with a particular projection rather than with divergences across a number of different projections.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 910

Exhibits in Support
Of Opening Testimony

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THE GREAT CRASH, THE OIL PRICE SHOCK, AND THE UNIT ROOT HYPOTHESIS

BY PIERRE PERRON[1]

We consider the null hypothesis that a time series has a unit root with possibly nonzero drift against the alternative that the process is "trend-stationary." The interest is that we allow under both the null and alternative hypotheses for the presence of a one-time change in the level or in the slope of the trend function. We show how standard tests of the unit root hypothesis against trend stationary alternatives cannot reject the unit root hypothesis if the true data generating mechanism is that of stationary fluctuations around a trend function which contains a one-time break. This holds even asymptotically. We derive test statistics which allow us to distinguish the two hypotheses when a break is present. Their limiting distribution is established and selected percentage points are tabulated. We apply these tests to the Nelson-Plosser data set and to the postwar quarterly real GNP series. In the former, the break is due to the 1929 crash and takes the form of a sudden change in the level of the series. For 11 out of the 14 series analyzed by Nelson and Plosser we can reject at a high confidence level the unit root hypothesis. In the case of the postwar quarterly real GNP series, the break in the trend function occurs at the time of the oil price shock (1973) and takes the form of a change in the slope. Here again we can reject the null hypothesis of a unit root. If one is ready to postulate that the 1929 crash and the slowdown in growth after 1973 are not realizations of an underlying time-invariant stochastic process but can be modeled as exogenous, then the conclusion is that most macroeconomic time series are not characterized by the presence of a unit root. Fluctuations are indeed stationary around a deterministic trend function. The only "shocks" which have had persistent effects are the 1929 crash and the 1973 oil price shock.

KEYWORDS: Hypothesis testing, intervention analysis, structural change, stochastic trends, deterministic trends, functional weak convergence, Wiener process, macroeconomic time series.

1. INTRODUCTION

THE UNIT ROOT HYPOTHESIS has recently attracted a considerable amount of work in both the economics and statistics literature. Indeed, the view that most economic time series are characterized by a stochastic rather than deterministic nonstationarity has become prevalent. The seminal study of Nelson and Plosser (1982) which found that most macroeconomic variables have a univariate time series structure with a unit root has catalyzed a burgeoning research program with both empirical and theoretical dimensions.

Nelson and Plosser's study was followed by a series of empirical analyses which basically confirmed their findings. Some (Stulz and Wasserfallen (1985) and Wasserfallen (1986), among others) applied a similar Dickey-Fuller (1979) statistical methodology to other economic series. On the statistical front, there

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emerged an interest in developing alternative approaches to test the unit root hypothesis. Examples include: the class of tests proposed by Phillips and Perron (1988) and the methodology suggested by Campbell and Mankiw (1987, 1988) and Cochrane (1988) using an estimate of the spectral density at frequency zero. Empirical applications of these methodologies generally reaffirmed the conclusion that most macroeconomic time series have a unit root (e.g., Perron (1988)).

These studies had many effects on economic theorizing. They seem to confirm previous analyses which had advanced the unit root hypothesis for particular economic series, e.g., consumption (Hall (1978)), velocity of money (Gould and Nelson (1974)), and stock prices (Samuelson (1973)). They also launched a series of theoretical investigations with implications consistent with a unit root, e.g., Blanchard and Summers (1986) for employment. Furthermore, a considerable stock of statistical tools was developed for more general models with integrated variables; these include the cointegration framework (Engle and Granger (1987)) and multivariate systems (Stock and Watson (1988) and Phillips and Durlauf (1986)).

As far as macroeconomic theories are concerned, the most important implication of the unit root revolution, is that under this hypothesis random shocks have a permanent effect on the system. Fluctuations are not transitory. This implication, as forcefully argued by Nelson and Plosser, has profound consequences for business cycle theories. It runs counter to the prevailing view that business cycles are transitory fluctuations around a more or less stable trend path. It is therefore of importance to assess carefully the reliability of the unit root hypothesis as an empirical fact.

The aim of this paper appears startling, given the results in the above mentioned literature. Our conclusion is that most macroeconomic time series are not characterized by the presence of a unit root and that fluctuations are indeed transitory. Only two events (shocks) have had a permanent effect on the various macroeconomic variables: the Great Crash of 1929 and the oil price shock of 1973.

Of course, to reach such a conclusion, a particular postulate must be introduced which differentiates our approach from the previous ones. This postulate is that the Great Crash and the oil price shock were not a realization of the underlying data-generating mechanism of the various series. In this sense, we consider these shocks as exogenous. The exogeneity assumption is not a statement about a descriptive model for the time series representation of the variables. It is used here as a device to remove the influence of these shocks from the noise function. A more detailed discussion of these issues and their implications can be found in Section 6.

These two shocks are rather different in nature. On one hand, the Great Crash created a dramatic drop in the mean of most aggregate variables. On the other hand, the 1973 oil price shock was followed by a change in the slope of the trend for most aggregates, i.e., a slowdown in growth. In this light, our aim is to show that most macroeconomic variables are "trend-stationary" if one allows a single change in the intercept of the trend function after 1929 and a single change in the slope of the trend function after 1973.

Our approach is in the spirit of the "intervention analysis" suggested by Box and Tiao (1975). According to their methodology, "aberrant" or "outlying" events can be separated from the noise function and be modeled as changes or "interventions" in the deterministic part of the general time series model. Using such a strategy makes it "possible to distinguish between what can and what cannot be explained by the noise" (Box and Tiao (1975, p. 72)). These "interventions" are assumed to occur at a known date. The same strategy is used in the present analysis in that we consider the time of the changes in the trend function as fixed rather than as a random variable to be estimated.

To make our point as unambiguous as possible, we use the same data set as Nelson and Plosser, as well as the real GNP series analyzed by Campbell and Mankiw. The data set used by Nelson and Plosser contains fourteen macroeconomic variables sampled annually. All series end in 1970 and contain only one break, the 1929 Great Crash. We shall not analyze the unemployment rate series since there is a general agreement that it is stationary. The real GNP series is postwar quarterly from 1947:I to 1986:III and so contains only one break as well, the 1973 oil shock. Furthermore, to make our analysis as similar as possible to previous ones, the statistical methodology applied here is an extension of the Dickey–Fuller methodology (as used by Nelson and Plosser) to test for the presence of a single unit root in a univariate time series.

The plan of the paper is as follows. Section 2 motivates the ensuing analysis and presents the alternative models considered. Section 3 shows that usual tests will not be able to reject the unit root hypothesis if in fact the deterministic trend of the series has a single break (either in the intercept or the slope). In Section 4, we develop formal statistical tests of the null hypothesis of a unit root which can distinguish the unit root hypothesis from that of a stationary series around a trend which has a single break. The asymptotic distributions under the null hypothesis are derived and tabulated. Empirical results from applying these procedures are presented in Section 5. Section 6 contains a discussion of some issues raised by our analysis and suggestions for future research. All theorems are proved in Appendix A.

2. MOTIVATION

The null hypothesis considered is that a given series $\{y_t\}_0^T$ (of which a sample of size $T+1$ is available) is a realization of a time series process characterized by the presence of a unit root and possibly a nonzero drift. However, the approach is generalized to allow a one-time change in the structure occurring at a time T_B $(1 < T_B < T)$. Three different models are considered under the null hypothesis: one that permits an exogeneous change in the level of the series (a "crash"), one that permits an exogenous change in the rate of growth, and one that allows both change. These hypotheses are parameterized as follows:

Null hypotheses:

Model (A) $y_t = \mu + dD(TB)_t + y_{t-1} + e_t,$

Model (B) $y_t = \mu_1 + y_{t-1} + (\mu_2 - \mu_1)DU_t + e_t,$

Model (C) $y_t = \mu_1 + y_{t-1} + dD(TB)_t + (\mu_2 - \mu_1)DU_t + e_t,$ where

$$D(TB)_t = 1 \quad \text{if} \quad t = T_B + 1, \quad 0 \text{ otherwise};$$
$$DU_t = 1 \quad \text{if} \quad t > T_B, \quad 0 \text{ otherwise}; \quad \text{and}$$
$$A(L)e_t = B(L)v_t,$$

$v_t \sim$ i.i.d. $(0, \sigma^2)$, with $A(L)$ and $B(L)$ pth and qth order polynomials, respectively, in the lag operator L.

The innovation series $\{e_t\}$ is taken to be of the ARMA(p, q) type with the orders p and q possibly unknown. This postulate allows the series $\{y_t\}$ to represent quite general processes. More general conditions are possible and will be used in subsequent theoretical derivations.

Instead of considering the alternative hypothesis that y_t is a stationary series around a deterministic linear trend with time invariant parameters, we shall analyze the following three possible alternative models:

Alternative hypotheses:

Model (A) $y_t = \mu_1 + \beta t + (\mu_2 - \mu_1)DU_t + e_t,$

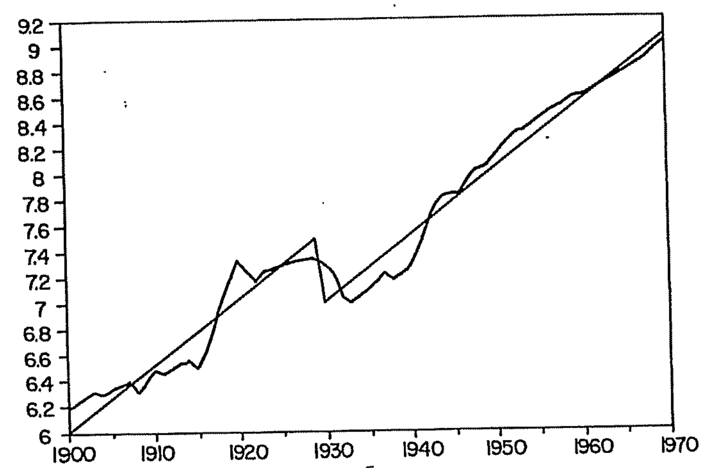
Model (B) $y_t = \mu + \beta_1 t + (\beta_2 - \beta_1)DT_t^* + e_t,$

Model (C) $y_t = \mu_1 + \beta_1 t + (\mu_2 - \mu_1)DU_t + (\beta_2 - \beta_1)DT_t + e_t$

where

$$DT_t^* = t - T_B, \quad \text{and} \quad DT_t = t \quad \text{if} \quad t > T_B \quad \text{and 0 otherwise.}$$

Here, T_B refers to the time of break, i.e., the period at which the change in the parameters of the trend function occurs. Model (A) describes what we shall refer to as the crash model. The null hypothesis of a unit root is characterized by a dummy variable which takes the value one at the time of break. Under the alternative hypothesis of a "trend-stationary" system, Model (A) allows for a one-time change in the intercept of the trend function. For the empirical cases we have in mind, T_B is the year 1929 and $\mu_2 < \mu_1$. Model (B) is referred to as the "changing growth" model. Under the alternative hypothesis, a change in the slope of the trend function without any sudden change in the level at the time of the break is allowed. Under the null hypothesis, the model specifies that the drift parameter μ changes from μ_1 to μ_2 at time T_B. In the empirical examples presented in Section 5, T_B is the first quarter of 1973 and $\beta_2 < \beta_1$, reflecting a slowdown in growth following the oil shock. Model (C) allows for both effects to take place simultaneously, i.e., a sudden change in the level followed by a different growth path.



Note: The broken straight line is a fitted trend (by OLS) of the form $\tilde{y}_t = \tilde{\mu} + \tilde{\gamma} DU_t + \tilde{\beta} t$ where $DU_t = 0$ if $t \leqslant 1929$ and $DU_t = 1$ if $t > 1929$.

FIGURE 1.—Logarithm of "Nominal Wages."

To motivate the use of these three models as possible alternatives to the unit root with drift hypothesis, we present in this section some descriptive analyses for three series: "nominal wages" (1900–1970), "quarterly real GNP" (1947:I–1986:III) and "common stock prices" (1871–1970).

Figure 1 shows a plot of the logarithm of the nominal wage series. A feature of this graph is the marked decrease between 1929 and 1930. Apart from this change, the trend appears fairly stable (same slope) over the entire period. The solid line is the estimated trend line from a regression on a constant, a trend and a dummy variable taking a value of 0 prior and at 1929 and value 1 afterwards. Table I presents the results from estimating (by OLS) a regression of the Dickey-Fuller type, i.e.:

$$y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \sum_{i=1}^{k} \tilde{c}_i \Delta y_{t-i} + \tilde{e}_t. \tag{1}$$

The first row presents the full sample regression. The coefficient on the lag dependent variable is 0.910 with a t statistic for the hypothesis that $\alpha = 1$ of -2.09. Using the critical values tabulated by Dickey and Fuller, we cannot reject the null hypothesis of a unit root. When the sample is split in two (pre-1929 and post-1929), the estimated value of α decreases dramatically: 0.304 for the pre-1929 sample and 0.735 for the post-1929 sample. However, due to the small samples available, the t statistics are not large enough (in absolute value) to reject the hypothesis that $\alpha = 1$, even at the 10 percent level.

Two features are worth emphasizing from this example: (a) the full sample estimate of α is markedly superior to any of the split sample estimates and relatively close to one. It appears that the 1929 crash is responsible for the near unit root value of α; and (b) the split sample regressions are not powerful enough

TABLE I

REGRESSION ANALYSIS FOR THE WAGES, QUARTERLY GNP, AND COMMON STOCK PRICE SERIES

Regression: $y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \Sigma_{i=1}^{k} \tilde{c}_i \Delta y_{t-i} + \tilde{e}_t$

Series/Period	k	$\tilde{\mu}$	$t_{\tilde{\mu}}$	$\tilde{\beta}$	$t_{\tilde{\beta}}$	$\tilde{\alpha}$	$t_{\tilde{\alpha}}$	$S(\tilde{e})$
(a) Wages								
1900–1970[a]	2	0.566	2.30	0.004	2.30	0.910	−2.09	0.060
1900–1929	7	4.299	2.84	0.037	2.73	0.304	−2.82	0.0803
1930–1970	8	1.632	3.60	0.012	2.64	0.735	−3.19	0.0269
(b) Common stock prices								
1871–1970[a]	2	0.481	2.02	0.003	2.37	0.913	−2.05	0.158
1871–1929	3	0.3468	2.13	0.0063	2.70	0.732	−2.29	0.1209
1930–1970	4	−0.5312	−1.64	0.0166	1.96	0.788	−1.89	0.1376
(c) Quarterly real GNP								
1947:I–1986:III	2	0.386	2.90	0.0004	2.71	0.946	−2.85	0.010
1947:I–1973:I	2	0.637	3.04	0.0008	2.99	0.910	−3.02	0.0099
1973:II–1986:III	1	0.883	2.23	0.0008	2.27	0.878	−2.23	0.0102

[a] Results taken from Nelson and Plosser (1982, Table 5).

to reject the hypothesis that $\alpha = 1$ even though the estimates are well below one. It would be useful, in this light, to have a more powerful procedure based on the full sample that would allow the 1929 break to be exogenous.

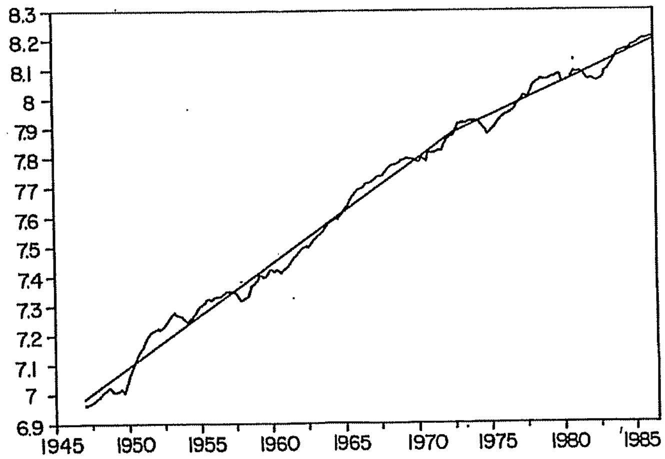
Figure 2 graphs the postwar quarterly real GNP series. Here, the series behave according to Model (B) where there is no sharp change in the level of the series at the 1973:I break point but rather a change in the slope. The solid line is a fitted trend where a dummy variable is included in the regression, taking the value 0 prior and at 1973:I and the value $(t - 105)$ after 1973:I (1973:I being the 105th observation in the sample). Table I compares regressions of the form (1) with full and split samples. Again, the estimate of α is lower in both subsamples than with

TABLE II

SAMPLE AUTOCORRELATIONS OF THE "DETRENDED" SERIES

Series		Period	T	Variance	r_1	r_2	r_3	r_4	r_5	r_6
Real GNP	A	1909–1970	62	0.010	0.77	0.45	0.23	0.11	0.05	0.04
Nominal GNP	A	1909–1970	62	0.023	0.68	0.31	0.12	0.08	0.11	0.12
Real per capita GNP	A	1909–1970	62	0.012	0.81	0.54	0.33	0.20	0.13	0.09
Industrial production	A	1860–1970	111	0.017	0.71	0.44	0.32	0.17	0.08	0.12
Employment	A	1890–1970	81	0.005	0.82	0.59	0.43	0.30	0.20	0.15
GNP deflator	A	1889–1970	82	0.015	0.82	0.63	0.45	0.31	0.17	0.06
Consumer prices	A	1860–1970	111	0.066	0.96	0.89	0.80	0.71	0.63	0.54
Wages	A	1900–1970	71	0.016	0.76	0.47	0.26	0.12	0.03	−0.03
Real wages	C	1900–1970	71	0.003	0.74	0.40	0.12	−0.12	−0.27	−0.33
Money stock	A	1889–1970	82	0.023	0.87	0.69	0.52	0.38	0.25	0.11
Velocity	A	1869–1970	102	0.036	0.90	0.79	0.70	0.62	0.57	0.52
Interest rate	A	1900–1970	71	0.587	0.77	0.58	0.38	0.25	0.15	0.11
Common stock prices	C	1871–1970	100	0.066	0.80	0.53	0.36	0.20	0.10	0.08
Quarterly GNP	B	47:I 86:III	159	0.001	0.94	0.83	0.70	0.57	0.45	0.35

Note: A, B, and C denote the detrending procedure corresponding to the given model under the alternative hypothesis.

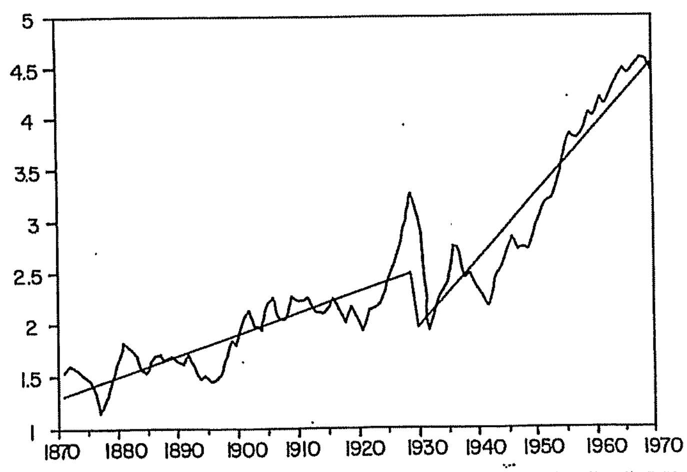


Note: The broken straight line is a fitted trend (by OLS) of the form: $\tilde{y}_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\gamma} DT_t^*$ where $DT_t^* = 0$ if $t \leqslant 1973{:}\mathrm{I}$ and $DT_t^* = t - T_B$ if $t > 1973{:}\mathrm{I} = T_B$.

FIGURE 2.—Logarithm of "Postwar Quarterly Real GNP."

the full sample (given the quarterly nature of the series, the difference is important). The same features discussed above appear to hold when there is a change in the slope of the trend function.

As a final example, consider the common stock price series graphed in Figure 3. The break point is again in 1929 but in this case there appears to be both a sudden change in the level of the series in 1929 and a higher growth rate after. The solid line is the estimated trend with two dummy variables added, an intercept dummy (0 prior and at 1929, 1 after 1929) and a slope dummy (0 prior



Note: The broken straight line is a fitted trend (by OLS) of the form $\tilde{y}_t = \tilde{\mu} + \tilde{\gamma}_1 DU_t + \tilde{\beta}t + \tilde{\gamma}_2 DT_t$ where $DU_t = DT_t = 0$ if $t \leqslant 1929$ and $DU_t = 1$, $DT_t = t$ if $t > 1929$.

FIGURE 3.—Logarithm of "Common Stock Prices."

and at 1929 and t after 1929). The estimated values of α (in regression (1)) with the full sample are 0.913 but are only 0.732 using the pre-1929 sample and 0.788 using the post-1929. Here again, the t statistics are not large enough, however, to reject the unit root hypothesis at even the 10 percent level using any of the subsamples.[2]

Table II presents the autocorellation function of the "detrended series" for the full set of variables analyzed by Nelson and Plosser, along with the postwar quarterly real GNP series. All series are detrended according to Model (A) (with a constant, a trend, and an intercept dummy) except for the postwar Quarterly Real GNP Series (with a slope dummy instead of the intercept dummy, Model (B)) and the real wage and common stock price series (with both a slope and intercept dummy, Model (C)). Unlike the "standard" detrended series (see Table 4 of Nelson-Plosser), the autocorrelations decay quite rapidly for all variables except for the consumer prices and velocity series. This behavior of the autocorrelation function is certainly not the one usually associated with either a random walk or a detrended random walk. Indeed, the "detrended" series appear stationary.

The results of this section motivate the analysis presented in the following sections. We first investigate the effects of the two types of changes in the trend function that we consider on the statistical properties of autoregressive estimates of the type found in regression (1) (both in finite samples and asymptotically). We find that such changes create a spurious unit root that may not vanish, even asymptotically. To overcome the problem of the low power associated with testing for a unit root using split samples, formal test statistics, which permit the presence of either or both an intercept and a slope shift, are developed in Section 4.

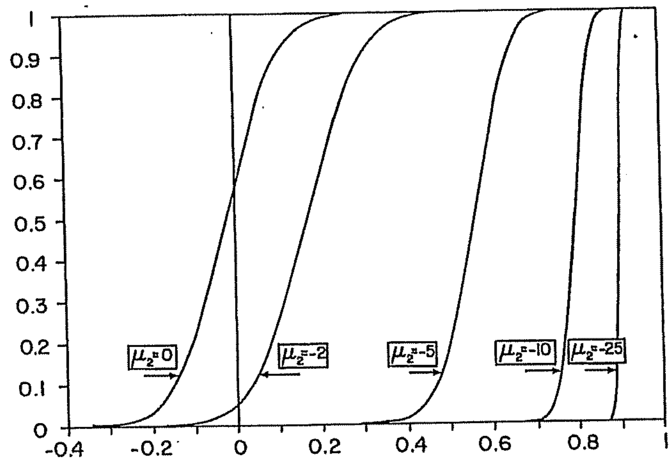
3. THE EFFECT OF A SHIFT IN THE TREND FUNCTION ON TESTS FOR A UNIT ROOT

To assess the effects of the presence of a shift in the level of the series or a shift in the slope (at a single point of time) on tests for the presence of a unit root, we first present a small Monte Carlo experiment. Consider first the "crash hypothesis" (Model (A)). We generated 10,000 replications of a series $\{y_t\}$ of length 100 defined by

$$y_t = \mu_1 + (\mu_2 - \mu_1)DU_t + \beta t + e_t \qquad (t = 1, \ldots, T), \tag{2}$$

where $DU_t = 1$ if $t > T_B$, and 0 otherwise.

[2]Dickey-Fuller tests for the presence of a unit root using split samples are presented in Appendix B for all the series considered. The results are presented for values of k ranging from 1 to 12. These results show that (i) the conclusions drawn are not sensitive to the value of k chosen; (ii) for some series it is possible to reject the unit root hypothesis, especially when considering the post-1929 subsample. Furthermore, the statistical significance of the lagged first-differences (not reported) suggest that a large value of k may be needed. For example, the t statistics on the eighth lagged first-difference is often statistically significant. A similar pattern will occur in the full sample tests reported in subsequent sections.



Note: $\tilde{\alpha}$ is the estimated autoregressive parameter in regression (4). The data-generating mechanism is given by equation (2) with $\mu_1 = 0$, $\beta = 1.0$ and $\{e_t\}$ i.i.d. $N(0,1)$, $T = 100$ and $T_B = 50$.

FIGURE 4.—C.D.F. of $\tilde{\alpha}$ under the "Crash" Model.

For simplicity, $\mu_1 = 0$, $\beta = 1$, $T_B = 50$, $T = 100$ and the innovations e_t are i.i.d. $N(0,1)$. For the "changing growth" hypothesis, a similar setup is considered except that y_t is generated by

$$y_t = \mu + \beta_1 t + (\beta_2 - \beta_1) DT_t^* + e_t \qquad (t = 1, \ldots, T), \tag{3}$$

where $DT_t^* = t - T_B$ if $t > T_B$, and 0 otherwise.

Again, $\mu = 0$, $\beta_1 = 1$, $T_B = 50$, $T = 100$, and $e_t \sim$ i.i.d. $N(0,1)$. For each replication, we computed the autoregressive coefficient $\tilde{\alpha}$ in the following regression, using ordinary least squares:

$$y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \tilde{e}_t. \tag{4}$$

Figure 4 graphs the cumulative distribution function of $\tilde{\alpha}$ when the data generating process (D.G.P.) is given by (2) for various values of μ_2. This experiment reveals that as the magnitude of the crash increases (μ_2 decreases), the c.d.f of $\tilde{\alpha}$ becomes more concentrated at a value ever closer to 1. The corresponding mean and variance of the sample of $\tilde{\alpha}$ generated are shown in Table III. Figure 5 graphs the c.d.f. of $\tilde{\alpha}$ when the D.G.P. is given by (3) for various values of β_2. As β_2 diverges from β_1, again, the c.d.f. becomes more concentrated and closer to one. The computed mean and variance of $\tilde{\alpha}$ presented in Table III confirms this behavior.[3]

[3]Note that when the error structure is i.i.d., $\tilde{\alpha}$ is free of nuisance parameters and hence can be used as a formal test statistic on the same ground as the t statistic. However, we also performed a similar experiment with the t statistic on $\tilde{\alpha}$ ($\alpha = 1$) in regression (4) as well as in a regression with additional lags of first-differences as regressors. The results obtained show the same behavior. If anything, the t statistic with extra lags of first-differences as regressors shows a still greater bias toward nonrejection of the null hypothesis of a unit root. These results are available upon request. We prefer to report our result in terms of the behavior of the estimator $\tilde{\alpha}$ instead of its t statistic because it makes clear that what causes the nonrejection is not due solely to the behavior of the variance estimator. What is of importance is that $\tilde{\alpha}$ is biased towards unity.

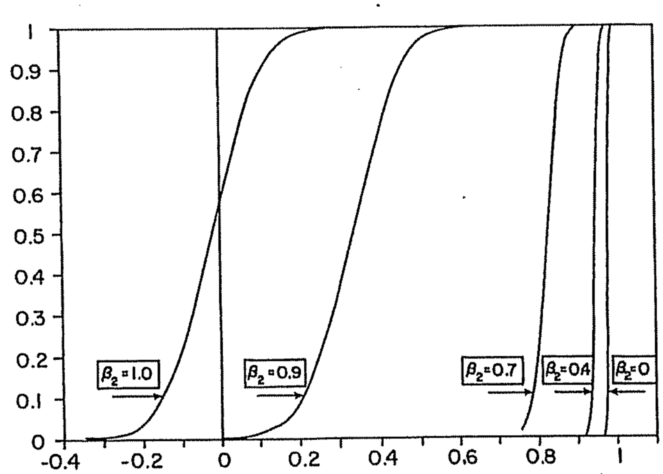
TABLE III
MEAN AND VARIANCE OF $\tilde{\alpha}$

	(a) Crash Simulations, $\mu_1 = 0$, $\beta = 1$				
	$\mu_2 = 0$	$\mu_2 = -2$	$\mu_2 = -5$	$\mu_2 = -10$	$\mu_2 = -25$
Mean	-0.019	0.172	0.558	0.795	0.899
Variance	0.00986	0.01090	0.00471	0.00089	0.00009
	(b) Breaking Trend Simulations, $\beta_1 = 1$, $\mu = 0$				
	$\beta_2 = 1.0$	$\beta_2 = 0.9$	$\beta_2 = 0.7$	$\beta_2 = 0.4$	$\beta_2 = 0.0$
Mean	-0.019	0.334	0.825	0.949	0.981
Variance	0.00986	0.00938	0.00094	0.00009	0.00001

See notes to Figure 4 for case (a) and Figure 5 for case (b).

What emerges from this experiment is that if the magnitude of the shift is significant, one could hardly reject the unit root hypothesis even if the series is that of a trend (albeit with a break) with i.i.d. disturbances. In particular, one would conclude that the shocks have permanent effects. Here, the shocks clearly have no permanent effects, only the one-time shift in the trend function is permanent.

To analyze the effect of an increase in the sample size on the distribution of $\tilde{\alpha}$ with a shift of a given magnitude, we derive the asymptotic limit of $\tilde{\alpha}$. To this end, we again consider processes generated by Models (A), (B), or (C) under the alternative hypotheses, but we enlarge the framework by allowing general conditions on the error structure $\{e_t\}$. Many such sets of conditions are possible and would allow us to carry out the asymptotic theory. For simplicity, we use the



Note: $\tilde{\alpha}$ is the estimated autoregressive parameter in regression (4). The data-generating mechanism is given by equation (3) with $\mu = 0$, $\beta_1 = 1.0$, $\{e_t\}$ i.i.d. $N(0,1)$, $T = 100$, $T_B = 50$.

FIGURE 5.—C.D.F. of $\tilde{\alpha}$ under the "Breaking Trend" Model.

"mixing-type" conditions of Phillips (1987) and Phillips and Perron (1988). These are stated in Assumption 1.

ASSUMPTION 1: *(a)* $E(e_t)=0$ *all* t; *(b)* $\sup_t E|e_t|^{\beta+\varepsilon}<\infty$ *for some* $\beta>2$ *and* $\varepsilon>0$; *(c)* $\sigma^2=\lim_{T\to\infty} T^{-1}E(S_T^2)$ *exists and* $\sigma^2>0$, *where* $S_T=\sum_1^T e_t$; *(d)* $\{e_t\}_1^\infty$ *is strong mixing with mixing numbers* α_m *that satisfy*: $\sum_1^\infty \alpha_m^{1-2/\beta}<\infty$.

These conditions are general enough to permit the series $\{e_t\}$ to be generated by a finite order ARMA(p,q) process with Gaussian innovations. To carry out the asymptotic analysis, we shall require that both the pre-break and post-break samples increase at the same rate as the total number of observations, T, increases. To this effect, we assume, for simplicity, that $T_B=\lambda T$ for all T. We refer to λ as the "break fraction." The asymptotic limits are taken as T increases to infinity in a sequence that ensures an integer value of T_B for a given λ. This type of increasing sequence is assumed throughout the paper. The results proved in Appendix A are presented in the following theorem.

THEOREM 1: *Let* $\{y_t\}_0^T$ *be a sample of size* $T+1$ *generated under one of the alternative hypotheses with the innovations* $\{e_t\}$ *satisfying Assumption* 1. *Let* '$\to$' *denote convergence in probability. Furthermore, let* $T_B=\lambda T$, *for all* T *and* $0<\lambda<1$; *then as* $T\to\infty$:

(a) *The "crash hypothesis": Under Model* (A)

$$\tilde{\alpha}\to\left\{[\mu_1-\mu_2]^2A+\gamma_1\right\}\left\{[\mu_1-\mu_2]^2A+\sigma_e^2\right\}^{-1}$$

where

$$A=[\lambda-4\lambda^2+6\lambda^3-3\lambda^4],\quad \gamma_1=\lim_{T\to\infty}T^{-1}\sum_1^T E(e_te_{t-1}),$$

and

$$\sigma_e^2=\lim_{T\to\infty}T^{-1}\sum_1^T E\left(e_t^2\right).$$

(b) *The "breaking trend hypothesis": Under either Model* (B) *or* (C)

(i) $\tilde{\alpha}\to 1,$

(ii) $$T(\tilde{\alpha}-1)\to\left\{3(-1+4\lambda-5\lambda^2+2\lambda^3)\right\}\cdot\left\{2(-3+4\lambda-3\lambda^2+3\lambda^3-\lambda^4)\right\}^{-1}.$$

Part (a) of Theorem 1 shows that under the crash hypothesis, the limit of $\tilde{\alpha}$ depends on the relative magnitude of $[\mu_1-\mu_2]^2$ A and σ_e^2. In particular, this limit gets closer to one as $[\mu_1-\mu_2]^2$ increases. Another feature is that the limit of $\tilde{\alpha}$ is always greater than the true first-order autoregressive coefficient of the stationary part of the series, γ_1/σ_e^2. However, since $\tilde{\alpha}$ does not converge to 1, the

Staff/910
Storm 12

usual statistics for testing that $\alpha = 1$, such as $T(\tilde{\alpha} - 1)$ or the t statistic on $\tilde{\alpha}$, would eventually reject the null hypothesis of a unit root. Nevertheless, added to the generally poor power properties of tests for a unit root is the consideration that the limit of $\tilde{\alpha}$ is inflated above its true value. These conditions are such that it could be difficult to reject the unit root hypothesis in finite samples.

There is another interpretation to the results under the crash hypothesis. As stated in model (A), the change in the intercept of the trend function is given by $(\mu_2 - \mu_1)$, a fixed value. This implies that in the asymptotic derivations we are considering a shift which decreases relative to the level of the series as the sample size increases. It may be more appropriate to specify the change in the intercept as a magnitude relative to the level of the series at the time of the break. Since at this period the level of the series is proportional to T_B, we can specify $(\mu_2 - \mu_1)$ as a proportion of T_B, say, $(\mu_2 - \mu_1) = \gamma T_B$. In this case the "crash" is proportional to the level of the series. Since $T_B \to \infty$ as $T \to \infty$, it is clear, from part (a), that under this interpretation, $\tilde{\alpha} \to 1$.

Such ambiguity does not occur under the "breaking trend hypothesis" (Models (B) or (C)) as is shown by part (b) of Theorem 1. Here, the limit of $\tilde{\alpha}$ is 1 irrespective of the behavior of the intercept and the limit of $T(\tilde{\alpha} - 1)$ is invariant to the relative magnitude of the shift (β_2 versus β_1). The expression in part (b, ii) is a function of λ. However, it varies from 0 to 1/2 for values of λ in the range (0,1). Since the one-sided 5 percent asymptotic critical value of $T(\tilde{\alpha} - 1)$ is -21.8 under the null hypothesis of a unit root (Fuller (1976)), Theorem 2 implies that the unit root hypothesis could not be rejected, even asymptotically.[4]

These results could be extended to more general test statistics, such as the t statistics. Nevertheless, the picture is clear. Tests of the unit root hypothesis are not consistent against "trend stationary" alternatives when the trend function contains a shift in the slope. Although they are not inconsistent against a shift in the intercept of the trend function (if the change is fixed as T increases), their power is likely to be substantially reduced due to the fact that the limit of the autoregressive coefficient is inflated above its true value. When interpreting the "crash" as proportional to the level of the series as T increases, $\tilde{\alpha}$ unambiguously converges to one and implies a considerable loss in power. There is therefore a need to develop alternative statistical procedures that could distinguish a process with a unit root from a process stationary around a breaking trend function.

4. ALTERNATIVE STATISTICAL PROCEDURES

In this section, we extend the Dickey-Fuller testing strategy to ensure a consistent testing procedure against shifting trend functions. We shall present several ways to do so, all of which are asymptotically equivalent, and discuss the main differences between each.

[4]After the first draft of this paper was written, we became aware of a result similar to part (b, i) of Theorem 1 proved by Rappoport and Reichlin (1987). In fact, in the case of deterministic trends with multiple shifts in slope, they prove the following more general result: "If the true model contains $K+1$ segments, then any fitted model involving K or less segments will, asymptotically, yield a larger sum of squared residuals than [a difference stationary] model" (p.9).

Consider first detrending the raw series $\{y_t\}$ according to either model (A), (B), or (C). Let $\{\tilde{y}_t^i\}$, $i=A, B, C$ be the residuals from a regression of y_t on (1) $i=A$: a constant, a time trend, and DU_t; (2) $i=B$: a constant, a time trend, and DT_t^*; (3) $i=C$: a constant, a time trend, DU_t, and DT_t. Furthermore, let $\tilde{\alpha}^i$ be the least squares estimator of α in the following regression:

$$\tilde{y}_t^i = \tilde{\alpha}^i \tilde{y}_{t-1}^i + \tilde{e}_t \qquad (i=A, B, C;\ t=1,2,\ldots,T). \tag{5}$$

Up to this point the extensions from the no break model are straightforward enough. However, matters are not so simple concerning the distribution of the statistics of interest, namely the normalized bias, $T(\tilde{\alpha}^i - 1)$, and the t statistic on $\tilde{\alpha}^i$, $t_{\tilde{\alpha}^i}$ $(i=A, B, C)$. Needless to say, the only manageable analytical distribution theory is asymptotic in nature. But two additional features are also present over the usual procedure: (a) extra regressors and (b) the split sample nature of these extra regressors. To this effect, we derive the asymptotic distribution of $T(\tilde{\alpha}^i - 1)$ and $t_{\tilde{\alpha}^i}$ under the null hypothesis of a unit root. As in Section 3, we require that the break point T_B increases at the same rate as the total sample size T. Again, for simplicity, it is assumed that $T_B = \lambda T$ with both T and T_B integer valued.

The method of proof is similar to that of Phillips (1987) and Phillips and Perron (1988). We use weak convergence results that hold for normalized functions of the sum of the innovations when the latter are assumed to satisfy Assumption 1. The limiting distributions obtained under this general setting are then specialized to the i.i.d. case. The asymptotic distributions in the i.i.d. case are evaluated using simulations, and critical values are tabulated. We then show how the results can be extended to innovations $\{e_t\}$ that follow the general ARMA(p,q) process in the same way that the Dickey-Fuller regressions are modified by adding extra lags of first-differences of the data as regressors.

The main results concerning the asymptotic distributions of the normalized bias estimators and the t statistics of the autoregressive coefficient under the null hypothesis of a unit root are presented in the next theorem.

THEOREM 2: *Let $\{y_t\}$ be generated under the null hypothesis of model i $(i=A, B, C)$ with the innovation sequence $\{e_t\}$ satisfying Assumption* 1. *Let $\Rightarrow$ denote weak convergence in distribution and $\lambda = T_B/T$ for all T. Then, as $T \to \infty$:*

(a) $\quad T(\tilde{\alpha}^i - 1) \Rightarrow H_i/K_i,$

(b) $\quad t_{\tilde{\alpha}^i} \Rightarrow (\sigma/\sigma_e) H_i/(g_i K_i)^{1/2},$

where

$$H_A = g_A D_1 - D_5\psi_1 - D_6\psi_2; \qquad K_A = g_A D_2 - D_4\psi_2 - D_3\psi_1;$$

$$H_B = g_B D_1 + D_5\psi_3 + D_8\psi_4; \qquad K_B = g_B D_2 + D_7\psi_4 + D_3\psi_3;$$

$$H_C = g_C D_9 + D_{13}\psi_5 - D_{14}\psi_6; \qquad K_C = g_C D_{10} - D_{12}\psi_6 + D_{11}\psi_5;$$

with

$$\psi_1 = 6D_4 + 12D_3; \qquad \psi_2 = 6D_3 + (1-\lambda)^{-1}\lambda^{-1}D_4;$$
$$\psi_3 = (1+2\lambda)(1-\lambda)^{-1}D_7 - (1+3\lambda)D_3;$$
$$\psi_4 = (1+2\lambda)(1-\lambda)^{-1}D_3 - (1-\lambda)^{-3}D_7;$$
$$\psi_5 = D_{12} - D_{11}; \qquad \psi_6 = \psi_5 + (1-\lambda)^2 D_{12}/\lambda^3;$$

and

$$D_1 = \left(\tfrac{1}{2}\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) - w(1)\int_0^1 w(r)\,dr;$$

$$D_2 = \int_0^1 w(r)^2\,dr - \left[\int_0^1 w(r)\,dr\right]^2;$$

$$D_3 = \int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)\int_0^1 w(r)\,dr; \qquad D_4 = \int_0^\lambda w(r)\,dr - \lambda\int_0^1 w(r)\,dr;$$

$$D_5 = w(1)/2 - \int_0^1 w(r)\,dr; \qquad D_6 = w(\lambda) - \lambda w(1);$$

$$D_7 = \int_\lambda^1 rw(r)\,dr - \lambda\int_\lambda^1 w(r)\,dr - \left((1-\lambda)^2/2\right)\int_0^1 w(r)\,dr;$$

$$D_8 = \left((1-\lambda^2)/2\right)w(1) - \int_\lambda^1 w(r)\,dr;$$

$$D_9 = \int_0^1 w(r)^2\,dr - \lambda^{-1}\left(\int_0^\lambda w(r)\,dr\right)^2 - (1-\lambda)^{-1}\left(\int_\lambda^1 w(r)\,dr\right)^2;$$

$$D_{10} = \left(w(1)^2 - \sigma_e^2/\sigma^2\right)/2 - \lambda^{-1}w(\lambda)\int_0^\lambda w(r)\,dr$$
$$- \left(w(1) - w(\lambda)\right)(1-\lambda)^{-1}\int_\lambda^1 w(r)\,dr;$$

$$D_{11} = \int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)(1+\lambda)\int_0^1 w(r)\,dr + \left(\tfrac{1}{2}\right)\int_0^\lambda w(r)\,dr;$$

$$D_{12} = \int_0^\lambda rw(r)\,dr - (\lambda/2)\int_0^\lambda w(r)\,dr;$$

$$D_{13} = (1-\lambda)w(1)/2 + w(\lambda)/2 - \int_0^1 w(r)\,dr;$$

$$D_{14} = \lambda w(\lambda)/2 - \int_0^\lambda w(r)\,dr;$$

$$g_A = 1 - 3(1-\lambda)\lambda; \qquad g_B = 3\lambda^3; \qquad g_C = 12(1-\lambda)^2;$$

and where $w(r)$ *is the unit Wiener process defined on* $C[0,1]$, $\sigma^2 = \lim_{T\to\infty} E[T^{-1} S_T^2]$, $S_T = \Sigma_1^T e_t$, *and* $\sigma_e^2 = \lim_{T\to\infty} E[T^{-1}\Sigma_1^T e_t^2]$.

Theorem 2 provides a representation for the limiting distribution of the normalized least squares estimators and their t statistics in terms of functionals of Wiener processes. These limiting distributions are functions of the parameter λ, the ratio of the pre-break sample size to total sample size. It is easy to verify that when λ is either 0 or 1, the limiting distributions are identical over all models and are given by:

$$T(\tilde{\alpha}-1) \Rightarrow H/K \quad \text{and} \quad t_{\tilde{\alpha}} \Rightarrow (\sigma/\sigma_e)H/K^{1/2}$$

where

$$H = \left(\tfrac{1}{2}\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) + 12\left[\int_0^1 r w(r)\,dr - \left(\tfrac{1}{2}\right)\int_0^1 w(r)\,dr\right] \cdot \left[\int_0^1 w(r)\,dr - \left(\tfrac{1}{2}\right)w(1)\right] - w(1)\int_0^1 w(r)\,dr,$$

$$K = \int_0^1 w(r)^2\,dr - 12\left(\int_0^1 r w(r)\,dr\right)^2 + 12\int_0^1 w(r)\,dr \int_0^1 r w(r)\,dr - 4\left(\int_0^1 w(r)\,dr\right)^2.$$

These latter asymptotic distributions correspond to those derived by Phillips and Perron (1988) in the case where no dummy variables are included.

The expressions for the limiting distributions in Theorem 2 depend on additional nuisance parameters, apart from λ, namely σ^2 and σ_e^2. As in Phillips (1987) and Phillips and Perron (1988), σ_e^2 is the variance of the innovations and σ^2 is, in the case of weakly stationary innovations, equal to $2\pi f(0)$ where $f(0)$ is the spectral density of $\{e_t\}$ evaluated at frequency zero. When the innovation sequence $\{e_t\}$ is independent and identically distributed, $\sigma^2 = \sigma_e^2$ and, in that case, the limiting distributions are invariant with respect to nuisance parameters, except λ.

Therefore, when $\sigma^2 = \sigma_e^2$, percentage points of the limiting distributions can be tabulated for given values of λ. Tables IV, V, and VI present selected percentage points that will allow us to carry hypothesis testing. The critical values are obtained via simulation methods. We briefly describe the steps involved. First, we generate a sample of size 1,000 of i.i.d. $N(0,1)$ random deviates, $\{e_t\}$. We then construct sample moments of the data which converge weakly to the various functionals of the Wiener process involved in the representation of the asymptotic distributions. For example, as $T \to \infty$, $T^{-1/2}\Sigma_1^T e_t \Rightarrow w(1)$, $T^{-1/2}\Sigma_1^{T_B} e_t \Rightarrow w(\lambda)$, $T^{-3/2}\Sigma_1^T \Sigma_{j=1}^t e_j \Rightarrow \int_0^1 w(r)\,dr$, $\Sigma_{t=1}^T(\Sigma_{j=1}^{t-1} e_j)e_t \Rightarrow (\frac{1}{2})(w(1)^2 - 1)$, etc. With a sample size of 1,000 and i.i.d. $N(0,1)$ variates, we can expect the approximation to be quite accurate. Once the various functionals are evaluated, we construct the expressions in Theorem 2 and obtain one realization of the limiting distributions

TABLE IV.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL A
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−34.17	−35.85	−35.07	−34.44	−34.07	−35.83	−35.59	−34.86	−34.65
2.5%	−28.93	−30.35	−29.92	−29.26	−29.00	−29.80	−29.61	−29.40	−29.35
5%	−25.04	−26.00	−25.90	−25.40	−25.25	−25.56	−25.99	−25.82	−25.40
10%	−21.45	−22.16	−21.93	−21.61	−21.55	−21.79	−22.33	−22.10	−21.48
90%	−4.57	−5.19	−5.13	−4.28	−3.85	−4.36	−5.15	−5.32	−4.62
95%	−3.40	−3.90	−3.80	−2.83	−2.38	−2.92	−3.86	−3.87	−3.27
97.5%	−2.35	−2.92	−2.85	−1.69	−1.42	−1.89	−2.78	−2.84	−2.13
99%	−1.28	−1.70	−1.60	−0.61	−0.40	−0.78	−1.58	−1.78	−1.39

TABLE IV.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\tilde{\alpha}}$ IN MODEL A
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.30	−4.39	−4.39	−4.34	−4.32	−4.45	−4.42	−4.33	−4.27
2.5%	−3.93	−4.08	−4.03	−4.01	−4.01	−4.09	−4.07	−3.99	−3.97
5%	−3.68	−3.77	−3.76	−3.72	−3.76	−3.76	−3.80	−3.75	−3.69
10%	−3.40	−3.47	−3.46	−3.44	−3.46	−3.47	−3.51	−3.46	−3.38
90%	−1.38	−1.45	−1.43	−1.26	−1.17	−1.28	−1.42	−1.46	−1.37
95%	−1.09	−1.14	−1.13	−0.88	−0.79	−0.92	−1.10	−1.13	−1.04
97.5%	−0.78	−0.90	−0.83	−0.55	−0.49	−0.60	−0.82	−0.89	−0.74
99%	−0.46	−0.54	−0.51	−0.21	−0.15	−0.26	−0.50	−0.57	−0.47

TABLE V.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL B
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−34.34	−37.16	−38.07	−39.21	−39.77	−40.08	−38.70	−36.18	−34.69
2.5%	−28.74	−31.97	−32.78	−33.42	−33.60	−33.21	−32.31	−31.45	−29.42
5%	−25.00	−27.16	−28.61	−29.23	−29.65	−29.51	−28.68	−27.24	−25.25
10%	−21.26	−23.10	−24.20	−25.04	−25.40	−25.15	−24.30	−23.01	−21.24
90%	−4.27	−5.09	−5.92	−6.62	−6.96	−6.71	−6.08	−5.26	−4.45
95%	−3.12	−3.85	−4.50	−5.06	−5.31	−5.15	−4.59	−3.82	−3.16
97.5%	−2.20	−2.69	−3.30	−3.90	−4.14	−3.94	−3.36	−2.72	−2.21
99%	−1.11	−1.58	−2.19	−2.50	−3.01	−2.54	−2.20	−1.50	−1.24

of the statistics $T(\tilde{\alpha}^i - 1)$, $t_{\tilde{\alpha}^i}$ $(i = A, B, C)$. We replicate this procedure 5,000 times and obtain the critical values from the sorted vector of replicated statistics. This procedure is performed for each statistic with nine values of the parameter λ, the ratio of pre-break sample size to total sample size.[5]

Several features are worth mentioning with respect to these critical values. First, as expected, for a given size of the test, the critical values are larger (in

[5]For some evidence on the adequacy of this method to obtain critical values for limiting distributions involving functions of Wiener processes, see Chan (1988).

TABLE V.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\tilde{\alpha}}$ IN MODEL B
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.27	−4.41	−4.51	−4.55	−4.56	−4.57	−4.51	−4.38	−4.26
2.5%	−3.94	−4.08	−4.17	−4.20	−4.26	−4.20	−4.13	−4.07	−3.96
5%	−3.65	−3.80	−3.87	−3.94	−3.96	−3.95	−3.85	−3.82	−3.68
10%	−3.36	−3.49	−3.58	−3.66	−3.68	−3.66	−3.57	−3.50	−3.35
90%	−1.35	−1.48	−1.59	−1.69	−1.74	−1.71	−1.61	−1.49	−1.34
95%	−1.04	−1.18	−1.27	−1.37	−1.40	−1.36	−1.28	−1.16	−1.04
97.5%	−0.78	−0.87	−0.97	−1.11	−1.18	−1.11	−0.97	−0.87	−0.77
99%	−0.40	−0.52	−0.69	−0.75	−0.82	−0.78	−0.67	−0.54	−0.43

TABLE VI.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL C
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−36.17	−39.97	−42.98	−45.52	−44.07	−44.75	−43.02	−41.48	−36.58
2.5%	−30.65	−34.92	−36.48	−37.12	−37.56	−37.72	−37.50	−35.16	−31.82
5%	−26.63	−29.95	−32.47	−33.22	−33.79	−33.19	−33.11	−30.70	−27.16
10%	−22.68	−25.50	−27.90	−29.39	−29.41	−29.04	−28.14	−25.79	−22.62
90%	−4.74	−5.85	−7.35	−8.43	−8.84	−8.55	−7.41	−6.17	−4.89
95%	−3.41	−4.34	−5.50	−6.67	−7.19	−6.79	−5.66	−4.52	−3.52
97.5%	−2.51	−3.19	−4.14	−5.37	−5.82	−5.47	−4.33	−3.35	−2.49
99%	−1.31	−2.14	−2.82	−3.96	−4.39	−4.24	−2.80	−2.02	−1.28

TABLE VI.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\tilde{\alpha}}$ IN MODEL C
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.38	−4.65	−4.78	−4.81	−4.90	−4.88	−4.75	−4.70	−4.41
2.5%	−4.01	−4.32	−4.46	−4.48	−4.53	−4.49	−4.44	−4.31	−4.10
5%	−3.75	−3.99	−4.17	−4.22	−4.24	−4.24	−4.18	−4.04	−3.80
10%	−3.45	−3.66	−3.87	−3.95	−3.96	−3.95	−3.86	−3.69	−3.46
90%	−1.44	−1.60	−1.78	−1.91	−1.96	−1.93	−1.81	−1.63	−1.44
95%	−1.11	−1.27	−1.46	−1.62	−1.69	−1.63	−1.47	−1.29	−1.12
97.5%	−0.82	−0.98	−1.15	−1.35	−1.43	−1.37	−1.17	−1.04	−0.80
99%	−0.45	−0.67	−0.81	−1.04	−1.07	−1.08	−0.79	−0.64	−0.50

absolute value) for each model than the standard Dickey-Fuller critical values when considering the left tail. One would therefore expect a loss in power. Secondly, although the critical values are not significantly influenced by the value of the parameter λ, the maximum (in absolute value) occurs around the value $\lambda = 0.5$, i.e., for a break at mid-sample.[6] In the left tail, critical values of the statistics are smallest (in absolute value) when λ is close to 0 or 1. This is to be

[6] The simulated critical values suggest that the limiting distributions are symmetric around $\lambda = 0.5$. This feature seems intuitively plausible. We have not, however, proved that such is the case.

expected since, as previously mentioned, the critical values are identical to those of Dickey and Fuller when $\lambda = 0, 1$.

Some critical values are worth noticing. Consider the t statistics. Under Model (A), the "crash hypothesis", the 5 percent critical value has a minimum (over values of λ) of -3.80. Under Models (B) and (C), the corresponding figures are -3.96 and -4.24 respectively. The critical values under the various models are therefore noticeably smaller than the standard Dickey-Fuller critical value of -3.41 (see Dickey (1976) and Fuller (1976)).

These sets of results can be used to perform hypothesis testing. One simply picks the critical value corresponding to the sample value of λ at the chosen significance level. Since we only provide critical values for a selected grid of λ's, the procedure suggested is to choose the critical value corresponding to the value of λ nearest to its sample value, i.e., T_B/T. Given that the differences in the critical values over adjacent values for λ in the tables are not substantially different, this procedure should not cause misleading inferences.

4.1. *Extensions to More General Error Processes: Case* (1)

Using regressions (5) ($i = A, B, C$) and the critical values in Tables IV, V, and VI is valid only in the case where the innovation sequence $\{e_t\}$ is uncorrelated. When there is additional correlation, as one would expect, an extension is necessary. Two approaches are possible. One is to follow the approach suggested by Phillips (1987) and Phillips and Perron (1988). This involves finding a set of transformed statistics that would converge weakly to the limiting distributions expressed in Theorem 2 with $\sigma^2 = \sigma_e^2$. The other approach is that suggested by Dickey and Fuller (1979) and Said and Dickey (1984).

Consider first the extension to Phillips' (1987) procedure. It is useful first to write the limiting distributions of Theorem 2 in a different, more compact form. To do so, we adopt the framework suggested by Ouliaris, Park, and Phillips (1988). Define $w_i(r)$ ($i = A, B, C$) to be the stochastic process on $[0,1]$ such that $w_i(r)$ is the projection residual of a Wiener process $w(r)$ on the subspace generated by the following set of functions: (1) $i = A$: $1, r, du(r)$, where $du(r) = 0$ if $r \leqslant \lambda$ and $du(r) = 1$ if $r > \lambda$; (2) $i = B$: $1, r, dt^*(r)$, where $dt^*(r) = 0$ if $r \leqslant \lambda$ and $dt^*(r) = r - \lambda$ if $r > \lambda$; (3) $i = C$: $1, r, du(r), dt(r)$, where $dt(r) = 0$ if $r \leqslant \lambda$ and $dt(r) = r$ if $r > \lambda$. Adopting this notation, an alternative representation of the limiting distributions in Theorem 2 is given by:

$$T(\tilde{\alpha}^i - 1) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r) + \delta\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1} \qquad (i = A, B, C)$$

and

$$t_{\tilde{\alpha}^i} \Rightarrow (\sigma/\sigma_e)\left(\int_0^1 w_i(r)\,dw(r) + \delta\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1/2} \qquad (i = A, B, C)$$

where $\delta = (\sigma^2 - \sigma_e^2)/(2\sigma^2)$.

Now, define $\tilde{\sigma}_i^2$ and $\tilde{\sigma}_{ei}^2$ to be, respectively, any consistent estimator of σ^2 and σ_e^2 based on the estimated residuals from regression (5)($i = A, B, C$).[7] Also define S_i^2 ($i = A, B, C$) to be the residual sum of squares from the regression y_{t-1} on (1) $i = A$: $1, t, DU_t$; (2) $i = B$: $1, t, DT_t^*$; and (3) $i = C$: $1, t, DU_t, DT_t$. We then define the transformed statistics as:

$$Z(\tilde{\alpha}^i) = T(\tilde{\alpha}^i - 1) - T^2(\tilde{\sigma}_i^2 - \tilde{\sigma}_{ei}^2)/2S_i^2 \qquad (i = A, B, C), \tag{6}$$

$$Z(t_{\tilde{\alpha}^i}) = (\tilde{\sigma}_{ei}/\tilde{\sigma}_i)t_{\tilde{\alpha}^i} - T(\tilde{\sigma}_i^2 - \tilde{\sigma}_{ei}^2)/2\tilde{\sigma}_i S_i \qquad (i = A, B, C). \tag{7}$$

Following Ouliaris, Park, and Phillips (1988), it is straightforward to show that:

$$Z(\tilde{\alpha}^i) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r)\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1} \qquad (i = A, B, C) \tag{8}$$

and

$$Z(t_{\tilde{\alpha}^i}) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r)\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1/2} \qquad (i = A, B, C). \tag{9}$$

The limiting distributions in (8) and (9) are those whose critical values are presented in Tables IV, V, and VI derived using the representation given by Theorem 2.

The other approach adopts the procedures suggested by Dickey and Fuller (1979, 1981) and Said and Dickey (1984) which add extra lags of the first differences of the data as regressors in equation (5). This extended framework is characterized by the following regression (again estimated by OLS):

$$\tilde{y}_t^i = \tilde{\alpha}^i \tilde{y}_{t-1}^i + \sum_{j=1}^{k} \tilde{c}_j \Delta \tilde{y}_{t-j}^i + \tilde{e}_t \qquad (i = A, B, C) \tag{10}$$

where

$$\Delta \tilde{y}_t^i = \tilde{y}_t^i - \tilde{y}_{t-1}^i.$$

In the above representation, $\tilde{\alpha}$ is the OLS estimator of α, the sum of the autoregressive coefficients and the test is again that $\alpha = 1$. The parameter k specifies the number of extra regressors added. In a simple AR(p) process, $k = p$. In a more general ARMA(p, q) process with p and q unknown, k must increase at a controlled rate with the sample size. Arguments similar to those developed by Said and Dickey can be used to show that the limiting distributions of the statistics $t_{\tilde{\alpha}^i}$ ($i = A, B, C$) are the same when the innovation sequence is an ARMA(p, q) process and regression (10) is used, as they are when the errors are i.i.d. and regression (5) is used. However, slightly more restrictive assumptions are needed with respect to the innovation sequence $\{e_t\}$ and the truncation parameter k for this asymptotic equivalence to hold. They are detailed in the following Assumption (see Said and Dickey (1984)).

[7] See Phillips (1987), Phillips and Perron (1988), and Perron (1988) for details.

ASSUMPTION 2: *(a)* $A(L)e_t = B(L)v_t$; *(b)* v_t *is a sequence of i.i.d.* $(0, \sigma^2)$ *random variables with finite* $(4+\delta)$*th moment for some* $\delta > 0$; *(c)* $k \to \infty$ *and* $T^{-1}k^3 \to 0$ *as* $T \to \infty$.

4.2. *Extensions to More General Error Processes*: *Case* (2)

A possible drawback of the methods suggested above is that they imply that the change in the trend function occurs instantaneously. Given, for instance, that the Great Depression was not an instantaneous event but lasted several years, one may wish to allow for such a transition period during changes in the trend function. One way to model this is to suppose that the economy reacts gradually to a shock to the trend function.[8] Consider, for instance, Model (A) where a crash occurs. A plausible specification of the trend function, say η_t^A, is given by:

$$\eta_t^A = \mu_1 + \beta t + \gamma\psi(L)\, DU_t \tag{11}$$

where $\psi(L)$ is a stationary and invertible polynomial in L with $\psi(0) = 1$ and $\gamma = \mu_2 - \mu_1$. The long run change in the trend function is given by $\gamma\psi(1)$ while the immediate impact is simply γ. A similar framework holds for models (B) and (C).

One way to incorporate such a gradual change in the trend function is to suppose that the economy responds to a shock to the trend function the same way as it reacts to any other shock, i.e. to impose $\psi(L) = B(L)^{-1}A(L)$ (see Section 2). In the literature on outliers specification the framework suggested here is analogous to the so-called "innovational outlier" model whereas the framework considered in Section 4.1 is analogous to the "additive outlier" model (see, e.g., Tsay (1986)). We can then implement tests for the presence of a unit root in a framework that directly extends the Dickey-Fuller strategy by adding dummy variables in regression (1). The following regressions, corresponding to Models (A), (B), and (C) are constructed by nesting the corresponding models under the null and alternative hypotheses:

$$y_t = \hat{\mu}^A + \hat{\theta}^A DU_t + \hat{\beta}^A t + \hat{d}^A D(TB)_t + \hat{\alpha}^A y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t, \tag{12}$$

$$y_t = \hat{\mu}^B + \hat{\theta}^B DU_t + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t, \tag{13}$$

$$y_t = \hat{\mu}^C + \hat{\theta}^C DU_t + \hat{\beta}^C t + \hat{\gamma}^C DT_t + \hat{d}^C D(TB)_t + \hat{\alpha}^C y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t. \tag{14}$$

The null hypothesis of a unit root imposes the following restrictions on the true parameters of each model: Model (A), the "crash hypothesis": $\alpha^A = 1$, $\beta^A = 0$,

[8] Again, this treatment is analogous to the methodology proposed by Box and Tiao (1975) concerning intervention analyses.

$\theta^A = 0$; Model (B), the "breaking slope with no crash": $\alpha^B = 1$, $\gamma^B = 0$, $\beta^B = 0$; and Model (C), where both effects are allowed: $\alpha^C = 1$, $\gamma^C = 0$, $\beta^C = 0$. Under the alternative hypothesis of a "trend stationary" process, we expect $\alpha^A, \alpha^B, \alpha^C < 1$; $\beta^A, \beta^B, \beta^C \neq 0$; $\theta^A, \theta^C, \gamma^B, \gamma^C \neq 0$. Finally, under the alternative hypothesis, d^A, d^C, and θ^B should be close to zero while under the null hypothesis they are expected to be significantly different from zero.

The asymptotic distribution of the t statistics $t_{\hat{\alpha}}A$ and $t_{\hat{\alpha}}C$ in (12) and (14) are the same, respectively, as the asymptotic distribution of $t_{\tilde{\alpha}}A$ and $t_{\tilde{\alpha}}C$ in (10). However such a correspondence does not hold for the t statistic $t_{\hat{\alpha}}B$ in (13). Apart from the one-time dummy variable $d(TB)_t$, regressions (13) and (14) are equivalent; hence the asymptotic distribution of $t_{\hat{\alpha}}B$ is identical to the asymptotic distribution of $t_{\hat{\alpha}}C$. This implies that in the above framework, it is not possible to test for a unit root under the maintained hypothesis that the trend function has a change in slope with the two segments joined at the time of the change. Consequently, tests for the presence of a unit root in Model (B) will have less power using regression (13) than using (10) where the asymptotic critical values of the t statistic on α are smaller (in absolute value). However, it is still possible to test for a unit root with constant drift against a trend stationary process as in Model (B) and use the critical values of Table V. One simply runs the regression:

$$(15) \qquad y_t = \hat{\mu}^B + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t.$$

The asymptotic distribution of the t statistic $t_{\hat{\alpha}}B$ in (15) is the same as the asymptotic distribution of the t statistic $t_{\tilde{\alpha}}B$ in (10). Given that the regressor DU_t is absent from (15), this case, however, implies that the change in drift is not permitted under the null hypothesis.

Finally, note that it is possible to apply Phillips' nonparametric procedure using regressions (12) through (14) without the lagged first-differenced regressors and applying the corrections given by (6) and (7). However, such a procedure has the unattractive feature of imposing only a one-period adjustment to the change in the trend function. In the notation of (11), it imposes $\psi(L) = 1 - \psi_1 L$ where ψ_1 is the coefficient on the first lag in the polynomial $B(L)^{-1}A(L)$.

The procedures outlined in this section permit testing for the presence of a unit root in a quite general time series process which allows a one-time break in the mean of the series or its rate of growth (or both). In the next section, we apply these procedures in the specific context of breaks at the time of the 1929 crash and the 1973 oil shock.

5. EMPIRICAL APPLICATIONS

We apply the test statistics derived in the previous section to the data set used by Nelson and Plosser and to the postwar quarterly real GNP series. The data set considered by Nelson and Plosser consists of fourteen major macroeconomic series sampled at an annual frequency. We omit the analysis of the unemployment rate series given that it is generally perceived as being stationary. The sample varies for each series with a starting date between 1869 and 1909. However, each series ends in 1970. Given that we entertain the hypothesis that only the 1929 Great Crash and the 1973 oil price shock caused a major change in trend function, each series in this data set contains only one break. It is therefore possible to apply the tests described in the previous section. Similarly, the quarterly postwar real GNP series contains a single break as the sample goes from 1947:I to 1986:III. Following Nelson and Plosser, we consider the logarithm of each series except for the interest rate for which we use the level.

Of the thirteen series in the Nelson-Plosser data set that we analyze, preliminary investigations showed that eleven were potentially well-characterized by a trend function with a constant slope but with a major change in their level occurring right after the year 1929. For these series, the maintained hypothesis is, therefore, that of Model (A) and given that the Great Crash did not occur instantaneously but lasted several years, we apply regression (12) to carry out our testing procedure. The two series that were not modeled as such are the "real wages" and "common stock price" series. For these series, it appeared that not only a change in the level occurred after 1929 but there was also an increase in the slope of the trend function after this date. For these reasons, the maintained hypothesis is that of Model (C), and we use regression (14) to implement our tests.

The postwar quarterly real GNP series offers yet a different picture. The 1973 oil price shock did not cause a significant drop in the level of the series. However, after that date, the slope of the trend function has sensibly decreased. This phenomenon is consistent with the much discussed slowdown in the growth rate of real GNP since the mid-seventies; see, for example, the recent symposium in the *Journal of Economic Perspectives* (1988). For these reasons, the maintained hypothesis is that of Model (B). Given the inherent difficulty in testing for a unit root allowing lagged effects for the change in the trend function, we apply regression (10) ($i = B$) to carry the testing procedure. Modeling the change in the trend function following the 1973 oil price shock as instantaneous, at least appears more plausible than the change that occurred during the Great Depression.

Table VII presents the corresponding estimated regressions for each series along with the t statistic on the parameters for the following respective hypotheses: $\mu = 0$, $\beta = 0$, $\theta = 0$, $\gamma = 0$, $d = 0$, and $\alpha = 1$. Recall that under the hypothesis of a unit root process $\mu \neq 0$ (in general), $\beta = 0$, $\theta = 0$ (except in regression Models (C)), $\gamma = 0$, $d \neq 0$, and $\alpha = 1$. Under the alternative hypothesis of stationary fluctuations around a deterministic breaking trend function: $\mu \neq 0$, $\theta \neq 0$, $\beta \neq 0$, $\gamma \neq 0$ (in general), $d = 0$, and $\alpha < 1$.

The value of k chosen is determined by a test on the significance of the estimated coefficients $\hat{c}_i$. We actually used a fairly liberal procedure choosing a value of k equal to say k^* if the t statistic on $\hat{c}_i$ was greater than 1.60 in absolute value and the t statistic on $\hat{c}_l$ for $l > k^*$ was less than 1.60 (with a maximum value for k of 8, except for the postwar quarterly real GNP series

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TABLE VII

TESTS FOR A UNIT ROOT

(a) Regression (12), Model A; $y_t = \hat{\mu} + \hat{\theta} DU_t + \hat{\beta} t + \hat{d} D(TB)_t + \hat{\alpha} y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t$

$T_B = 1929$	T	λ	k	$\hat{\mu}$	$t_{\hat{\mu}}$	$\hat{\theta}$	$t_{\hat{\theta}}$	$\hat{\beta}$	$t_{\hat{\beta}}$	$\hat{d}$	$t_{\hat{d}}$	$\hat{\alpha}$	$t_{\hat{\alpha}}$	$S(\hat{e})$
Real GNP	62	0.33	8	3.441	5.07	−0.189	−4.28	0.0267	5.05	−0.018	−0.30	0.282	-5.03^{a}	0.0509
Nominal GNP	62	0.33	8	5.692	5.44	−0.360	−4.77	0.0359	5.44	0.100	1.09	0.471	-5.42^{a}	0.0694
Real per capita GNP	62	0.33	7	3.325	4.11	−0.102	−2.76	0.0111	4.00	−0.070	−1.09	0.531	-4.09^{b}	0.0555
Industrial production	111	0.63	8	0.120	4.37	−0.298	−4.58	0.0323	5.42	−0.095	−0.99	0.322	-5.47^{a}	0.0875
Employment	81	0.49	7	3.402	4.54	−0.046	−2.65	0.0057	4.26	−0.025	−0.77	0.667	-4.51^{a}	0.0295
GNP deflator	82	0.49	5	0.669	4.09	−0.098	−3.16	0.0070	4.01	0.026	0.53	0.776	-4.04^{b}	0.0438
Consumer prices	111	0.63	2	0.065	1.12	−0.004	−0.21	0.0005	1.75	−0.036	−0.79	0.978	−1.28	0.0445
Wages	71	0.41	7	2.38	5.45	−0.190	−4.32	0.0197	5.37	0.085	1.36	0.619	-5.41^{a}	0.0532
Money stock	82	0.49	6	0.301	4.72	−0.071	−2.59	0.0121	4.18	0.033	0.68	0.812	-4.29^{b}	0.0440
Velocity	102	0.59	0	0.050	0.932	−0.005	−0.20	−0.0002	−0.35	−0.136	−2.01	0.941	−1.66	0.0663
Interest rate	71	0.41	2	−0.018	−0.088	−0.343	−2.06	0.0105	2.64	0.197	0.64	0.976	−0.45	0.2787

(b) Regression (14), Model C; $y_t = \hat{\mu} + \hat{\theta} DU_t + \hat{\beta} t + \hat{\gamma} DT_t + \hat{d} D(TB)_t + \hat{\alpha} y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t$

$T_B = 1929$	T	λ	k	$\hat{\mu}$	$t_{\hat{\mu}}$	$\hat{\theta}$	$t_{\hat{\theta}}$	$\hat{\beta}$	$t_{\hat{\beta}}$	$\hat{\gamma}$	$t_{\hat{\gamma}}$	$\hat{d}$	$t_{\hat{d}}$	$\hat{\alpha}$	$t_{\hat{\alpha}}$	$S(\hat{e})$
Common stock prices	100	0.59	1	0.353	4.09	−1.051	−4.29	0.0070	4.43	0.0139	3.98	0.128	0.76	0.718	-4.87^{b}	0.1402
Real wages	71	0.41	8	2.115	4.33	−0.190	−3.71	0.0107	3.79	0.0066	3.33	0.031	0.78	0.298	-4.28^{c}	0.0330

(c) Regression (10), Model B; $y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\gamma} DT_t^{*} + \tilde{y}_t$; $\tilde{y}_t = \tilde{\alpha} \tilde{y}_{t-1} + \sum_{i=1}^{k} \tilde{c}_i \Delta \tilde{y}_{t-i} + \tilde{e}_t$

$T_B = 1973{:}I$	T	λ	k	$\tilde{\mu}$	$t_{\tilde{\mu}}$	$\tilde{\beta}$	$t_{\tilde{\beta}}$	$\tilde{\gamma}$	$t_{\tilde{\gamma}}$	$\tilde{\alpha}$	$t_{\tilde{\alpha}}$	$S(\tilde{e})$
Quarterly real GNP	159	0.66	10	6.977	1160.51	0.0087	97.73	−0.0031	−12.06	0.86	-3.98^{c}	0.0097

NOTE: a, b, and c denote statistical significance at the 1%, 2.5%, and 5% level respectively.

where we used a maximum of 12). This liberal procedure is justified in the sense that including too many extra regressors of lagged first-differences does not affect the size of the test but only decreases its power. Including too few lags may have a substantial effect on the size of the test.

Consider first the series for which we applied Model (A). To evaluate the significance of the t statistic on $\hat{\alpha}$, we use the critical value presented in Table IV.B with a value of λ closest to the ratio of pre-break sample size to total sample size. Of the eleven series in that group, the unit root hypothesis cannot be rejected even at the 10 percent level for three of them: "consumer prices," "interest rate" and "velocity." However, we can reject the null hypothesis of a unit root at that 2.5 percent level or better for all other eight series. We can reject it at the 1 percent level for the following series: "real GNP," "nominal GNP," "industrial production," "employment," and "wages," and at the 2.5 percent level for the series "real per capita GNP," "GNP deflator," and "money stock." In some cases the coefficient $\hat{\alpha}$, which is an estimate of the sum of the autoregressive coefficients, is dramatically different from one. For example, it is 0.282 for "real GNP" and 0.322 for "industrial production."

Given that the unit root hypothesis can be rejected for the eight series mentioned above, we can assess the significance of the other coefficients using the fact that the asymptotic distribution of their t statistic is standardized normal. In all cases, the estimated coefficients on the constant ($\hat{\mu}$), the post-break dummy ($\hat{\theta}$), and the trend ($\hat{\beta}$) are significant at least at the 5 percent level. All series showed a trend function with a positive slope and a significant decrease in level just after 1929. For these eight series the coefficient on the break dummy ($\hat{d}$) is not significant. These results strongly suggest that, except for the "consumer price," "velocity," and "interest rate" series, the underlying process is one of stationary fluctuations around a deterministic trend function.

Consider now panel (b) of Table VII which presents the results for the "common stock price," and "real wages" series estimated under Model (C). We can reject the null hypothesis of a unit root at the 2.5 percent level for "common stock prices" and at the 5 percent level for the "real wages" series. In both cases, the constant ($\hat{\mu}$), the post-break constant dummy ($\hat{\theta}$), the trend ($\hat{\beta}$), and the post-break slope dummy ($\hat{\gamma}$) are highly significant, while the break dummy ($\hat{d}$) is not. The coefficients $\hat{\alpha}$ for the "real wages" series is very low at 0.298 while for the "common stock price" it is at 0.718 showing substantial mean reversion effects. This finding about the "common stock price" series is particularly striking given the vast amount of theoretical and empirical studies supporting the random walk hypothesis in this situation.

Finally, panel (c) of Table VII presents the results for the postwar quarterly real GNP series using regression (10) corresponding to Model (B). In this case, the null hypothesis that $\alpha = 1$ can be rejected at the 5 percent level with an estimated coefficient $\tilde{\alpha}$ equal to 0.86. This result is especially significant given the usual poor power properties of tests for a unit root against stationary alternatives when using a data set with a small span sampled frequently (see, e.g., Perron (1987) and Shiller and Perron (1985)). The other estimated coefficients in panel (c) confirm the relevance of the "trend stationary" model versus the "unit root" model. The coefficient on the post-break slope dummy coefficient ($\tilde{\gamma}$) is highly significant. The estimated regression is therefore consistent with an underlying process characterized by stationary fluctuations around a deterministic trend function with a decrease in the slope after 1973.[9]

Table A3 in Appendix B presents the estimated value for the sum of the autoregressive coefficient, α, and its t statistic for the null hypothesis $\alpha = 1$, for all values of the truncation lag parameter k between 1 and 12. In general, the results are quite robust to which value of k is selected.[10]

The results presented in this section are quite striking. The unit root hypothesis can be rejected for all but three series. To obtain these results, only a rather weak postulate needed to be imposed, namely the presence of a one-time change in the trend function. We claim that this is a weak postulate for the following reasons. As shown by Nelson and Plosser and Campbell and Mankiw, all the series analyzed have a unit root if the trend function is not allowed to change. This view implies that the 1929 crash is simply one big outlier in the innovation sequence. On the other hand, it also implies that the post-1973 growth slowdown is a succession of smaller innovations and that the mean of the innovations is different for the pre-1973 and the post-1973 period. These alternative interpretations are, we think, less appealing than the hypothesis of a break in the trend function, especially given that we allow such a break under both the null and alternative hypotheses.

Given that the "consumer price," "velocity," and "interest rate" series appear to be characterized by the presence of a unit root, it seems worthwhile to see if this feature is stable in the pre and post 1929 samples. The subsample Dickey-Fuller type regressions are presented in Appendix B for values of k between 1 and 12. Consider first the "consumer price index." With $k = 2$, the estimated value of the sum of the autoregressive coefficients, $\tilde{\alpha}$ is 0.965 for the pre-1929 sample with a t statistic of -1.28. We therefore cannot reject the null hypothesis of a unit root for this subperiod. However, for the post-1929 sample, the picture is rather different; when $k = 7$, $\tilde{\alpha}$ has a value of 0.704 with a t statistic of -4.56 significant at the 1 percent level. The nonrejection of the unit root hypothesis using the full sample is due to the pre-1929 sample. After 1929, the unit root is no longer present.

The case for the "velocity" series has a special feature. It has been well documented that the U.S. velocity series declined steadily until 1946, remained at a fairly constant level until 1970, before increasing (see, for example, Poole (1988) and Gould and Nelson (1974)). For this reason, we discuss applications of the standard Dickey-Fuller procedure for the following three samples: 1869–1929, 1930–1945, 1946–1970. We cannot reject the unit root hypothesis with the pre-1929 sample even though $\tilde{\alpha}$ is only 0.865 ($k = 0$). However, the picture is

[9]Basically, the same estimates of the sum of the autoregressive coefficient α and its t statistic were obtained using regressions (13) and (14), for all values of k, showing some robustness for the results presented. We also applied Phillips' nonparametric procedure to the detrended series (equations (6) and (7), $i = B$). These test statistics did not allow the rejection of the null hypothesis of a unit root.

[10]One notable exception is the quarterly real GNP series where the t statistic is significant at the 5 percent level with $k = 2$ or $k = 10$. It is significant at the 2.5 percent level with $k = 11$, with a value of -4.32. We choose to report the result of $k = 10$ because the 10th lagged first-difference was highly significant (t statistic of 2.29) while the 11th and 12th lags were not.

dramatically different using post-1929 samples. For the period 1930–1945, with $k=1$, $\tilde{\alpha}$ is estimated at -0.011 with a t statistic (for testing $\alpha=1$) of -3.44 which is significant at the 5 percent level. Though this result should be taken with caution due to the small number of observations, it is suggestive of a quite different behavior. The period 1946–1970 affords a modest amount of additional information and yields still more dramatic results: with $k=4$, $\tilde{\alpha}$ is equal to 0.00 with a t statistic (for $\alpha=1$) of -5.86, significant at the 1 percent level using the Dickey-Fuller critical values. It therefore appears that the "velocity" and "consumer price" series yield similar results: the presence of a unit root before 1929 but not after.

The results for the interest rate series indicate that, in this case, the unit root hypothesis cannot be rejected at usual significance levels for both subsamples (even though α is estimated at 0.540 ($k=3$) with the pre-1929 sample). Indeed, given our previous results, we can conclude that only the "interest rate" series is characterized by the presence of a unit root after 1929. All the other series are better construed as stationary fluctuations around a deterministic trend function for this period.

6. DISCUSSION AND CONCLUDING COMMENTS

When testing for the presence of a unit root in a time series of data against the hypothesis of stationary fluctuations around a deterministic trend function, the use of a long span of data has definite advantages. It allows tests with larger power compared to using a smaller span, in most cases even if the latter allows more observations (see Shiller and Perron (1985) and Perron (1987)). The drawback, however, is that a data set with a large span has more chance to include a major event which one would rather consider as an outlier or as exogenous given its relative importance. The arguments in this paper rest on the postulate that two such events have occurred in the 20th century: the 1929 Great Crash and the slowdown in growth after the oil shock of 1973. We therefore considered, as a relevant alternative, a trend function with a change in the intercept in 1929 and a change in the slope after 1973.

Let us discuss, in more detail, what are the relevant issues in drawing particular conclusions about the nature of economic fluctuations from our results. It is particularly important to put our results into perspective and also highlight what has not been shown.

The first important issue to point out is that we have not provided a formal unconditional statistical model of the time series properties of the various aggregates. A rejection of the null hypothesis of a unit root conditional on the possibility of shifts in the underlying trend function at known dates does not imply that the various series can be modeled as stationary fluctuations around a completely deterministic breaking trend function. As a matter of general principle, a rejection of the null hypothesis does not imply acceptance of a particular alternative hypothesis. However, since the tests were designed to have power against a specific class of alternative hypotheses, it is useful to look among close members of that class to propose an interesting statistical model for the various aggregates. Only with such a model is it possible to provide forecasts with appropriate standard errors.

We certainly do not entertain the view that the trend function including its changes are deterministic. This would imply that one would be able to forecast with certainty future changes. This is indeed quite unappealing. What we have in mind in specifying our class of maintained hypotheses can be parameterized as follows:

$$(16)\qquad y_t=\eta_t+Z_t,\qquad \eta_t=\mu_t+\beta_t t,$$

where $A(L)Z_t=B(L)e_t$; $e_t\sim$ i.i.d.$(0,\sigma^2)$; $\mu_t=\mu_{t-1}+V(L)v_t$, and $\beta_t=\beta_{t-1}+W(L)w_t$. Here, the Z_t's are (not necessarily stationary) deviations from the trend function η_t. The intercept and the slope of the trend functions, μ_t and β_t, are themselves random variables modeled as integrated processes with $W(L)$, $V(L)$ stationary and invertible polynomials. However, the important distinction is that the timing of the occurrence of the shocks v_t and w_t are rare relative to the sequence of innovations $\{e_t\}$, for example, poisson processes with arrival rates specified such that their occurrences are rare relative to the frequency of the realizations in the sequence $\{e_t\}$. The intuitive idea behind this type of modeling is that the coefficients of the trend function are determined by long-term economic fundamentals (e.g., the structure of the economic organization, population growth, etc.) and that these fundamentals are rarely changed. In our examples, v_t is nonzero in 1929 (the great depression) and w_t is nonzero in 1973 (the oil price shock).

In this sense, our exogeneity assumption about the changes in the trend function is a device that allows taking these shocks out of the noise function into the trend function without specific modeling of the stochastic nature of the behavior of μ_t and β_t. It is in this sense that our approach does not provide an unconditional representation of the time series properties of the various variables.

Estimation of models of the form (16) by specifying a probability distribution for the error sequences $\{e_t, w_t, v_t\}$ is clearly an important avenue of future research. Interesting recent advances on this topic have been provided by Hamilton (1987) and Lam (1988) where the slope of the trend function is allowed to take two different values and the changes are modeled as a binomial process. However, no methods are currently available to test whether Z_t is integrated or not in this framework.[11] Problems in estimation of models of the form (16) are further compounded by the fact that, according to our view, only one nonzero realization of both v_t and w_t would be present in the data set typically available for the series of interest.

In the above framework, the purpose of this paper is to test whether Z_t is an integrated process or not, i.e. to test whether the shocks $\{e_t\}$ have persistent effects that do not vanish over a long horizon. Our approach is to remove from the noise function two events that occurred at two dates where we believe positive occurrences of the shocks $\{v_t, w_t\}$ happened and to model them as part

[11]Both authors studied the behavior of the postwar quarterly real GNP with possible shifts in the slope of the trend function. Hamilton (1987) imposes Z_t to be an integrated process while Lam (1988) leaves Z_t unconstrained.

of the trend function. The fact that we model these changes as exogenous implies that our results are conditional. That is, conditional upon the presence of a change in the trend function in 1929 and 1973, the fluctuations are transitory (i.e., Z_t is stationary).

An important direction for future research is to make this conditional result into an unconditional statement. This could, in principle, be achieved by a direct test for structural change in the trend function. In a sense, our procedure allows such a test, but conditional on a change occurring at a fixed known date. Hence, problems of pre-testing and "data mining" could be raised regarding the role of looking, ex-post, at the data on the choice of the date.[12] Accordingly, what is needed is a test for structural changes in the trend function occurring at unknown dates. The problem, however, is that care must be applied to ensure that the test has an adequate size under both the unit root and trend-stationary hypotheses. No such test is currently available in the literature. We hope to report, in the near future, developments in this area and applications in this context.

However, an important issue of observational equivalence could not even be settled by such a formal test for structural change. Consider, for instance, the following limiting case in the crash model.[13] A trend-stationary model with a break and where the errors have zero variance is observationally equivalent to a unit root model with drift where the errors have a high probability of being zero but are occasionally nonzero and finite. In general, when the variance of the errors is nonzero, the two models will be nearly observationally equivalent with the disturbances in the unit root model having fat tails. We are able to make a distinction in our empirical result through the mixing conditions (see Assumptions 1 and 2) which prohibit fat tailed disturbances. Any formal test for structural change would, presumably, also have to impose some mixing condition prohibiting fat-tailed disturbances, thereby not resolving this issue of near-observational equivalence.

In fact, any test for the presence of a unit root against trend-stationary alternatives is subject to another type of observational equivalence, as recently argued by Cochrane (1987) and Blough (1988). Indeed, in finite samples, any trend-stationary process is nearly observationally equivalent to a unit root process with a strong mean-reversion component, i.e. where the errors have a moving-average component with a root near minus one.[14] The fact that we reject the unit root hypothesis excluding the event of 1929 suggests that if there is a unit root at all the correlation structure of the innovation sequence must exhibit substantial mean reversion.

[12] See, for example, Christiano (1988).
[13] This issue and its following illustration were raised by a referee.
[14] This observational equivalence problem only disappears asymptotically. In other words, in finite samples, any test for a unit root with ARMA errors should have zero power. Formally, the critical values should be determined such that the test has a given fixed size over all possible values of the nuisance parameters (here, the additional correlation in the errors). Given the near observational equivalence, any such test would have zero power by definition. The unit root tests can be rationalized by arguing that we are willing to have the wrong size over some of the parameter space exactly because for all practical purposes it does not matter whether we label a series as trend stationary or difference stationary with a strong mean-reversion component.

To sum up: trend stationary processes with a break are nearly observationally equivalent to unit root processes with strong mean-reversion and a fat-tailed distribution for the error sequence. Whichever view one adopts cannot be decided by data alone. Nevertheless, the picture under any of these views is basically the same: shocks had little, if any, persistence effect over a long horizon. Only those associated with the Great Depression and the oil price shock significantly altered the long run behavior of the series.

While choosing one view over the other is a matter of convenience for interpreting the data, it has profound implications for a multitude of statistical procedures. Indeed, under the unit root view one must ensure the validity of the procedures under fat-tailed disturbances, and at the moment very few are appropriate in a time series context. Hence for all practical purposes, it may be more advantageous to adopt the trend-stationary view with breaks and detrend our series accordingly prior to analyzing the remaining noise.

Department of Economics, Princeton University, Princeton, NJ 08544, U.S.A.; and Centre de Recherche et Développement en Economique, Université de Montréal, C.P. 6128, Succ. A, Montréal, Canada, H3C – 3J7.

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APPENDIX A

The conditions imposed by Assumption 1 permit us to use a functional weak convergence result due to Herrndorf (1984). Let $S_t = \Sigma_{j=1}^{t} e_j (S_0 = 0)$ and define the following variable lying in the space $D[0,1]$:

$$X_T(r) = \sigma^{-1} T^{-1/2} S_{[Tr]} = \sigma^{-1} T^{-1/2} S_{j-1}, \quad (j-1)/T \leqslant r < j/T \qquad (j = 1, \ldots, T)$$

$$X_T(1) = \sigma^{-1} T^{-1/2} S_T.$$

Herrndorf's theorem states that under the conditions of Assumption 1, $X_T(r) \Rightarrow w(r)$ where $\Rightarrow$ denotes weak convergence to the associated probability measure and $w(r)$ is the unit Wiener process defined on $C[0,1]$, the space of all continuous functions on the interval $[0,1]$. Following Phillips (1987) and Phillips and Perron (1988), it is easy to derive the following lemma related to functions of S_t. These results will be used in proving both Theorems 1 and 2.

Lemma A.1: *Let $S_t = \Sigma_{j=1}^{t} e_j (S_0 = 0)$ and assume that the innovation sequence $\{e_t\}$ satisfies the conditions of Assumption* 1. *Furthermore, let $T_B = \lambda T$ for all T; then as $T \to \infty$:*

(a) $$T^{-3/2} \sum_{1}^{T_B} S_j \Rightarrow \sigma \int_0^\lambda w(r)\, dr;$$

(b) $$T^{-2} \sum_{1}^{T_B} S_j^2 \Rightarrow \sigma^2 \int_0^\lambda w(r)^2\, dr;$$

(c) $$T^{-5/2} \sum_{1}^{T_B} j S_j \Rightarrow \sigma \int_0^\lambda r w(r)\, dr;$$

(d) $$T^{-3/2} \sum_{1}^{T_B} j e_j \Rightarrow \sigma \left(\lambda w(\lambda) - \int_0^\lambda w(r)\, dr \right);$$

(e) $$T^{-1} \sum_{1}^{T} S_{j-1} e_j \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right).$$

The results in (a) through (d) are simple extensions of those in Phillips (1987) and Phillips and Perron (1988); part (e) is proved in Phillips (1987). The previous results can be recovered by simply letting $\lambda = 1$ in which case $T_B = T$. For example, to prove part (a):

$$T^{-3/2}\sum_1^{T_B} S_j = \sigma \sum_1^{T_B} \int_{t-1/T}^{t/T} T^{-1/2}\sigma^{-1} S_{[Tr]}\, dr = \sigma \int_0^{\lambda} X_T(r)\, dr \Rightarrow \sigma \int_0^{\lambda} w(r)\, dr$$

using Herrndorf's weak convergence result and the continuous mapping theorem (see, e.g., Billingsley (1968)). The proofs of (b), (c), and (d) are entirely analogous.

Proof of Theorem 1: We consider first the most general model (C) in which both β (the slope) and μ (the intercept) are allowed to change, i.e.:

$$\text{(A.1)} \quad \begin{aligned} y_t &= \mu_1 + \beta_1 t + e_t && (0 \leqslant t \leqslant T_B). \\ y_t &= \mu_2 + (\beta_2 - \beta_1) T_B + \beta_2 t + e_t && (T_B < t \leqslant T). \end{aligned}$$

The following lemma provides a convenient representation of the sample moments of $\{y_t\}$.

Lemma A.2: *Assume that $\{y_t\}_0^T$ is generated according to (A.1) with the innovation sequence $\{e_t\}$ satisfying Assumption 1; then,*

(a)
$$\begin{aligned} \sum_1^T t y_{t-1} = {} & (1/6)\left[\beta_1(3\lambda - \lambda^3) + \beta_2(2 - 3\lambda + \lambda^3)\right] T^3 \\ & + (\tfrac{1}{2})\left[\mu_1 \lambda^2 + \mu_2(1 - \lambda^2) + \lambda(1-\lambda)(\beta_1 - \beta_2)\right] T^2 \\ & + \left[(3/2)\mu_1\lambda + (3/2)(1-\lambda)\mu_2 - \mu_2 - (1/3)\beta_1\lambda - (1/3)\beta_2(1-\lambda)\right] T \\ & + \left[T^{-3/2}\sum_1^T t e_{t-1}\right] T^{3/2} + o_p(T), \end{aligned}$$

(b)
$$\begin{aligned} \sum_1^T y_{t-1} = {} & (\tfrac{1}{2})\left[\beta_1(\lambda^2 - 2\lambda) + \beta_2(1 + 2\lambda - 3\lambda^2)\right] T^2 \\ & + \left[\lambda\mu_1 + (1-\lambda)\mu_2 + (3/2)\beta_1\lambda - (\tfrac{1}{2})\beta_2(1 + 3\lambda)\right] T \\ & + \left[T^{-1/2}\sum_1^T e_{t-1}\right] T^{1/2} - (\mu_2 - \mu_1), \end{aligned}$$

(c)
$$\begin{aligned} \sum_1^T y_{t-1}^2 = {} & (1/3)\left[\beta_1^2\lambda^2(3 - 2\lambda) + \beta_2^2(1-\lambda)^3 + 3\beta_1\beta_2\lambda(1-\lambda)^2\right] T^3 \\ & + \left[\mu_1\beta_1\lambda^2 + \mu_2\beta_2(1-\lambda^2) - (\tfrac{1}{2})\left(\beta_1\lambda + \beta_2(1-\lambda)^2\right)\right] T^2 \\ & + 2\left[\lambda(\beta_1 - \beta_2) T^{-1/2} \sum_{T_B+1}^T e_t + \beta_1 T^{-3/2} \sum_1^{T_B} t e_t - \beta_2 T^{-3/2} \sum_{T_B+1}^T t e_t\right] T^{3/2} \\ & + \Bigg[\lambda\mu_1^2 + (1/6)\beta_1^2\lambda^2 + \mu_1\beta_1\lambda + (1-\lambda)\mu_2^2 + (1/6)\beta_2^2(1-\lambda) \\ & \qquad + \mu_2\beta_2(1-\lambda) - 2\mu_2\beta_2 + T^{-1}\sum_1^T e_{t-1}^2\Bigg] T + o_p(T), \end{aligned}$$

(d)
$$\sum_{1}^{T} y_t y_{t-1} = (1/3)\left[\beta_1^2\lambda^2(3-2\lambda)+\beta_2^2(1-\lambda)^3+3\beta_1\beta_2\lambda(1-\lambda)^2\right]T^3$$
$$+\left[\mu_1\beta_1\lambda^2+\mu_2\beta_2(1-\lambda^2)\right]T^2$$
$$+2\left[\beta_1 T^{-3/2}\sum_{1}^{T_B} te_{t-1}+\beta_2 T^{-3/2}\sum_{T_B+1}^{T} te_{t-1}+\lambda(\beta_1-\beta_2)T^{-1/2}\sum_{T_B+1}^{T} e_t\right]T^{3/2}$$
$$+\left[\mu_1^2\lambda+\mu_2^2(1-\lambda)-(1/3)\left(\lambda\beta_1^2+(1-\lambda)\beta_2^2\right)\right.$$
$$\left.+\lambda\left(\beta_2^2-\beta_1\beta_2\right)+\lambda\beta_1(\mu_2+\mu_1)-2\lambda\mu_2\beta_2\right]T+o_p(T).$$

It is straightforward but tedious to show that $\tilde{\alpha}$ is given by $\tilde{\alpha}=A/D$ where

(A.2)
$$A=(T^2/2+T/2)\sum ty_{t-1}\sum y_t$$
$$-(T^3/3+T^2/2+T/6)\sum y_{t-1}\sum y_t - T\sum ty_{t-1}\sum ty_t$$
$$+(T^2/2+T/2)\sum y_{t-1}\sum ty_t+(T^4/12-T^2/12)\sum y_t y_{t-1}$$

and

(A.3)
$$D=(T^4/12-T^2/12)\sum y_{t-1}^2 - T\left(\sum ty_{t-1}\right)^2$$
$$+(T^2+T)\sum ty_{t-1}\sum y_{t-1}-(T^3/3+T^2/2+T/6)\left(\sum y_{t-1}\right)^2$$

where all summations run from 1 to T. To prove part (b) we derive the limits of $T^{-7}A$ and $T^{-7}D$ using Lemma A.2:

$$T^{-7}D=(1/12)T^{-3}\sum y_{t-1}^2 - T^{-6}\left(\sum ty_{t-1}\right)^2$$
$$+T^{-3}\sum ty_{t-1}\cdot T^{-2}\sum y_{t-1}-(1/3)T^{-4}\left(\sum y_{t-1}\right)^2+o_p(1)$$
$$=(1/36)\left[\beta_1^2\lambda^3+\beta_2^2(1-3\lambda+2\lambda^3)+3\beta_2\beta_1\lambda(1-\lambda^2)\right]$$
$$-(1/36)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]^2$$
$$+(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]$$
$$-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2+o_p(1).$$

Simple algebra yields:

(A.4)
$$T^{-7}D \to (1/36)(-3\lambda^2+4\lambda^3-3\lambda^4+3\lambda^5-\lambda^6)(\beta_1-\beta_2)^2.$$

Similarly,

$$T^{-7}A=T^{-3}\sum ty_{t-1}\cdot T^{-2}\sum y_{t-1}-(1/3)T^{-4}\left(\sum y_{t-1}\right)^2-T^{-6}\left(\sum ty_{t-1}\right)^2$$
$$+(1/12)T^{-3}\sum y_t y_{t-1}+o_p(1)$$
$$=(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\cdot\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]$$
$$-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2$$
$$-(1/36)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]^2$$
$$+(1/36)\left[\beta_1^2\lambda^3+\beta_2^2(1-3\lambda+2\lambda^3)+3\beta_2\beta_1\lambda(1-\lambda^2)\right]+o_p(1)$$

and

$$T^{-7}A \to (1/36)(-3\lambda^2+4\lambda^3-3\lambda^4+3\lambda^5-\lambda^6)(\beta_1-\beta_2)^2.$$

Therefore, $\tilde{\alpha}=T^{-7}A/T^{-7}D\to 1$ proving part (b, i). To prove part (b, ii), note that $T(\tilde{\alpha}-1)=T^{-6}(A-D)/T^{-7}D$. Simple manipulation yields:

$$\begin{aligned}T^{-6}(A-D) &= (1/12)T^{-2}\sum y_t y_{t-1}-(1/12)T^{-2}\sum y_{t-1}^2+T^{-5}\sum ty_{t-1}\sum y_{t-1}\\&\quad+(1/6)T^{-3}y_T\sum y_{t-1}-\left(\tfrac{1}{2}\right)T^{-4}y_T\sum ty_{t-1}-(1/12)T^{-4}\left(\sum y_{t-1}\right)^2\\&\quad+o_p(1)\\&=(1/24)\left[\beta_1^2\lambda^2+\beta_2^2(1-\lambda)^2+2\beta_1\beta_2\lambda(1-\lambda)\right]\\&\quad+(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]\\&\quad+(1/12)\left[(\beta_1-\beta_2)\lambda+\beta_2\right]\cdot\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]\\&\quad-(1/12)\left[(\beta_1-\beta_2)\lambda+\beta_2\right]\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\\&\quad-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2+o_p(1)\end{aligned}$$

and

$$T^{-6}(A-D)\to(1/24)(\beta_1-\beta_2)^2[-\lambda^2+4\lambda^3-5\lambda^4+2\lambda^5].$$

Therefore,

$$T(\tilde{\alpha}-1)\to(3/2)[-1+4\lambda-5\lambda^2+2\lambda^3]\cdot[-3+4\lambda-3\lambda^2+3\lambda^3-\lambda^4]^{-1}$$

proving part (b,ii).

Proof of Part (a): The proof of part (a) is straightforward but tedious. The following arguments present the main steps. First, the expressions for the moments of $\{y_t\}$ in Lemma A.2 can be written as follows:

$$\begin{aligned}&\sum\nolimits_1^T ty_{t-1}=a_1T^3+b_1T^2+c_1T^{3/2}+d_1T+o_p(T),\\&\sum\nolimits_1^T y_{t-1}=a_2T^2+b_2T+c_2T^{1/2}+d_2,\\&\sum\nolimits_1^T y_{t-1}^2=a_3T^3+b_3T^2+c_3T^{3/2}+d_3T+o_p(T),\\&\sum\nolimits_1^T y_t y_{t-1}=a_4T^3+b_4T^2+c_4T^{3/2}+d_4T+o_p(T).\end{aligned}$$

The coefficients a_i, b_i, c_i and d_i $(i=1,\ldots,4)$ are given by the corresponding expressions in Lemma A.2 where the condition $\beta_1=\beta_2=\beta$ is imposed. From (A.3), the denominator of $\tilde{\alpha}$ is given by:

$$\begin{aligned}T^{-5}D&=\left[a_3/12-a_1^2+a_1a_2-a_2^2/3\right]T^2\\&\quad+\left[b_3/12-2a_1b_1+a_1b_2+b_1a_2+a_1a_2-(2/3)a_2b_2-a_2^2/2\right]T\\&\quad+\left[c_3/12-2a_1c_1+a_1c_2+c_1a_2-(2/3)a_2c_2\right]T^{1/2}\\&\quad+\left[d_3/12-a_3/12-b_1^2-2a_1d_1+a_1d_2+b_1b_2\right.\\&\qquad\left.+d_1a_2+a_1b_2+b_1a_2-b_2^2/3-(2/3)a_2d_2-a_2b_2-a_2^2/6\right]+o_p(1).\end{aligned}$$

Now, tedious algebra shows that the $0(T^2)$, $0(T)$, and $0(T^{1/2})$ coefficients all cancel out and the sum of the 0(1) coefficients yields the following result:

$$T^{-5}D \to (1/12)\sigma_e^2 + (1/12)[\mu_1 - \mu_2]^2[\lambda - 4\lambda^2 + 6\lambda^3 - 3\lambda^4].$$

To analyze the limit of $T^{-5}A$, the numerator of $\tilde{\alpha}$, we need the expansions for Σy_t and $\Sigma t y_t$. These are given by:

$$\sum_1^T t y_t = a_1 T^3 + (b_1 + \beta/2)T^2 + c_1 T^{3/2} + (1/3)(d_1 + (5/6)\beta + \mu_2)T + o_p(T),$$

$$\sum_1^T y_t = a_2 T^2 + (b_2 + \beta)T + c_2 T^{1/2} + d_2.$$

Then we can write, using (A.2):

$$\begin{aligned} T^{-5}A = {} & [a_1 a_2 - a_2^2/3 - a_1^2 + a_4/12]T^2 \\ & + [a_1 a_2 + (b_2 + \beta)(a_1/2 - a_2/3) + (b_1 + \beta/2)(a_2/2 - a_1) - a_2^2/2 + b_4/12 \\ & \qquad + a_1 b_2/2 - a_1 b_1 - a_2 b_2/3 + b_1 a_2/2]T \\ & + [a_1 c_2 + c_1 a_2 - (2/3)a_2 c_2 - 2a_1 c_1 + c_4/12]T^{1/2} \\ & + [(b_2 + \beta)(b_1/2 + a_1/2 - b_2/3 - a_2/2) \\ & + (1/3)(d_1 + (5/6)\beta + \mu_2)(a_2/2 - a_1) \\ & + (b_1 + \beta/2)(b_2/2 + a_2/2 - b_1) + d_1 a_2/2 + b_1 a_2/2 - a_2 d_2/3 - a_2 b_2/2 \\ & - a_2^2/6 - d_1 a_1 + a_1 d_2/2 + d_4/12 + a_4/12]. \end{aligned}$$

Again, tedious algebra shows that the $0(T^2)$, $0(T)$, and $0(T^{1/2})$ terms all cancel out and that the sum of the coefficients remaining yields the following result:

$$T^{-5}A \to (1/12)\gamma_1 + (1/12)[\mu_1 - \mu_2]^2[\lambda - 4\lambda^2 + 6\lambda^3 - 3\lambda^4].$$

This proves part (a).

Proof of Theorem 2: We first note some invariance properties of the estimators $\tilde{\alpha}^i$ $(i = A, B, C)$: $\tilde{\alpha}^A$ is invariant with respect to μ and d; $\tilde{\alpha}^B$ is invariant to μ_1 and μ_2; and $\tilde{\alpha}^C$ is invariant to d, μ_1 and μ_2. Hence, without loss of generality, we can study the limiting distribution of $T(\tilde{\alpha}^i - 1)$ and $t_{\tilde{\alpha}^i}$ under the null hypothesis that the sequence $\{y_t\}$ is generated according to:

$$y_t = y_{t-1} + e_t \qquad (t = 1, \ldots, T) \tag{A.5}$$

with the innovation sequence satisfying Assumption 1. It is also straightforward to show that under (A.5), $\tilde{\alpha}^i$ $(i = A, B, C)$ are asymptotically equivalent to the least-squares estimators $\hat{\alpha}^i$ $(i = A, B, C)$ in the following regressions:

$$y_t = \hat{\mu}^A + \hat{\theta}^A DU_t + \hat{\beta}^A t + \hat{\alpha}^A y_{t-1} + \hat{e}_t^A, \tag{A.6}$$

$$y_t = \hat{\mu}^B + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \hat{e}_t^B, \tag{A.7}$$

$$y_t = \hat{\mu}^C + \hat{\theta}^C DU_t + \hat{\beta}^C t + \hat{\gamma}^C DT_t + \hat{\alpha}^C y_{t-1} + \hat{e}_t^C, \tag{A.8}$$

where $DU_t = 1$ and $DT_t = DT_t^* = 0$ if $t \leqslant T_B$ and $DU_t = 0$, $DT_t^* = t - T_B$, $DT_t = t$ if $t > T_B$. Since we are also concerned with regressions of the type (A.6)–(A.8) later in the text, we shall derive the limiting distributions concerning $\tilde{\alpha}^i$ $(i = A, B, C)$ using the representation of $\hat{\alpha}^i$ $(i = A, B, C)$. Note, however, that $\hat{\alpha}^A$ in (A.6) and $\hat{\alpha}^C$ in (A.9) are not invariant to the value of the parameter d under the null hypothesis. To achieve invariance, one must introduce a dummy variable $D(TB)_t$ taking value 1 at $t = T_B + 1$ and 0 elsewhere, as is done in regressions (12) and (14). Under the null hypothesis, $\hat{\alpha}^B$ is not invariant to a drift taking two distinct values: μ_1 and μ_2. To achieve invariance, the variable DU_t must be introduced in (A.7). However, this affects the limiting distribution of $\hat{\alpha}^B$ which becomes equivalent to that of $\hat{\alpha}^C$. Hence, one cannot analyze directly the case of a joint segmented trend function in a one-step type regression. We now turn to the proof of the theorem deriving the limiting distribution of $T(\hat{\alpha}^i - 1)$ and $t_{\hat{\alpha}^i}$ $(i = A, B, C)$ in (A.6) through (A.8).

The following Lemma provides weak convergence results for the sample moments of the data and will be used extensively. Its proof is a simple extension of Lemma A.1 and follows the methods of Phillips (1987) and Phillips and Perron (1988).

LEMMA A.3: *Let $\{y_t\}_0^T$ be a stochastic process generated according to (A.5) with the innovation sequence satisfying Assumption 1. Furthermore, let $T_B = \lambda T$; then as $T \to \infty$:*

(a) $$T^{-3/2}\sum_1^{T_B} y_t \Rightarrow \sigma\int_0^\lambda w(r)\,dr,$$

(b) $$T^{-5/2}\sum_1^{T_B} t y_t \Rightarrow \sigma\int_0^\lambda r w(r)\,dr,$$

(c) $$T^{-2}\sum_1^{T_B} y_t^2 \Rightarrow \sigma^2\int_0^\lambda w(r)^2\,dr,$$

(d) $$T^{-1}\sum_1^{T} y_{t-1}e_t \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right).$$

Parts (a), (b), and (c) are simple generalizations of results in Phillips (1987) and Phillips and Perron (1988) where $T_B = T$ and hence $\lambda = 1$; part (d) is proved in Phillips (1987).

Using the property that a regression of the form $y = X_1\beta_1 + X_2\hat{\beta}_2 + \hat{e}$ yields a numerically identical estimator $\hat{\beta}_2$ as obtained in a regression of the form $y^* = X_2^*\hat{\beta}_2 + \hat{e}$ where y^* and X_2^* are projections of y and X_2, respectively, on the space spanned by the vectors in X_1, (A.6), (A.7), and (A.8), can be written as:

(A.9) $$Y_{it} = \hat{\beta}^i X_{1it} + \hat{\psi}_i X_{2it} + \hat{\alpha}^i y^*_{it-1} + \hat{e}_{it} \qquad (t = 1,\ldots,T;\ i = A, B, C),$$

where

$$\hat{\psi}_A = \hat{\theta}^A;\quad \hat{\psi}_B = \hat{\gamma}^B;\quad \hat{\psi}_C = \hat{\gamma}^C,$$
$$Y_{At} = Y_{Bt} = y_t - \overline{Y},$$
$$y^*_{At-1} = y^*_{Bt-1} = y_{t-1} - \overline{Y}_{-1},$$
$$X_{1At} = X_{1Bt} = t - \bar{t},$$
$$X_{1Ct} = t - c_1 \text{ if } t \leq T_B \text{ and } = t - c_2 \text{ otherwise},$$
$$X_{2At} = DU_t - \lambda,$$
$$X_{2Bt} = -\bar{t}^* \text{ if } t \leq T_B \text{ and } = t - T_B - \bar{t}^* \text{ otherwise},$$
$$X_{2Ct} = t - c_1 \text{ if } t \leq T_B \text{ and } = 0 \text{ otherwise},$$
$$Y_{Ct} = y_t - A \text{ if } t \leq T_B \text{ and } = y_t - B \text{ otherwise},$$
$$y^*_{Ct-1} = y_{t-1} - A' \text{ if } t \leq T_B \text{ and } = y_{t-1} - B' \text{ otherwise},$$

and

$$\bar{t} = T^{-1}\sum_1^T t = (T+1)/2,\quad \bar{t}^* = T^{-1}\sum_1^{T-T_B} t = T(1-\lambda)^2/2 + (1-\lambda)/2,$$
$$c_1 = \bar{t} - T(1-\lambda)/2,\quad c_2 = \bar{t} + T\lambda/2,$$
$$A = \overline{Y} + \lambda^{-1}T^{-1}\sum_1^{T_B}(y_t - \overline{Y}),\quad B = \overline{Y} - (1-\lambda)^{-1}T^{-1}\sum_1^{T_B}(y_t - \overline{Y}),$$
$$A' = \overline{Y}_{-1} + \lambda^{-1}T^{-1}\sum_1^{T_B}(y_{t-1} - \overline{Y}_{-1}),\quad B' = \overline{Y}_{-1} - (1-\lambda)^{-1}T^{-1}\sum_1^{T_B}(y_{t-1} - \overline{Y}_{-1}),$$
$$\overline{Y} = T^{-1}\sum_1^T y_t,\quad \overline{Y}_{-1} = T^{-1}\sum_1^T y_{t-1}.$$

Now, let $Y_l' = (y_{l,0}^*, \ldots, y_{l,T-1}^*)$, $E' = (e_1, \ldots, e_T)$, $Z_l' = [X_{1l}, X_{2l}]$, $X_{1l} = (X_{1l,1}, \ldots, X_{1l,T})$, $X_{2l} = (X_{2l,1}, \ldots, X_{2l,T})$; then, under the null hypothesis,

(A.10) $$\hat{\alpha}^l - 1 = (Y_l'Y_l)^{-1}Y_l'E - (Y_l'Y_l)^{-1}Y_l'Z_l\left[Z_l'(I - P_{Y_l})Z_l\right]^{-1}Z_l'\left[I - P_{Y_l}\right]E$$

where $P_{Y_l} = Y_l(Y_l'Y_l)^{-1}Y_l'$. Furthermore, define the following terms:

$$Z_l'Z_l = \begin{bmatrix} a_l & b_l \\ b_l & c_l \end{bmatrix}, \quad Z_l'Y_l = \begin{bmatrix} H_l \\ J_l \end{bmatrix}, \quad Z_l'E = \begin{bmatrix} K_l \\ L_l \end{bmatrix}.$$

Straightforward manipulation yields the following representation for $\hat{\alpha}^l - 1$:

(A.11) $$\begin{aligned} \hat{\alpha}^l - 1 = {} & \left[\left(a_lc_l - b_l^2\right)Y_l'E - c_lH_lK_l + b_lJ_lK_l - a_lJ_lL_l + b_lH_lL_l\right]/ \\ & \left[\left(a_lc_l - b_l^2\right)Y_l'Y_l - a_lJ_l^2 - c_lH_l^2 + 2b_lH_lJ_l\right] \\ \equiv {} & E_l/F_l. \end{aligned}$$

The quantities involved are defined as follows with their respective limits as $T \to \infty$, obtained using Lemma A.3:

$$a_A = a_B = T^3/12 - T/12, \quad T^{-3}a_A = T^{-3}a_B \to 1/12,$$

$$b_A = -(1-\lambda)\lambda T^2/2, \quad T^{-2}b_A \to -(1-\lambda)\lambda/2,$$

$$c_A = (1-\lambda)\lambda T, \quad T^{-1}c_A \to (1-\lambda)\lambda,$$

$$Y_A'Y_A = Y_B'Y_B = \sum_1^T (y_{t-1} - \overline{Y}_{-1})^2,$$

$$T^{-2}Y_A'Y_A = T^{-2}Y_B'Y_B \Rightarrow \sigma^2\left[\int_0^1 w(r)^2\,dr - \left(\int_0^1 w(r)\,dr\right)^2\right],$$

$$Y_A'E = Y_B'E = \sum_1^T (y_{t-1} - \overline{Y}_{-1})e_t,$$

$$T^{-1}Y_A'E = T^{-1}Y_B'E \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) - \sigma^2 w(1)\int_0^1 w(r)\,dr,$$

$$H_A = H_B = \sum_1^T t(y_{t-1} - \overline{Y}_{-1}),$$

$$T^{-5/2}H_A = T^{-5/2}H_B \Rightarrow \sigma\int_0^1 rw(r)\,dr - (\sigma/2)\int_0^1 w(r)\,dr,$$

$$J_A = \sum_1^{T_B}(y_{t-1} - \overline{Y}_{-1}), \quad T^{-3/2}J_A \Rightarrow \sigma\int_0^\lambda w(r)\,dr - \sigma\lambda\int_0^1 w(r)\,dr,$$

$$K_A = K_B = \sum_1^T tu_t - \bar{t}\sum_1^T u_t, \quad T^{-3/2}K_A = T^{-3/2}K_B \Rightarrow (\sigma/2)w(1) - \sigma\int_0^1 w(r)\,dr,$$

$$L_A = \sum_1^{T_B}(e_t - \overline{E}), \quad T^{-1/2}L_A \Rightarrow \sigma w(\lambda) - \sigma\lambda w(1),$$

$$b_B = \sum_{T_B+1}^T (t - \bar{t})(t - T_B), \quad T^{-3}b_B \to (1-\lambda)^2(1+2\lambda)/12,$$

$$c_B = T_B\bar{t}^{*2} + \sum_1^{T-T_B}(t - \bar{t}^*)^2, \quad T^{-3}c_B \to (1-\lambda)^3(1+3\lambda)/12,$$

$$J_B = \sum_{T_B+1}^T (t - T_B)(y_{t-1} - \overline{Y}_{-1}),$$

$$T^{-5/2}J_B \Rightarrow \sigma\int_\lambda^1 rw(r)\,dr - \lambda\sigma\int_\lambda^1 w(r)\,dr - \left((1-\lambda)^2/2\right)\sigma\int_0^1 w(r)\,dr,$$

$$L_B=\sum_{T_B+1}^{T}(t-T_B)(e_t-\bar{E}),\quad T^{-3/2}L_B\Rightarrow\left((1-\lambda^2)/2\right)\sigma w(1)-\sigma\int_\lambda^1 w(r)\,dr,$$

$$a_C=\sum_1^{T_B}(t-c_1)^2+\sum_{T_B+1}^{T}(t-c_2)^2,\quad T^{-3}a_C\to(1-\lambda)^2/12+\lambda^3/12,$$

$$b_C=\sum_1^{T_B}(t-c_1)^2,\quad T^{-3}b_C\to\lambda^3/12,$$

$$c_C=\sum_1^{T_B}(t-c_1)^2,\quad T^{-3}c_C\to\lambda^3/12,$$

$$Y_C'Y_C=\sum_1^{T_B}(y_{t-1}-A')^2+\sum_{T_B+1}^{T}(y_{t-1}-B')^2,$$

$$T^{-2}Y_C'Y_C\Rightarrow\sigma^2\left[\int_0^1 w(r)^2\,dr-\lambda^{-1}\left(\int_0^\lambda w(r)\,dr\right)^2-(1-\lambda)^{-1}\left(\int_\lambda^1 w(r)\,dr\right)^2\right],$$

$$Y_C'E=\sum_1^{T_B}(y_{t-1}-A')e_t+\sum_{T_B+1}^{T}(y_{t-1}-B')e_t,$$

$$T^{-1}Y_C'E\Rightarrow(\sigma^2/2)\left(w(1)^2-\sigma_e^2/\sigma^2\right)-\lambda^{-1}\sigma^2 w(\lambda)\int_0^\lambda w(r)\,dr$$
$$-\sigma^2(w(1)-w(\lambda))(1-\lambda)^{-1}\int_\lambda^1 w(r)\,dr,$$

$$H_C=\sum_1^{T_B}(t-c_1)(y_{t-1}-A')+\sum_{T_B+1}^{T}(t-c_2)(y_{t-1}-B'),$$

$$T^{-5/2}H_C\Rightarrow\sigma\left[\int_0^1 rw(r)\,dr-\left(\tfrac{1}{2}\right)(1+\lambda)\int_0^1 w(r)\,dr+\left(\tfrac{1}{2}\right)\int_0^\lambda w(r)\,dr\right],$$

$$J_C=\sum_1^{T_B}(t-c_1)(y_{t-1}-A'),\quad T^{-5/2}J_C\Rightarrow\sigma\left[\int_0^\lambda rw(r)\,dr-(\lambda/2)\int_0^\lambda w(r)\,dr\right],$$

$$K_C=\sum_1^{T_B}(t-c_1)e_t+\sum_{T_B+1}^{T}(t-c_2)e_t,$$

$$T^{-3/2}K_C\Rightarrow\sigma\left[\left(\tfrac{1}{2}\right)(1-\lambda)w(1)+\left(\tfrac{1}{2}\right)w(\lambda)-\int_0^1 w(r)\,dr\right],$$

$$L_C=\sum_1^{T_B}(t-c_1)e_t,\quad T^{-3/2}L_C\Rightarrow\sigma\left[(\lambda/2)w(\lambda)-\int_0^\lambda w(r)\,dr\right].$$

Now, using (A.11), we can write the statistics as follows:

(A.12) $T(\hat{\alpha}^A-1)=T^{-5}E_A/T^{-6}F_A,$

(A.13) $t_{\hat{\alpha}}A=T^{-5}E_A/\left[\hat{S}_A^2\cdot T^{-6}F_A\cdot T^{-4}\left(a_Ac_A-b_A^2\right)\right]^{1/2},$

(A.14) $T(\hat{\alpha}^i-1)=T^{-7}E_i/T^{-8}F_i,\quad i=B,C,$

(A.15) $t_{\hat{\alpha}}i=T^{-7}E_i/\left[\hat{S}_i^2\cdot T^{-8}F_i\cdot T^{-6}\left(a_ic_i-b_i^2\right)\right]^{1/2},\quad i=B,C,$

where $\hat{S}_i^2=T^{-1}\Sigma_1^T\hat{e}_t^i$.

The results of Theorem 2 follow taking the limits of the expressions in (A.12) through (A.15) as $T\to\infty$, using the weak convergence results of the relevant moments (given above) and the fact that $\hat{S}_i^2(i=A,B,C)$ converges in probability to σ_e^2 as $T\to\infty$.

APPENDIX B

EXTENDED SET OF RESULTS FOR TESTS OF A UNIT ROOT USING SPLIT AND FULL SAMPLES

TABLE A1

TESTS FOR A UNIT ROOT ON PRE-1929 SAMPLES

Regression: $y_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\alpha}y_{t-1} + \Sigma_{i=1}^{k}\tilde{d}_i \Delta y_{t-i} + \tilde{e}_t$

		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	$\tilde{\alpha}$	0.44	0.42	0.43	0.32								
	$t_{\tilde{\alpha}}$	−2.33	−1.83	−1.43	−1.27								
Nominal GNP	$\tilde{\alpha}$	0.60	0.52	0.45	0.44	0.57							
	$t_{\tilde{\alpha}}$	−2.14	−2.04	−1.80	−1.12	−0.89							
Real per capita GNP	$\tilde{\alpha}$	0.39	0.37	0.37	0.23								
	$t_{\tilde{\alpha}}$	−2.44	−1.91	−1.51	−1.36								
Industrial production	$\tilde{\alpha}$	0.69	0.72	0.65	0.64	0.69	0.73	0.68	0.71				
	$t_{\tilde{\alpha}}$	−3.14	−2.57	−3.00	−2.83	−2.18	−1.78	−1.93	−1.43				
Employment	$\tilde{\alpha}$	0.76	0.80	0.80	0.78	0.82	0.74	0.61	0.56				
	$t_{\tilde{\alpha}}$	−2.16	−1.65	−1.72	−1.91	−1.43	−2.05	−2.85	−2.63				
GNP deflator	$\tilde{\alpha}$	0.84	0.80	0.78	0.77	0.79	0.75	0.74	0.71				
	$t_{\tilde{\alpha}}$	−2.44	−2.79	−2.66	−2.54	−2.10	−2.19	−2.05	−2.05				
Consumer prices	$\tilde{\alpha}$	0.95	0.97	0.96	0.96	0.96	0.97	0.96	0.96				
	$t_{\tilde{\alpha}}$	−1.89	−1.28	−1.37	−1.50	−1.47	−1.29	−1.37	−1.41				
Wages	$\tilde{\alpha}$	0.76	0.73	0.68	0.66	0.63	0.54	0.30	0.43				
	$t_{\tilde{\alpha}}$	−2.32	−2.22	−2.35	−2.09	−1.90	−2.08	−2.82	−1.67				
Real wages	$\tilde{\alpha}$	0.44	0.50	0.49	0.43	0.24	0.28	0.09	0.68				
	$t_{\tilde{\alpha}}$	−2.83	−2.23	−2.05	−1.89	−2.21	−1.71	−1.84	−0.63				
Money stock	$\tilde{\alpha}$	0.75	0.71	0.55	0.61	0.55	0.46	0.25	−0.04				
	$t_{\tilde{\alpha}}$	−2.88	−2.89	−4.20	−2.71	−2.53	−2.54	−3.01	−3.37				
Velocity	$\tilde{\alpha}$	0.89	0.90	0.91	0.90	0.93	0.91	0.89	0.90				
	$t_{\tilde{\alpha}}$	−1.52	−1.33	−1.22	−1.17	−0.82	−0.93	−1.12	−1.08				
Interest rate	$\tilde{\alpha}$	0.73	0.71	0.54	0.54								
	$t_{\tilde{\alpha}}$	−1.73	−1.53	−2.06	−1.59								
Common stock prices	$\tilde{\alpha}$	0.81	0.86	0.73	0.75	0.76	0.75	0.64	0.68	0.61			
	$t_{\tilde{\alpha}}$	−1.95	−1.27	−2.29	−1.83	−1.60	−1.55	−2.09	−1.75	−2.06			
Quarterly real GNP[a]	$\tilde{\alpha}$	0.93	0.91	0.92	0.93	0.93	0.92	0.91	0.90	0.90	0.88	0.86	0.89
	$t_{\tilde{\alpha}}$	−2.51	−3.02	−2.52	−2.23	−2.18	−2.41	−2.60	−2.83	−2.68	−3.04	−3.40	−2.62

[a]The sample for Quarterly Real GNP is 47:I–73:I.

TABLE A2

TESTS FOR A UNIT ROOT ON POST-1929 SAMPLES

Regression: $y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \Sigma_{i=1}^{k} \tilde{d}_i \Delta y_{t-i} + \tilde{e}_t$

		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	$\tilde{\alpha}$	0.72	0.75	0.75	0.78	0.74	0.66	0.56	0.33	0.22	0.18	0.30	0.09
	$t_{\tilde{\alpha}}$	−3.48	−3.00	−2.57	−1.96	−2.16	−2.65	−3.03	−5.32	−3.97	−3.19	−2.05	−2.34
Nominal GNP	$\tilde{\alpha}$	0.76	0.87	0.87	0.89	0.86	0.79	0.72	0.63	0.56	0.51	0.41	0.40
	$t_{\tilde{\alpha}}$	−3.37	−1.87	−1.60	−1.35	−1.66	−2.40	−2.93	−4.10	−3.39	−3.20	−2.91	−2.24
Real per capita GNP	$\tilde{\alpha}$	0.78	0.79	0.79	0.82	0.78	0.71	0.63	0.43	0.34	0.32	0.46	0.30
	$t_{\tilde{\alpha}}$	−3.05	−2.91	−2.55	−1.96	−2.19	−2.64	−3.03	−5.36	−3.91	−3.08	−1.89	−2.13
Industrial production	$\tilde{\alpha}$	0.68	0.69	0.66	0.63	0.71	0.64	0.53	0.23	0.03	−0.11	−0.03	−0.24
	$t_{\tilde{\alpha}}$	−2.84	−2.75	−2.65	−2.52	−1.76	−2.13	−2.55	−5.75	−4.38	−3.61	−2.40	−2.33
Employment	$\tilde{\alpha}$	0.78	0.80	0.80	0.83	0.80	0.72	0.67	0.47	0.55	0.42	0.24	0.10
	$t_{\tilde{\alpha}}$	−3.14	−2.66	−2.34	−1.80	−2.02	−2.64	−2.70	−5.61	−2.94	−3.24	−3.30	−2.79
GNP deflator	$\tilde{\alpha}$	0.85	0.92	0.91	0.87	0.87	0.83	0.72	0.76	0.75	0.81	0.75	0.68
	$t_{\tilde{\alpha}}$	−2.60	−1.32	−1.68	−2.29	−2.25	−2.64	−4.47	−3.08	−2.57	−1.73	−2.14	−2.48
Consumer prices	$\tilde{\alpha}$	0.84	0.91	0.90	0.88	0.85	0.81	0.70	0.68	0.62	0.72	0.67	0.58
	$t_{\tilde{\alpha}}$	−2.92	−1.64	−1.76	−2.10	−2.50	−2.72	−4.55	−3.45	−3.21	−1.98	−2.04	−2.39
Wages	$\tilde{\alpha}$	0.78	0.88	0.89	0.88	0.85	0.81	0.77	0.76	0.78	0.75	0.66	0.60
	$t_{\tilde{\alpha}}$	−3.37	−1.69	−1.41	−1.46	−1.77	−2.12	−2.27	−3.19	−2.02	−2.48	−3.06	−2.81
Real wages	$\tilde{\alpha}$	0.72	0.71	0.70	0.75	0.68	0.54	0.58	0.36	0.40	0.23	0.14	−0.35
	$t_{\tilde{\alpha}}$	−3.33	−3.10	−2.55	−1.84	−2.14	−2.79	−2.05	−3.31	−2.14	−2.34	−1.89	−2.11
Money stock	$\tilde{\alpha}$	0.89	0.93	0.92	0.91	0.89	0.87	0.86	0.79	0.67	0.63	0.59	0.39
	$t_{\tilde{\alpha}}$	−3.01	−1.85	−2.03	−2.55	−2.50	−2.59	−2.57	−4.57	−5.93	−3.61	−2.83	−4.05
Velocity	$\tilde{\alpha}$	0.61	0.67	0.63	0.71	0.69	0.66	0.60	0.52	0.49	0.63	0.50	0.36
	$t_{\tilde{\alpha}}$	−3.82	−2.70	−2.80	−1.97	−1.95	−1.91	−2.11	−2.33	−2.16	−1.43	−1.82	−2.54
Interest rate	$\tilde{\alpha}$	1.07	0.98	1.01	1.03	1.04	1.06	0.97					
	$t_{\tilde{\alpha}}$	1.11	−0.28	0.14	0.37	0.51	0.60	−0.25					
Common stock prices	$\tilde{\alpha}$	0.65	0.84	0.79	0.79	0.75	0.64	0.58	0.64	0.62	0.66	0.58	0.52
	$t_{\tilde{\alpha}}$	−3.48	−1.58	−1.99	−1.89	−2.13	−3.07	−2.96	−1.99	−2.00	−1.63	−1.64	−1.56
Quarterly real GNP[a]	$\tilde{\alpha}$	0.88	0.84	0.85	0.84	0.82	0.80	0.77	0.80	0.73	0.65	0.52	0.52
	$t_{\tilde{\alpha}}$	−2.23	−2.74	−2.39	−2.44	−2.48	−2.63	−2.80	−2.19	−2.78	−3.30	−4.03	−3.17

[a] The sample for Quarterly Real GNP is 73:II–86:III.

TABLE A3

TESTS FOR A UNIT ROOT ON THE FULL SAMPLES

	(1)[a]		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	(12)	$\tilde{\alpha}$	0.71	0.68	0.66	0.63	0.62	0.55	0.43	0.28	0.19	0.19	0.15	0.13
		$t_{\tilde{\alpha}}$	−4.04	−4.06	−3.86	−3.73	−3.48	−3.87	−4.81	−5.03	−4.89	−4.14	−4.16	−4.20
Nominal GNP	(12)	$\tilde{\alpha}$	0.70	0.69	0.69	0.70	0.66	0.60	0.56	0.47	0.46	0.41	0.23	0.34
		$t_{\tilde{\alpha}}$	−4.43	−4.17	−3.87	−3.58	−4.01	−4.70	−4.88	−5.42	−5.18	−5.38	−7.86	−5.98
Real per capita GNP	(12)	$\tilde{\alpha}$	0.76	0.73	0.72	0.70	0.70	0.64	0.53	0.43	0.39	0.42	0.37	0.34
		$t_{\tilde{\alpha}}$	−3.62	−3.58	−3.37	−3.21	−2.94	−3.27	−4.09	−4.08	−3.89	−3.14	−3.23	−3.17
Industrial production	(12)	$\tilde{\alpha}$	0.67	0.65	0.59	0.56	0.61	0.57	0.48	0.32	0.40	−0.37	−0.29	−0.32
		$t_{\tilde{\alpha}}$	−4.63	−4.46	−4.84	−4.69	−3.83	−3.98	−4.65	−5.47	−4.15	−4.05	−4.45	−4.08
Employment	(12)	$\tilde{\alpha}$	0.78	0.80	0.77	0.76	0.78	0.73	0.67	0.60	0.64	0.62	0.59	0.58
		$t_{\tilde{\alpha}}$	−3.77	−3.29	−3.72	−3.78	−3.12	−3.94	−4.51	−4.76	−3.59	−3.58	−3.59	−3.49
GNP deflator	(12)	$\tilde{\alpha}$	0.84	0.82	0.81	0.78	0.78	0.75	0.74	0.71	0.70	0.69	0.67	0.68
		$t_{\tilde{\alpha}}$	−3.79	−3.99	−3.89	−4.16	−4.04	−4.20	−4.10	−4.32	−4.28	−4.34	−4.35	−4.00
Consumer prices	(12)	$\tilde{\alpha}$	0.97	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.97	0.97
		$t_{\tilde{\alpha}}$	−1.87	−1.28	−1.68	−2.19	−2.06	−1.89	−2.01	−2.01	−1.90	−1.93	−1.49	−1.44
Wages	(12)	$\tilde{\alpha}$	0.77	0.76	0.74	0.73	0.71	0.68	0.62	0.62	0.64	0.63	0.60	0.67
		$t_{\tilde{\alpha}}$	−4.31	−4.15	−4.25	−4.05	−4.21	−4.73	−5.41	−4.91	−4.62	−4.63	−4.69	−3.64
Real wages	(14)	$\tilde{\alpha}$	0.68	0.63	0.57	0.52	0.49	0.47	0.38	0.30	0.29	0.28	0.27	0.29
		$t_{\tilde{\alpha}}$	−3.87	−3.97	−4.11	−4.06	−3.89	−3.62	−4.02	−4.28	−4.11	−3.82	−3.64	−3.37
Money stock	(12)	$\tilde{\alpha}$	0.87	0.87	0.85	0.86	0.84	0.81	0.78	0.76	0.74	0.74	0.72	0.77
		$t_{\tilde{\alpha}}$	−3.94	−3.61	−3.86	−3.66	−3.82	−4.29	−4.69	−4.56	−4.36	−4.29	−4.32	−3.18
Velocity	(12)	$\tilde{\alpha}$	0.93	0.94	0.95	0.96	0.97	0.97	0.96	0.95	0.96	0.96	0.94	0.98
		$t_{\tilde{\alpha}}$	−1.82	−1.53	−1.41	−1.11	−0.74	−0.79	−0.94	−1.09	−0.91	−0.89	−1.22	−0.49
Interest rate	(12)	$\tilde{\alpha}$	1.01	0.98	0.97	0.98	0.98	0.99	1.004	1.01	1.01	1.03	0.99	0.97
		$t_{\tilde{\alpha}}$	0.12	−0.45	−0.53	−0.34	−0.31	−0.24	0.07	0.22	0.12	0.46	−0.08	-0.40
Common stock prices	(14)	$\tilde{\alpha}$	0.72	0.73	0.72	0.74	0.76	0.76	0.75	0.75	0.73	0.67	0.62	0.60
		$t_{\tilde{\alpha}}$	−4.87	−4.39	−4.43	−3.91	−3.53	−3.52	−3.51	−3.41	−3.52	−4.19	−4.50	−4.35
Quarterly real GNP	(10)	$\tilde{\alpha}$	0.92	0.90	0.91	0.90	0.90	0.90	0.89	0.89	0.88	0.86	0.84	0.87
	$i=B$	$t_{\tilde{\alpha}}$	−3.33	−3.97	−3.47	−3.18	−3.16	−3.39	−3.51	−3.42	−3.55	−3.98	−4.32	−3.28

[a]The number in column (1) refers to the regression model used to test for a unit root using the full samples. See the discussion in the text.

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How Big Is the Random Walk in GNP?

John H. Cochrane

University of Chicago

This paper presents a measure of the persistence of fluctuations in GNP based on the variance of its long differences. That measure finds little long-term persistence in GNP. Previous research on this question found a great deal of persistence in GNP, suggesting models such as a random walk. A reconciliation of this paper's results with previous research shows that conventional criteria for time-series model building can produce misleading estimates of persistence.

I. Introduction

Macroeconomists once viewed fluctuations in gross national product as temporary deviations from a trend. The economic theory of business cycles described temporary deviations from "potential GNP," which was assumed to evolve smoothly over time, and data were routinely detrended prior to analysis. A body of recent empirical work (described below) has questioned this time-honored view. By using a variety of time-series models, it finds that fluctuations in GNP are permanent—that a decline in GNP today lowers forecasts of GNP into the infinite future.

This paper reexamines the long-run properties of GNP and argues that GNP does, in fact, revert toward a "trend" following a shock. However, that reversion occurs over a time horizon characteristic of business cycles—several years at least. Therefore, the short-run properties of GNP are consistent with a model with very persistent shocks,

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and one can incorrectly infer a great deal of long-horizon persistence by fitting a time-series model to this short-run behavior.

The class of time-series model most commonly used to describe temporary deviations about trend is

$$y_t = bt + \sum_{j=0}^{\infty} a_j \epsilon_{t-j}, \tag{1}$$

where y_t stands for log GNP, bt describes the trend, and ϵ_t is a random disturbance.[1] Fluctuations in y_t are temporary if $\Sigma a_j \epsilon_{t-j}$ is a stationary stochastic process (y_t is then called "trend stationary"). For $\Sigma a_j \epsilon_{t-j}$ to be stationary, the a_j must approach zero for large j. As a result, a decline in GNP below trend today has no effect on forecasts of the level of GNP, $E_t(y_{t+j})$, in the far future, and it implies that growth rates of GNP must rise above their historical average for a few periods until the trend line is reestablished.

The simplest time-series model that captures permanent fluctuations in GNP is a random walk with drift:

$$y_t = \mu + y_{t-1} + \epsilon_t. \tag{2}$$

Fluctuations in a random walk are permanent in the following sense: suppose that $\epsilon_t = -1$, so that y_t falls one unit below last period's expected value. Then, since $y_{t+j} = y_t + j\mu + \epsilon_{t+1} + \ldots + \epsilon_{t+j}$, forecasts $E_t(y_{t+j})$ fall by one unit for the indefinite future. Also, a low or negative growth rate today implies nothing about growth rates in the future, and there is no tendency for future levels of GNP to revert to a trend line. The random walk is also nonstationary.

The distinction between a random walk (2) and a trend-stationary series (1) is extreme. Long-range forecasts of a random walk move one for one with shocks at each date, while long-range forecasts of a trend-stationary series do not change at all. There are two related ways to think about a series that lies between these two extremes.

First, one can ask how much long-term forecasts respond to shocks. In one interpretation, the measure of this paper asks the question, How much does a one-unit shock to GNP affect forecasts in the far future? If by one unit, it finds a random walk; if by zero, it finds a trend-stationary process like (1). It can also find numbers between zero and one, characterizing a series that returns toward a "trend" in the far future, but does not get all the way there, or it can find a number greater than one, characterizing a series that will continue to

[1] Simple univariate time-series models like (1) should be thought of as a way of capturing the dynamic behavior of y_t that results from a rich multivariate world. They are not "structural" in any way.

diverge from its previously forecast value following a shock. Campbell and Mankiw (1987) originated and emphasize this interpretation.

Second, one can model a series whose fluctuations are partly temporary and partly permanent as a combination of a stationary series and a random walk. The random walk carries the permanent part of a change and the stationary series carries the temporary part of a change. Then, one can ask how important the permanent or random walk component is to the behavior of the series. In a second interpretation, the measure of this paper asks the question, How large is the variance of shocks to the random walk or permanent component of GNP compared with the variance of yearly GNP growth rates? Or, equivalently, How big is the random walk in GNP?

If the variance of the shocks to the random walk component is zero, the series is trend-stationary, and long-term forecasts do not change in response to shocks. If the variance of the shocks to the random walk component is equal to the variance of first differences, the series is a pure random walk. As before, there is a continuous range of possibilities between zero and one and beyond one.

A model consisting of a random walk plus a stationary component may seem quite special. However, I show below that we can think of *any* series whose growth rates or first differences are stationary (any series with a unit root) as a combination of a stationary series plus a random walk. The decomposition into stationary and random walk components is a convenient way of thinking about the properties of a time series, but it adds no structure. I also show that the response to innovations is proportional to the square root of the variance of shocks to a random walk component, so we can freely transform between these two interpretations.

The idea that GNP may contain a random walk goes back to Irving Fisher's "Monte Carlo hypothesis," examined by McCulloch (1975). There is now a large literature following the first half of Nelson and Plosser (1982) that applies the Dickey and Fuller (1979, 1981) and subsequent tests for unit roots to aggregate time series. Since a series with a unit root is equivalent to a series that is composed of a random walk and a stationary component, tests for a unit root are attempts to distinguish between series that have no random walk component (or for which the variance of shocks to the random walk component is zero) and series that have a random walk component (or for which the variance of shocks to the random walk component is between zero and infinity). Stated this way, it is clear why tests for a unit root have low power: it is hard to tell a stationary series from a stationary series plus a very small random walk. This paper and the related literature cited in it go beyond testing for the presence or absence of a unit root or random walk component and measure how important the unit root or random walk component is to the behavior of a series.

Implications of the Random Walk in GNP

The size of a random walk in GNP is important from a purely statistical viewpoint. Many statistical procedures rely critically on the distinction between series that do not contain a random walk component (1), which we can and should detrend, and first-difference stationary series—(3) below, or series that do contain a random walk component—which we should first-difference prior to analysis. Hypothesis tests that rely on asymptotic distribution theory are an important example because that distribution theory is often quite sensitive to the presence of a random walk component. A measurement of the size of the random walk component can be a better guide to the proper procedure than a unit root test because if the random walk component is small but still nonzero, then an asymptotic distribution theory based on trend stationarity may provide a better approximation in a given small sample than the theory based on a unit root.

The size of a random walk in GNP has been cast as a direct test between competing models of the economy. For example, Nelson and Plosser (1982) interpreted their result that GNP has a large random walk component as evidence for stochastic equilibrium models over traditional monetary or Keynesian business cycle models. They argued that traditional models produce only temporary deviations from trend, while models that find the ultimate source of GNP variability in technology shocks can produce permanent fluctuations.

With the advantages of hindsight, it now seems that the size or existence of a random walk component in GNP cannot directly distinguish broad classes of economic theories of the business cycle at their present stage of development. The Kydland and Prescott (1982) and Long and Plosser (1983) stochastic equilibrium models were constructed precisely to generate temporary fluctuations about trend. On the other hand, King et al. (1987) show that one can modify these models to produce a random walk component by introducing a random walk in the technology shocks or a linear technology for human or physical capital accumulation. Presumably, the same modifications would introduce a random walk component into monetary or "Keynesian" models as well.

Furthermore, the results of this paper are compatible with a variety of random walk components. I show below that an AR(2) about a deterministic trend, which has no random walk component, and a model with a random walk whose variance is 0.18 times the variance of first differences of log GNP account equally well for the results of

Staff/911
Storm/5

this paper. Also, the standard errors in this paper are large, and I argue that this is unavoidable. I conclude that the existence or size of a random walk component in GNP is not a precisely measured "stylized fact" that we should require any reasonable model to reproduce.

The most promising direct use for the point estimates of the size of a random walk component in this paper may be the calibration of a given model rather than a test that can distinguish competing classes of models. If a model (like the ones cited above) produces a random walk in GNP, the results of this paper suggest that the parameters of that model should be picked to also generate interesting short-run dynamics of GNP, so that the variance of yearly changes in GNP is much larger than the variance of shocks to its random walk component.

Other Estimates

Several authors have estimated the persistence of fluctuations in GNP, and their estimates vary greatly. Nelson and Plosser (1982) matched a model consisting of permanent and temporary components to a stylized autocorrelation function for growth rates of GNP and concluded that the permanent component was more important than the temporary component. Watson (1986) and Clark (1987) estimated different unobserved components models and found a small permanent component. Campbell and Mankiw (1987) estimated the effect of a shock on long-term forecasts of GNP from the parameters of low-order autoregressive, moving average (ARMA) representations of postwar GNP and found a large random walk component.

Several authors have examined the persistence of fluctuations in other time series using a variety of methods. Rose (1986) presents a survey of papers that find large random walk components in various macroeconomic time series. In finance, conventional wisdom favored the random walk model while macroeconomists favored the trend-stationary model. Poterba and Summers (1987), Fama and French (1988), and Lo and MacKinlay (1988) use variance ratio estimators similar to the one used in this paper and related estimators to document a temporary component in stock prices. Huizinga (1987) uses a closely related estimator to document a temporary component in real exchange rates. Cochrane and Sbordone (1988) present a multivariate extension.

This Paper's Technique

In this paper, I measure the size of a random walk component in GNP from the variance of its long differences. The intuition behind this measure comes from the following argument: Imagine that log GNP, denoted y_t, is a pure random walk (model [2]). Then the variance of its k-differences grows linearly with the difference k: $\mathrm{var}(y_t - y_{t-k}) = k\sigma_\epsilon^2$. On the other hand, if log GNP is stationary about a trend (model [1]), the variance of its k-differences approaches a constant, twice the unconditional variance of the series: $\mathrm{var}(y_t - y_{t-k}) \rightarrow 2\sigma_y^2$. Now plot $(1/k)\mathrm{var}(y_t - y_{t-k})$ as a function of k. If y_t is a random walk, the plot should be constant at σ_ϵ^2. If y_t is trend-stationary, the plot should decline toward zero.

Next, suppose that fluctuations in GNP are partly permanent and partly temporary, which we can model as a combination of a stationary series and a random walk. Now the plot of $(1/k)\mathrm{var}(y_t - y_{t-k})$ versus k should settle down to the variance of the shock to the random walk component.

If fluctuations in GNP are partly temporary—if the random walk component is small and a shock today will be partially reversed in the long run—that reversal is likely to be slow, loosely structured, and not easily captured in a simple parametric model. The variance of k-differences can find such loosely structured reversion, whereas many other approaches cannot. I show in Section IV that this difference can reconcile the results of this paper with other measures of the permanence of fluctuations in GNP.

Results

Figure 1 and table 1 present $(1/k)\mathrm{var}(y_t - y_{t-k})$ for log real per capita GNP, 1869–1986. Pre-1939 data are taken from Friedman and Schwartz (1982). I use real per capita GNP to eliminate possible nonstationarity induced by inflation or population growth. (Henceforth, I will refer to log real per capita GNP as just "GNP.") Figure 1 and table 1 also include asymptotic standard errors, discussed below. Table 1 also presents $1/k$ times the variance of k-differences divided by the variance of first differences (the variance ratio). The units in table 1 and figure 1 are annual percentage growth.

Since $1/k$ times the variance of k-differences settles down to about one-third of the variance of first differences, figure 1 and table 1 suggest that the innovation variance of the random walk component is about one-third of the variance of year-to-year changes: annual growth rates of GNP contain a large temporary component. In fact, I show below that the pattern of figure 1 is consistent with a deterministic trend, which has *no* permanent or random walk component, and whose fluctuations are entirely temporary.

Figure 2 presents the log of real per capita GNP. Notice that this data set looks as if it has a trend in it. Fluctuations occur, but the level

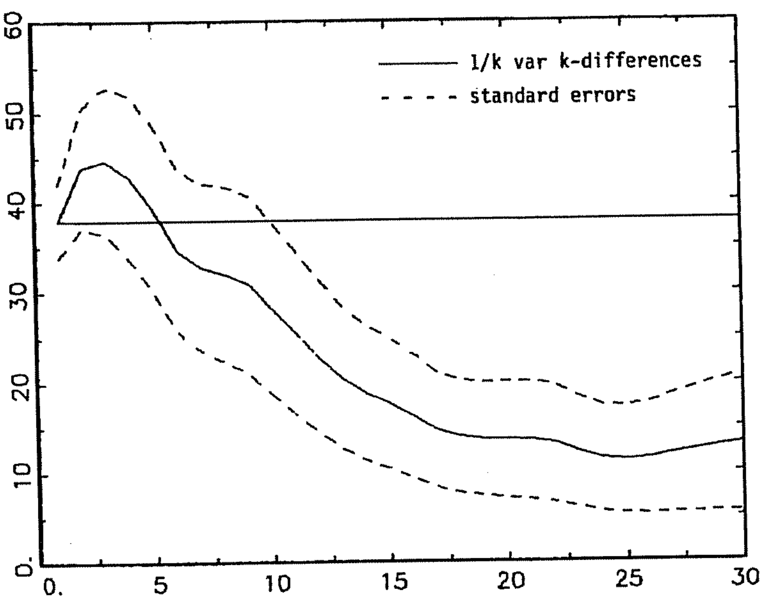

FIG. 1.—$1/k$ times the variance of k-differences of log real per capita GNP, 1869–1986, with asymptotic standard errors.

of the series always returns to the "trend line." Furthermore, that trend line is linear: there are no "waves" of low-frequency movement. These characteristics drive the finding of a small random walk component. (Note that low-frequency movement generated by a nonlinear trend, a shift, etc. would show up as a large random walk component in this and most other estimation techniques based on linear time-series models.)

Prewar GNP data are more variable than postwar data, and one might suspect that this characteristic drives the result. However, figure 3 and table 1 present $1/k$ times the variance of k-differences for postwar GNP, and the same pattern is evident. Both the variance of first differences and the variance of the random walk component are lower, but their proportions do not change much.[2]

[2] The pattern of fig. 2 is sensitive to the precise specification of the variables. First, the variance of quarterly differences of seasonally adjusted GNP is less than one-fourth the variance of yearly differences, so the variance ratio is higher if one uses quarterly rather than annual differences in the denominator. This observation explains most of the difference between fig. 2 and the results reported by Campbell and Mankiw (1988), who use a similar technique on quarterly data. Second, taking the variance of overlapping k-year differences of quarterly data vs. the variance of k-year differences of annual averages, including or excluding population growth, taking logs or not, and even changing the sample by a few years can all change the variance ratio by about one standard error.

TABLE I

1/*k* TIMES THE VARIANCE OF *k*-DIFFERENCES OF GNP

	k (Years)									
	1	2	3	4	5	10	15	20	25	30
					1869–1986					
$\hat{\sigma}_k^2$	40.0	43.8	44.6	42.8	39.2	28.2	17.7	13.6	11.3	13.1
	(4.1)	(6.6)	(8.2)	(9.1)	(9.4)	(9.5)	(7.3)	(6.5)	(6.0)	(7.7)
$\hat{\sigma}_k^2/\hat{\sigma}_1^2$	1.00	1.15	1.17	1.13	1.03	.74	.47	.36	.30	.35
	(.11)	(.17)	(.22)	(.24)	(.25)	(.25)	(.19)	(.17)	(.16)	(.20)
$\hat{\sigma}_k$	6.1	6.6	6.7	6.5	6.3	5.3	4.2	3.7	3.4	3.6
					1947–86					
$\hat{\sigma}_k^2$	7.0	8.2	8.0	7.3	6.5	4.5	2.9	2.6		
	(1.3)	(2.2)	(2.6)	(2.8)	(2.8)	(2.7)	(2.1)	(2.2)		
$\hat{\sigma}_k^2/\hat{\sigma}_1^2$	1.00	1.17	1.14	1.05	.93	.63	.42	.38		
	(.19)	(.31)	(.37)	(.39)	(.39)	(.38)	(.30)	(.32)		
$\hat{\sigma}_k$	2.7	2.9	2.8	2.7	2.6	2.1	1.7	1.6		

NOTE.—$\hat{\sigma}_k^2$ is 1/*k* times the sample variance of *k*-differences. Standard errors (in parentheses) are the Bartlett standard error, with $\hat{\sigma}_1^2$ used for the random walk component; i.e., standard error is $(4k/3T)^{.5}\hat{\sigma}_1^2$. $\hat{\sigma}_k^2/\hat{\sigma}_1^2$ and its standard error are the same quantities divided by $\hat{\sigma}_1^2$. $\hat{\sigma}_k$ is the square root of $\hat{\sigma}_k^2$; its units are percentage growth rates.

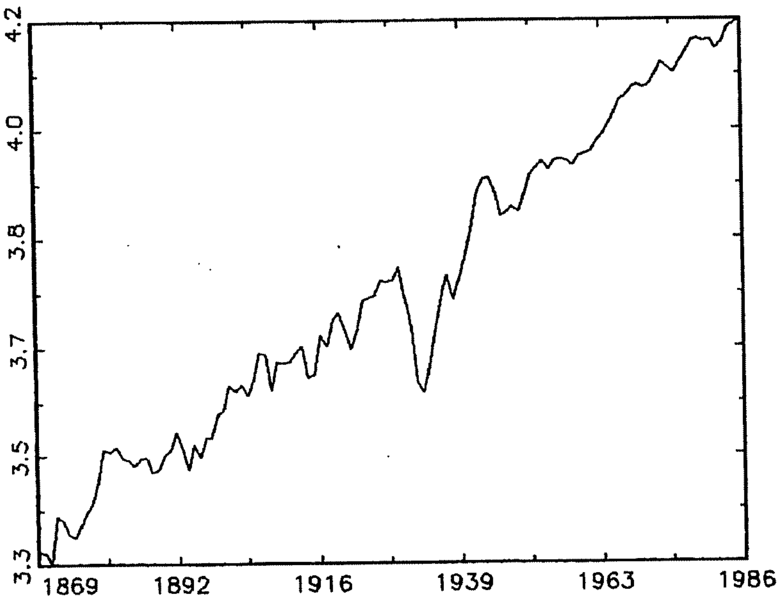

FIG. 2.—Log real per capita GNP, 1869–1986

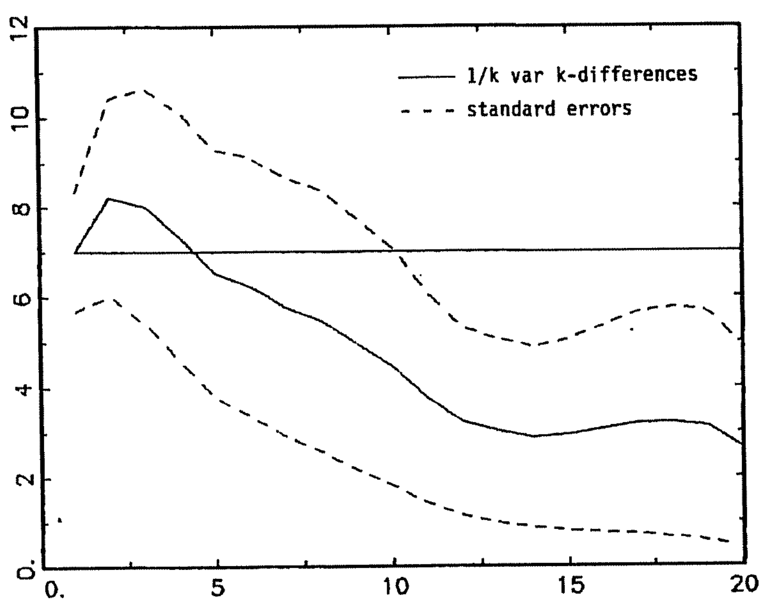

FIG. 3.—$1/k$ times the variance of k-differences of log real per capita GNP, 1947–86, with asymptotic standard errors.

Staff/911
Storm/10

Romer (1986) argued that prewar GNP data overstate the actual cyclical variability of GNP. This possibility will not bias the estimate of the variance of the random walk component. Taking k-differences acts as a filter that ignores cyclical fluctuations and concentrates on the variability of longer "runs," so a different GNP data set will have a different variance of k-differences if the early GNP has a significantly different and more variable trend line, not if its cyclical fluctuations are different. A graph similar to figure 1, using Romer's adjusted early GNP series, produces a variance of a random walk component very similar to that of figure 1. It should because Romer kept the decade trends the same in her corrections for cyclical volatility. Her criticism, or the seasonal adjustment of quarterly data, will affect the variance of first differences, so the variance *ratio* can be biased by excessive volatility or smoothness of the first differences.

The presence of a splice in 1947 also does not drive the result. Every long series of GNP data contains at least one splice. The wide surveys used to construct later data are simply not available for earlier periods, so some projection using a restricted set of industries is unavoidable. However, forcing the *levels* of the "old" and "new" GNP series to match at a certain date does not bias the variance of k-differences. It is biased only if the old series has different growth rates over long horizons.

The body of this paper consists of an investigation of $1/k$ times the variance of k-differences as an estimate of the random walk component in GNP. Section II provides several interpretations of a random walk component. Section III discusses estimation. Section IV reconciles these results with previous research that found a large random walk component by showing how conventional time-series estimation techniques can provide misleading estimates of a random walk component. Section V contains a summary and concluding remarks.

II. Unit Roots and Random Walk Components

This section discusses and documents several claims in the Introduction about the representation of time series. It shows that first-difference stationary time series or time series with a unit root are equivalent to time series that are composed of a stationary and a random walk component. It argues that the variance of shocks to a random walk component is just a convenient interpretation of the parameters of an arbitrary first-difference stationary series, but it requires no additional structure. It shows how to transform between the variance of a random walk component and the response of long-term forecasts to a shock.

Staff/911
Storm/11

Assume that log GNP follows a first-difference stationary linear process; that is, growth rates of GNP are stationary. In this case, log GNP has a moving average representation of the form

$$\Delta y_t = (1 - L)y_t = \mu + A(L)\epsilon_t = \mu + \sum_{j=0}^{\infty} a_j \epsilon_{t-j}, \tag{3}$$

which I take as the starting point; L is the lag operator, $Ly_t = y_{t-1}$. The first equality defines the notation Δy_t and $(1 - L)y_t$ for first differences of y_t. The last equality defines the lag polynomial notation $A(L)$. The ϵ_t are independent identically distributed (i.i.d.) error terms with common variance σ^2_ϵ.

The random walk process (2) obviously has a representation of the form (3). The trend-stationary process (1) is a limiting case of (3): if $\mu = b$ and if the lag polynomial $A(L)$ in (3) has a unit root—that is, we can express $A(L) = (1 - L)B(L)$—we recover (1) by canceling the terms $(1 - L)$. Many unobserved components models are first-difference stationary and hence have a representation (3). Nelson and Plosser (1982) and Watson (1986) are examples. On the other hand, (3) does not include nonlinear processes such as Quah (1986), a process with a nonlinear trend, or second-difference stationary processes (the growth rates of GNP follow a random walk) as in Clark (1987).

Given the representation (3), we have the following fact.

FACT 1. Any first-difference stationary processes can be represented as the sum of stationary and random walk components.

To show that a representation as stationary plus random walk components exists, we simply construct it from the representation (3). This decomposition comes from Beveridge and Nelson (1981). Let

$$y_t = z_t + c_t, \tag{4}$$

where

$$z_t = \mu + z_{t-1} + \left(\sum_{j=0}^{\infty} a_j\right)\epsilon_t,$$

$$-c_t = \left(\sum_{j=1}^{\infty} a_j\right)\epsilon_t + \left(\sum_{j=2}^{\infty} a_j\right)\epsilon_{t-1} + \left(\sum_{j=3}^{\infty} a_j\right)\epsilon_{t-2} + \dots .$$

This decomposition is constructed so that $\lim_{k\to\infty} E_t y_{t+k} = z_t + k\mu$; that is, long-term forecasts of y_t converge to z_t plus $k\mu$. In this sense, z_t is the permanent component of y_t. Beveridge and Nelson call it a stochastic trend. Long-term forecasts of y_t are unaffected by c_t, the temporary component.

The innovation variance of the random walk component $\sigma^2_{\Delta z}$ is a natural measure of the importance of the random walk component.

From the definition (4) we can write the variance of the random walk component $\sigma^2_{\Delta z}$ in terms of the moving average representation (3):

$$\sigma^2_{\Delta z} = (\Sigma a_j)^2 \sigma^2_\epsilon = |A(1)|^2 \sigma^2_\epsilon \tag{5}$$

(sums without indices run from zero to infinity).

In the Beveridge and Nelson decomposition (4), the innovations in the random walk and stationary components are identical. In a more general combination of random walk and stationary components, the innovations may be correlated:

$$\begin{aligned} y_t &= z_t + c_t, \\ z_t &= \mu + z_{t-1} + \eta_t, \\ c_t &= B(L)\delta_t, \quad E(\eta_t\,\delta_t) \text{ arbitrary.} \end{aligned} \tag{6}$$

If we start with a process (6), Δy_t is stationary, and so the process has a representation of the form (3). Most processes of the form (3) can be decomposed into a variety of processes (6), with varying correlation between the innovations; but only the decomposition (4) is *guaranteed* to exist.[3]

Since a variety of decompositions into stationary and random walk components of the form (6) exist for any given stationary process (3), a measure based on the variance of the random walk component would be in serious trouble if it depended crucially on which arbitrary decomposition we choose. Fortunately, it does not, as seen in the following fact.

FACT 2. In every decomposition of a process (1) into stationary and random walk components (6), the innovation variance of the random walk component is the same: $\sigma^2_{\Delta z} = (\Sigma a_j)^2\sigma^2_\epsilon$.

To show fact 2, start with an arbitrary decomposition (6). The corresponding moving average representation of the form (3) is

$$(1 - L)y_t = \mu + \nu_t + (1 - L)B(L)\delta_t \equiv \mu + A(L)\epsilon_t. \tag{7}$$

The last equality defines the parameters $A(L)$ of a moving average representation from the parameters $B(L)$ of (6). Now form the Beveridge and Nelson decomposition of both sides of the last equality in (7). Since the processes on both sides of the last equality are the same, they must have the same variance of a random walk component, so we must have[4] $|A(1)|^2\sigma^2_\epsilon = \sigma^2_\nu$. The correlation between ν_t and

[3] Watson (1986) derives this fact. For example, if we seek a representation with uncorrelated innovations, the spectral density of the combination can be no less than the spectral density of each component; thus such a representation exists only if the spectral density of the first differences has a global minimum at zero.

[4] This statement can be more compactly derived by noting that for the processes on each side of the last equality in (7) to be the same, their spectral densities must be the same at all frequencies, and zero in particular.

Staff/911
Storm/13

δ_t is irrelevant for this argument, so the innovation variance of every decomposition (6) of the same moving average representation (3) must have the same variance of shocks to the random walk component. This argument demonstrates fact 2.

There is one more interpretation, which will be useful in the next section. The spectral density[5] of Δy_t is, by (1), $S_{\Delta y}(e^{-i\omega}) = |A(e^{-i\omega})|^2\sigma_\epsilon^2$. Therefore, we have the following fact.

FACT 3. The innovation variance of the random walk component is equal to the spectral density of Δy_t at frequency zero, that is,

$$\sigma_{\Delta z}^2 = (\Sigma a_j)^2\sigma_\epsilon^2 = S_{\Delta y}(e^{-i0})\sigma_\epsilon^2 \tag{8}$$

or, dividing by the variance of first differences,

$$\frac{\sigma_{\Delta z}^2}{\sigma_{\Delta y}^2} = \frac{(\Sigma a_j)^2}{\Sigma a_j^2} = \frac{S_{\Delta y}(e^{-i0})}{\sigma_{\Delta y}^2}. \tag{8'}$$

Equations (8) and (8′) summarize three equivalent ways of looking at the long-run properties of a series: we can break it into permanent (random walk) and temporary (stationary) components, we can examine the response of long-term forecasts to an innovation, or we can examine the spectral density at frequency zero of its first differences. All three interpretations allow us to think of the permanence of the fluctuations in a series as a continuous phenomenon rather than a discrete choice. Furthermore, equations (8) and (8′) show that the quantity $\sigma_{\Delta z}^2$ or $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2$ defined from the Beveridge and Nelson decomposition (3) is no more than a useful interpretation of the sum of the moving average coefficients Σa_j. The decomposition into stationary and random walk components adds no structure.

The variance of shocks to the random walk component or spectral density at frequency zero of first differences also captures *all* the effects of a unit root on the behavior of a series in a finite sample. As a sample of T observations of a series is completely characterized by its $T - 1$ autocovariances, it is also completely characterized by $T - 1$ periodogram ordinates. By changing the periodogram ordinate at frequency zero of first differences without changing the others, we can make a stationary series into a series with a unit root or random walk component and vice versa.[6]

Since the size of a random walk component is a continuous choice, any test for trend stationarity ($\sigma_{\Delta z}^2 = 0$ or $S_{\Delta y}(e^{-i0}) = 0$) must have arbitrarily low power against the alternative of a small enough ran-

[5] I use the notation $S(e^{-i\omega})$ for the spectral density at frequency ω and, hence, $S(e^{i0})$ for the spectral density at $\omega = 0$.

[6] With an infinite sample, or in population, this proposition does not hold. The spectral density is defined only almost everywhere; and in some cases we can bound the variation of the population spectral density function with very weak assumptions.

dom walk component $\sigma^2_{\Delta z}$. As a result, efforts to categorize series as trend-stationary or difference-stationary and read great things into the difference between the two will not be very fruitful.

III. Estimation

I claimed in the Introduction that the variance of k-differences could be used to estimate the innovation variance of a random walk component. To document that claim and to provide standard errors, this section discusses the statistical properties of the variance of k-differences.

Asymptotic Properties

Let σ^2_k denote $1/k$ times the population variance of k-differences of y_t, $\sigma^2_k = k^{-1}\operatorname{var}(y_t - y_{t-k})$; σ^2_k is related to the autocorrelation coefficients of Δy_t by

$$\sigma^2_k = \left(1 + 2\sum_{j=1}^{k-1}\frac{k-j}{k}\rho_j\right)\sigma^2_{\Delta y}, \tag{9}$$

where $\sigma^2_{\Delta y} = \operatorname{var}(y_t - y_{t-1})$ and $\rho_j = \operatorname{cov}(\Delta y_t \Delta y_{t-j})/\sigma^2_{\Delta y}$. The derivation is straightforward but tedious, so it is presented in the Appendix. Equation (9) shows that the limit of σ^2_k is indeed the innovation variance of the random walk component:

$$\lim_{k\to\infty} \sigma^2_k = \left(1 + 2\sum_{j=1}^{\infty}\rho_j\right)\sigma^2_{\Delta y} = S_{\Delta y}(e^{-i0}) = \sigma^2_{\Delta z}. \tag{10}$$

The second equality is the definition of spectral density, while the third is reproduced from equation (8).

Equation (9) suggests that we could also estimate $1/k$ times the variance of k-differences by using sample autocorrelations $\hat\rho_j$ in the place of their population values ρ_j. (Huizinga [1987] and Campbell and Mankiw [1988] perform the calculation this way.) The right-hand side of (9) with $\hat\rho_j$ in place of ρ_j is the definition of the Bartlett estimator of the spectral density at frequency zero (Anderson 1971, p. 511). Hence, $1/k$ times the variance of k-differences is asymptotically equivalent to the Bartlett estimator.[7]

[7] $1/k$ times the variance of k-differences and the conventional Bartlett estimate are not identical in small samples. The estimates of sample autocorrelations implied by the sample variance of k-differences underweight observations k dates away from the endpoints, compared with the usual estimates of autocorrelation. The difference disappears asymptotically but may be important in small samples. Also, the conventional Bartlett estimate is not unbiased in small samples, as the corrected $1/k$ times the variance of k-differences $\hat\sigma^2_k$ is for a random walk. I thank John Huizinga for pointing this out.

Staff/911
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The properties of the Bartlett estimator are well known, so we can establish the asymptotic properties of $1/k$ times the variance of k-differences by reference to those of the Bartlett estimator. In particular, (1) if $k/T \rightarrow 0$ as $T \rightarrow \infty$, where T is the sample size, $1/k$ times the sample variance of k-differences is a consistent estimate of the spectral density at frequency zero; (2) the asymptotic variance of σ_k^2 is $4kS^2(e^{-i0})/3T$ (Anderson 1971, p. 531).

The equivalence between $1/k$ times the variance of k-differences and the Bartlett estimator provides a useful interpretation of the variance of k-differences for readers familiar with spectral density estimation; in turn, the variance of k-differences is a useful and intuitive time domain counterpart to the Bartlett spectral density estimator. To use the Bartlett estimator, we have to decide what k to use: how many autocovariances or autocorrelations to include in (9) or how many periodogram ordinates to smooth. The choice of k requires a trade-off between bias and efficiency, and it is usually made arbitrarily. In this context, a plot of $1/k$ times the variance of k-differences versus k is an experimental determination of the proper k or window width.

Small-Sample Properties

In small samples, $1/k$ times the variance of k-differences and the Bartlett estimator can be biased, and the asymptotic standard errors may be a poor approximation to the actual standard errors. In this subsection, I discuss corrections for small-sample bias, and I present some Monte Carlo experiments to evaluate standard errors.

I corrected for two sources of small-sample bias in the sample variance of k-differences. These corrections produce an estimator of σ_k^2 that is unbiased when applied to a pure random walk with drift. First, I used the sample mean of the first differences to estimate the drift term μ at all k rather than estimate a different drift term at each k from the mean of the k-differences. Second, I included a degrees of freedom correction $T/(T - k + 1)$. Without this correction, $1/k$ times the variance of k-differences declines toward zero as $k \rightarrow T$ for any process because you cannot take a variance with one data point.

I will use the notation $\hat{\sigma}_k^2$ to denote $1/k$ times the bias-corrected sample variance of k-differences. The formula for $\hat{\sigma}_k^2$ is presented in the Appendix as equation (A3). The Appendix also contains a proof that $\hat{\sigma}_k^2$ is unbiased when y_t is a random walk with drift.

Table 2 presents standard errors from a Monte Carlo experiment using 100 observations of a random walk with drift. I picked the innovation variance of this random walk $\sigma_\epsilon^2 = \sigma_{\Delta z}^2 = 1$. The mean of $\hat{\sigma}_k^2$ was very close to one at all k in this experiment, confirming the bias corrections for a pure random walk. The table presents the standard

TABLE 2

Monte Carlo Standard Errors for $1/k$ Times the Variance of k Differences
Model: $y_t = 1 + y_{t-1} + \epsilon_t$; $\sigma^2_\epsilon = 1$ (T = 100, 500 trials)

	100k/T									
	1	2	3	4	5	10	20	30	40	50
Monte Carlo	.137	.160	.200	.231	.263	.409	.607	.772	.888	.896
Bartlett*	.115	163	.200	.231	.258	.365	.516	.632	.730	.816

* This row gives $(4k/3T)^{.5}$

errors from the Monte Carlo experiment and the corresponding Bartlett standard errors for comparison. The Bartlett errors slightly understate the Monte Carlo errors at large k/T, but the difference is small compared to the size of the standard errors. Monte Carlo experiments with different sample sizes and random walk variance confirm that the standard errors of table 2 scale with k/T and the innovation variance of the random walk.

What about processes that are more complicated than a pure random walk? The Appendix presents a derivation of $E(\hat{\sigma}^2_k)$ for a first-order moving average: $(1 - L)y_t = \mu + (1 + \theta L)\epsilon_t$. It shows that $E(\hat{\sigma}^2_k)$ approaches $\sigma^2_{\Delta z}$ for large k, so $\hat{\sigma}^2_k$ can recover the variance of the random walk component for this process as well.

I ran several further Monte Carlo simulations to examine whether the variance of k-differences is robust when applied to more complicated processes for GNP. I fit a variety of ARMA processes to first differences of log real per capita GNP, simulated 118 observations of each process, and computed $\hat{\sigma}^2_k$ in 100 trials. In each case, the mean of $\hat{\sigma}^2_k$ at $k = 30$ was equal to the variance of the random walk component implied by the estimated ARMA processes—$k = 30$ was large enough to identify the random walk from the stationary components—and the standard errors at large k were close to those implied by table 2, scaled to the variance of the random walk component.

All the low-order ARMA processes produced $\hat{\sigma}^2_k$ lines that *rise* for k from 1 to 5 and then are flat at the variance of the random walk component from k = 10 on, unlike figure 1. They implied $\sigma^2_{\Delta z} > \sigma^2_{\Delta y}$. Two processes that do capture the behavior of figure 1 are an AR(15), figure 4, and AR(2) about a deterministic trend, figure 5. In the next section, I will discuss why the low-order ARMA models failed to capture the behavior of figure 1. For now, note that since they replicate the behavior of $\hat{\sigma}^2_k$ for GNP, figures 4 and 5 can provide small-sample standard errors. These standard errors are similar to the asymptotic standard errors used in figure 1.

Figures 4 and 5 also include $\hat{\sigma}^2_k$ for GNP from figure 1, marked

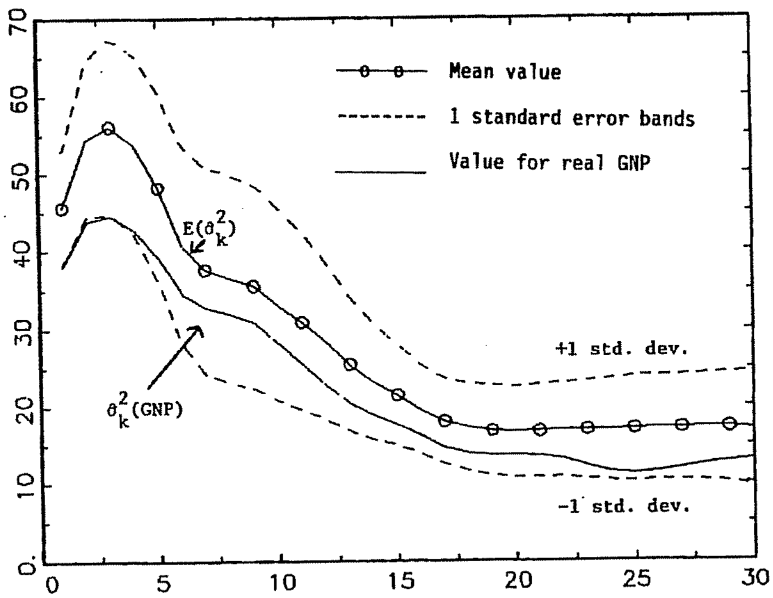

FIG. 4.—Monte Carlo simulation of an AR(15)

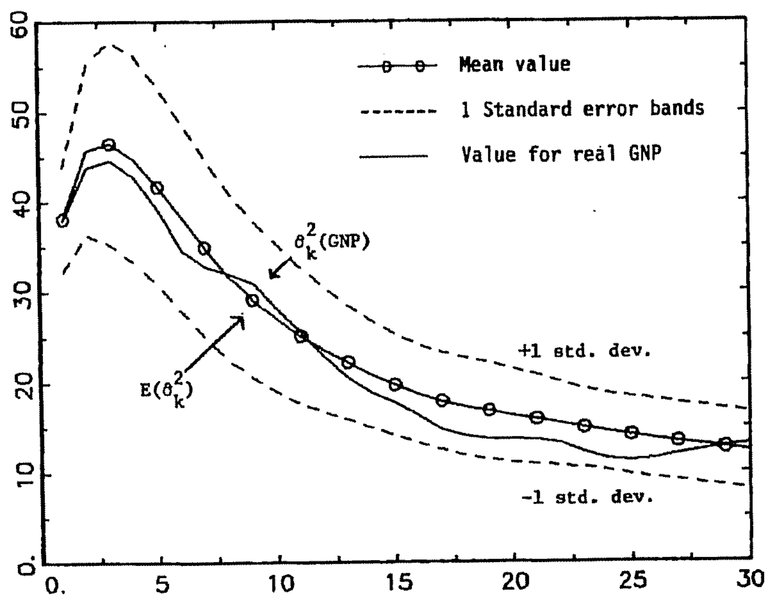

FIG. 5.—Monte Carlo simulation of an AR(2) with a linear trend

$\hat{\sigma}_k^2$(GNP). Since the $\hat{\sigma}_k^2$(GNP) line falls inside the one-standard-error bands, neither model can be rejected for real GNP. However, the standard errors from the random walk (table 2) or any of the other low-order ARMA processes are large enough that we cannot reject them at 5 percent either. (Note that the standard errors scale with the size of the random walk component. Under the hypothesis of a random walk, the standard errors are bigger than indicated in fig. 1.) A confidence interval includes both $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2 = 0$ and 1.

While this is unfortunate, I will argue below that estimates of a random walk component are limited by the number of nonoverlapping "long runs" in the data set, so that large efficiency gains are not possible without imposing additional structure on the time-series process for GNP. As a result, this and related exercises can provide a point estimate of the size of a random walk component with associated standard errors but will not provide useful tests to discriminate between models that imply various sizes of the random walk component.

The parameters of the AR(15) model imply that the variance ratio $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2 = .18$, while the AR(2) about a trend implies $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2 = 0$. Hence, the simulations behind figures 4 and 5 also reveal an *upward* bias in $\hat{\sigma}_k^2$ as an estimate of the random walk component when the series has a small random walk component or is trend-stationary.

In summary, $1/k$ times the variance of k-differences $\hat{\sigma}_k^2$ provides an upward-biased point estimate of the variance ratio $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2$ of about .34, and two models with $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2 = .18$ and 0 replicate the behavior of the variance of k-differences of GNP. However, standard errors are large enough that we cannot statistically reject variance ratios between zero and one at conventional levels of significance.

IV. Reconciliation with Previous Estimates

Given the definition of the random walk component in terms of the parameters of a moving average representation, (4) or (8) above, the obvious thing to do is either to estimate a parsimonious time-series model for Δy_t and calculate Σa_j or to identify and estimate a simple parametric unobserved components model like (4). Campbell and Mankiw (1987) and Nelson and Plosser (1982) did just that, respectively, and both found large random walk components. Why do Nelson and Plosser and Campbell and Mankiw find large random walk components, while Watson (1986), Clark (1987), and I find small ones? Though there are small differences in definition—which quantities we look at to measure the importance of unit roots or random walk components—the major difference is in estimation strategies.

Nelson and Plosser specified an unobserved components model of the form

$$\begin{aligned} y_t &= u_t + v_t, \\ (1 - L)u_t &= \mu + A(L)\epsilon_t, \quad \epsilon_t \text{ i.i.d.}, \\ v_t &= B(L)\delta_t, \quad \delta_t \text{ i.i.d.} \end{aligned} \tag{11}$$

(ϵ_t and δ_t may be correlated). They identified the two components from a stylized autocorrelation function of GNP growth rates. If the first autocorrelation of Δy_t is positive but the others are zero, then the only model of the form (11) that works is $A(L) = 1$ and $B(L) = (1 + \theta L)$. By examining plausible parameter values for this restricted model, Nelson and Plosser concluded that $\sigma_\epsilon^2 > \sigma_\delta^2$.[8]

Campbell and Mankiw (1987) estimated parsimonious ARMA representations of log GNP, using seasonally adjusted quarterly postwar data. They measured the importance of the random walk component by $\Sigma a_j = A(1)$, the change in z_t (the long-term forecast) in response to a unit univariate innovation in GNP. They found values for $A(1)$ equal to or larger than one, which imply an innovation variance of the random walk component greater than the variance of first differences of GNP.[9]

[8] This measure of the importance of a random walk component has the conceptual disadvantage that it depends on which arbitrary unobserved components decomposition we choose. For example, since every series of the form (11) has a unique moving average representation, we could rewrite (11) as $(1 - L)y_t = \mu + C(L)\nu_t$, ν_t i.i.d., and eliminate the stationary component. Alternatively, we could use the Beveridge and Nelson decomposition of Sec. II to make the component with a unit root into a pure random walk:

$$\begin{aligned} y_t &= z_t + c_t, \\ (1 - L)z_t &= \mu + \nu_t, \quad \nu_t \text{ i.i.d.}, \\ c_t &= C(L)\zeta_t, \quad \zeta_t \text{ i.i.d.} \end{aligned}$$

These representations are observationally equivalent to the first form (11), but the measure $\sigma_\epsilon^2/\sigma_\delta^2$ changes according to which one we choose. In contrast, the innovation variance of a random walk component is invariant to the choice of decomposition (fact 2 in Sec. II). Also, the ratio of the innovation variance of the two components is not a good measure of their relative importance because the proportion of the variance of Δy_t explained by u_t and v_t depends on the coefficients of $A(L)$ and $B(L)$ as well as the ratio $\sigma_\epsilon^2/\sigma_\delta^2$.

[9] There are some conceptual disadvantages to scaling a persistence measure by the univariate innovations of y_t. The univariate innovations are not observable and must be inferred from a model; the univariate innovations do not correspond to the "surprise" movement because we live in a multivariate environment; a series may have small innovations but a large variance. For example, $\Delta y_t = 1.5\Delta y_{t-1} - .95\Delta y_{t-2} + \epsilon_t$. For this process, $\Sigma a_j = 2.22$ but $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2 = (\Sigma a_j)^2/(\Sigma a_j^2) = 0.20$. However, for the GNP data used in this paper, there is little qualitative difference between the two definitions, and the difference in results must be explained by differences in estimation strategy.

In performing the Monte Carlo simulations of Section II, I also found that low-order ARMA models of GNP imply that σ_k^2 should rise with k, and they imply a large random walk component, while in fact σ_k^2 declines and the estimated random walk component is small. To replicate the behavior of σ_k^2 for GNP, I had to estimate an AR(15) or impose a deterministic trend.

To investigate this fact further, I fit a variety of ARMA processes to GNP growth rates, ranging from white noise out to an AR(15) (see table 3).[10] All representations past white noise are adequate by usual standards: the Durbin-Watson statistics are close to 2, the significance levels of the Q-statistic are around .5, the parameters of overfit models are statistically insignificant, and so forth. But the variance ratio and Σa_j start at about 1.2 for second-order processes and decline steadily to a variance ratio of .18 and $\Sigma a_j = .5$ for an AR(15). Low-order ARMA models systematically overestimate the random walk component of GNP, even though they adequately represent the series by all the usual diagnostic tests. The question is, why?

The innovation variance of a random walk component is a property of the very long-run behavior of a series alone. It is the spectral density at the frequency $\omega = 0$ corresponding to a period or "run" of infinity, it is related to the infinite sum of the moving average coefficients $|\Sigma a_j|^2$ or the autocorrelation coefficients $(1 + 2\Sigma\rho_j)$, and it corresponds to the effect of a shock today on forecasts into the infinite future. In theory, then, we should have to wait an *infinite* amount of time to get just one observation on the size of the random walk component!

In practice, we typically believe that the dynamic response of GNP to a shock is flat after a suitable long run has arrived.[11] This belief is implicit above: the graphs stop after the thirtieth difference, reflecting a belief that after 30 years the temporary effects of business cycles are over. The number of nonoverlapping long runs is a rough guide to the number of degrees of freedom (precisely, the number of periodogram ordinates) in this exercise. With a 10–20-year long run there are no more than five to 10 independent observations in 100 years of data and two to four observations in postwar data. Obviously, using more frequently sampled data does not help.

Estimating an unobserved components model or a parsimonious

[10] I used the RATS program to perform the estimation. Autoregressive models are estimated by ordinary least squares and moving average models by conditional maximum likelihood. The unreported moving average models did not converge.

[11] Precisely, if the coefficients of the moving average representation (1) are zero past a long-run value $M < \infty$, then the derivative of the spectral density of Δy at zero is bounded. If y_t is in fact trend-stationary and the spectral density of Δy at frequency zero is in fact zero, then the slope of the spectral density of Δy at zero is also zero.

TABLE 3

ARMA Representations of GNP

	White Noise	AR(1)	MA(1)	ARMA (1, 1)	AR(2)	MA(2)	AR(3)
Durbin-Watson statistic	1.67	1.97	1.97	1.99	1.91	1.99	1.96
Q-statistic*	34.82 (30)	27.68 (29)	27.58 (29)	27.43 (28)	26.95 (29)	27.75 (29)	24.58 (27)
Significance level	.25	.54	.54	.49	.52	.48	.60
Variance ratio $(\Sigma a_j)^2/(\Sigma a_j^2)$	1.00	1.39	1.34	1.40	1.23	1.27	.97
A(1) $(= \Sigma a_j)$	1.00	1.20	1.11	1.18	1.11	1.16	1.02
	MA(3)	**AR(4)**	**ARMA (3, 1)**	**MA(4)**	**AR(5)**	**AR(10)**	**AR(15)**
Durbin-Watson statistic	1.97	2.06	2.00	1.91	1.95	1.99	2.01
Q-statistic*	24.95 (27)	28.63 (26)	24.89 (26)	29.21 (26)	26.16 (25)	20.04 (20)	12.17 (15)
Significance level	.58	.33	.53	.30	.40	.46	.67
Variance ratio	.75	.74	1.07	.34	.53	.41	.18
A(1)	.89	.90	1.07	.60	.77	.69	.45

* Degrees of freedom are in parentheses.

ARMA model is an attempt to circumvent this problem. These models make identifying restrictions across frequencies: they draw inferences about the long-run (high-order autocorrelation or low-frequency) dynamics from a model fit to the short-run (low-order autocorrelation or high-frequency) dynamics. For an example that demonstrates how "effective" these procedures are, Campbell and Mankiw (1987) report estimates such as $A(1) = 1.306 \pm .073$ for the 20-year forecast of GNP. Since there are only two nonoverlapping 20-year forecasts in their data set, it is clear how heavily their estimates of $A(1)$ depend on the identifying assumption that the series follow a given low-order ARMA model.

If the short- and long-run dynamics of GNP can both be captured by the assumed time-series model, these procedures can help estimation because we have much more data on high-frequency fluctuations. However, if the long-run dynamics cannot be captured in the model used to study the short run, these identification procedures bias conclusions about long-run behavior.

I offer two ways to see this fact. First, recall that the variance of the shock to the random walk component is related to the sum of the autocorrelations by

$$\frac{\sigma^2_{\Delta z}}{\sigma^2_{\Delta y}} = 1 + 2\sum_{j=1}^{\infty} \rho_j. \tag{12}$$

When we model short-run dynamics, we safely ignore high-order statistically insignificant autocorrelations or we slightly misspecify them by fitting a simple model. But all autocorrelations enter into (12) equally, so a large number of small high-order autocorrelations can offset a few large low-order autocorrelations.

Second, GNP growth has a positive autocorrelation at short lags and a small random walk component at long lags. A simple time-series model may not be able to capture both kinds of behavior. For example, if $(1 - L)y_t = \mu + (1 + \theta L)\epsilon_t$, we need $\theta > 0$ to capture positive first-order autocorrelation but $\theta < 0$ to capture a small random walk component. Faced with a choice, maximum likelihood estimates match the short-run behavior (they fit $\theta > 0$ in the example) and misrepresent the long-run behavior.

The Appendix contains a demonstration of this property of maximum likelihood estimates. It shows that maximum likelihood estimates of a model such as a low-order ARMA or a simple parametric unobserved components model pick parameters that match the model's and the actual spectral density over the entire frequency range. Therefore, maximum likelihood will sacrifice accuracy in the small region around $\omega = 0$ to better match spectral densities at higher frequencies.

In summary, the low-order ARMA approach of Campbell and Mankiw and the unobserved components approach of Nelson and Plosser cannot match the short-run dynamics and the small random walk component in the long-run dynamics at the same time. Faced with the choice, they capture the short-run dynamics and incorrectly imply large random walk components.

On the other hand, Clark's (1987) and Watson's (1986) decompositions can accommodate the behavior of GNP in both frequency ranges. (See, e.g., Watson's fig. 1*b*, in which he shows how his model can represent a large number of small high-order autocorrelations that a low-order ARMA cannot match.) Both Watson and Clark find a small random walk component. However, their decompositions also imply identifying restrictions to estimate long-run behavior from short-run dynamics. Since these restrictions are no more or less plausible than Nelson and Plosser's or Campbell and Mankiw's, they might not be able to capture the pattern of high-order correlations in other data sets as they seem to do for GNP.

Since the size of the random walk component is a property of the periodogram ordinate at frequency zero alone, any estimation technique must make some identifying restriction across the frequency range. The variance of k-differences assumes that past a certain k the random walk component is adequately identified, empirically determined as the point in which the graph (fig. 1) flattens out. Therefore, the variance of k-differences (or any other spectral window estimator) uses 10–20-year period information to identify the infinite-run property, the random walk component. The variance of k-differences does not use information about dynamics at business cycle frequencies to identify long-run movements, and this is its important advantage.

V. Conclusion

The variance of k-differences (fig. 1 and table 1) produced a point estimate that the innovation variance of the random walk component of GNP is about one-third the variance of yearly GNP growth rates. That estimate is upward biased for small random walk components: the parameters of two models that replicated the behavior of the variance of k-differences of GNP implied variance ratios of .18 (AR(15)) and 0 (AR(2) about a deterministic trend). I conclude that if there is a random walk component in GNP at all, it is small.

Another way to characterize these results, without reference to random walk components, is that GNP growth is positively autocorrelated at short lags, but there are many small negative autocorrelations at long lags. These bring future GNP back toward, if not all the way back to, its previously forecast value following a shock.

These results do *not* mean that "GNP follows an AR(2) about a deterministic trend." Our forecasts of the future may quite rightly be much more variable than the "trend" in GNP we have seen in the recent 118-year past might suggest.[12] These results *do* mean that an AR(2) about a deterministic trend or a difference-stationary ARMA process with a very small random walk component is a good in-sample characterization of the behavior of GNP.

In reconciling these results with previous research, I argued that conventional criteria for time-series model identification and estimation can produce misleading estimates of the random walk component of a series like GNP. The random walk component is a property of all autocorrelations taken together, but conventional procedures concentrate on the first few autocorrelations in order to parsimoniously capture short-run dynamics. When used to estimate the size of a random walk component, they impose identifying restrictions across the frequency range to infer the long-run properties of a series from its short-run dynamics. I argued that, in the absence of credible identifying restrictions, it is best to leave the short run out altogether, as the variance of k-differences or some other spectral window estimator does.

However, this view—that we should use only long-run properties of GNP data to estimate the long-run behavior of GNP—implies that standard errors of univariate estimates of the random walk component will remain large in century-long macroeconomic data and larger still in postwar macroeconomic data because there are inherently few nonoverlapping long runs available. These observations argue against the research strategy that says that the presence of a unit root and the size of a random walk component are crucial and well-documented stylized facts that any theoretical model must replicate.

Appendix

A. Derivation of Equation (9)

Start with

$$(1 - L)y_t = \mu + A(L)\epsilon_t = \mu + \sum_{j=0}^{\infty} a_j \epsilon_{t-j}. \tag{A1}$$

[12] A plausible model for GNP should have some random walk component. If GNP is truly stationary about a linear trend, then the variance of the forecast error of the level of GNP is the same for all dates in the far future. As long as there is some random walk component, the variance of forecast errors will grow unboundedly over the forecast horizon. However, only a very small random walk component is required to achieve this desirable property.

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Using

$$(1 - L^k)(1 - L)^{-1} = (1 + L + L^2 + \ldots + L^{k-1}),$$

$$y_t - y_{t-k} = k\mu + \sum_{j=0}^{k-1} \left(\sum_{l=0}^{j} a_l\right) \epsilon_{t-j} + \sum_{j=k}^{\infty} \left(\sum_{l=j-k+1}^{j} a_l\right) \epsilon_{t-j}. \tag{A2}$$

Taking its variance,

$$\sigma_k^2 \equiv k^{-1}\,\mathrm{var}(y_t - y_{t-k}) = k^{-1}\left[\sum_{j=0}^{k-1}\left(\sum_{l=0}^{j} a_l\right)^2 + \sum_{j=k}^{\infty}\left(\sum_{l=j-k+1}^{j} a_l\right)^2\right]\sigma_\epsilon^2.$$

To simplify the algebra, express σ_k^2 as a difference equation

$$k\sigma_k^2 - (k-1)\sigma_{k-1}^2 = \left[\sum_{j=0}^{\infty}\left(a_j^2 + 2a_j \sum_{l=1}^{k-1} a_{j+l}\right)\right]\sigma_\epsilon^2,$$

$$\sigma_1^2 = \left(\sum_{j=0}^{\infty} a_j^2\right)\sigma_\epsilon^2,$$

so

$$1 + 2\sum_{j=1}^{k-1} \rho_j = \frac{k\sigma_k^2 - (k-1)\sigma_{k-1}^2}{\sigma_1^2},$$

where ρ_j = the jth autocorrelation of $(1 - L)y_t$, $\rho_j = \Sigma_{l=0}^{\infty} a_l a_{l+j} / \Sigma_{l=0}^{\infty} a_l^2$. Therefore,

$$\frac{\sigma_k^2}{\sigma_1^2} = k^{-1}[1 + (1 + 2\rho_1) + (1 + 2\rho_1 + 2\rho_2) + \ldots] = 1 + 2\sum_{j=1}^{k-1} \frac{k-j}{k} \rho_j.$$

B. Derivation of $E(\hat{\sigma}_k^2)$ *for an MA(1)*

Assume that (A1) takes the form

$$(1 - L)y_t = \mu + (1 + \theta L)\epsilon_t$$

and assume that ϵ_t are i.i.d. normal. The data set is $T + 1$ observations of the levels of y_t or T observations of its first differences. By definition,

$$\hat{\sigma}_k^2 = \frac{T}{k(T-k)(T-k+1)} \sum_{j=k}^{T} \left[y_j - y_{j-k} - \frac{k}{T}(y_T - y_0)\right]^2. \tag{A3}$$

Equation (A2) specializes to

$$y_j - y_{j-k} = k\mu + \epsilon_j + \theta\epsilon_{j-k} + (1 + \theta)\sum_{l=1}^{k-1} \epsilon_{j-l},$$

and similarly for $y_T - y_0$. Collecting terms in ϵ_j and noting that $E(\epsilon_j\epsilon_k) = 0$ if $j \neq k$, we get (after some algebra)

$$E(\hat{\sigma}_k^2) = (1 + \theta)^2\sigma_\epsilon^2 - \frac{2\theta}{k}\,\frac{1 + (k^2/T^2) - [2k/T(T-k-1)]}{1 - (k/T)}\,\sigma_\epsilon^2.$$

Note that (1) as $T \to \infty$, $E(\hat{\sigma}_k^2) \to [(1 + \theta)^2 - (2\theta/k)]\sigma_\epsilon^2$; (2) as $k \to \infty$, $k < T$, $E(\hat{\sigma}_k^2) \to (1 + \theta)^2\sigma_\epsilon^2 = \sigma_{\Delta z}^2$; (3) for $\theta = 0$, $E(\hat{\sigma}_k^2) = \sigma_\epsilon^2 = \sigma_{\Delta z}^2$ for all k, T such that $k < T$.

C. *How Maximum Likelihood Imposes Identifying Restrictions across Frequencies*

Let $x_t = (1 - L)y_t = A(L)\epsilon_t$. Assume that $A(0) = 1$, that $A(L)$ is one-sided and has zeros outside the unit circle, so that the spectral density of x is bounded away from zero, and that A has an inverse, so that x has an autoregressive representation $B(L)x_t = \epsilon_t$. Consider estimating $A(L)$ or $B(L)$ by maximum likelihood via a simple time-series or unobserved components model. For simplicity, assume infinite data, $\epsilon_t \sim N(0, \sigma_\epsilon^2)$, and σ_ϵ^2 known. (The same point survives generalization to more complex estimation environments.) In this case, maximum likelihood is equivalent to

$$\min E[\hat{B}(L)x_t]^2 \quad \text{subject to } \hat{B}(L) \in \mathfrak{B}, \tag{A4}$$

where $\hat{B}(L)$ is the autoregressive representation of the estimated model, and $\mathfrak{B}$ is the restricted space of autoregressive representations allowed by the chosen time-series model. Since variance is the integral of spectral density, (A4) is the same as

$$\min(2\pi^{-1}) \int_{-\pi}^{\pi} |\hat{B}(e^{-i\omega})|^2 S_x(e^{-i\omega})d\omega \quad \text{subject to } \hat{B}(e^{-i\omega}) \in \mathfrak{B}. \tag{A5}$$

The following expression is equivalent:

$$\min \int_{-\pi}^{\pi} |\hat{B}(e^{-i\omega}) - B(e^{-i\omega})|^2 S_x(e^{-i\omega})d\omega \quad \text{subject to } \hat{B}(e^{-i\omega}) \in \mathfrak{B}. \tag{A6}$$

To see this, expand $|\hat{B} - B|^2$ and substitute $AA^*\sigma_\epsilon^2 = S_x$ (an asterisk denotes complex conjugation; I dropped the $e^{-i\omega}$'s). Then (A6) becomes

$$\min \int_{-\pi}^{\pi} (\hat{B}\hat{B}^* + BB^* - B\hat{B}^* - B^*\hat{B})AA^*d\omega. \tag{A7}$$

The first term is just (A5). Since $A^{-1} = B$, the second term is 2π, and the third and fourth are

$$\int_{-\pi}^{\pi} (\hat{B}A + \hat{B}^*A^*)d\omega.$$

Under the assumption that A and B are one-sided and that $A(0) = B(0) = 1$,

$$\int_{-\pi}^{\pi} \hat{B}A\,d\omega = \int_{-\pi}^{\pi}\left(1 + \sum_{j=1}^{\infty} \hat{b}_j e^{-i\omega j}\right)\left(1 + \sum_{j=1}^{\infty} a_j e^{-i\omega j}\right)d\omega;$$

since $\int_{-\pi}^{\pi} e^{-i\omega j}d\omega = 0$, $\int_{-\pi}^{\pi} \hat{B}A\,d\omega = \int_{-\pi}^{\pi} \hat{B}^*A^*d\omega = 2\pi$. Therefore, (A6) reduces to (A5) plus constants.

Equation (A6) is analogous to Sims's (1972) approximation formula, reproduced in Sargent (1979, p. 293). The message of (A6) is that maximum likelihood attempts to match the frequency response of the autoregressive representation across the entire frequency range, weighted by the true spectral density of x_t. The method of maximum likelihood will sacrifice accuracy of the estimated $B(e^{-i\omega})$ at a point in the frequency range ($\omega = 0$) in order to achieve a better fit over an interval. Similarly, it will sacrifice accuracy in a small window (20 years to infinity is $\pi/10$ wide) to gain accuracy in a large window (2–4 years is $\pi/2$ wide). If $S_x(e^{-i\omega})$ is smaller near $\omega = 0$ than elsewhere, as the variance of k-differences suggests for GNP, then (A6) shows that maximum likelihood further deemphasizes accuracy in windows about zero.

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Inflation Expectations: How the Market Speaks

The Federal Reserve wants to know what people think—specifically, the Fed wants to know what people think the future path of inflation is. One reason is that people's expectations about inflation influence their behavior in the marketplace, and that, in turn, has consequences for future inflation. Being able to forecast future inflation plays a critical role in the Fed's efforts to meet its mandate of promoting price stability in the U.S. economy.

Estimates of longer-term inflation expectations have been available from various surveys for quite some time. While useful, these survey estimates suffer a bit from the "talk is cheap" problem. What one would like, instead, is evidence that reflects people's "putting their money where their mouth is." And, indeed, in recent years, such a source of evidence has emerged, with the introduction of new financial instruments. These market-based estimates represent a bet by market participants on the future course of the economy, usually in terms of certain economic indicators or asset prices, and they have been shown to be better predictors than survey-based estimates.

One of these new financial instruments is the Treasury Inflation-Protected Security, or TIPS, which was introduced by the U.S. Department of Treasury in 1997 as a new class of government debt obligation. The key feature of TIPS is that the payments to investors adjust automatically to compensate for the actual change in the Consumer Price Index (CPI). Conventional Treasury securities, in contrast, do not provide such protection, so investors in those securities protect themselves by demanding nominal interest rates that compensate them for expected inflation as well as for bearing the risk that actual inflation could turn out to differ from their expectations. In principle, having information from both types of Treasury securities allows researchers to separate out the inflation compensation component embedded in nominal interest rates.

This *Economic Letter* discusses the structure of TIPS contracts, the development of the market in recent years, and the measure of inflation compensation derived from comparing TIPS yields to nominal yields.

How TIPS work

TIPS are one of two types of inflation-protected securities sold by the U.S. Treasury (the other type is Series I savings bonds for small investors). In 1997, the Treasury Department started issuing TIPS that are structured along the lines of the Real Return Bonds issued by the government of Canada. Like conventional Treasury notes and bonds, TIPS make interest payments every six months and a payment of principal when the securities mature. However, unlike conventional Treasury notes and bonds, both the semiannual interest payments and the final redemption payments of TIPS are tied to inflation.

All TIPS are issued by the Treasury using the single-price auction—the same auction used for all of Treasury's marketable securities. The interest rate on TIPS, which is set at auction, remains fixed throughout the term of the security. To protect against inflation, the Treasury adjusts the principal value of the TIPS using the CPI, published by the Bureau of Labor Statistics. Thus, TIPS are redeemed at maturity at their inflation-adjusted principal or their original par value, whichever is greater. While TIPS pay a fixed rate of interest that is determined at the initial auction, this rate is applied not to the par value of the security but to the inflation-adjusted principal. So, if inflation rises throughout the term of the security, every interest payment will be greater than the previous one. To the extent that both the semiannual interest payments and the final redemption value of TIPS rise and fall with the CPI, the nominal return on TIPS hedges perfectly against inflation.

The market for TIPS has grown steadily and now includes three terms to maturity: 5 years, 10 years, and 20 years. The Treasury auctions 5-year and 20-year TIPS semiannually and 10-year TIPS quarterly. As of 2005, there are about $200 billion TIPS outstanding, as part of the total $4 trillion Treasury marketable securities outstanding. The trading volume of TIPS also has increased gradually but still remains small compared to other Treasury securities; hence, TIPS generally are not as liquid as comparable Treasuries.

Extracting implied inflation expectations from TIPS

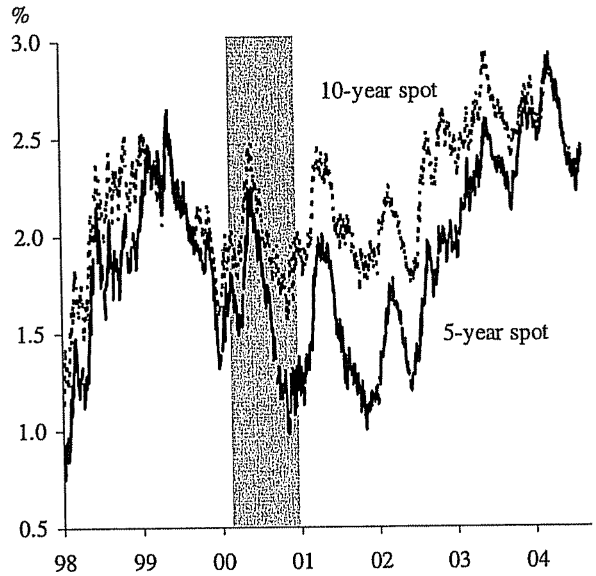
In principle, comparing the yields between conventional Treasury securities and TIPS can provide a useful measure of the market's expectation of future CPI inflation. At a basic level, the yield-to-maturity on a conventional Treasury bond that pays its holder a fixed nominal coupon and principal must compensate the investor for future inflation. Thus, this nominal yield includes two components: the real rate of interest and the inflation compensation over the maturity horizon of the bond. For TIPS, the coupons and principal rise and fall with the CPI, so the yield includes only the real rate of interest. Therefore, the difference, roughly speaking, between the two yields reflects the inflation compensation over that maturity horizon.

This inflation compensation is sometimes referred to as the breakeven inflation rate because, if future inflation were at this rate, the realized returns of holding a conventional Treasury bond and TIPS would be exactly the same. Figure 1 charts the breakeven inflation rate over the next five years by comparing the yield on the 5-year Treasury note to the yield on 5-year TIPS, and the breakeven inflation rate over the next ten years by using the 10-year Treasury note and 10-year TIPS, from 1998 to present.

There are two important caveats in using the breakeven inflation rate to measure inflation expectations. First, the breakeven inflation rate actually measures the compensation that conventional Treasury bondholders receive for expected inflation and for bearing the risk that realized inflation may deviate from expected inflation. The breakeven inflation rate hence has two components: expected inflation and the inflation risk premium. Ideally, one would like to subtract the inflation risk premium from the breakeven inflation rate to obtain a pure measure of inflation expectations. Nevertheless, assuming the inflation risk premium to be fairly stable over a short period of time, the changes in the breakeven inflation rate capture the changes in inflation expectations.

Second, TIPS yields contain a liquidity premium. While the market for TIPS is growing, it is still relatively small compared to the market for conventional Treasuries. Therefore, to the extent that TIPS are less liquid than Treasuries, investors would demand a liquidity premium for holding TIPS over conventional Treasuries. Because the breakeven inflation rate is obtained by comparing the yields on TIPS and similar maturity conventional Treasury bonds, the breakeven rate captures not only the inflation compensation but also the liquidity premium demanded by TIPS investors. In Figure 1, it is quite clear that the breakeven inflation rates exhibit an upward trend. This probably reflects artificially low breakeven rates when TIPS were introduced. At that time, the amount of TIPS outstanding was small and the investor base for TIPS was narrow, so TIPS were not very liquid and their yields likely contained a relatively large liquidity premium to compensate investors for holding TIPS in their portfolio. As the TIPS market has grown, the liquidity premium in TIPS has shrunk, resulting in higher breakeven inflation rates.

Figure 1
1998 to present: Breakeven inflation rates



Interpretations

The breakeven inflation rate overstates inflation expectations because of the inflation risk premium in Treasury yields, but it understates inflation compensation because of the liquidity premium in TIPS yields. With a more mature TIPS market, and over relatively short time periods, both the inflation risk premium and the liquidity premium are likely to be fairly constant. Thus, the changes in breakeven inflation rates can be interpreted as the market measure of changes in inflation expectations. Estimates of intermediate-term inflation expectations can be extracted using 5-year TIPS and conventional Treasury securities. To focus on a relatively short recent time period, Figure 2 shows the 5-year breakeven inflation rate since July 2004. Note that this measure of inflation expectations over the next five years has fluctuated between 2% and 3% over the past 12 months. In part, the swings reflect temporary factors, such as movements in energy prices, cyclical factors, and the influences of monetary policy.

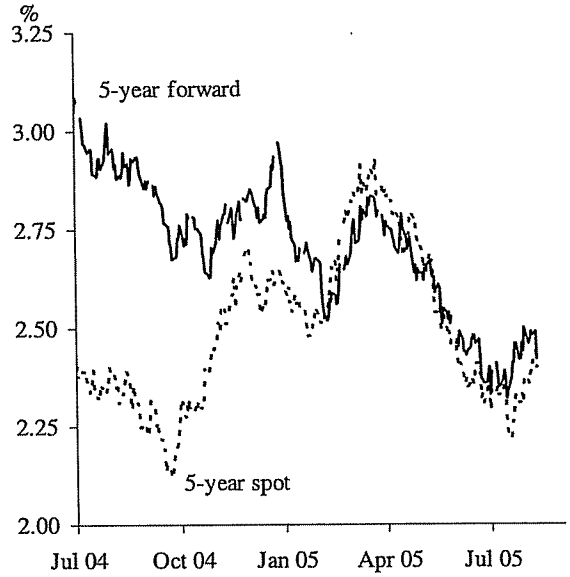
Estimates of longer-term inflation expectations can be derived using the forward nominal yields and forward real bond yields. For example, suppose one is interested in inflation expectations for the period from 2010–2015, that is a five-year period beginning five years from now. The forward nominal yield for that period is implied by the 5-year and 10-year nominal yield. The forward real yield is, likewise, implied by the 5-year and 10-year TIPS yield. And comparing the forward nominal yield to the forward TIPS yield implies a forward breakeven inflation rate.

Figure 2 plots the 5-year forward 5-year breakeven inflation rate. It suggests that longer-term inflation expectations have been trending down from about 3% to about 2.5% since the beginning of the current monetary policy tightening cycle. Compared to the spot 5-year forward breakeven rate, it is noteworthy that the forward breakeven inflation rate is more stable. This is because longer-term inflation expectations tend to be less affected by cyclical factors.

One interpretation of this measure of longer-term inflation expectations is that it captures the market's assessment of how well the Federal Reserve promotes price stability in the long run. From that perspective, the decline in this measure—by more than one-half a percentage point over the last 12 months, despite rapidly rising energy prices—suggests that the market views the run-up in energy prices as transitory and that it is confident in the Fed's commitment to promoting longer-term price stability.

Figure 2

July 2004 to present: Breakeven inflation rates



Conclusions

Given the Federal Reserve's dual mandates, promoting maximum sustainable output and employment and promoting price stability, having credibility in fighting inflation gives the central bank more room to promote economic growth. For example, with longer-term inflation expectations currently seemingly well anchored, the recent run-up in energy prices has not led to widespread fears about future inflation; therefore, the Fed has not had to tighten more aggressively. Nonetheless, the Fed cannot be complacent—the credibility of its commitment to price stability was earned through years of consistent performance, and to maintain that credibility, the Fed will need to continue to earn it. And to gauge its success, the Fed will also continue to pay close attention to longer-term inflation expectations.

Simon Kwan
Vice President

Empirical TIPS

Richard Roll

U.S. Treasury Inflation-Indexed Securities (commonly known as TIPS) were first issued in January 1997. Through the third quarter of 2003, 12 TIPS had been issued, with original maturities ranging from 5 to 30 years. One TIP bond has already matured. This study documents the correlations of TIPS returns with the returns on nominal bonds and with equity returns over the past seven years; TIPS real and effective nominal durations; and changes in the volatility of TIPS over time. TIPS are used here to estimate real yield curves, which are then compared against nominal yield curves to derive the term structure of anticipated inflation on a daily basis. An explanation offered for the dramatic decline in TIPS real yields since 1999 is supported by empirical tests. Finally, given plausible assumptions about future expected returns, the article shows that an investment portfolio diversified between U.S. equities and nominal bonds would be improved by the addition of TIPS.

In January 1997, the U.S. Treasury issued a unique new security—a bond with 10 years to maturity and with payments linked to the U.S. Consumer Price Index (CPI).[1] This bond is officially named a "marketable Treasury Inflation-Indexed Security," but it is commonly called TIPS, for Treasury inflation-protected security. Through September of 2003, 12 different TIPS had been issued, with maturity dates ranging from July 2002 through April 2032 (see **Table 1**).

The inflation linkage of U.S. TIPS adheres to the model for indexed bonds issued previously by the government of Canada. In this structure, the nominal principal is accreted daily on the basis of an extrapolation of inflation during the most recent reporting period for the price index. The bond's coupons are a fixed percentage of the accreted principal, so they also are effectively linked to the CPI. For U.S. TIPS, the Treasury has established a floor in the event of deflation (which no longer seems such an unlikely event). At maturity, TIPS will be redeemed at the greater of their inflation-adjusted principal or their par amount at original issue. During the lifetime of a TIP bond, its accreted principal could decline with deflation below the original par, so the coupons could decline below their originally stated dollar amounts, but the principal will eventually be redeemed at no less than the original face amount.

Richard Roll is Japan Alumni Chair in International Finance at the Anderson Graduate School of Management, University of California at Los Angeles.

In the secondary market, TIPS prices are quoted as percentages of par. Consequently, the settlement amount includes the trade price multiplied by an inflation accrual factor established officially by the Treasury for every day of the month and all outstanding TIPS. Accrued interest, which depends on the same accrual factor, is added in to obtain the total settlement payment. Details on nominal holding-period returns are given in Appendix A.

Almost seven years of daily TIPS trading experience have accumulated, so sample sizes are more than adequate to establish some empirical facts about TIPS behavior. This article's modest goal is to report those facts. TIPS share certain features with equities, in that they provide protection against inflation.[2] They also possess bondlike features, such as promised fixed payments. Now seems to be a good moment to undertake a systematic empirical study of these interesting new assets.[3] Consequently, I calculated and report here the available history of real yields and real durations of TIPS. The article presents empirical measures of the effective *nominal* durations of TIPS (i.e., the sensitivity of their returns to nominal yields and to changes in the shape of the nominal term structure of interest rates). It provides correlations of TIPS returns with nominal bonds and with equities. It provides empirical estimates of the entire term structure of anticipated inflation derived by combining TIPS and nominal bonds. The article also offers a tax-based conjecture to explain the dramatic recent decline in real yields and provides

Table 1. Assets and Sample Periods

Coupon	Issued	Maturity	Daily Returns Begin	End
A. TIPS				
3.625	Jul 1997	Jul 2002	16 Jul 1997	11 Jul 2002
3.375	Jan 1997	Jan 2007	22 Jan 1997	30 Sep 2003
3.625	Jan 1998	Jan 2008	15 Jan 1998	30 Sep 2003
3.875	Jan 1999	Jan 2009	15 Jan 1999	30 Sep 2003
4.250	Jan 2000	Jan 2010	19 Jan 2000	30 Sep 2003
3.500	Jan 2001	Jan 2011	17 Jan 2001	30 Sep 2003
3.375	Jan 2002	Jan 2012	15 Jan 2002	30 Sep 2003
3.000	Jul 2002	Jul 2012	15 Jul 2002	30 Sep 2003
1.875	Jul 2003	Jul 2013	10 Jul 2003	30 Sep 2003
3.625	Apr 1998	Apr 2028	15 Apr 1998	30 Sep 2003
3.875	Apr 1999	Apr 2029	16 Apr 1999	30 Sep 2003
3.375	Oct 2001	Apr 2032	15 Oct 2001	30 Sep 2003
B. U.S. Treasury Constant-Maturity Nominal Bonds				
3 Month			22 Jan 1997	30 Sep 2003
1 Year			22 Jan 1997	30 Sep 2003
5 Year			22 Jan 1997	30 Sep 2003
10 Year			22 Jan 1997	30 Sep 2003
30 Year			22 Jan 1997	15 Feb 2002
C. Equity Indexes				
vwretd			22 Jan 1997	30 Jun 2003
ewretd			22 Jan 1997	30 Jun 2003
sprtrn			22 Jan 1997	30 Jun 2003

Notes: In Panel C, "vwretd" is the CRSP NYSE + Amex + Nasdaq value-weighted index with dividends reinvested, "ewretd" is the CRSP equal-weighted index with dividends reinvested, and "sprtrn" is the S&P 500 Index with dividends included.

some supporting evidence. Finally, the article addresses the benefits of including TIPS in a balanced and diversified investment portfolio.

Data

Table 1 lists the 12 TIPS, 5 nominal bonds, and 3 equity indexes used in this study. The sample period begins with the first available TIPS return, on 22 July 1997, and it ends on 30 September 2003. All outstanding TIPS were included in the study, but only the issue with a January 2007 maturity has data covering the entire sample period. Barclays Capital kindly provided TIPS transaction prices.

To develop a sample of nominal bond returns, I downloaded constant-maturity yields from the U.S. Treasury website (www.ustreas.gov) for five different maturities. Approximate holding-period returns (in percentages per day) were computed from yields by the following formula:

$$R_t = \frac{Y_{t-j}}{252} + D_{t-j}(Y_{t-j} - Y_t), \qquad (1)$$

where R_t is return at time t, Y_t is the nominal yield on date t (in percentage per year), and D_{t-j} is the modified duration in years computed on day $t-j$.[4] The divisor is based on 252 trading days in a year. Most often, $j = 1$, so the yield change is from day $t-1$ to day t, but $j > 1$ when the yield change is across a holiday or weekend.

Equity returns were measured by three broad indexes—the value-weighted and equal-weighted CRSP (Center for Research in Securities Prices) indexes for all major U.S. exchanges and the S&P 500 Index. In each case, dividends were reinvested to obtain total index returns. Table 1 lists the data availability period for each of the 20 assets.

Asset Characteristics

The characteristics discussed in this section for TIPS, nominal bonds, and equities are daily nominal holding-period returns, correlations, real yields, real and effective nominal durations, and sensitivities to the nominal term structure's shape. The final subsection turns attention to the time-varying volatility of TIPS returns.

Daily Nominal Holding-Period Returns. Using all available observations, **Table 2** reports descriptive statistics for daily nominal returns. Means and standard deviations are given in percentage per year. Note that the number of observations used in computing each pairwise correlation differs among asset pairs because of the availability of joint observations. (A few assets had no joint observations.)

During the sample period, TIPS experienced exceptional average returns. The January 2007 issue, which has been around the longest, had a mean daily return of 6.86 percent per year for the entire sample period. The latter part of the sample period was particularly favorable for TIPS. For example, the January 2032 TIP bond, issued in October 2001, had an annualized mean return of more than 15 percent. Real yields on TIPS declined during the sample period from more than 3.5 percent to the neighborhood of 1.0–2.5 percent, depending on maturity.

Nominal bonds also did well in this period. The 30-year bond had an annualized average sample return of about 10 percent in the five years prior to its retirement in February 2002.

In comparison, equities fared rather poorly on average. The S&P 500 experienced an annualized average return of only 6.11 percent over the entire sample period, and of course, its return was strongly negative in 2001–2002. The equal-weighted return appears to be quite high, on average, but this sample mean is severely biased upward by bid–ask bounce and daily rebalancing (to equal weights).[5]

Table 2. Daily Returns: Means and Standard Deviations

Asset	Return: Mean	Return: Standard Deviation	N
A. TIPS			
Jul 2002	5.93%	1.08%	1,262
Jan 2007	6.86	2.70	1,701
Jan 2008	7.89	2.95	1,453
Jan 2009	8.73	3.26	1,200
Jan 2010	10.90	3.86	944
Jan 2011	10.00	4.82	693
Jan 2012	11.80	5.70	442
Jul 2012	11.40	6.70	316
Jul 2013	3.88	10.10	58
Apr 2028	9.77	6.69	1,392
Apr 2029	11.40	7.16	1,138
Apr 2032	15.20	10.70	504
B. U.S. Treasuries			
3 Month	4.18%	0.22%	1,609
1 Year	4.97	0.74	1,609
5 Year	7.97	4.54	1,609
10 Year	9.49	7.58	1,609
30 Year	10.00	11.30	1,219
C. Equities			
vwretd	7.21%	20.80%	1,624
ewretd	22.30	15.20	1,624
sprtrn	6.11	21.20	1,624

Notes: The sample period varies by asset but begins at earliest in January 1997 and ends at latest in August 2002. N is the number of daily sample observations in the mean and standard deviation. The mean return and standard deviation were annualized by using 252 trading days a year.

As for volatility, TIPS returns exhibited lower volatility in the period than nominal bonds with similar maturities, as one would expect. For example, the January 2010 bond, whose maturity ranged from 10 to 7 years during the period, had an annualized daily standard deviation of 3.86 percent a year.[6] This percentage is half the volatility of the 10-year nominal bond and is substantially less than the volatility of the 5-year nominal bond. The 30-year nominal bond volatility was 11.3 percent a year (under the assumption of independent returns over time). In contrast, the two TIPS with original maturities of 30 years that have been outstanding the longest, the April 2028 and April 2029 issues, had annualized return standard deviations of, respectively, 6.69 percent and 7.16 percent. Changes in nominal yields are much more volatile than changes in real yields for the obvious reason that changes in nominal yields include shocks in expected inflation.

Table 3 shows that TIPS returns are strongly correlated with each other, particularly for adjacent maturities. Returns for the 30-year TIPS, with coefficients of 0.999, are almost perfectly correlated. The eight TIPS that had 10 years to maturity at issuance, those with maturities from January 2007 through July 2013, have correlations in the upper 90 percent range. Their correlations are somewhat lower with the longest-term TIPS (the three original 30-year issues) but are still in the upper 80 percent range. Only the single short-term TIP bond, which matured in July 2002, has somewhat lower correlation with other TIPS—and only when it was close to maturity.[7]

Long-term nominal bonds are positively correlated with long-term TIPS. These correlations, mainly in the range of 0.5–0.8, are not usually as large as those between adjacent TIPS. Shorter-term nominal bonds, such as the three-month and one-year bonds, are more weakly correlated both with TIPS and with longer-term nominal bonds. Interestingly, the shortest-term nominal bond and the shortest-term TIP bond (July 2002) are not highly correlated; the coefficient is only 0.229. This characteristic suggests that shocks in expected inflation were the predominant source of nominal interest rate volatility during the full sample period.

One of the most striking patterns in Table 3 involves the negative correlations between equities and bonds, both TIPS and nominal bonds. The evidence is that these correlations have become increasingly negative lately; that is, more recently issued TIPS display larger (in absolute value) correlations with equities. The correlations between nominal bonds and equities are similar to correlations between equities and TIPS that were outstanding during most of the sample. Over long historical periods, equities have been positively correlated with nominal bonds, so these sample period results are somewhat unusual.[8]

Daily TIPS returns have significant first-order serial correlation but, as **Table 4** shows, virtually no autocorrelation at longer lags. The same is true for nominal bonds with 1-, 5-, and 10-year maturities. The three-month nominal bond return has quite a bit of serial dependence, even for lags as long as five days. For TIPS and for longer-term nominal bonds, the serial dependence may be statistically significant but is probably not economically relevant. Notice that the total explanatory power (adjusted R_2) of the autocorrelation function is 1–2 percent in most cases. For the three-month nominal bond return, however, the explanatory power is more than 18 percent. The CRSP value-weighted equity and S&P 500 indexes are not greatly autocorrelated, but the equal-weighted equity return is, perhaps spuriously and attributable to daily rebalancing.

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Table 3. Daily Returns: Correlations

	TIPS												U.S. Treasuries					Equities		
	Jul 2002	Jan 2007	Jan 2008	Jan 2009	Jan 2010	Jan 2011	Jan 2012	Jul 2012	Jul 2013	Apr 2028	Apr 2029	Apr 2032	3 Month	1 Year	5 Year	10 Year	30 Year	vwretd	ewretd	sprtrn
TIPS																				
Jul 2002		0.757	0.722	0.626	0.604	0.543	0.183	NA	NA	0.486	0.392	0.277	0.229	0.426	0.414	0.387	0.344	−0.069	−0.127	−0.044
Jan 2007	1,262		0.980	0.972	0.959	0.950	0.954	0.950	0.962	0.777	0.781	0.814	0.148	0.496	0.634	0.620	0.457	−0.167	−0.187	−0.156
Jan 2008	1,135	1,453		0.987	0.979	0.974	0.968	0.963	0.973	0.815	0.817	0.842	0.164	0.532	0.688	0.674	0.494	−0.243	−0.241	−0.242
Jan 2009	882	1,200	1,200		0.991	0.987	0.980	0.977	0.982	0.840	0.840	0.861	0.156	0.521	0.710	0.703	0.502	−0.280	−0.282	−0.282
Jan 2010	626	944	944	944		0.996	0.991	0.988	0.991	0.860	0.861	0.877	0.179	0.551	0.762	0.771	0.584	−0.312	−0.299	−0.316
Jan 2011	375	693	693	693	693		0.996	0.994	0.994	0.875	0.874	0.887	0.236	0.568	0.793	0.812	0.641	−0.362	−0.348	−0.365
Jan 2012	124	442	442	442	442	442		0.999	0.997	0.920	0.921	0.919	0.333	0.621	0.840	0.866	0.756	−0.485	−0.468	−0.482
Jul 2012	0	316	316	316	316	316	316		0.998	0.926	0.926	0.925	0.347	0.632	0.862	0.890	NA	−0.533	−0.508	−0.529
Jul 2013	0	58	58	58	58	58	58	58		0.954	0.954	0.952	0.215	0.750	0.887	0.917	NA	NA	NA	NA
Apr 2028	1,074	1,392	1,392	1,200	944	693	442	316	58		0.999	0.998	0.085	0.399	0.610	0.644	0.554	−0.200	−0.184	−0.201
Apr 2029	820	1,138	1,138	1,138	944	693	442	316	58	1,138		0.999	0.097	0.408	0.635	0.675	0.589	−0.235	−0.222	−0.238
Apr 2032	186	504	504	504	504	504	442	316	58	504	504		0.251	0.498	0.736	0.798	0.829	−0.350	−0.348	−0.348
U.S. Treasuries																				
3 Month	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469		0.527	0.285	0.230	0.195	−0.092	−0.112	−0.085
1 Year	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469	1,609		0.779	0.699	0.572	−0.207	−0.238	−0.197
5 Year	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469	1,609	1,609		0.945	0.829	−0.243	−0.274	−0.232
10 Year	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469	1,609	1,609	1,609		0.906	−0.211	−0.241	−0.201
30 Year	1,098	1,215	979	740	498	258	22	0	0	921	680	79	1,219	1,219	1,219	1,219		−0.016	−0.061	0.005
Equities																				
vwretd	1,254	1,619	1,371	1,119	865	614	367	242	0	1,310	1,057	429	1,546	1,546	1,546	1,546	1,218		0.853	0.984
ewretd	1,254	1,619	1,371	1,119	865	614	367	242	0	1,310	1,057	429	1,546	1,546	1,546	1,546	1,218	1,624		0.784
sprtrn	1,254	1,619	1,371	1,119	865	614	367	242	0	1,310	1,057	429	1,546	1,546	1,546	1,546	1,218	1,624	1,624	

NA = not available.

Notes: The sample period varies by asset but begins at earliest in January 1997 and ends at latest in September 2003. Correlation coefficients computed from all available joint observations are reported in the shaded area, and the corresponding numbers of available observations are given in the unshaded area.

Table 4. Autocorrelations of Daily Asset Returns
(t-statistics in parentheses)

Asset	Partial Autocorrelation Coefficient by Lag					
	1 Day	2 Days	3 Days	4 Days	5 Days	Adjusted R^2
A. TIPS						
Jul 2002	0.1214	–0.0110	–0.0136	0.0340	–0.0097	1.17%
N = 1,257	(4.30)	(–0.39)	(–0.48)	(1.20)	(–0.34)	
Jan 2007	0.1374	–0.0266	0.0043	0.0044	–0.0009	1.57
N = 1,696	(5.64)	(–1.08)	(0.18)	(0.18)	(–0.04)	
Jan 2008	0.1483	–0.0237	0.0449	–0.0172	0.0099	1.97
N = 1,448	(5.62)	(–0.89)	(1.68)	(–0.65)	(0.37)	
Jan 2009	0.1407	–0.0123	0.0501	–0.0228	0.0308	1.84
N = 1,195	(4.85)	(–0.42)	(1.71)	(–0.78)	(1.06)	
Jan 2010	0.1260	–0.0127	0.0569	–0.0261	0.0274	1.39
N = 939	(3.84)	(–0.38)	(1.72)	(–0.79)	(0.83)	
Jan 2011	0.1223	–0.0152	0.0552	–0.0375	0.0403	1.18
N = 688	(3.19)	(–0.39)	(1.43)	(–0.97)	(1.05)	
Jan 2012	0.0981	–0.0130	0.0832	–0.0462	0.0593	0.81
N = 437	(2.03)	(–0.27)	(1.72)	(–0.95)	(1.22)	
Jul 2012	0.0886	–0.0153	0.0895	–0.0545	0.0649	0.39
N = 311	(1.55)	(–0.27)	(1.56)	(–0.95)	(1.13)	
Jul 2013	–0.1674	–0.1094	0.1132	–0.0958	0.1480	–0.11
N = 53	(–1.14)	(–0.75)	(0.79)	(–0.67)	(1.02)	
Apr 2028	0.1350	–0.0201	0.0564	–0.0411	0.0650	2.08
N = 1,387	(5.02)	(–0.74)	(2.07)	(–1.51)	(2.40)	
Apr 2029	0.1227	–0.0151	0.0590	–0.0375	0.0753	1.87
N = 1,133	(4.12)	(–0.50)	(1.96)	(–1.25)	(2.51)	
Apr 2032	0.1241	–0.0193	0.0823	–0.0370	0.1020	2.06
N = 499	(2.76)	(–0.42)	(1.82)	(–0.81)	(2.25)	
B. U.S. Treasuries						
3 Month	0.1893	0.0938	–0.0201	0.1826	0.1983	18.32%
N = 1,604	(7.72)	(3.82)	(–0.82)	(7.44)	(8.10)	
1 Year	0.0951	–0.0113	–0.0134	–0.0003	–0.0004	0.61
N = 1,604	(3.80)	(–0.45)	(–0.53)	(–0.01)	(–0.02)	
5 Year	0.0614	–0.0366	–0.0286	–0.0139	0.0035	0.31
N = 1,604	(2.45)	(–1.46)	(–1.14)	(–0.55)	(0.14)	
10 Year	0.0517	–0.0227	–0.0395	–0.0192	0.0158	0.24
N = 1,604	(2.07)	(–0.90)	(–1.57)	(–0.77)	(0.63)	
30 Year	0.0517	0.0008	–0.0306	–0.0163	0.0111	–0.01
N = 1,214	(1.80)	(0.03)	(–1.06)	(–0.57)	(0.39)	
C. Equities						
vwretd	0.0207	–0.0377	–0.0174	0.0167	–0.0531	0.20%
N = 1,619	(0.83)	(–1.52)	(–0.70)	(0.67)	(–2.14)	
ewretd	0.2069	0.0046	0.0979	0.0701	–0.0079	6.44
N = 1,619	(8.31)	(0.18)	(3.88)	(2.76)	(–0.32)	
sprtrn	–0.0169	–0.0375	–0.0355	0.0106	–0.0488	0.21
N = 1,619	(–0.68)	(–1.51)	(–1.43)	(0.43)	(–1.96)	

Real Yields, Durations, and Sensitivities. This section reports real yields, real durations and effective nominal durations of TIPS, and the sensitivity of TIPS to changes in the shape of the nominal yield curve.

Real yields. Like nominal Treasury bonds, TIPS yields and durations can be computed directly from prices and promised cash payments. In calculating the real yield, inflation can be ignored because the transaction price and coupons are stated as percentages of the accrued face amount. Thus, the real yield is simply the internal rate of return that equates the current price plus accrued real interest to the discounted future real payments. Real duration can be calculated in the usual way, with inflation ignored.

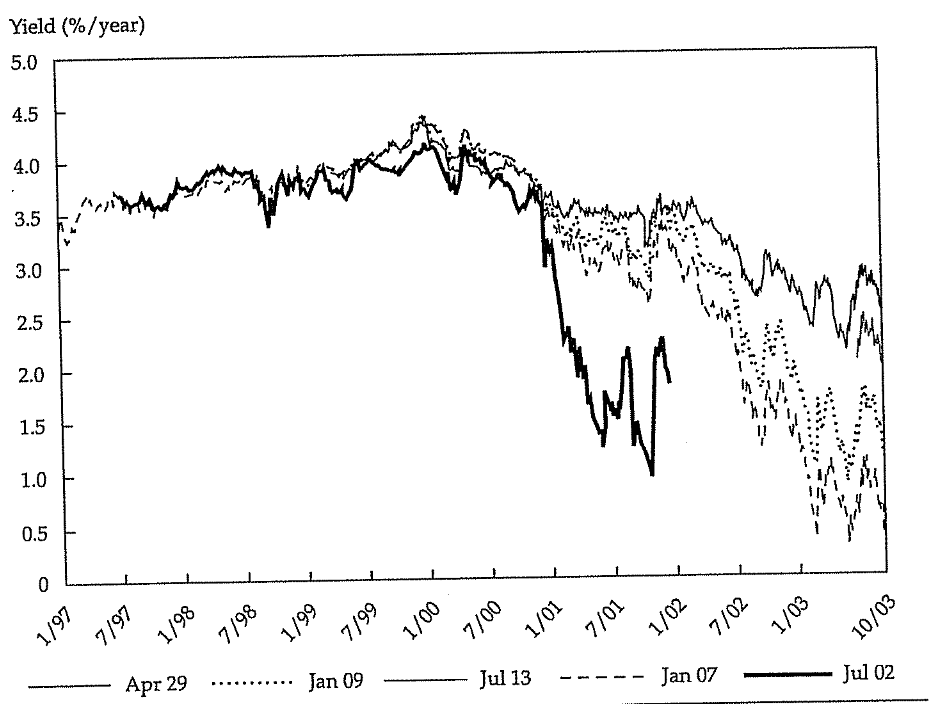
In a depiction of real yields for all 12 TIPS in the study, individual yields would be almost impossible to distinguish because they are so close together. So, **Figure 1** presents the July 2002 yield, which is clearly distinguished from the others, and the highest and lowest yields as of 30 September 2003 (respectively, the April 2029 and January 2007 TIPS).[9] The other yields lay in between at that date and were almost always ranked higher for successively longer maturities (two are included in Figure 1 to illustrate this pattern). Indeed, the April 2029 yield plots virtually on top of the April 2028 yield.

As Figure 1 clearly shows, TIPS yields of all maturities have declined dramatically since the beginning of 2000. From well over 4 percent a year, yields fell to less than 1 percent for the shorter-term issues and to less than 3 percent for the longest-term issue. Yields for maturities out to 2013 were below 2.5 percent at the end of the sample period.

Real and effective nominal durations. **Figure 2** shows real Macauley durations for all 12 TIPS in the study. Macauley duration is simply a weighted average of the calendar times until various payments, where each weight is proportional to the discounted (at the real yield) present value of the payment. Because Macauley duration is a real duration, the future payments are simply the TIPS stated coupon multiplied by the currently accrued principal plus the final (currently accrued) principal repayment.

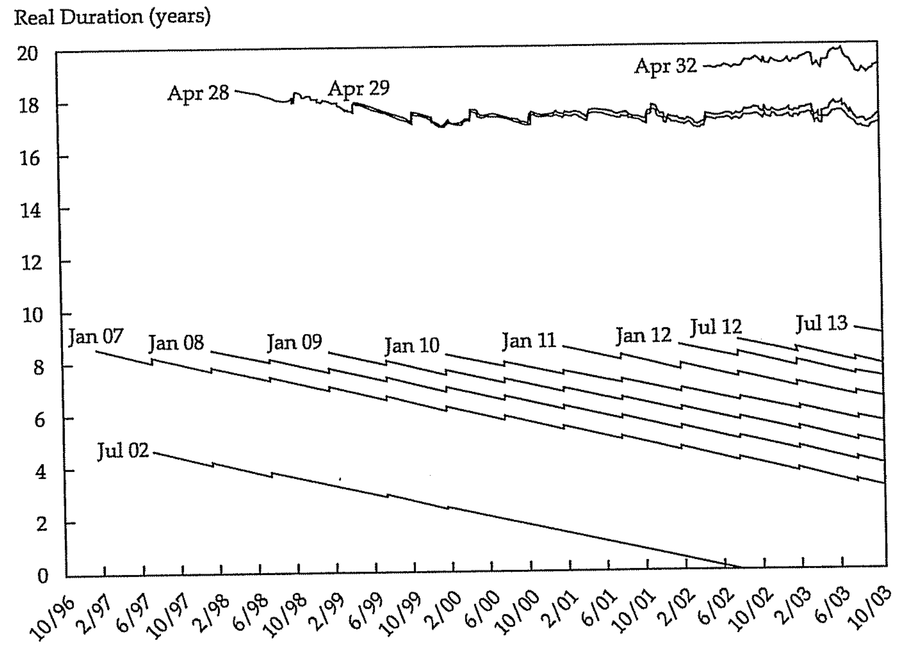
Individual cases are easily discernible in Figure 2 because, understandably, real durations rank monotonically from longest to shortest maturity. These durations are unremarkable except for the slight jump on each ex-coupon date. Only the three longest-term TIPS exhibit perceptible reactions to yield changes; otherwise, they are smoothly declining. The real durations of these issues have not declined at all during the past several years (because yields have fallen enough to more than offset aging).

Figure 1. Real Yields on TIPS, January 1997–September 2003



Note: Bond-equivalent yields—that is, semiannually compounded.

Figure 2. Real Durations of TIPS, January 1997–September 2003



The relatively low coupons of TIPS explain the smoothly declining durations for short-term issues. Low coupons imply that the final principal repayment represents the preponderance of present value and thus Macauley's duration is relatively insensitive to yield changes. (Recall that a zero-coupon bond, whose entire value depends on the single final payment, always has, entirely independent of yield, a Macauley duration equal to maturity.)

Real duration measures the response of TIPS' returns to infinitesimal changes in the real yield. Because real yields and coupons on TIPS are generally lower than nominal yields and coupons on otherwise similar nominal Treasury bonds, TIPS real durations are longer than nominal bond durations. But such comparisons mix apples and oranges because real and nominal yields do not have the same volatility. If nominal yields are essentially real yields plus expected inflation, nominal yields must have larger volatilities unless real yields and inflation are quite negatively correlated.[10]

Consequently, it is of considerable practical interest to estimate TIPS durations with respect to changes in nominal yields, thereby placing TIPS and nominal bonds on a comparable footing. This estimate cannot be made analytically because there is no obvious connection between nominal yields and TIPS prices. It can be accomplished empirically, however, by regressing TIPS returns on concurrent changes in nominal yields. The negative of the slope coefficient in such a regression is an estimate of modified duration.[11]

The second column of **Table 5** reports such empirical nominal durations for TIPS, where the regressor was a simple average of the constant-maturity 5- and 10-year nominal yield change. Of course, any nominal maturity could have been used and the resulting duration estimates would have differed. Those reported in Table 5 should be taken as indications of effective TIPS durations compared with the average duration of 5- and 10-year nominal Treasuries. At yields of 4 percent, 5 percent, and 6 percent, the nominal 5-year/10-year average modified duration for bonds selling at par would be, respectively, 6.40, 6.16, and 5.94 years. As shown in Table 5, TIPS durations are usually shorter than these bond durations, even when the TIPS maturities are much longer. For example, the April 2029 issue, whose maturity was at least 26 years throughout the sample, has an estimated duration of only 4.6 years in Table 5. Except for the aberrations because of the relatively short period of data availability for the January 2012, July 2012, and July 2013 TIPS, estimated durations increase monotonically with maturity.

■ *Sensitivity to changes in the shape of the nominal yield curve.* The second set of regressions in Table 5 (in the right-most three columns) report how TIPS respond to general changes in the shape of the nominal yield curve. Following Litterman and Scheinkman (1991), the shape of the nominal yield curve on each date was characterized by its level, slope, and curvature, as estimated by a simple model whose technical details are given in

Table 5. TIPS Empirical Durations and Factor Sensitivities
(t-statistics in parentheses; adjusted R^2s in percents)

TIPS	Duration (effective years)	Factor Sensitivities Shift	Tilt	Flex
Jul 2002	0.585	–0.548	0.4664	–0.0061
N = 1,247	(18.34)	(–12.21)	(5.74)	(–0.06)
	21.2%	18.2%	*1.826*	*5.087*
Jan 2007	2.003	–2.048	–0.4081	0.8929
N = 1,674	(32.99)	(–23.95)	(–2.66)	(4.28)
	39.4%	37.8%	*1.842*	*8.204*
Jan 2008	2.288	–2.42	–0.7189	1.386
N = 1,428	(34.52)	(–25.73)	(–4.39)	(6.19)
	45.5%	44.5%	*1.771*	*6.443*
Jan 2009	2.552	–2.726	–1.174	1.937
N = 1,178	(32.40)	(–23.86)	(–6.23)	(7.26)
	47.1%	47.9%	*1.806*	*5.526*
Jan 2010	3.089	–3.509	–1.672	2.9
N = 926	(32.36)	(–25.52)	(–7.94)	(9.27)
	53.1%	57.0%	*1.851*	*7.382*
Jan 2011	3.725	–4.642	–2.449	5.055
N = 676	(29.30)	(–22.83)	(–8.73)	(10.63)
	56.0%	63.1%	*1.822*	*5.642*
Jan 2012	5.171	–5.302	–5.264	8.252
N = 429	(27.98)	(–13.28)	(–9.54)	(11.71)
	64.6%	71.9%	*1.896*	*2.389*
Jul 2012	6.154	–5.495	–4.751	5.105
N = 304	(25.94)	–(11.88)	(–7.44)	(5.27)
	68.9%	79.9%	*1.987*	*1.077*
Jul 2013	9.257	–8.985	–3.462	7.53
N = 57	(14.40)	(–3.21)	(–1.08)	(2.06)
	78.7%	84.2%	*2.033*	*0.837*
Apr 2028	4.227	–5.143	–5.955	6.336
N = 1,367	(24.68)	(–24.27)	(–16.23)	(12.60)
	30.8%	46.4%	*1.827*	*2.699*
Apr 2029	4.622	–5.677	–6.672	7.577
N = 1,116	(23.40)	(–23.01)	(–16.41)	(13.10)
	32.9%	50.9%	*1.892*	*2.359*
Apr 2032	7.836	–9.072	–10.91	15.67
N = 490	(20.82)	(–13.72)	(–12.41)	(12.65)
	46.9%	68.5%	*1.915*	*0.944*

Notes: For the second regression, two additional diagnostics are reported, in italics. The first is the Durbin–Watson statistic, and the second is excess kurtosis of the residuals. In the first regression, these diagnostics were similar to those of the regressions, so they were omitted to save space.

Appendix B. Changes in the general shape of the term structure from one day to another can be measured by simultaneous changes in the level, slope, and curvature—designated, respectively, as "shift," "tilt," and "flex" in Table 5. Such changes are illustrated in **Figure 3**.

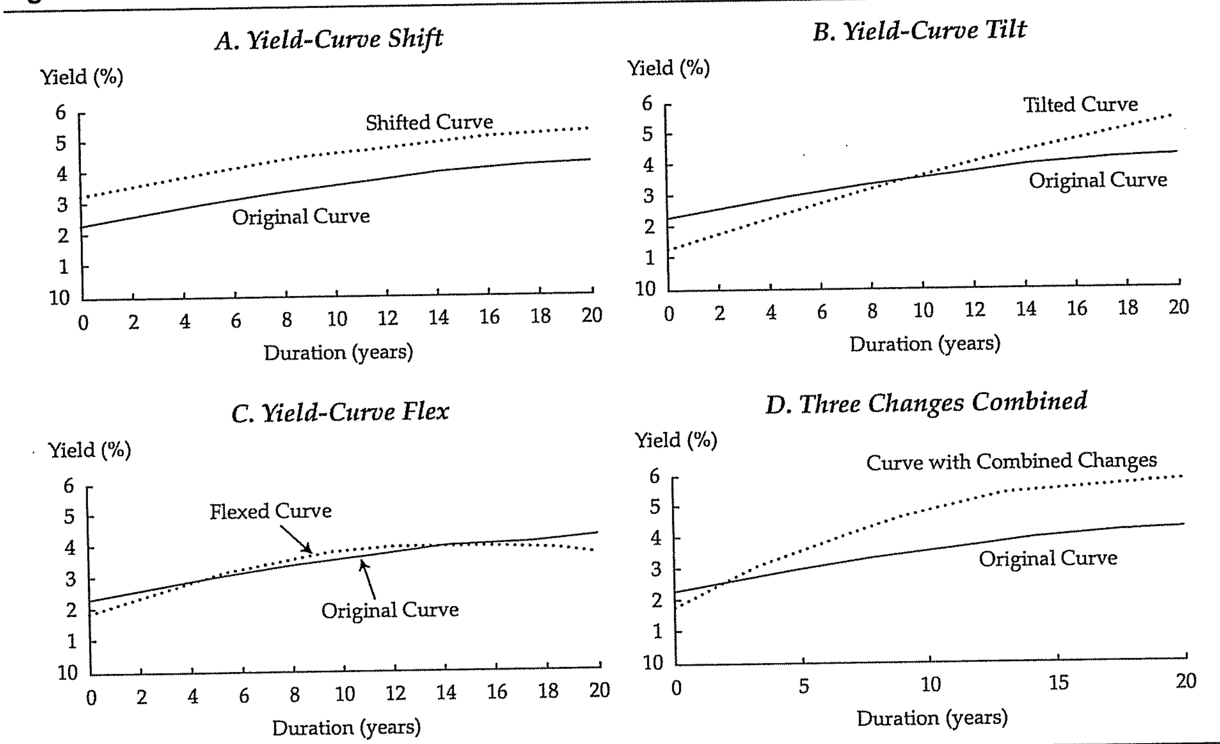
First, notice in Table 5 that the shift effect is similar in most cases to the negative of estimated duration reported in the second column. This similarity suggests that the 5-year/10-year nominal bond average is a reasonable indicator of term-structure level. Second, the longer-term TIPS are significantly and negatively related to the tilt factor, whereas the shortest-term TIP bond is significantly positively related to tilt. Thus, increases in the slope of the nominal term structure (tilting around an intermediate maturity) drive down (up) long-term (short-term) TIPS prices just as they do nominal bond prices. Finally, increases in curvature, or flex, affect positively all but the shortest-term bond (whose coefficient is insignificant), and the significance generally increases with maturity among bonds with long sample periods. Greater curvature of the underlying *real* term structure (i.e., more concavity from below) coincides with lower long-term real yields, all else being equal.

The explanatory power of the regressions in Table 5 is lower than would generally be found for nominal Treasury bonds. Typically, a three-factor model consisting of shift, tilt, and flex explains well over 90 percent of the returns on nominal bonds. But for the TIP bond with the longest sample period (the January 2007 issue), the explanatory power is only slightly more than 37 percent. Notice that the explanatory power seems to be quite a bit higher recently. For the July 2013 bond, whose sample includes only the most recent 57 trading days, the adjusted R^2 is 84 percent.

Although the results in Table 5 are interesting and provide some insight into the behavior of TIPS, the regression is undoubtedly misspecified. The most obvious reason is that each bond has aged during the sample period. Neither its actual duration nor its responses to the changes in the term-structure shape are constants. Of course, the materiality of this maturation is likely to be minor for the very long term TIPS because they have not aged much as a fraction of their original maturities. At the other extreme, however, the shortest-term issue has already matured, so its duration must have fallen to zero during the sample period.

A second problem is possible autocorrelation in the residuals. Table 4 showed that TIPS returns are significantly autocorrelated at the first daily lag. The Durbin–Watson statistics in the penultimate column of Table 5 similarly reveal a mild case of

Figure 3. Theoretical Yield-Curve Movements



autocorrelation in the regression residuals. Finally, the residuals contain quite a bit of excess kurtosis (see the last column of Table 5). Excess kurtosis implies either thick tails or nonstationary probability distributions, which would, in turn, imply the econometric problem of heteroscedasticity.

An econometric correction for autocorrelation and heteroscedasticity in regression residuals is available. Newey and West (1987) derived an asymptotically consistent covariance matrix for the estimated coefficients that produces corrected standard errors and, hence, *t*-statistics. As a robustness check, I calculated the Newey–West estimator for the second regression of Table 5 involving the term-structure shape factors.[12] The results reveal that most *t*-statistics are somewhat smaller when Newey–West is used instead of ordinary least-squares (OLS) regression. Only a few were rendered insignificant, however, by the Newey–West correction. Consequently, I conclude that the mild degree of autocorrelation and the presence of heteroscedasticity have not produced seriously misleading OLS results.

To tackle the problem of bond maturation, I added supplementary time-dependent regressors to the models of Table 5 to capture declining TIPS sensitivity coefficients with decreasing bond maturity. The basic idea is that sensitivities should approximately satisfy a decreasing linear function of time. For example, duration at time t would be $D_t = D_0(1 - t/M)$, where M is the original maturity of the bond, t is an index of maturation that varies from $t = 0$ at issuance to $t = M$ at maturity, and D_0 is the bond's duration at issuance. The same function can be used for the shift, tilt, and flex factors. With the duration regression as an example, the model becomes

$$R_{i,t} = \alpha_i + \beta_{i,1}\Delta Y_t + \beta_{i,2}\left[\left(\frac{t}{M}\right)\Delta Y_t\right], \qquad (2)$$

where ΔY_t is the nominal yield change (on the average of the 5-year/10-year constant-maturity nominal Treasury bond). The first slope coefficient should be duration at issuance, and the second coefficient should be its negative. The results are in **Table 6**.

The first TIP bond, maturity July 2002, looks fairly sensible. Notice that the duration coefficient estimate is 0.816, which is larger than the duration from Table 5, 0.585. It should be larger because the duration coefficient in Table 6 pertains to the origination date, whereas the duration estimate in Table 5 is essentially an average over the entire life of the bond. The second coefficient (in the Table 6 column labeled "Duration*t") is negative (–0.409) and significant, as it should be, although it seems to be too small.[13] In the second Table 6 regression for this bond, we see similar plausible results. The significant origination date coefficients (shift and flex) have time-dependent coefficients with opposite signs, although only Flex*t is significant.

All the longer-term TIPS in Table 6 have completely unexpected and startling patterns of coefficients. Not one of the Duration*t coefficients is negative, and most are actually significantly positive.[14] Because maturities of these bonds became shorter by as much as seven years during the sample period, this outcome can only mean that *real-interest-rate* volatility increased dramatically in the latter part of the period. Additional supporting evidence for an increase in real rate volatility is provided by the time-varying coefficient Shift*t. These coefficients would all be positive if volatility were constant. Instead, most are negative, and many are significant. Notice that the most recently issued TIP bond, maturity July 2013, for which all the sample observations are in the last three months, has extremely large time-dependent coefficients. For this bond, the adjusted R^2 is 85 percent, but many coefficients are insignificant. Consequently, one more item, multicollinearity, should probably be added to the list of econometric difficulties.

Time-Varying Volatility. A formal model of time-varying volatility for TIPS and other asset returns, the pleasant GARCH(1,1), is reported in **Table 7**.[15] Almost everything is significant for TIPS and, indeed, for all the assets. The evidence of persistence is strong because the lagged conditional variance has a coefficient in excess of 0.8 in most cases. This persistence seems to have been a bit higher in the latter part of the period (as revealed by slightly larger coefficients for the more recently issued TIPS).

Confirmatory visual evidence of nonconstant volatility is presented in **Figure 4** for the January 2007 issue, the bond outstanding for the longest time. Both rolling 21-day (21 trading days or approximately one month) volatility and the conditional volatility from GARCH(1,1) are plotted. The rolling volatility was positioned on the center date of each 21-day period, which explains why it appears to coincide without a lag with the GARCH conditional volatility.

Three features of the plots in Figure 4 stand out. First, a substantial decline in volatility occurred during the first 20 months of this TIP bond's existence. Because the January 2007 issue was the very first, one might reasonably surmise that some learning about TIPS trading characteristics was taking place in those early days. TIPS were

Table 6. Intertemporal Changes in TIPS Empirical Durations and Factor Sensitivities
(*t*-statistics in parenthesis; adjusted R^2s in percents)

TIPS	Duration	Duration*t	Shift	Tilt	Flex	Shift*t	Tilt*t	Flex*t
Jul 02	0.816	−0.409	−0.684	0.321	−0.590	0.217	0.328	0.951
N = 1,247	(11.75)	(−3.74)	(−7.37)	(1.60)	(−2.36)	(1.35)	(1.08)	(2.35)
		22.0%		21.4%		*1.837*		*4.563*
Jan 07	0.877	2.976	−0.660	0.637	−1.563	−3.987	−2.111	7.021
N = 1,674	(6.44)	(9.18)	(−3.59)	(1.58)	(−3.14)	(−8.01)	(−2.23)	(5.56)
		42.3%		40.6%		*1.859*		*8.806*
Jan 08	0.620	5.347	−0.474	1.644	−1.772	−6.316	−6.126	10.25
N = 1,428	(4.47)	(13.47)	(−2.54)	(4.32)	(−3.83)	(−10.27)	(−5.58)	(7.03)
		51.6%		51.1%		*1.814*		*9.181*
Jan 09	−0.159	10.44	0.230	1.066	−1.880	−11.91	−6.372	15.51
N = 1,178	(−0.98)	(18.53)	(0.99)	(2.40)	(−3.64)	(−12.29)	(−3.89)	(7.52)
		59.0%		59.2%		*1.812*		*8.801*
Jan 10	0.376	13.81	−0.765	1.189	−1.168	−13.78	−12.16	21.61
N = 926	(1.90)	(15.14)	(−2.76)	(2.89)	(−2.21)	(−8.74)	(−5.46)	(7.29)
		62.4%		65.0%		*1.812*		*7.272*
Jan 11	1.164	20.57	−2.258	1.089	1.749	−14.95	−22.06	19.09
N = 676	(5.42)	(13.97)	(−6.67)	(2.29)	(2.12)	(−5.31)	(−5.70)	(3.06)
		65.8%		69.9%		*1.797*		*4.345*
Jan 12	2.208	35.04	−3.021	−3.073	5.720	−25.20	−4.439	−5.480
N = 429	(6.63)	(10.26)	(−4.27)	(−3.08)	(5.13)	(−3.29)	(−0.44)	(−0.44)
		71.6%		78.9%		*1.829*		*1.421*
Jul 12	3.944	39.90	−3.125	−4.506	2.635	−48.33	9.644	43.98
N = 304	(10.16)	(6.92)	(−4.01)	(−4.37)	(1.56)	(−3.80)	(0.61)	(1.78)
		73.1%		82.6%		*1.904*		*1.590*
Jul 13	11.12	−204.1	−17.88	7.140	12.35	887.2	−1,022	−500.2
N = 57	(9.09)	(−1.77)	(−3.32)	(1.13)	(1.89)	(1.93)	(−1.91)	(−0.91)
		79.5%		85.0%		*2.105*		*0.911*
Apr 28	−0.311	46.22	2.59E-02	3.321	−4.646	−51.72	−81.71	112.
N = 1,367	(−0.90)	(14.74)	(0.07)	(4.27)	(−4.97)	(−12.89)	(−11.46)	(11.88)
		40.3%		58.1%		*1.786*		*3.075*
Apr 29	−1.151	71.55	−8.76E-02	2.119	−3.371	−69.53	−94.96	139.2
N = 1,116	(−2.81)	(15.67)	(−0.19)	(2.31)	(−3.13)	(−10.87)	(−8.65)	(10.07)
		45.0%		62.8%		*1.798*		*3.069*
Apr 32	3.013	166.2	−6.783	−6.318	12.74	−69.950	−111.3	44.26
N = 490	(4.80)	(9.22)	(−6.50)	(−4.75)	(6.69)	(−2.12)	(−2.68)	(0.71)
		54.7%		72.0%		*1.784*		*1.441*

Notes: For the second regression, two additional diagnostics are reported, in italics. The first is the Durbin–Watson statistic, and the second is excess kurtosis of the residuals. In the first regression, these diagnostics were similar to those of the regressions, so they were omitted to save space.

unfamiliar instruments in the U.S. fixed-income market at the time, so differences of opinion could have brought about volatility that slowly dissipated as traders learned more about these securities. Second, the late-1998 crisis dramatically increased volatility for roughly five months, September 1998 through January 1999. Then for two years, volatility was low, hovering around 0.10 percent a day. Finally, toward the end of 2000, volatility jumped dramatically and has fluctuated around 0.15–0.30 percent a day ever since.

Volatilities for the original 10-year issues, January 2007 through 2013, are generally ordered by remaining maturity.[16] The single short-term bond

Table 7. Time Variation in Return Volatility Estimated by GARCH(1,1): $h_t = \alpha_0 + \alpha_1\varepsilon^2_{t-1} + \rho h_{t-1}$ (t-statistics in parentheses)

Asset	Lagged Squared Innovation, α_1	Lagged Conditional Variance, ρ
	A. TIPS	
Jul 2002	0.105	0.878
	(6.51)	(53.2)
Jan 2007	0.132	0.865
	(8.04)	(59.0)
Jan 2008[a]	0.134	0.866
	(7.43)	(54.5)
Jan 2009	0.103	0.893
	(6.27)	(56.0)
Jan 2010	0.116	0.884
	(5.70)	(47.3)
Jan 2011	0.086	0.890
	(3.95)	(31.2)
Jan 2012	0.061	0.932
	(3.11)	(39.4)
Jul 2012	0.063	0.881
	(1.82)	(11.6)
Apr 2028	0.195	0.818
	(7.86)	(40.9)
Apr 2029[a]	0.048	0.953
	(6.07)	(120.0)
Apr 2032[a]	0.044	0.947
	(3.75)	(62.1)
	B. U.S. Treasuries	
3 Month	0.203	0.731
	(7.02)	(22.1)
1 Year	0.131	0.805
	(6.28)	(27.4)
5 Year	0.065	0.907
	(5.04)	(47.2)
10 Year	0.059	0.909
	(4.63)	(43.5)
30 Year	0.054	0.843
	(2.81)	(14.2)
	C. Equities	
vwretd	0.108	0.851
	(5.82)	(34.6)
ewretd	0.247	0.744
	(8.92)	(30.2)
sprtrn	0.096	0.854
	(5.26)	(31.4)

[a]Possible nonstationarity in the conditional volatility.

Notes: In the variance equation of GARCH(1,1), h is the conditional variance and ε is the innovation. GARCH(1,1) was estimated using daily returns on TIPS, identified by the security's maturity month, on U.S. Treasuries, and on equities. Sample sizes are the same as in Table 2 (less 1 for the single lag). The January 2013 TIP bond did not have enough observations for GARCH convergence.

of July 2002 is the only issue whose volatility appears to have declined from the beginning of 2001 through its maturity. All the others had considerably more volatility in 2001–2003 than in the two preceding calendar years, 1999–2000. Volatility was also relatively high around the Russian debt crisis in late 1998.

What is the source of the substantially higher volatility in the past two calendar years than in the previous two years? To deduce something about this question, **Figure 5** shows the ratio of volatilities for two consecutive two-year periods, 1999–2000 versus 2001–2002, not only for TIPS but also for the other assets. (TIPS issued after 2000 are not included.) Notice that all but the very shortest-term TIP bond had about 80 percent higher volatility in 2001–2002 than in 1999–2000. This pattern is matched neither by nominal bonds nor by equities. Volatility increased somewhat in both these asset classes, but it reached 40 percent only for the one-year nominal T-bond. Equities show increases of 10–20 percent. Curiously, although the volatility increase seems to grow with maturity for TIPS, it declines with maturities beyond one year for nominal bonds.

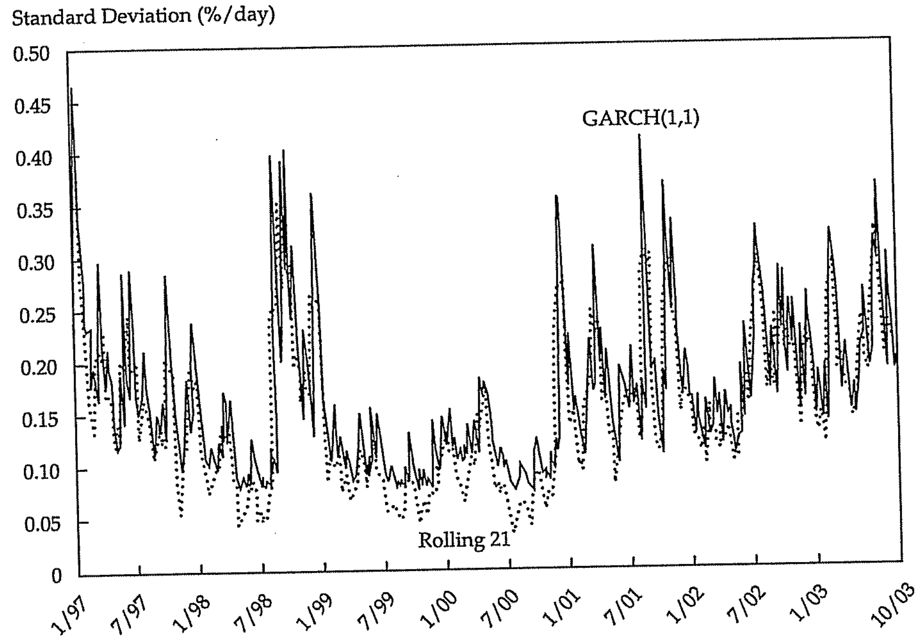
A story consistent with this pattern involves the relative volatilities of real interest rates and expected inflation. If real interest volatility increases while inflation volatility declines or does not increase very much, one would expect TIPS volatility to increase (and possibly increase more for longer maturities) more than nominal bond return volatility (which could even be negatively associated with maturity). Volatility of the real interest rate also affects equities, but because they are much more volatile in general and subject to other sources of risk, the relative impact of real-interest-rate volatility should be smaller for equities than for TIPS.

The Term Structures of Expected Inflation and Real Yields

This section discusses the term structures of nominal yields, real yields, and expected inflation.

Historical Patterns. Although only 12 TIPS have thus far been issued by the U.S. Treasury, when any 4 of them are outstanding, one can estimate the general shape of the term structure of real yields by exploiting the three-factor model used in the "Yields, Durations, and Sensitivities" section for nominal yields and explained in Appendix B. The method involves using real yields and real durations from TIPS to estimate the *real* yield curve's level, slope, and curvature on each trading date. The difference between the nominal and real yield curves is the yield curve of anticipated inflation (plus the inflation risk premium, if any). Hence, this difference also can be estimated for each date.

Figure 4. January 2007 TIPS Volatility: Comparison of GARCH(1,1) and Rolling 21-Day Results, January 1997–September 2003



Note: Standard deviations in percent per day.

Figure 5. Ratio of Return Standard Deviations, 2001–2002 vs. 1999–2000

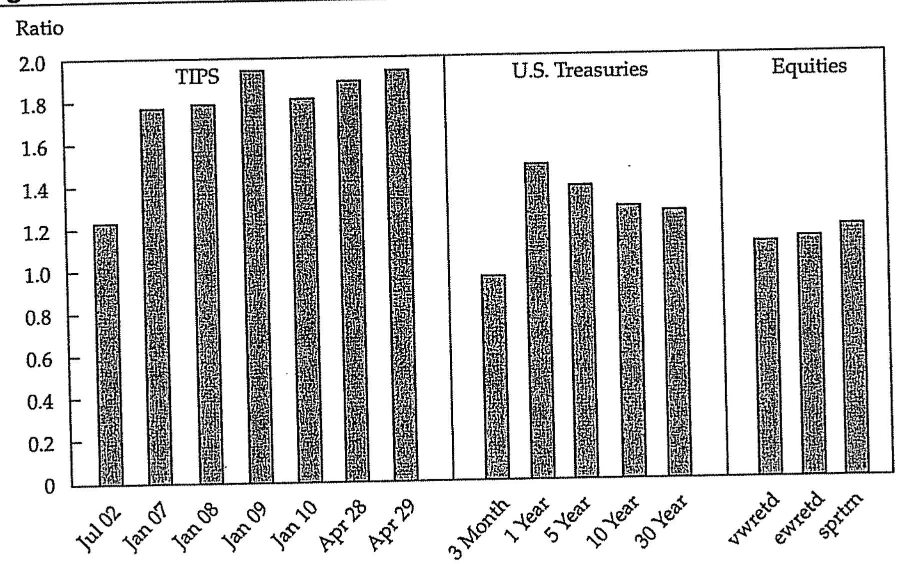


Figure 6, Figure 7, and **Figure 8** summarize the results by plotting, respectively, the level, slope, and curvature estimates for both the nominal and real term structures over time.[17] The vertical difference between the nominal and real term structures provides the corresponding term structure of anticipated inflation plus any inflation risk premium. For clarity, this structure is also plotted over time in **Figure 9**.

To obtain a visual image of the term structure on a given date, combine the level, tilt, and curvature estimates for that date. For example, the term structure of anticipated inflation around 15 January 2001 (see Figure 9) had an average level of about 1.5 percent, was tilted slightly upward from the short to the long end, and had convex downward curvature. For a later date—say, 15 January 2002—the inflation term structure had a lower average level

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Figure 6. Term-Structure Levels: Nominal and Real, January 1999–September 2003

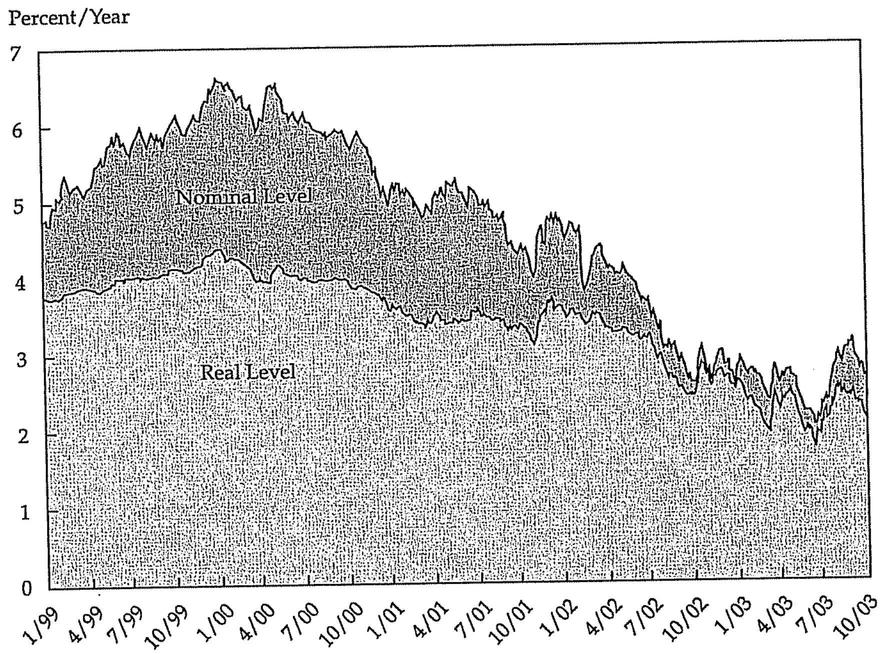


Figure 7. Term-Structure Slopes: Nominal and Real, January 1999–September 2003

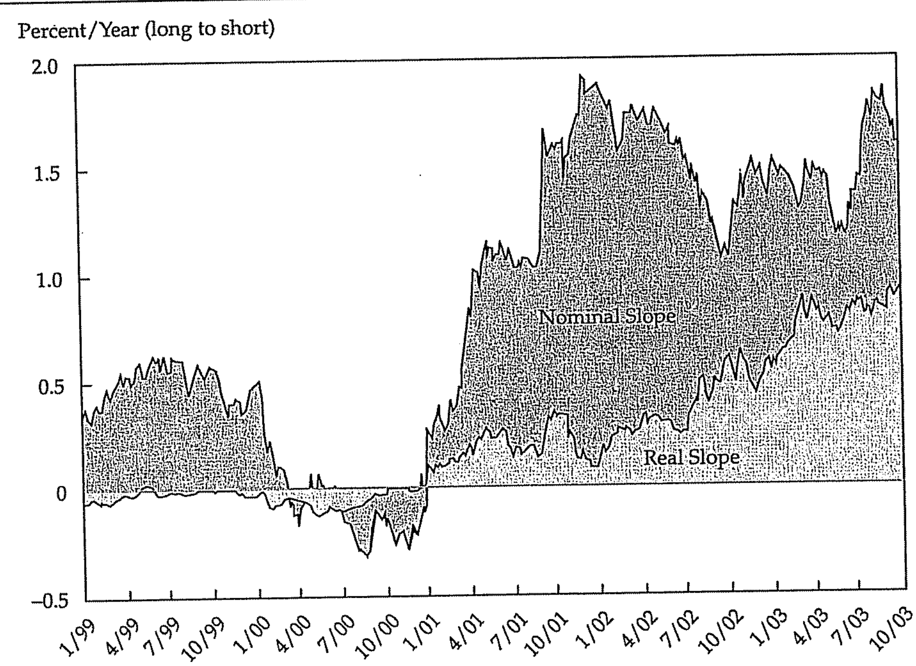


Figure 8. Term-Structure Curvatures: Nominal and Real, January 1999–September 2003

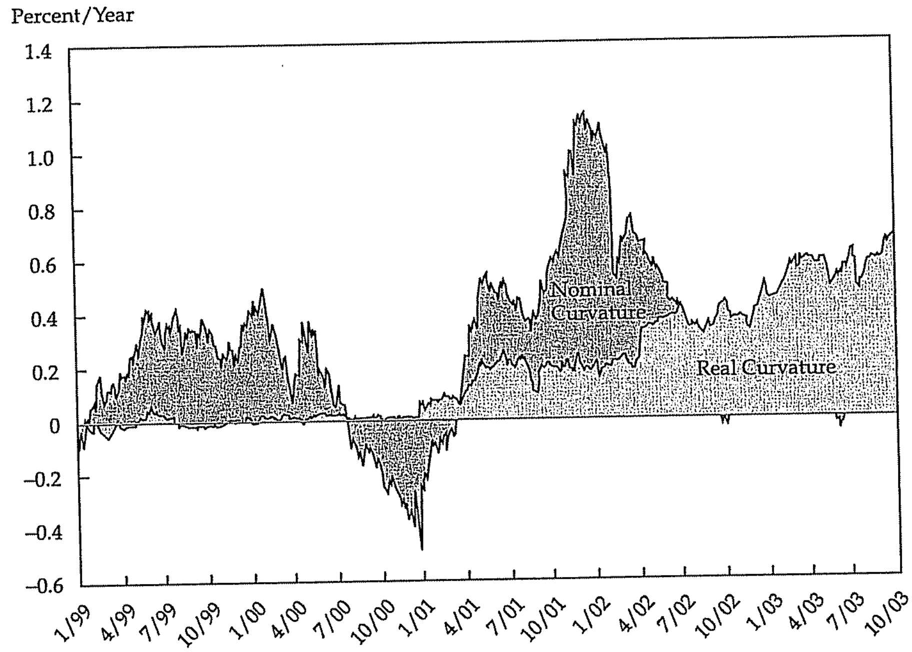
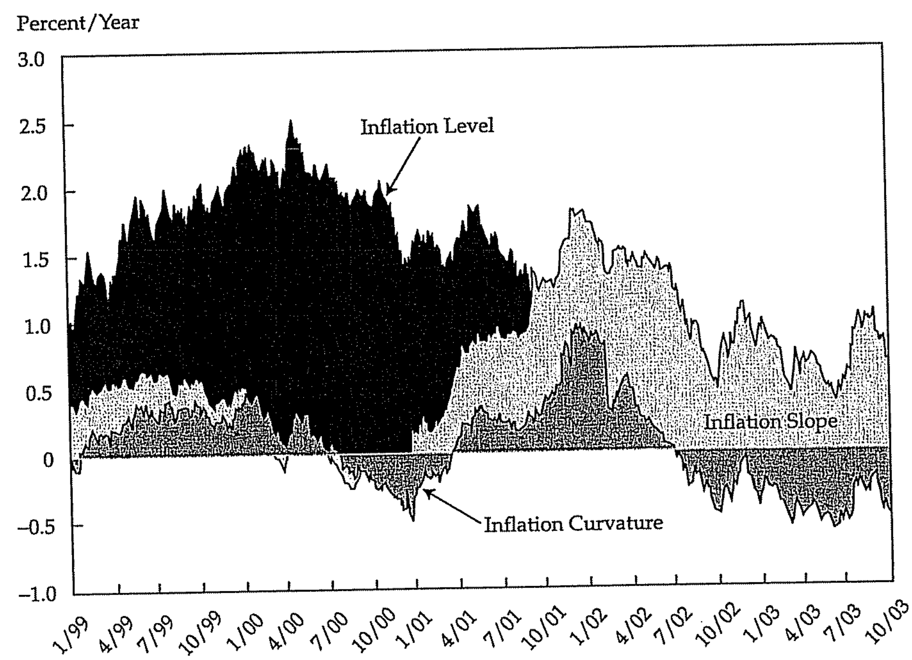


Figure 9. The Term-Structure of Anticipated Inflation, January 1999–September 2003



but was steeply upward sloping (about 1.5 percent from the short end to the long end) and had a pronounced *concave* downward curvature.

The term-structure levels in Figure 6 track *average* nominal- and real-interest-rate movements over time. A dramatic decrease has indeed occurred in both nominal and real interest rates since the beginning of calendar year 2000. The decline in nominal rates has been larger because anticipated inflation also has declined. The inflation level has recently been close to zero, as shown by the relatively small gap between the nominal- and real-yield-curve levels toward the right (latest) end of Figure 6.

As a rule, the nominal yield curve is more steeply sloped than the real yield curve (see Figure 7). This pattern is, of course, consistent with an inflation risk premium that increases with maturity. Notice in Figure 7 or Figure 9 that a sharply positive slope is presently a notable feature of the anticipated inflation term structure. This pattern is consistent with a market consensus belief that inflation will not remain for long at its current low level.

For a brief period during the last half of 2000, the nominal yield curve was less steeply sloped than the real yield curve. At the time, the market consensus must have been forecasting a decline in anticipated inflation, enough of a decline to outweigh any term-dependent risk premium. That forecast proved to be accurate; the estimated expected inflation level did decline.

Figure 8 shows that term-structure curvature was less in absolute value for the real yield curve than for the nominal yield curve until the middle of 2002, but the real curvature has been larger subsequently. The real curvature was mostly positive (concave downward) throughout the sample period and has been materially increasing lately. In term-structure theory, curvature is often associated with volatility, so the recent increase in TIPS return volatility is broadly consistent with the observed curvature trend. The nominal curvature was also mostly positive during the sample period except for the last quarter of 2000, when inflation was expected to decrease.

An obvious caveat applies to these results. Only sparse points along the real yield curve are available, so estimation error is a potentially significant problem. Caution is urged—particularly with respect to the term structure of anticipated inflation.

Possible Explanation for Real-Yield Decline. Real interest rates have fluctuated more in the past three years than in the prior two years. At the same time, inflation seems to have declined both in level and in volatility. TIPS returns have been extraordinarily high during this later period, and yields have declined precipitously. Evidently, TIPS returns can be high when inflation is low, even though real rates have increased in volatility. Is there a link between decreasing anticipated inflation and lower TIPS yields?

Because TIPS are well linked to official inflation, one might think there should be no connection between changes in their yields and changes in expected inflation. In an earlier paper (Roll 1996), however, I argued that inflation and TIPS yields might be coupled because of their tax treatment, which essentially stipulates full taxation of the real yield *and* the inflation accrual. For a taxable investor, the anticipated after-tax real yield on TIPS is

$$\gamma = r(1-\tau) - \frac{\tau I^e}{(1+I^e)}, \tag{3}$$

where τ is the effective tax rate, r is the pretax real yield on TIPS, and I^e is the rate of anticipated inflation.

When anticipated inflation changes, the pretax yield on TIPS must respond to maintain the same level of taxable demand. In other words, to maintain a constant after-tax real yield, the following must hold:

$$\partial\gamma = 0 \Rightarrow \frac{\partial r}{\partial I^e} = \frac{\tau}{\left[\left(1-\tau\right)(1+I^e)^2\right]}. \tag{4}$$

For example, if the effective tax rate is 30 percent and the expected inflation is 3 percent a year, $\partial r/\partial I^e \approx 0.396$ (i.e., a decrease in anticipated inflation of 1 percent would induce a reduction in the pretax yield on TIPS of nearly 40 bps).

These results agree with prevailing market opinion that expected inflation has declined during the past two years. And plenty of tertiary evidence exists; for example, the Treasury auctioned three-month (nominal) bills on 23 December 2002 at an average yield of less than 1.2 percent a year. Even if the real interest rate were only 0.5 percent a year, this latest T-bill yield implies an anticipated inflation over the next quarter considerably below 1 percent (a year).

Falling inflation could explain why TIPS real yields have fallen (and why holding-period returns have been so high). Moreover, the magnitudes seem to be in the right ballpark; inflation fell from perhaps 3 percent during 1999–2000 to less than 1 percent at the end of 2002. At a marginal tax rate of 30 percent, a concurrent reduction should have occurred in TIPS real yields of roughly 80–100 bps, and indeed, this reduction is close to the observed decline.

This interpretation of recent TIPS history does, however, have a hole in it. It presumes that the marginal TIPS investor actually pays taxes. If TIPS are held mainly by tax-exempt organizations, such as pension funds and 401(k) plans, this tax-related explanation is less compelling. At the moment, however, there seem to be few alternative explanations for the dramatic recent holding-period returns of TIPS.

A tax-induced relationship between TIPS real yields and anticipated inflation implies more than simply a long-term trend. Even daily real yield fluctuations should be affected by concurrent changes in the market's consensus belief about future inflation. We have already constructed empirical estimates of the daily term structures of expected inflation reported in the previous section. These can be related to TIPS' real yields. As a first attempt at uncovering a possible tax effect, **Table 8** reports (in the "One Factor" columns) changes in the real yields of TIPS regressed on concurrent changes in the level of expected inflation (that is, the estimated level of the inflation yield curve from the previous section). The regression equation is

$$\Delta y_{j,t} = \alpha + \beta \Delta I^e{}_t + \varepsilon_{j,t}, \qquad (5)$$

where $\Delta y_{j,t}$ is the real yield change for TIPS j from day $t-1$ to day t and $\Delta I^e{}_t$ is the contemporaneous change in the estimated level of anticipated inflation.

In every case, except the July 2013 issue (which has only a short period of data available), a strong positive relationship exists between changes in estimated anticipated inflation and changes in real yields. This finding is all the more impressive in that changes in real yields are themselves *negatively* related to estimated changes in anticipated inflation (because changes in anticipated inflation are the difference between the fitted levels of the nominal and real yield curves). If measurement error had been material, a spurious negative relationship might have been found between real yield changes and anticipated inflation changes, but as it turns out, there is no evidence of this at all. The slope coefficients from the one-factor model in Table 8 are estimates of $\tau/[(1-\tau)(1+I^e)^2]$, where τ is the effective tax rate and I^e is true expected inflation. Except for the July 2013 aberration mentioned previously, these coefficients are all positive (and significant), ranging from about 0.1 to more than 0.3. Assuming an expected inflation of 1 percent, the implied marginal tax rates range from about 10 percent for the longer TIPS to about 19 percent for the shortest.[18] This seems sensible, in that tax-exempt investors, such as pension funds, have long horizons and are likely to be attracted to the longer-term maturities.

The second regression reported in Table 8 reveals that a simple bivariate comparison of real yields and inflation is too simplistic. Obviously, tax-paying investors are concerned not only about current inflation but also, perhaps to a greater extent, about future inflation and implied future after-tax yields. Except for the shortest TIP bond, the slope and curvature of the inflation yield curve are probably more pertinent for after-tax yields. This seems to be particularly the case for the inflation term structure's slope. As the three-factor regressions of Table 8 reveal, the estimated inflation yield-curve slope has a positive and highly significant association with real yields for all TIPS beyond the shortest maturity. Evidently, increases in anticipated future inflation (as measured by the inflation term structure's slope) induce immediate and large increases in pretax real yields on TIPS. Inflation term-structure curvature also has an impact on current real yields, perhaps because it is associated with inflation volatility.

What explanations other than taxes could induce the strong empirical relations between real yields and anticipated inflation documented in Table 8? The joint response of real interest rates and inflation to business cycles might be a possibility. If, for example, inflation *and* real interest rates increase (decrease) during an expansion (recession), their mutual correlation would not necessarily imply causation. Future research may settle this important issue. At the present, simply remember that, whatever the cause, *a positive and strong relation definitely exists between real yields and anticipated inflation*. TIPS real yields are *not* independent of inflation.

TIPS in Investment Portfolios

Upon the appearance of any new asset, investors are anxious to know how it fits into well-diversified portfolios. In this section, I attempt a preliminary foray into this complicated terrain with the use of the three broad classes of assets discussed so far—TIPS, nominal T-bonds, and equities. Of course, any real-world investment portfolio would not restrict itself to such broad asset classes, but the exploration still might yield some insights into how TIPS fit into an overall investment strategy.

An optimized portfolio in the mean–variance sense depends on three inputs—expected returns, return volatilities, and correlations. Candidates for some of these ingredients have already been discussed—namely, the sample values given in Tables 2 and 3. A glance at these tables shows, however, that one should not blindly accept such historical estimates in a forward-looking portfolio allocation problem (as is always true of historical estimates).

Table 8. Tests of the Tax Conjecture
(t-statistics in parentheses; R^2s in percents; Durbin–Watson statistics in italics)

	One Factor		Three Factor		
TIPS Statistic	Shift	Implied Tax Rate	Shift	Tilt	Flex
Jul 2002	0.234		0.136	0.027	0.192
$N = 74$	(5.22)	19%	(2.02)	(0.25)	(1.48)
	3.3% *1.65*		3.6%		*1.66*
Jan 2007	0.212		–0.128	0.625	0.301
$N = 1{,}156$	(8.98)	18%	(–4.66)	(17.20)	(5.98)
	6.4% *1.71*		42.7%		*1.64*
Jan 2008	0.195		–0.121	0.643	0.242
$N = 1{,}156$	(8.45)	17%	(–4.51)	(18.14)	(4.92)
	5.7% *1.73*		42.4%		*1.67*
Jan 2009	0.178		–0.108	0.639	0.184
$N = 1{,}156$	(8.09)	15%	(–4.22)	(18.90)	(3.93)
	5.3% *1.73*		42.2%		*1.68*
Jan 2010	0.213		–0.095	0.681	0.156
$N = 909$	(7.85)	18%	(–2.99)	(18.50)	(2.88)
	6.3% *1.75*		45.9%		*1.70*
Jan 2011	0.221		–0.231	0.807	0.317
$N = 660$	(6.50)	18%	(–6.15)	(20.30)	(4.87)
	5.9% *1.77*		59.1%		*1.82*
Jan 2012	0.187		–0.421	1.066	0.278
$N = 415$	(4.01)	16%	(–10.50)	(27.40)	(4.10)
	3.5% *1.82*		78.7%		2.02
Jul 2012	0.344		–0.427	1.124	0.183
$N = 292$	(3.88)	26%	(–7.64)	(22.80)	(2.09)
	4.6% *1.82*		80.7%		*2.09*
Jul 2013	–0.182		–0.807	1.219	0.316
$N = 53$	(–0.60)	–23%	(–7.65)	(14.40)	(2.15)
	–1.2% *2.37*		91.7%		*2.53*
Apr 2028	0.103		–0.080	0.397	0.125
$N = 1{,}156$	(6.42)	10%	(–3.99)	(15.00)	(3.40)
	3.4% *1.77*		31.5%		*1.75*
Apr 2029	0.107		–0.076	0.398	0.123
$N = 1{,}095$	(6.35)	10%	(–3.63)	(14.50)	(3.21)
	3.5% *1.77*		31.6%		*1.75*
Apr 2032	0.159		–0.421	0.634	0.371
$N = 354$	(2.87)	14%	(–8.51)	(13.70)	(4.54)
	2.0% *1.85*		61.6%		*1.97*

Notes: Daily changes in real yields on TIPS were regressed on concurrent daily changes in estimates of the inflation term structure. For the first regression, the implied estimated marginal tax rate was computed under the assumption of a 1 percent expected inflation rate.

For one thing, historical mean returns, particularly returns computed over such short sample periods as seven years, are completely unreliable as estimates of future *expected* returns. Indeed, they are almost nonsensical. Equities, for example, had mean returns lower than most TIPS for the five years ending in July 2003.[19] Probably few nonbehaviorists expect this pattern to continue.

Moreover, sample estimation errors are not confined to the historical means provided in Table 2. Correlations are a critical input for portfolio optimization, but the correlation matrix reported in Table 3 is not even positive definite, so it cannot be used directly; matrix inversion is required.[20] And practically, many of the TIPS are so highly correlated that including them all makes little sense.[21]

As a consequence, I decided (rather arbitrarily) to restrict this exploration to two individual TIPS that have long sample periods, the January 2007 and the April 2028 issues; two constant-maturity nominal bonds, the 1-year and the 10-year; and one equity index, the CRSP value-weighted index.

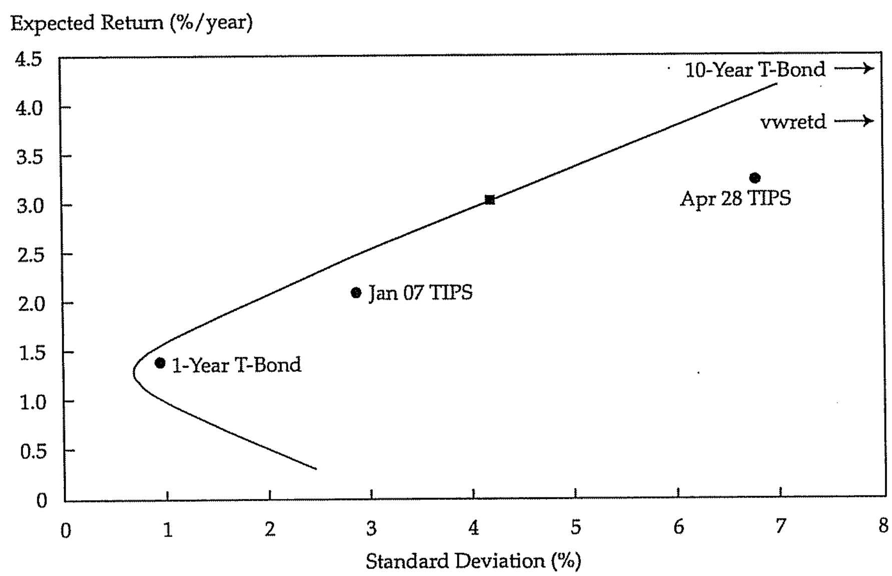
Finally, as the reader has already seen, the volatility of all asset classes fluctuated materially over the six+ years of TIPS history. So, to use all available sample observations in computing standard deviations and correlations would not be wise.

Because portfolio allocation is forward looking, one should use recent estimates of inputs rather than long-term historical values. Thus, I decided to compute the covariance matrix (i.e., standard deviations and correlations) from the beginning of January 2001 through the middle of 2002 and construct examples of "optimized" portfolios toward the end of 2002. I picked an arbitrary day, 13 December 2002, to calculate mean–variance-optimized portfolios.

For the expected returns on nominal bonds, I simply used their closing yields to maturity on the day of portfolio optimization, 13 December 2002. For TIPS, I used their real yields on the same day plus an assumed rate of expected inflation (which will be varied in some of the results to be reported shortly). For equities, I assumed an annual premium of 4 percent over the one-year nominal bond yield. This value could and should be debated. It is a bit high, in my opinion, but it enhances the desirability of equities relative to TIPS and is, therefore, conservative from the perspective of advocating TIPS for a diversified portfolio.

Under the assumption of an expected inflation of 0.4 percent a year, the efficient frontier resulting from this optimization is plotted in **Figure 10**. The 10-year nominal bond and the CRSP value-weighted equity index lie off the chart to the right because their volatilities are so high. Nonetheless, they are held in positive amounts in some of the portfolios along the efficient frontier. For example,

Figure 10. Efficient Frontier with Two TIPS, Two (Nominal) T-Bonds, and the CRSP Value-Weighted Index



Notes: Based on nominal yields for 13 December 2002 and 2001–02 data for daily returns. Expected returns and volatilities in percent per year. Assumptions: Expected inflation = 0.4 percent a year; equity premium = 4.0 percent a year.

the portfolio indicated by the square has an expected return equal to the yield on a five-year nominal bond, which on 13 December 2002 was very close to 3 percent a year. This portfolio is fairly evenly distributed among the five assets, although it has slightly more than 20 percent in each of the two TIPS and slightly less than 20 percent in equities. Its composition is plotted as the second pillar in **Figure 11**.

Figure 11 shows how the inflation assumption affects optimal portfolio composition. The impact is dramatic. Varying assumed inflation by only 10 bps significantly changes the relative allocation to TIPS and nominal bonds. If at the end of 2002 you had predicted inflation greater than 0.4 percent in 2003, you would have wanted to emphasize TIPS. Indeed, if your inflation expectation had been 0.9 percent (still less than 1 percent a year), you would have wanted to put nearly 90 percent of your assets in TIPS! Conversely, if you had thought inflation was going to be very low in 2003, say 0.3 percent or less, nominal bonds would have been your cup of tea.

The inflation-driven results in Figure 11 are not hard to understand: Current nominal bond yields already embed expected inflation, whereas TIPS yields do not. So, when inflation is added to TIPS real yields to obtain their nominal expected returns, the greater inflation is, the more favorable TIPS appear.

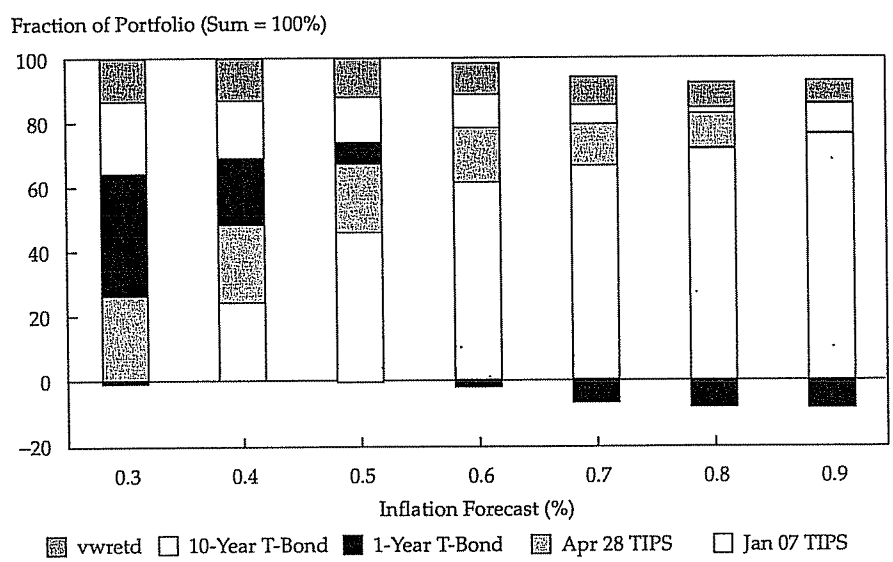
Several caveats are appropriate. First, I took no account of the possible tax–inflation interaction with respect to TIPS real returns. But I argued previously that if inflation increases, TIPS' real returns could decline because of these securities' tax treatment. Second, I did not consider any impact of inflation on the equity premium. Perhaps it should decrease with inflation, or perhaps it should increase. Who knows? Finally, and most importantly, the seeming knife-edged response of portfolio composition here is partly attributable to the small number of assets being considered. If I had used several hundred assets rather than five, the acute sensitivity would have been attenuated to some extent. Nonetheless, a large change in the total allocation to inflation-protected securities relative to nominal bonds would have taken place with a change in anticipated inflation.

The bottom line is: TIPS probably belong in many well-diversified portfolios, even when anticipated inflation is rather low, such as 0.4 percent. TIPS are not strongly correlated with other asset classes, and they have low volatility, much lower than that of nominal bonds with similar maturity. They seem to represent a new diversification opportunity to enhance returns and reduce risk.

Conclusions

TIPS have existed for almost seven years. At the point of this writing, 12 bonds had been issued and 1 had already matured. This article presents an empirical survey of their trading characteristics.

Figure 11. Composition of Optimal Portfolios to Match Five-Year Nominal Yield on 13 December 2002 for Various Inflation Forecasts



TIPS are well protected against inflation (at least as measured by the CPI). A daily *real* yield to maturity and a real duration can be computed in the usual way from the transaction price, real accrued interest, and future real payments, while always ignoring inflation.

Daily *nominal* holding-period returns can be calculated from the change in the trading prices, properly adjusted for the inflation accrual and the accrued interest. Such nominal returns can then be compared with other nominal returns.

Evidence presented here indicates the following about TIPS daily returns since their introduction in January 1997 through September 2003:

- First, TIPS nominal return volatility is less than the volatility of ordinary Treasuries of similar maturity.
- TIPS are highly correlated with each other, particularly for adjacent maturities.
- Over their period of availability, TIPS were negatively correlated with equities (as were nominal bonds) but the correlations were small in absolute magnitude.
- Nominal effective durations are much lower for TIPS than for nominal bonds.
- TIPS respond to changes in the shape of the nominal term structure. Their response to parallel shifts is congruent with their effective empirical durations. Longer (shorter) TIPS do poorly (well) when the term structure tilts upward. Increasing nominal term-structure curvature differentially affects long- and short-term TIPS (as with nominal bonds).
- There is strong evidence of time-varying volatility in TIPS returns.

Even though only a few TIPS issues are outstanding, one can use TIPS to estimate the term structure of real yields and, by comparing the real and nominal yield curves, can derive an estimate of the term structure of expected inflation.[22] The results reveal that short-term anticipated inflation is very low currently. Lower inflationary expectations may explain the recent decline in TIPS real yields. Although TIPS are well linked to the CPI, their tax treatment could render them indirectly subject to inflation because inflation accruals are fully taxed. Hence, a decline in anticipated inflation could induce a reduction in real yields.

Finally, TIPS probably belong in most well-diversified investment portfolios. Under plausible assumptions, TIPS enhance the risk–return characteristics available with other asset classes. Moreover, to the extent that inflation is expected to increase, they should be the dominant component of any portfolio intended to match the nominal return of a mid-maturity bond while minimizing risk.

I am indebted to Barclays Capital for making the TIPS data available, to Kevin Lee and Feifei Li for outstanding research assistance, and to seminar participants at the Harvard Business School, the Universität Konstanz, and the Universität Mannheim.

Appendix A. Calculation of Nominal Holding-Period Returns on TIPS

The explanation in this appendix uses the following definitions:

P_t = price on day t as a percentage of accrued face value
A_t = accrued interest on day t
F_t = face (accrued) value as of day t
C = stated annual coupon
k = number of coupon payments per year ($k = 2$ for TIPS)
CPI_m = CPI-U for calendar month m
CPI_B = CPI-U on the base (issue) date
A_t = accrual factor for day t within month m ($1 \leq t \leq 31$)
N_m = number of days within month m
G_m = growth factor for days within calendar month m

Accrual of Face Value. The growth factor is fixed so that the accrual factor on the first day of month m corresponds to the CPI reported for month $m - 3$. Thus, the accrual factor for the first day of month $m + 1$ corresponds to the CPI reported for month $m - 2$. For month m,

$$G_m = \sqrt[N_m]{CPI_{m-2}/CPI_{m-3}}. \tag{A1}$$

Then, for each day t within month m, the principal amount of the bond, together with the accrued interest and gross purchase cost, are adjusted by the inflation accrual factor:

$$F_t = \frac{CPI_{m-3}}{CPI_B} G_m^{t-1}. \tag{A2}$$

The seeming skip of one month is explained by the delay in publication of the CPI. For example, the CPI for May is revealed only sometime in early June, so the accrual factor has to depend on the latest available CPI, which, during the first days of June, is for April.

During the TIPS' first month, an analogous method is used to establish CPI_B corresponding to the issue date. If N_I is the number of days in the month of issue (month I) and t is the actual issue date within the month ($1 \le t \le N_I$), then G_I is calculated from Equation A1 and

$$CPI_B = CPI_{I-3}G_I^{t-1}. \quad \text{(A3)}$$

Accrued Interest. The stated coupon is C/k paid k times each year on the accrued face value. Consequently, if F_p is the face value as of coupon payment date p, the actual amount paid is $(F_pC)/k$.

Accrued interest is calculated between coupon payment dates by using the accrued face amount on the settlement date. If n is the next coupon payment date and λ is the previous coupon date, then on settlement date t ($\lambda < t < n$), the accrued interest is

$$A_t = F_t\frac{(t-\lambda)}{(n-\lambda)}\frac{C}{k}. \quad \text{(A4)}$$

Return. Settlement occurs within one business day. For a trade occurring on day t, the accrued interest and principal accrual are determined as of the next trading day. Hence, the one-day return for day t is

$$R_t = \frac{P_tF_{t+j} - P_{t-k}F_t + A_{t+j} - A_t}{P_{t-k}F_t + A_t}, \quad \text{(A5)}$$

where j is the number of days between the trading day and the next business day and k is the number of days between the trading day and the previous business day. Abstracting from holidays, $j = 1$ when t = Monday, . . ., Thursday and $j = 3$ when t = Friday. Similarly, $k = 1$ when t = Tuesday, . . ., Friday and k = 3 when t = Monday. For returns across holidays, j and k could be 2 or 4.

Appendix B. Calculating Changes in the Shape of the Term Structure

A parsimonious (three-factor) model of the term structure's shape can be estimated on each observation date by a nonlinear regression of yield against functions of duration:

$$Y_{j,t} = Level_t + Slope_tX_{L,j} + Curvature_tX_{Q,j}, \quad \text{(B1)}$$

where $Y_{j,t}$ is the yield for the jth bond on date t and where $X_{L,j,t} = a_t + b_tD_{j,t}$ and $X_{Q,j,t} = -(3X^2_{L,j,t} - 1)/2$ are, respectively, linear and quadratic Legendre transformations[23] of $D_{j,t}$, the estimated duration on day t of bond j.[24] The transformation coefficients are

$$b_t = \frac{2}{\max(D_t) - \min(D_t)} \quad \text{(B2)}$$

and

$$a_t = 1 - b_t\max(D_t), \quad \text{(B3)}$$

which assures that the transformed durations span the required range. The estimated regression coefficients, $Level_t$, $Slope_t$, and $Curvature_t$, jointly depict the general shape of the term structure on date t.

Changes in $Level_t$, $Slope_t$, and $Curvature_t$ from one day to the next provide a depiction of daily movements in the general shape of the term structure. Repeating the estimation over all sample days provides a time series of term-structure shape changes, or factors. The shift factor gives the change in term-structure level (i.e., $Shift_t = Level_t - Level_{t-1}$). Similarly, the tilt factor measures the change in term-structure slope: $Tilt_t = Slope_t - Slope_{t-1}$. And the change in curvature, the flex factor, is measured as $Flex_t = Curvature_t - Curvature_{t-1}$.

The shift factor is related to the usual notion of duration because it represents a parallel movement in the term structure. The tilt factor is related to "convexity." No common term is related to the flex factor, although bond market professionals sometimes refer to a similar construct as a "change in convexity."

Given a time series of shift, tilt, and flex factors, a bond's response to changes in term-structure shape can be estimated with a regression such as

$$R_{i,t} = \beta_0 + \beta_{Shift}(Shift_t) + \beta_{Tilt}(Tilt_t) + \beta_{Flex}(Flex_t) + \varepsilon_{i,t}, \quad \text{(B4)}$$

where $R_{i,t}$ is the daily return on the ith bond and $\varepsilon_{i,t}$ is a residual.

The three regression coefficients can be interpreted as follows: β_{Shift} will generally be negative and should approximate the bond's duration in absolute value; β_{Tilt} will be positive for short-term bonds and negative for long-term bonds; β_{Flex} should usually be positive for very long term and very short term bonds and negative for bonds of intermediate maturities.

Notes

1. The index used for TIPS is, more specifically, the U.S. City Average All Items Consumer Price Index for All Urban Consumers (CPI-U), published monthly by the U.S. Bureau of Labor Statistics.
2. See, for example, Arnott (2003).
3. Recently, Jarrow and Yildirim (2003) derived and tested a theoretical pricing model for TIPS and provided analytic valuation formulas for TIPS derivatives.
4. To calculate the duration, I assumed that the constant-maturity yield prevailed for a par bond.

5. See Canina, Michaely, Thaler, and Womack (1998).
6. To approximate an annual rate, daily standard deviation was multiplied by $\sqrt{252}$. This approach assumes independence over time.
7. This statement can be deduced from the fact that the correlation between the July 2002 TIPS and the January 2007 TIPS is 0.757 (sample size 1,262), whereas the July 2002 and January 2012 correlation is only 0.183 (sample size 124). The January 2012 correlation was computed from observations close to the short-term TIPS' maturity date.
8. From January 1926 through December 1996, based on monthly returns, the S&P 500 had correlations of 0.180, 0.136, and 0.0847 with, respectively, long-term, intermediate-term, and one-year Treasury bonds (based on data from Ibbotson Associates).
9. A plot of all the TIPS is available upon request. The shortest-term TIPS exhibited rather bizarre price behavior as it neared maturity in July 2002. For many trading days, its real yield was even negative. The cause might have been measurement error in the recorded trade price; when a bond approaches maturity, even slight errors are magnified as the internal rate of return is annualized. Because of its odd behavior, I did not plot this particular TIPS' yields in Figure 1 for its final half-year of existence.
10. Specifically, unless $\rho < -\frac{1}{2}\sigma_I/\sigma_r$, where σ_I (σ_r) is the standard deviation of anticipated inflation (real yield) and ρ is correlation.
11. Modified duration is Macauley's duration divided by $(1 + Y/k)$, where Y is the yield and k is the compounding frequency. For discrete compounding, modified duration's units are not exactly years but they are close.
12. A table with these results will be provided to interested readers upon request.
13. The absolute value of Duration*t should be approximately the same as the coefficient labeled "Duration."
14. The single exception is the July 2013 TIPS, which provided only 57 observations.
15. GARCH stands for generalized autoregressive conditional heteroscedasticity.
16. To save space, the patterns described in this paragraph are not depicted, but a plot is available upon request.
17. These plots begin in January 1999 because this month is the first time that four different TIPS were outstanding.
18. Although I used 1 percent for expected inflation, this calculation is not sensitive to the inflation assumption.
19. The S&P 500 return averaged only 6.11 percent a year during the sample period. Most TIPS did better. Remember that the equal-weighted CRSP index, which appears to have done quite well in Table 2, has a mean return that is strongly upwardly biased.
20. A correlation matrix computed from simultaneous observations with no missing values will generally be positive definite, and thus invertible, unless there are more assets than sample periods or there is perfect linear dependence among some groups of variables. In the case of Table 3, however, there were large differences among assets in the number of available observations.
21. For example, the 0.999 correlation between the April 2028 and 2029 TIPS suggests that either could be included but not both are needed.
22. Technically, the estimate is the term structure of expected inflation plus the inflation risk premium, if any.
23. The Legendre transformations were used because they are approximately orthogonal over the range –1 to +1. They are exactly orthogonal if continuous from –1 to +1. Curvature is positive if the term structure is concave downward. See mathworld.wolfram.com/LegendreTransformation.html.
24. For constant-maturity nominal Treasury yields, the duration was estimated by assuming that the yield was valid for a bond selling at par.

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CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 913

Exhibits in Support
Of Opening Testimony

June 4, 2010

Staff/913
Storm/1

79 FERC ¶ 61,309

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 396-B

Northwest Pipeline Corporation	))	Docket Nos. RP93-5-025 and RP93-96-005

OPINION AND ORDER ON INITIAL DECISION

Issued: June 11, 1997

970623-0370-2

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JUN 11 1997

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Northwest Pipeline Corporation	))	Docket Nos. RP93-5-025 and RP93-96-005

OPINION NO. 396-B

Appearances

Steven W. Snarr for Northwest Pipeline Company

James Holt for the Canadian Association of Petroleum Producers, Northwest Natural Gas Company, Washington Natural Gas Company, and the Public Utility Commission of Oregon

Sandra J. Delude, Marc G. Denkinger, and Richard E. Kelly for the Staff of the Federal Energy Regulatory Commission

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

Northwest Pipeline Corporation	))	Docket Nos. RP93-5-025 and RP93-96-005

OPINION NO. 396-B

OPINION AND ORDER ON INITIAL DECISION

(Issued June 11, 1997)

On October 22, 1996, the Administrative Law Judge (ALJ) issued an Initial Decision in a supplemental proceeding ordered by the Commission to inquire into the appropriate long-term growth rate to be used in computing the rate of return on equity to be applied in this case. 1/ In his decision, the ALJ rejected the methodologies advocated by the parties and recommended an alternative approach. Parties filed exceptions to the determinations made by the ALJ. 2/ As discussed below, the Commission will use the long-term growth rate of the economy as a whole, as measured by the gross domestic product (GDP), to determine the long-run growth rate in this proceeding. In a contemporaneous order being issued in Williston Basin Interstate Pipeline Company, Docket No. RP92-163-007, another case remanded for consideration of the long-term growth issue, the Commission also is using the growth of GDP as its measure of long-term growth.

With the determination of the appropriate method of ascertaining long-term growth rate in this case, the Commission's methodological approach to determining rate of return has reached maturity. The Commission therefore intends to use the approach in this case in future cases.

1/ Northwest Pipeline Corporation, 77 FERC ¶ 63,007 (1996).

2/ Briefs on Exceptions and Briefs Opposing Exceptions were filed by Northwest Pipeline Corporation (Northwest), Commission Staff, and jointly by the Canadian Association of Petroleum Producers, The Public Utility Commission of Oregon, Washington Natural Gas Company, and Northwest Natural Gas Company (Intervenors).

Background

During the initial litigation of this proceeding, the parties relied upon the discounted cash flow (DCF) methodology for determining the rate of return on equity. The DCF methodology is based on the premise that a stock is worth the present value of its future cash flows, discounted at a market rate commensurate with the stock's risk. Under the constant growth DCF formula used by Commission Staff and Northwest, the cost of capital is equated with the dividend yield (dividends divided by market price) plus the estimated constant growth in dividends to be reflected in capital appreciation. 3/ Because Northwest is not a publicly traded company the DCF analysis was performed using a proxy group of companies whose primary source of revenue was from interstate pipeline operations.

After the testimony was filed in this proceeding, the Commission issued an order in Ozark Gas Transmission System, 4/ finding that in performing a DCF analysis a projection of growth rates limited to five years, with no evidence of what is anticipated beyond that point, is inconsistent with the DCF model and cannot be relied on in a DCF analysis. The record in this proceeding was based primarily on 5-year growth estimates for the proxy companies derived from the Institutional Brokers Estimate System (IBES), and contained no long-term growth forecasts.

In Opinion No. 396, 5/ the Commission took official notice of DRI/McGraw Hill data for gas consumption and retail prices (as used in Ozark) for the years 2000 to 2010 to calculate a long-term growth rate. On rehearing, a number of parties raised questions about the use of the DRI/McGraw Hill data, and in Opinion No. 396-A, 6/ the Commission granted rehearing, determining that an evidentiary record was needed to afford the parties a full opportunity to explore the issue of the proper method for determining a long-term growth rate. The Commission therefore remanded the issue to an ALJ for an expedited hearing for the sole purpose of determining a long-term growth rate.

The ALJ rejected the approach used by the Commission in Opinion No. 396, which was similar to the Ozark approach, as well as the approaches suggested by the parties. Instead, he derived the long-term growth rate by using a projection of growth in gas

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3/ Ozark Gas Transmission System, 68 FERC ¶ 61,032 at 61,104 n.16 (1994).

4/ 68 FERC ¶ 61,032 (1994),

5/ Northwest Pipeline Company, 71 FERC ¶ 61,253 (1995).

6/ Northwest Pipeline Company, 76 FERC ¶ 61,068 (1996).

consumption (derived from the Department of Energy's Energy Information Administration ("EIA"), *Annual Energy Outlook, 1993)* and adjusting that data for inflation. 7/ In contrast, in the Williston case, the ALJ followed the Ozark approach. 8/

The parties in this proceeding filed Briefs on Exceptions on November 21, 1996, and Briefs Opposing Exceptions on December 11, 1996. Commission Staff and Northwest filed exceptions to the ALJ's determination. The Intervenors essentially supported the ALJ's result. In their Brief Opposing Exceptions, the Intervenors also offered an additional approach to determining long-term growth, which they asserted produces essentially the same result as the ALJ's approach.

Discussion

After reviewing the data sources and methodologies used by the parties and the ALJ, the Commission concludes that a projection of long-term growth for the specific pipeline companies in the proxy group or for the pipeline industry as a whole cannot be reasonably developed based on available data sources. The Commission, therefore, has determined to use as its long-term growth rate for the proxy companies, the long-term growth rate of the United States GDP. The Commission will discuss below the weaknesses it finds with the methodologies proposed by the parties and the ALJ, and the Commission's reason for choosing the long-term growth rate of the economy.

A. Positions of the Parties and the ALJ

1. Northwest's Approach

Northwest contends that DRI/McGraw Hill or EIA should not be used for determining long-term growth, because the record fails to show that investors rely on such data. Northwest further argues that reliance on a single methodology is unduly formulaic. Rather, Northwest maintains that the determination of rate of return requires the exercise of considered judgment, and that the analysis provided by its expert, Dr. Olson, should be adopted as a considered and reasoned expert judgment on the appropriate growth rate.

If the Commission should reject Dr. Olson's growth rate, Northwest submits that the methodology proposed by Commission

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7/ The ALJ chose to use the EIA as opposed to the DRI/McGraw Hill data, because the EIA data are publicly available, while the DRI/McGraw Hill which must be purchased.

8/ Williston Basin Interstate Pipeline Company, 77 FERC ¶ 63,001 (1996).

Staff should be used. Northwest contends that the ALJ's result is unreasonable because it produces an overall rate of return on equity of 11.62% which is inconsistent with the 12-14% rates of return on equity approved by the Commission in other recent cases.

Dr. Olson principally relies upon the IBES five-year growth estimates, with an adjustment to attempt to take long-term growth into account. 9/ The IBES data yielded a growth rate of 11.40% which Dr. Olson judged should be lowered to 10 to 10.5%. In making this judgment, Dr. Olson found that the IBES consensus for pipelines had been about 10% for 5 years or more, which he interpreted as an indication that investors would expect they would stay at that level. He also looked at the ten year forecast for the economy which he found strong, and, therefore, concluded that there was no reason to expect a decline in the IBES growth rate. Third, he relied on the 1993 Ibbotson Yearbook showing historic data on growth in stock prices as being consistent with a long-term growth estimate of 11.40%.

The Commission in Ozark required a projection of long-term growth because the use of short-term growth data alone was not consistent with the DCF model, and because short-term growth data could be atypically high or low depending on an industry cycle. Northwest's reliance upon short-term growth data from IBES is at odds with the Commission's rationale for rejecting sole reliance on such data. Although Northwest's expert witness sought to make subjective adjustments to the short-term growth data, the Commission agrees with the ALJ's conclusion that these adjustments were unsupported by objective evidence. For instance, Northwest's witness relied upon trends in historical IBES data in attempting to predict future growth rates. But such trends could reflect atypical historical factors, such as recovery from heavy losses suffered during gas price regulation, and Northwest has not presented convincing evidence that the past industry trends are likely to continue into the future. 10/ Northwest's reliance on short-term growth data for the long-run analysis also is at odds with the approach used by large brokerage houses. The investment community bases its long-term

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9/ Exhibit No. N-1-R, at 18.

10/ See Ozark, 68 FERC at 61,105 (historical data is not a good proxy for determining future growth trends unless it is accompanied by a showing that the future will replicate the past); Wyoming Interstate Company, 69 FERC ¶ 61,259, at 61,992 (1994)(need to create a nexus between past data and future growth), vacated, 70 FERC ¶ 61,320 (1995).

growth estimates for individual companies on projections of the long-term growth of the economy. 11/

2. Commission Staff

Commission Staff multiplied projections for growth in consumption by the projection for growth in gas prices to arrive at an estimate of long-term growth of the pipeline industry. Staff witness Shriver relied both on the DRI/McGraw Hill and EIA data, which is derived, in part, from the DRI/McGraw Hill data. The EIA data yielded a long term growth estimate about one percentage point (or 100 basis points) lower than the DRI/McGraw Hill figure. 12/ The Staff witness found support for his result in the correspondence between his long-term growth figure of 7.72% and the 7% to 7.5% long-term growth estimates for the United States economy that two large investment firms, Merrill Lynch and Prudential-Bache Securities, use in their stock valuation models. 13/

Commission Staff's use of revenue for the gas commodity as a proxy for the revenue earned by pipelines is problematic. As the ALJ found, there is no reason to believe that the use of pricing and revenue data for the gas commodity should correlate with transmission prices and revenues. 14/ After unbundling, most pipelines (including Northwest) no longer derive revenue from gas sales, so there is no longer a basis for drawing a connection between commodity and transmission revenue. 15/

Commission Staff, in its Brief on Exceptions, contends its approach is reasonable based on its evidence of a relationship

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11/ *See* Exhibit Nos. S-6-R and S-7-R. (Merrill Lynch and Prudential-Bache).

12/ While Commission Staff initially advocated the use of the DRI/McGraw Hill data, it did not object, in its Brief on Exceptions, to the ALJ's use of EIA data.

13/ Exhibit Nos. S-6-R and S-7-R.

14/ The ALJ argued that growth in gas commodity prices sometimes may be inversely related to increases in pipeline revenues in certain circumstances -- for instance, he postulates that a sustained decrease in gas commodity prices relative to other fuels would likely cause an increase in pipeline transmission revenues. In support, he pointed to Northwest's decision to expand its facilities to accommodate increased demand created by lower commodity prices. 77 FERC at 65,020.

15/ 77 FERC at 65,019-20.

between revenue, earnings, and growth. 16/ Commission Staff further contends the use of commodity pricing data is justified by the Commission's historical practice of relying on proxy groups drawn from the natural gas industry to estimate rates of return for pipelines without publicly traded stock.

As the ALJ points out, however, the ratios used by Commission Staff do not truly address the question whether to use commodity gas prices as a proxy for transmission prices. 17/ The tables introduced by Staff were intended to show only that growth in revenues by the firms in the proxy group are correlated to their growth in earnings and growth in dividends (which is what the growth factor in the DCF analysis is designed to measure). The data thus are unrelated to whether commodity revenue is a good proxy for transmission revenues.

Moreover, the goal in choosing proxy companies is to obtain a surrogate for the rate of return that investors in a pure transmission company would expect. The Commission, as well as the parties in this case, therefore, traditionally select as the proxy group, companies in the natural gas business whose business (revenues and assets) is, as much as possible, related to transmission. Again, therefore, there is no connection between the use of a proxy group of companies whose businesses are related to transmission, and the reliance upon revenue projections for the sale of the gas commodity.

3. Intervenors' Approaches

Intervenors' expert witness, Mr. Parcell, presented three different approaches for determining long-term growth rates. Approach 1, which they preferred, gives a lower weight (1/3) to the DRI/McGraw Hill projections for growth in gas price increases than to the projections for growth in consumption, resulting in a 2.28% long-term growth. 18/ Their justification for using this weighting scheme is that growth in the price of natural gas is not relevant to pipeline earnings, since gas prices are not necessarily correlated with transportation prices.

16/ Commission Staff compared the net profit margin (the ratio of net income to operating revenues) and the dividend payout ratio (the ratio of dividends to net income). Exhibit S-2-R.

17/ 77 FERC at 65,020.

18/ In approach 1, Intervenors add the growth data (.73) multiplied by 3 and the price data (6.92), producing 9.11, and then divide that figure by 4 to yield 2.28%.

Intervenors do not make clear what the weighting is designed to measure. Changing relative weights, for instance, means that the figure is not a true representation of revenue. The choice of the 3 to 1 weight is arbitrary, with Intervenors offering no evidence as to why the 3 to 1 weight is better than a lower or higher factor. In addition, the weighting scheme also diminishes the effect of inflation, and the Commission agrees with the ALJ that inflation needs to be included in projecting growth rates. 19/

Intervenors' Approach 2 combines the DRI/McGraw Hill estimates for gas consumption with the retail price of natural gas, stated in real, rather than current dollars. Approach 3 uses long-term growth estimates for the economy less inflation, producing a 2.20% long-term growth rate. Both of these approaches, based on real, rather than current dollars, similarly fail to adjust for inflation.

In their Brief Opposing Exceptions, Intervenors introduced yet another approach, which would cure the problem of using projected growth in commodity revenues as a proxy for growth in transmission revenues. The Intervenors contend growth in the price for pipeline transmission can be derived by calculating the difference between the average selling price of natural gas and the average acquisition price as determined from either the DRI/McGraw Hill or EIA data. 20/ This difference, they assert, represents the growth in transportation and distribution prices. Intervenors would then multiply the derived growth in transmission prices by the growth in consumption to determine the growth rate in transmission revenue. They maintain this results in a growth rate almost exactly the same as that determined by the ALJ. 21/

19/ 77 FERC at 65,031. The weighting scheme emphasizes the consumption figure (which is not adjusted for inflation) over the price figure (which includes an inflation component). Dividing the price component by 4, as the Intervenors propose, reduces the inflation component. Exhibit I-1-R.

20/ They calculate this difference by first calculating the difference in average selling price and average acquisition price in the year 2000 and for the year 2010. They then calculate the average growth rate needed to increase from the 2000 figure to the 2010 figure.

21/ The ALJ multiplied growth in gas consumption by the inflation rate. The growth in gas consumption would be the same in the two approaches and, coincidentally, the Intervenors' derived growth in transmission prices equals
(continued...)

However, even in theory, this approach does not isolate pipeline transmission prices since it could include gathering and LDC transmission costs as well as other distribution costs. In addition, other than showing the mathematical calculations, Intervenors offer no evidence to show that the EIA or DRI/McGraw Hill data on acquisition and selling prices can properly be manipulated to derive an appropriate surrogate for transmission prices.

4. ALJ's Approach

The ALJ found deficiencies with all of the approaches presented by the parties. 22/ Given these problems, the ALJ sought to develop a revised approach that would be more analytically sound. He developed a long-term growth rate using the growth in gas consumption multiplied by the projected inflation rate. Since the growth figures for consumption are volume, not price, related, the ALJ maintained that reasonable investors would expect the price of transmission services to at least inflate along with prices of all goods and services. In effect, this approach is based on the assumption that pipeline transmission rates will grow only at the rate of inflation. This analysis produced a long-term growth figure of 4.52%, with a final rate of return on equity of 11.62%.

The ALJ's approach does avoid the problem of projecting revenue growth for the gas commodity, rather than for pipeline transmission. However, this approach is conservative, because it assumes gas transmission rates increase only at the rate of inflation, with no real growth in rates.

B. Commission Decision

As the preceding analysis has shown, despite the efforts of the parties and the ALJ, there is no reasonable basis for choosing one of the parties' or the ALJ's proposed approach as a better method for making a direct estimate of the long-term growth rate for the pipeline industry. Nor does the record show that investors rely upon any of the proposed approaches in making investment decisions.

Indeed, the record shows that Merrill Lynch and Prudential-Bache do not attempt to make long-term growth projections for specific industries or companies in doing DCF analyses. Instead, they use the long-term growth of the United States economy as a

21/ (...continued)
the figure used by the ALJ for inflation.

22/ 77 FERC at 65,022.

whole as the long-term growth figure for all firms, including regulated firms in the gas business. 23/

As the record here shows, there is no perfect data source or methodology for determining the long-term growth figure for a particular pipeline or the pipeline industry. Based on its review of the record, the Commission has concluded that the long-term growth of the United States economy as a whole is a reasonable measure to use as the long-term growth measure for the DCF analysis.

First, the record shows that as companies reach maturity over the long-term, their growth slows, and their growth rate will approach that of the economy as a whole. 24/ Second, it is reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy, because regulation will generally prevent the firm from being extremely profitable during good periods, but also protects it somewhat during bad periods. 25/

Third, the purpose of using the DCF analysis in this proceeding is to approximate the rate of return an investor would reasonably expect from a pipeline company. No evidence in the record shows that investors rely upon any of the approaches suggested by the parties for determining long-term growth. In

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23/ See Exhibit Nos. S-6-R and S-7-R.

24/ See Exhibit Nos. S-6-R, at 2 and S-7-R, at 4 (Merrill Lynch and Prudential-Bache analyses); Exhibit No. S-1-R, at 13-14 (Commission Staff testimony). Northwest's expert also found that short-term growth rates for firms are expected to decline at some point. Exhibit No. N-1-R, at 14.

25/ The use of average rates of return to determine a utility's return generally have been found reasonable. See Consolidated Gas Co. v. Newton, 267 F. 231, (S.D.N.Y. 1920)("assumed to be a condition of investors' [in a regulated entity] bargain that their profit shall measurably follow the general rates") (L. Hand, J); Bluefield Water Works v. Public Service Commission, 262 U.S. 679, 692-93 (1923)(utility has no entitlement to profits such as realized or anticipated in highly profitable enterprises or speculative ventures). The Commission also has used general economy-wide measures (interest rates) to adjust the rate of return. See Mississippi Industries v. FERC, 808 F.2d 1525, 1568 (D.C. Cir. 1987); Boston Edison Company, 42 FERC ¶ 61,374, at 62,094 (1988), aff'd, 885 F.2d 962, 966-67 (1st Cir, 1989); Union Electric Company, 40 FERC ¶ 61,046, at 61,138-39 (1987), rev'd on other grounds, 890 F.2d 1193, 1201-1205 (D.C. Cir. 1989).

contrast, the record shows that the long-term growth of the economy is used by two large investment houses in conducting DCF analyses for investment purposes.

Fourth, all the witnesses in this proceeding used the long-term growth of the economy as a whole as confirmation or support for their analyses. 26/ Although the principal approaches proposed by the parties and the ALJ are not without merit, each has sufficient flaws (as discussed above) that the Commission finds little purpose in attempting to distinguish one approach as being superior to the others. Instead, rather than using the long-term growth rate of the economy as indirect confirmation or support, the Commission chooses to use this measure directly as its measure of long-term growth.

Accordingly, the long-term growth of the United States economy as a whole, as measured by the growth in GDP, should be used as the long-term growth figure to be applied in the DCF model adopted in Opinion No. 396. This model uses a two-step approach, calculating a short-run growth rate from the IBES data and a long-run growth rate and averaging the two to determine the constant growth rate.

The Commission recognizes that its DCF model differs from the DCF analysis used by the investment houses. In contrast to the two-step Commission model, the investment houses use a more complex three stage analysis, where Stage 1 is a five-year near-term estimate, Stage 2 is the transition to maturity, and Stage 3 is the steady state or long-run growth rate of the economy as a whole. In effect, Stage 2 represents the rate at which growth declines from the higher short-term projections to the Stage 3 long-run growth rate of the economy. The determination of the Stage two growth rate requires a judgment by the analyst of the length of time Stage 2 will last, 27/ and whether the growth will decline slowly, quickly, or at a steady rate. Once the figures

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26/ Northwest's witness looked at the ten-year consensus forecast for the economy as a whole as a basis for evaluating the trends in IBES data. Exhibit N-1-R, at 19. Commission Staff's witness compared his result with that of the long-term growth forecasts of Merrill Lynch and Prudential-Bache. Exhibit No. S-1-R, at 13-24. Intervenors proposed using the long-term growth of the economy as an alternate means of determining long-term growth. Exhibit No. I-1-R, at 18. See also Transcontinental Gas Pipe Line Corporation, 77 FERC ¶ 63,023, at 65,147, 65,151-52 (1997) (using long-term growth of the economy as confirmation and support).

27/ The length of the second stage can run upwards of 15 years.

are determined, the analyst must solve for the rate of return using an iterative process. 28/

The Commission has determined not to use the investment house approach, because the calculations are far more involved, requiring the exercise of subjective judgment. Stage 2 of the analysis requires a determination of the length of the transition stage and the rate of decline. An investment analyst attempting to predict the future course of a firm's business has an incentive to make the best assessment possible so that his or her clients will make a wise investment. But such predictions of the future are not well-suited to litigation where the witness for each party is likely to choose from among reasonable alternatives, those data and methodologies that most favor his or her client's financial interest, and there are no objective criteria for the Commission to make distinctions between what will be the equally well-reasoned and well-supported judgments of the equally well-credentialed experts. 29/

The record in this case contains projections of long-term growth of GDP from three sources: DRI/McGraw Hill, EIA, and Wharton Economic Forecasting Associates. 30/ The projections from DRI/McGraw Hill and EIA in the record are on a current basis (including inflation). However, the Intervenors, who supplied the Wharton projection in this case, did not place Wharton's projection of the inflation rate in the record. As discussed above, 31/ inflation needs to be included in projecting growth rates, and the Commission, therefore, will not use the Wharton estimate in this case. 32/ The DRI/McGraw Hill estimate was

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28/ See Exhibit S-7-R, at 2.

29/ For instance, in this case, Northwest has argued that the Commission should accept the "pragmatic" adjustments of the IBES figures made by its witness in place of the judgments and analyses of the other equally well-qualified witnesses for Commission Staff and Intervenors. Northwest's Brief on Exceptions, at 10 (November 21, 1996).

30/ Exhibit No. S-3-R, at 1 (EIA, DRI/McGraw Hill); Exhibit No. I-1-R, at 19 (Wharton).

31/ See text accompanying note 19, supra.

32/ Although the record also contains projections of the long-term growth rates used by Merrill Lynch and Prudential-Bache, the record does not reflect the basis upon which these numbers were developed. Given the absence of record evidence supporting these figures and the inability to replicate these figures in future cases, the Commission has (continued...)

6.44% and the EIA estimate was 6.33%. Averaging these figures yields a long-term growth figure of 6.39%.

In Opinion No. 396, the Commission identified all of the remaining data elements to be included in calculating the rate of return for the proxy companies and determined that Northwest's return should be at the mid-point of the range. 33/ Applying the 6.39% long-term growth rate would yield a mid-point of 12.59% which Northwest must use as its rate of return in making its compliance filing in this case. 34/

Other recent Commission cases on rate of return have all used a similar approach to that adopted here. The recent decisions have all used the two-step DCF methodology, with the IBES figures used as the short-term growth rate. 35/ And, except in the case of new construction, the rate of return has been within the range of the proxy companies. 36/ The only dispute has been over the derivation of the long-term growth rate. Now that the Commission in this and the Williston case has determined the data to be used for long-term growth rate, the essential components of the policy are complete. A description of the Commission's preferred approach, therefore, may help avoid time-

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32/ (...continued)
chosen not to use the Merrill-Lynch and Prudential-Bache long-term growth projections in this case.

33/ 71 FERC, at 61,992, 62,017-18 (Appendix B).

34/ The calculations are shown in the Appendix.

35/ See Ozark Gas Transmission System, 68 FERC ¶ 61,032, at 61,104 (1994); Panhandle Eastern Pipeline Company, 71 FERC ¶ 61,228, at 61,834 (1995); Panhandle Eastern Pipeline Company, 74 FERC ¶ 61,109, at 61,361-62 (1996); Williams Natural Gas Company, 77 FERC ¶ 61,277, at 62,194 (1996); TransColorado Gas Transmission Company, 69 FERC ¶ 61,066, at 61,286 (1994)(average of 5-year estimate and long-run growth).

36/ Compare the cases cited supra note 35 (approving rates within the zone of reasonableness) with Discovery Producers Services L.L.C., 78 FERC ¶ 61,194, at 61,842 (1997) and Nautilus Pipeline Company, L.L.C., 78 FERC ¶ 61,325 (1997) (approving rates of return above the highest in the proxy group).

consuming, expensive, and generally unproductive litigation on this issue in the future. 37/

As in this case, the Commission prefers to use the two-step DCF methodology to calculate the zone of reasonableness for the firms in the proxy group. The IBES figures should be used for the short-run growth rate of each of the proxy companies and the growth rate of the GDP, on a current basis, should be used as the long-term growth rate. The two growth rates should then be averaged and added to the dividend yield for the proxy companies to determine the rate of return.

For determining long-term growth, the parties in this case supported the use of projections from three well-known forecasting firms: EIA, DRI/McGraw Hill, and Wharton. In order to further minimize disputes over the long-term growth figures in the future, the Commission will use an average of the projections from these three sources to determine the long-term growth estimate. The record in this case contained 10-year projections for long-term growth rate. In the DCF model, however, dividends are expected to grow indefinitely, with the indefinite future generally equating to about a 50 year period. 38/ While the economic projections from these three sources do not extend 50 years, DRI/McGraw Hill and Wharton projections generally extend to 25 years, with EIA being somewhat shorter. Pipelines, therefore, should include in their section 4 filings an average of the growth rate of nominal gross domestic product from these three sources for 25 years (or if 25 year data are not available, the longest period available from the source). The pipelines should permit intervenors to review the data used in the calculations to verify their accuracy.

This analysis will generate a rate of return for each of the companies in the proxy group. The rate of return for the subject pipeline will be chosen from the lowest, midpoint, 39/ or highest of the firms in the proxy group depending on the assessment of the pipeline's risk or other special circumstances. Pipelines will be permitted rates of return outside of this range only in special cases, for example, where the pipeline demonstrates that its capital structure is markedly different from that of the

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37/ See Transcontinental Gas Pipe Line Corporation, 77 FERC ¶ 63,023, at 65,158 (1997)(each participant "has taken a different approach, incorporating different inputs, making different assumptions, and ultimately generating different cost of equity recommendations").

38/ Ozark, 68 FERC, at 61,105.

39/ The midpoint is the average of the highest and lowest companies in the proxy group.

proxy group or for start-up companies or new entrants whose business and financial risk differs from that of the proxy companies.

The Commission orders:

(A) The Initial Decision is reversed as discussed in the body of this opinion.

(B) Within 45 days of this order, Northwest must file revised tariff sheets and rates, including all workpapers, in compliance with this order and Opinion Nos. 396 and 396-A.

By the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Secretary.

Appendix

Calculation of DCF Growth

	IBES Growth Rate 40/	GDP Growth Rate	Average
Coastal	15	6.39	10.7
Enron	15	6.39	10.7
PEC	8	6.39	7.2
Sonat	11	6.39	8.7
Transco	8	6.39	7.2

Cost of Capital Derivation

	Dividend Yield 41/	Growth Rate	Cost of Capital
Coastal	1.65	10.7	12.35
Enron	2.95	10.7	13.65
PEC	4.38	7.2	11.58
Sonat	4.51	8.7	13.21
Transco	4.33	7.2	11.53
Midpoint			12.59

40/ 71 FERC, at 62,018 (Table No. 2).

41/ 71 FERC, at 62,018 (Table No. 4).

CASE: UE 215
WITNESS: Steve Storm

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ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

Decoding Developments in Today's Electric Industry — Ten Points in the Prism

Susan F. Tierney, Ph.D.
Analysis Group

Boston, Massachusetts
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Table of Contents

DECODING DEVELOPMENTS IN TODAY'S ELECTRIC INDUSTRY

HIGH ELECTRICITY PRICES, HIGH ANXIETY

Electricity prices have been rising around the U.S. in recent years. Almost no part of the country has been spared. In some regions, rates have gone up gradually over the past decade. In other regions, prices are sharply up over a shorter period of time. Everyone knows about the most famous and painful example: California during the days of the 2000/2001 electricity crisis. But sudden price increases have popped up elsewhere, too — like Maryland and Illinois, and other places where multi-year electricity rate freezes have ended and where electricity consumers have begun to face prices that are no longer sheltered from actual market conditions. Even consumers in traditionally regulated states like Florida, Arkansas, Louisiana and Hawaii experienced relatively large electricity price increases across the past few years.[1] The sudden price increases have put pressure on household and business budgets around the country. This, in turn, has grabbed the attention of the media, provoked politicians, and generally led to finger-pointing and demands for explanations of who or what is to blame.

There's nothing fun about any of this. No consumer likes price increases of any kind, let alone those we feel we can't control and that we figure must be caused by someone else's mischief. There's something especially grating about electricity price increases, it seems. Maybe it's because we bought into Thomas Edison's promise that "I shall make electricity so cheap that only the rich can afford to burn candles." Perhaps it's because our society has such a deep dependency on electricity, not just for basic necessities like light and cooling, but for all of the wonderful devices and gadgets it powers. Maybe it's because electricity is just "invisible": it simply exists very dependably in the sockets in our homes and offices whenever we plug in, and we don't think twice about it (until, of course, the bill arrives).

For most Americans, in fact, electricity is out of sight, out of mind. We know it's there, but there's nothing really to see. Electricity "brings good things to light," and it's the things we see, not the electricity itself. We live our lives and go about our business without making — let alone, understanding — any sort of connection between the light switch, the new gadgets plugged into the socket, and the pressure we put on electricity suppliers to meet our on-the-spot power requirements with near-perfect reliability. The sheer "invisibility" of electricity makes it all the harder to understand why it costs so much. If electricity is already in the wall, why is the price going up? What does your new phone charger have to do with power plants and the price of natural gas?

This isn't to say that consumers are to blame for price increases. They're not. Nor is "the system" to blame, although occasionally we can find some genuine villains along the way. Perhaps some small portion of the blame should be attached to the specific social paradigm in which we accept electricity as just "being there."

The power is there in the wall. We don't really know (or care) where it comes from, as long as it behaves. When it doesn't, we assume that someone somewhere must be doing something wrong, since we didn't. We simply take it for granted that the invisible and wonderful but utterly boring electricity will be there — and that when price increases occur, there must be something wrong in the system that needs to be fixed.

Taking something for granted until prices rise isn't unique to electricity, of course. We don't pay attention to something until it disappoints. It's human nature. When something goes wrong, we assume we can "fix" it, so we try to "do something." This seems true in many markets, but the threshold for our interventionist tendencies seems particularly low where electricity is concerned due in part to its history as a regulated industry. Our traditional regulatory paradigm gives us a predisposition to intervene when the opportunity arises. While the instinct to intervene when prices increase may be an understandable one, it needs to be tempered with a degree of humility about the real opportunities to improve market performance and prices in the face of economic realities. And because we have just undergone a restructuring of the electric industry in many parts of the country,[2] there is a natural inclination to consider the potential link between these changes and the price increases we've been experiencing.

DECODING TODAY'S ELECTRIC PRICES — LOOKING THROUGH A COMPLEX PRISM

So, what *is* happening in the electric industry? And what should — and can — be done about it? There are no satisfyingly simple answers to these questions, but there is some light we can shed on the situation. Let's start with an even "top ten" issues, described in this paper. These ten facets of the prism reveal an industry that continues to provide significant value to the economy and to consumers, even as prices seem to be rising — everywhere.

These facets also suggest that relatively high electricity prices are likely to be the "new normal" in the electric industry, and this is likely to occur for consumers served in regions with vertically integrated electric utilities under cost-based regulation, or in ones relying substantially on markets. This reality stems from fundamental economic forces tied to global markets for fossil fuels and other products, and the need to address other critical economic and social challenges such as continued demand for power, aging infrastructure and global warming. Even so, and presuming a degree of regulatory and policy stability going forward and reliance to a considerable degree on market forces, we can expect private investors to supply capital for the grid, for greater improvements in energy efficiency and in power production facilities. We can look forward to an electric sector producing lower pollution levels than in the past. All of this is good for consumers.

Part of helping consumers realize these benefits will be for government officials to adopt policies giving consumers the tools they need — improved information, pricing signals and service provisions that overcome the "invisibility" inherent in today's electricity system. Many of these, in turn, are aided by competitive elements in the industry that allow for real-time pricing, innovation and a focus on customers. Part of helping consumers is also applying care when adopting "fixes," so that the cure doesn't end up being worse than the disease. For an industry as complex as the electric industry, it seems particularly prudent to allow further evolution in the paths being taken in different parts of the country. This kind of regulatory stability — in the regions with vertically-integrated utilities, and in the regions relying on increasingly robust competitive industry structures — will go a long way to providing the environment that will support our shared goals for an efficient, reliable and environmentally acceptable electricity system.

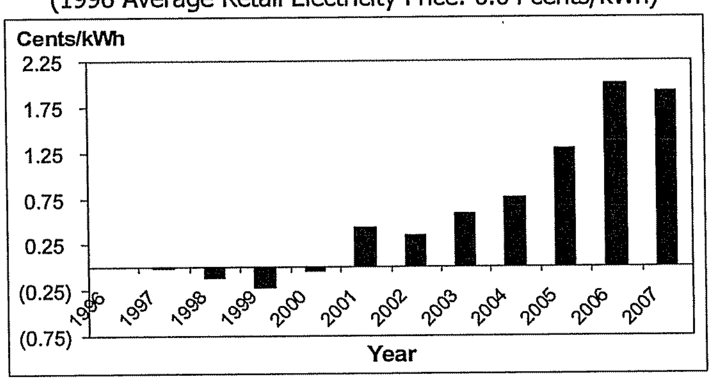
1. "ELECTRICITY IS NOT TOO CHEAP TO METER."

This may seem too obvious to even mention. But just because we now scoff at Lewis Strauss' vision made fifty years ago — that "*our children will enjoy in their homes electrical energy too cheap to meter*"— doesn't mean that we have really embraced today's situation, that electricity is not cheap to produce and deliver to consumers. Consumers still take for granted that they'll get reliable electricity at low rates. And there's hardly a politician around the country who doesn't hold on to the dream of lowering the cost of electricity for their consumers.

This continuing view — that electricity should be cheap, and that there's someone to blame when it's not — is not reality-based. That's not to say that there are never instances where someone is to blame when prices spike; there are. This can occur where a utility takes advantage of its position to benefit its affiliate or to shift cost overruns on to consumers; or where a power plant owner or power trader actually manipulates electricity markets. But it is another thing altogether to presume that high prices equate to market manipulation or the exercise of market power.

Like energy prices in general, electricity prices seem high. With prices at around 6.6 cents per kilowatt-hour ("kWh") in 1996, the average American has seen prices go up approximately a third over the past decade (although there were decreases in prices during the late 1990s). (See Figure 1.)

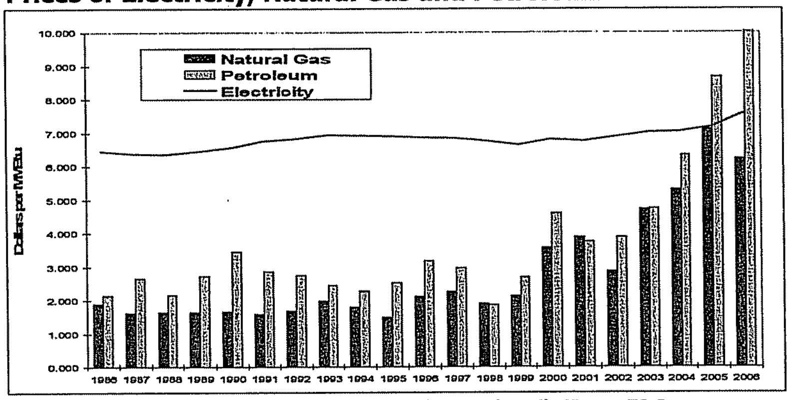
Figure 1
U.S. Retail Electricity Prices:
Difference in Average Annual Electricity Prices Relative to Prices in 1996
(1996 Average Retail Electricity Price: 6.64 cents/kWh)



Source: U.S. Energy Information Administration ("EIA"), with prices through April 2007[3]

Electricity prices have been rising for several reasons. First, the price of the fuels used to produce power has climbed in recent years. The single most expensive part of the electrical bill is tied to power production costs including purchased fuel. Fossil fuels — used to produce just over 70 percent of the nation's power[4] — have experienced significant price increases in the past few years after a period of comparative calm during the 1990s. The most dramatic increases have been for natural gas and petroleum (see Figure 2) which account for approximately one-fifth of the nation's power generation. Electricity prices tend to track changes in fossil fuel prices over time, with prices beginning to rise starting around 2000.[5]

Figure 2
Prices of Electricity, Natural Gas and Petroleum — 1987-2006



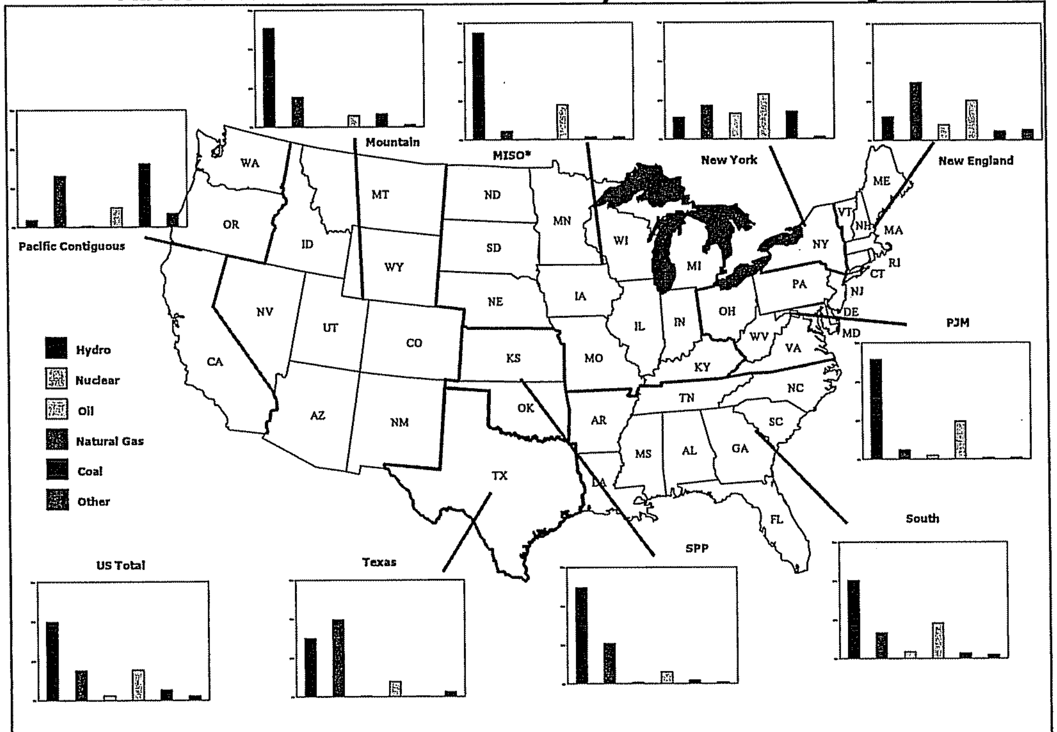
Source: EIA, Electric Power Annual, 2005 (2006), Figure ES-3.

Most Americans understand that oil prices are high, because gasoline prices are so visible at the pump. While not much oil is consumed to produce power, oil is still often used to produce power during peak demand periods and thus tends to influence electricity prices at certain times of year. More importantly for electricity, after a decade of relative calm prices for natural gas during the 1990s, natural gas prices shot up starting in late 1999, as the markets tightened in North America. While natural gas prices spiked following the Hurricanes of 2005, they have dropped since then, although they remain relatively high. Even coal — the lowest-cost fossil fuel, and the fuel used to produce over half of the power generated in the U.S. — has experienced 40-percent price increases since 2000.[6]

Of course, these fuel-cost-related impacts on electricity prices vary dramatically across the country because of sharp regional differences in the fuels used to generate power. As shown in Figure 3 (which indicates each region's reliance on different fuels to produce electricity), some regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices (as shown in Figure 4). States in parts of the country (such as the South, the Mountain states, and the Midwest) that produce more than 50 percent of their power from coal have among the lowest electricity rates in the country. Of the 30 states with rates below the average state electricity rate in 2006 (as shown in Figure 4), 26 of them were from these regions with a high percentage of power produced by coal.

Besides fossil fuel price increases, other important factors have also contributed to high electricity prices. For example, the nation's electric system is growing, and new investment has been required to keep the lights on. Peak electrical demand in the U.S. grew nearly 12 percent from 2000 to summer of 2007 (an increase of approximately 80,000 MW).[7] To put that in context, Texas' peak demand in the summer of 2006 was over 62,339 MW,[8] so from 2000 to 2007, the U.S. added more than a Texas-sized amount of new demand. During that same time period, more than 210,000 MW of new power production capacity was put into operation, which is roughly equivalent to the addition of one large power plant a week over the entire period.[9] Using a conservative, back-of-the-envelope estimate of capital costs, this represents an investment of roughly $99 billion.[10]

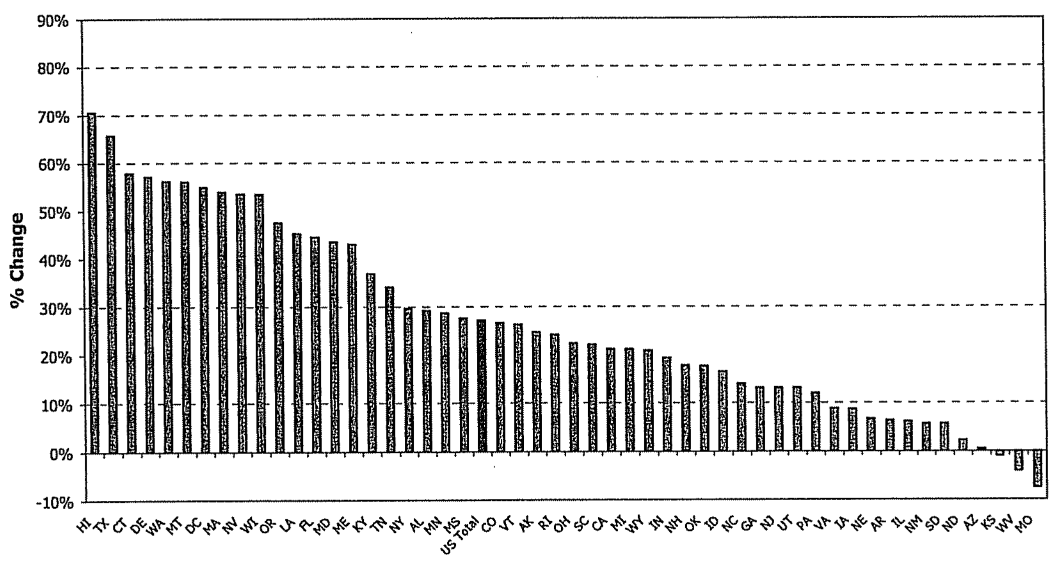
Figure 3
Mix of Fuel Used to Generate Electricity in Different U.S. Regions



Source: EIA.
*Note: MISO contains SD, NE, MO and KY.

Figure 4

Percent Change in Average Electricity Prices Across All States 1995 - 2007



Source: EIA.
Note: 2007 data repesents the annual average for 2007, using data from January through April.

In addition, power plants in many regions (e.g., California, Texas, and the Northeast/ Mid-Atlantic states) have had to install air-pollution control equipment and use cleaner (and more expensive) fuels in the past decade to address various clean-air requirements. The electric power sector spent more than $21 billion to come into compliance with air- and water-pollution laws from 2002 through 2005[11] and these costs have already begun to show up in electricity prices in these regions.

Investment in the power grid to deliver electricity from power plants to end users is up as well, after many years during which investment in power lines had been declining. Over 2,500 circuit miles of high voltage transmission lines were added in 2005 alone — equivalent to the length of a new line stretching most of the way across the U.S.[12] Utilities' annual investment in transmission and distribution systems amounted to approximately $24.2 billion in 2006, up from $10.4 billion in 1995.[13]

Further, cost of construction materials is up — sharply. Recent reports indicate significant cost increases in the materials and components associated with power projects, after a decline in such costs for decades.[14] "Prices for iron and steel, cement, and concrete — commodities used heavily in the construction of new energy projects — rose sharply from 2004 to 2006.... [I]ron and steel prices have increased by 9 percent from 2002 to 2003, 9 percent from 2003 to 2004, and 31 percent from 2004 to 2005."[15] Growing demand in other global markets, including China, exacerbates these conditions.

The indications are that the price effects of these combined factors are not likely to abate any time soon.[16] Investment requirements are also expected to remain high. The U.S. government estimates that 258,000 MW of new capacity is needed between 2006 and 2030, equivalent to four new "Texan" size electrical additions and a total investment of $412 billion (2005 dollars) — or even higher, if today's high construction-related cost increases continue.[17] These estimates may overstate investment requirements if Americans spend more on energy efficiency technologies than in the past, but in any case, future costs for electricity supply (and demand reduction) loom large. Further, grid operators see significant new investment requirements to expand and upgrade regional power service.[18] Installing more advanced metering technologies to enable consumers to see — and better manage — their electrical use would be in addition to those other costs.

Meeting existing clean-air regulations affecting power plants will cost the industry an additional $2.7 billion a year in 2010, and $4.4 billion in 2015, according to federal regulators.[19] Consumers in states relying on significant amounts of coal-fired generation will be most affected by these costs. Also, any costs related to the adoption of new laws to regulate greenhouse gas emissions from the power sector in the future will further affect cost of production at such plants. Some states (e.g., the Northeast and California) have already adopted caps on carbon emissions from power plants, and it appears increasingly likely that Congress will adopt a national program before too long. Estimates of such costs vary considerably, in part because of the uncertainty about what eventual carbon-control programs and laws will look like. For example, one study that modeled the impact of a national carbon policy imposing a price of $10/ton of CO_2 suggests increases in electricity rates in the Midwest and South would be approximately twice the size of such increases in New England and New York, in large part due to the Midwest's and the South's higher dependence on coal-fired generation. Even so, estimated electricity prices would still likely be lower in the South and Midwest than in New England and New York even taking these carbon-control-costs into account.[20]

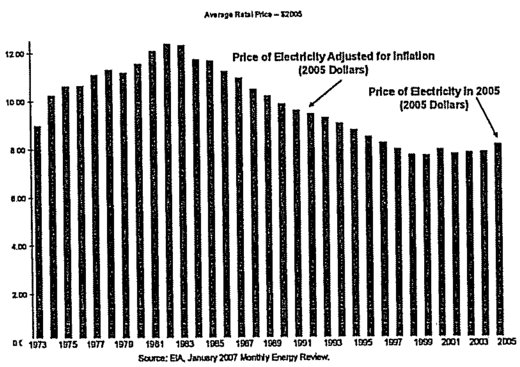
In light of the realities of these costs — and the continuing growth in demand for electricity by Americans — it is simply unrealistic to expect that electricity prices are going to drop any time soon. Electricity is not cheap to produce, transmit and deliver, and electricity prices are not likely to decline materially in upcoming years — for a variety of legitimate reasons.

2. ALTHOUGH PRICES ARE RISING, ELECTRICITY STILL PROVIDES HIGH VALUE.

Compared to many other goods and services we depend upon in our daily lives, electricity remains a relative bargain. First, even though electricity prices have increased since 2000, inflation-adjusted electricity prices are still only about 2/3rd of what they were at their highest in the early 1980s. (See Figures 5.a and 5.b, below.) In those terms, electricity prices in 2000 were at their lowest point in over 20 years. Similarly, as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than what we spent during the 1980s. (See Figure 6.)

Figure 5
Average All-In Retail Price of Electricity (Including Fuel Costs), 1973-2005

Price of Electricity (adjusted for inflation)
Figure 5.a



Price of Electricity (real dollars)
Figure 5.b

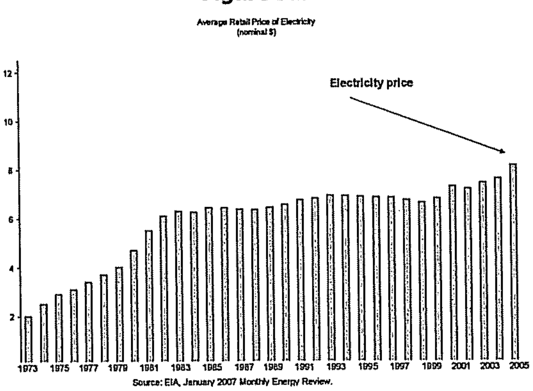
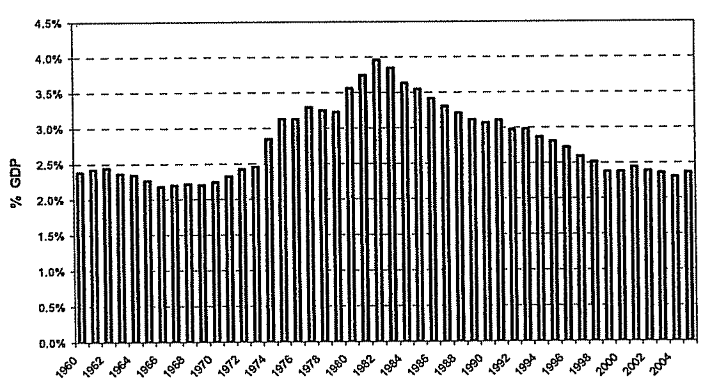


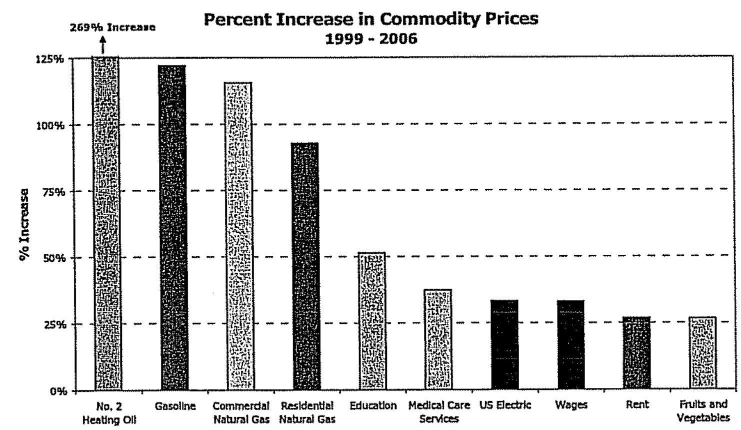
Figure 6

Total Retail Expenditure on Electricity as a Percent of U.S. GDP
1960-2005



In spite of recent increases, electricity prices have risen more slowly than those for other goods and services, as shown in Figure 7. Among different types of energy purchased by consumers from 1999 through 2006, electricity price increases were lower (33 percent) than those for heating oil (269 percent), gasoline (122 percent), and natural gas delivered to commercial users (116 percent) and to homes (93 percent). During the same time frame, educational expenses rose 52 percent, while medical care expenses increased 37 percent. Electricity prices rose at about the same rate as wages (33 percent), and only slightly higher than other expenses (e.g., rent, fruits/vegetables).

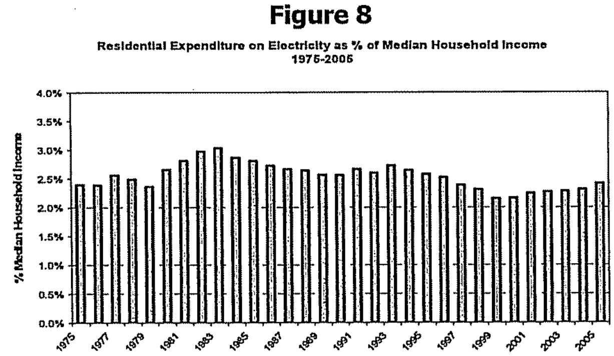
Figure 7



Sources: Electric, oil and natural gas data from EIA, all other data from BLS.
Notes: All prices are annual averages of monthly data except for wages, which are reported annually. No. 2 Heating Oil represents the New York

Again, to put electricity price increases in context, household electricity expenses as a percentage of household median income are no higher now than they were a decade ago (Figure 8), yet the average American is using much more electricity than in the past (as shown in Figure 9, which indicates that the average household's electricity use per hour has increased 25 percent in the past quarter century).[21]

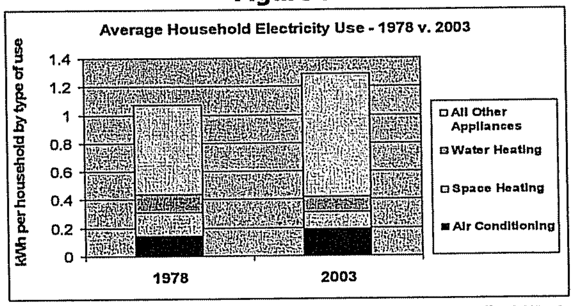
Figure 8



Source: EIA, Annual Energy Review 2005, Tables 8.9 and 8.10; U.S. Census Bureau, Current Population Survey, Historical Income Tables,

These trends in increasing use of electricity are hardly surprising, given the significant increase in electronic consumer products and in the many technologies and tools in our offices, shops and factories that depend on reliable electricity supplies. We tend to forget that every cell phone charger, every computer, and every air conditioner adds to our reliance on electricity. Overall, our standard of living depends on the invisible energy source that's delivered to the socket.

Figure 9



Source: Basheda et. al., "Why are Electricity Prices Increasing?" 2007, Appendix A.

3. ELECTRICITY PRICES SEEM TO BE RISING EVERYWHERE, AND IT'S TOO SIMPLE TO ASSIGN THE PRICE INCREASES TO EITHER "REGULATION" OR "COMPETITION."

While electricity prices have risen all around the country, some regions' price increases have been higher and more volatile than others. One factor — a region's dependence on coal to produce power — was mentioned previously as important in regions experiencing lower prices and smaller price increases.

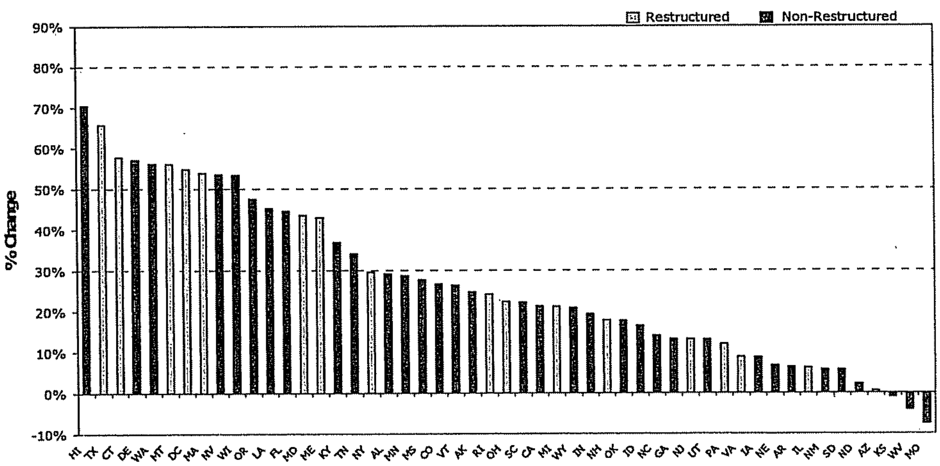
One nagging question, though, is whether there is something else to blame — that is, whether the steps taken to introduce competition into the industry over the past decade have rendered it more susceptible to price increases. Some states took steps to restructure their electric industries, allowing companies other than electric utilities to provide power to consumers, giving non-utility generators the opportunity to buy utility power plants, opening up the power sector for greater competition and investment, moving to market mechanisms (rather than regulators' oversight of utilities' cost-based investments) as the means to set electricity prices, and so forth. Many regions — including restructured and non-restructured states — developed Regional Transmission Organizations ("RTOs") to independently operate the grid and to administer bid-based centralized wholesale power markets, using them to determine efficient dispatch as well as market-clearing prices. In a general sense, many of these trends to restructure the electric industry occurred in parallel with the electricity price increases experienced in some parts of the country, so the question is whether these structural changes caused — rather than accompanied — the recent price increases.[22]

To be clear, though, price increases have occurred in both states that restructured and states that did not. Figure 10 reports the percentage change in rates in the various states from 1995 through April 2007. The period spans the years between when many states began to consider implementing changes in the industry, on the one hand, and when they ended their "rate freezes" that were adopted as part of the restructuring changes, on the other.[23] (States that restructured are light blue while those retaining a traditional industry structure are dark green.) Over this period, average retail prices in states that restructured their electric industries rose only slightly higher than rates in the states that retained traditional regulation.[24]

Figure 11 shows slightly different information, comparing the rates in different states according to whether their companies principally joined an RTO, or not. The comparison period spans from the beginning of 1995 — around the time when industry participants in many regions began to explore establishing an RTO — to those in April 2007.[25] Here, states with utilities that are members of organized wholesale power markets administered by RTOs are in light blue, while those states not principally served by an RTO market are in dark green. These figures show that states with restructured electric industries — whether in states that adopted retail choice or states whose utilities joined RTOS — are spread fairly evenly throughout the distribution of all states, some with high price increases and others with lower price impacts since 1995.

Figure 10

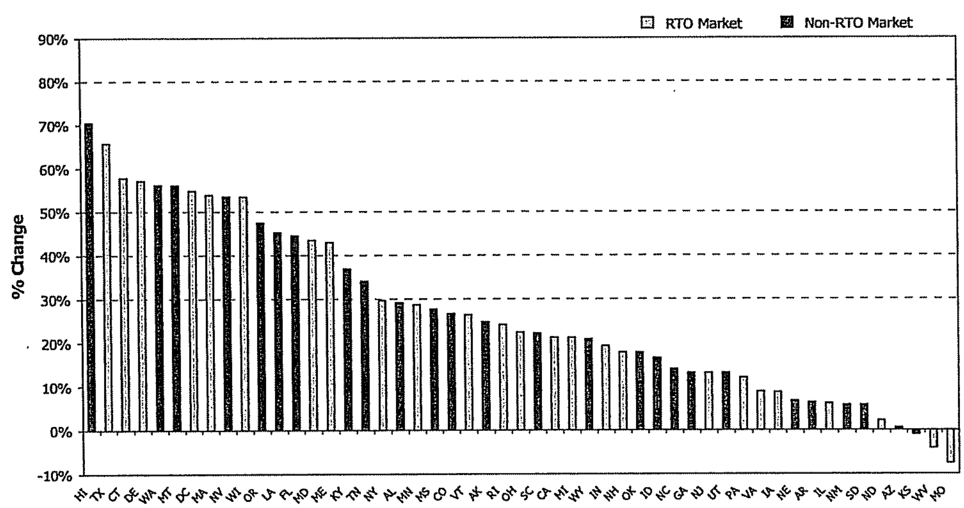
Percent Change in Average Electricity Prices Restructured and Non-Restructured States 1995 - 2007



Source: EIA.

Figure 11

Percent Change in Average Electricity Prices RTO Market and Non-RTO Market States 1995 - 2007



Source: EIA.

Both Figures 10 and 11 show several themes. First, changes in states' electricity prices are all over the map, with average price increases from 1995 to early 2007 as high as 71 percent (in Hawaii, a state that did not restructure its electric industry), to as low as -8 percent (in Missouri — a state served by an RTO market, but that also did not restructure its electric industry to allow for retail choice). Figures 10 and 11 also suggest that "restructuring" has not had an easily discernable and consistent impact on prices across the various states. Rather, the differences in retail prices relate to a number of differences across states and regions, including — along with restructuring status and wholesale market design — such things as the availability of unique resources for generating power (e.g., hydro in the Pacific Northwest); regional differences in fuel costs (largely due to power generation mix and fuel transportation costs, as shown in Figure 3); the types of customers served; the size (or scale) of utilities; economic growth rates, and the need for new generation and transmission investment; the strictness of environmental requirements; a variety of differences in state-level regulations; taxes; and labor and materials costs.[26]

It is fairly well understood that for the most part, the states that pursued early efforts to restructure their electric industries were ones that already had high electricity prices during the 1990s. These were states where at the time, a number of features — rate increases associated with new power plant investment, cost overruns, expensive long-term contracts, combined with opportunities to build new generating capacity at costs lower than prevailing electricity prices — motivated large electricity consumers (and their political representatives) to complain about utilities' high price levels under traditional regulation and seek the option to buy power from the electricity supplier of their choice.

Fifteen of the 17 states that now[27] have higher-than-average retail electricity rates were also among the 19 states with higher-than-average rates on the eve of restructuring the electric industry in 1996.[28] Almost all of the high-priced states[29] in 1996 went on to restructure their industries during the 1990s, and several others[30] did so as well.

Notably, in 1995 the states that eventually restructured had electricity rates that were 22 percent higher (on average) than the other states (and 24 percent higher in 1997, on the eve of many restructuring laws);[31] by 2006, this gap had narrowed to 20 percent higher (having been as low as 12 percent higher in 2000, near the start of natural gas price increases).[32] Stated another way, electricity prices were higher in restructured states than in non-restructured states in 1995, but are less so in 2006. In fact, an important factor motivating states to implement restructuring were the high prices that prevailed during the 1990s and the potential for restructuring to achieve reductions in such rates relative to what they otherwise would have been.

4. DESPITE SOME NEW COSTS AND SLOW DEVELOPMENT OF RETAIL COMPETITION (EXCEPT FOR LARGE CUSTOMERS), RESTRUCTURED MARKETS HAVE PROVIDED MEASURABLE BENEFITS.

There were many motivations at the roots of past efforts to introduce competition into the electric industry: desires to produce and deliver power more efficiently; intentions to reduce the influence of utilities' preferences for investments that expanded rate-base even when such investments failed to provide commensurate consumer benefits; hopes to bring about innovation and improvements in risk management; and the goal of allowing consumers to make choices about their power suppliers. While many surely wanted "lower prices" and many promised this would be the result of restructuring, economists have reminded us that this was in effect a goal of having prices lower than they would otherwise be under traditional regulation. To date, some of these benefits have transpired; others have been less successful.[33]

Across the country in states that have allowed customers to choose their retail supplier of power, many large, sophisticated electricity customers including universities, factories, large and small department stores, and others, have opted to manage their own power supplies — determining their supplier, managing their demand, and hedging their price risks.[34] For the most part, even these actions have not prevented such customers from feeling the effect of the overall rise in the price of electricity and of the underlying fuels used to generate it, nor could they have avoided it under rate regulation. But it has enabled them to realize savings relative to what their prices would have been, had they continued to buy power from the utility. By contrast, small residential customers has been far less successful, when measured by the statistics showing that few small residential customers have chosen, or even had a feasible option, to buy power from a competitive retail supplier.[35] A major contributing factor to this slow development has been rate freezes and price caps implemented in many states as part of the restructuring plans which have shielded small customers from price increases for many years.

Many of the nation's power plants are now much more efficient than in the past. Just as in any competitive market, the opportunity to profit by producing at a cost below market prices — and to increase output through productivity gains — has created incentives for producers to undertake needed investments and improvements in operating practices to achieve such cost savings.[36] Plant divestiture combined with competitive conditions has led to operational improvements in existing plants that in one way or another have reduced their operating costs.[37] These improvements include: increases in the efficiency of fuel-consumption (i.e., heat rates) of fossil fuel-fired facilities;[38] decreases in the length of refueling outages, lower operations and maintenance expenses, and greater plant availability at nuclear facilities;[39] and decreases in labor and other non-fuel operations and maintenance costs across all facilities.[40] Improvements that increase plant availability are particularly valuable because they increase the quantity of power produced by less-costly power facilities. The cost savings from such increases in plant availability — as measured by the difference between the cost of facilities with improved availability and the most expensive generation that does not need to be dispatched — has been estimated by a number of studies.[41]

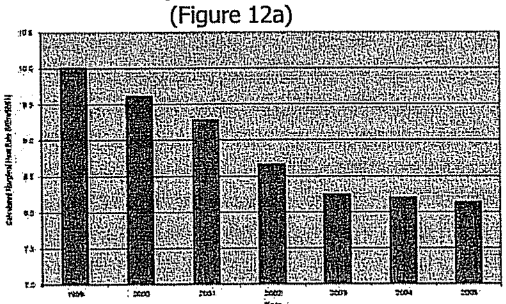
Another benefit of restructured markets is that they have improved the efficiency by which plants are "dispatched" (i.e., turned on and off) to meet consumer demand. In principal, all grid operators, whether operating in markets administered by RTO/ISOs or in a particular utility's "control area," attempt to dispatch the least-costly plants to meet consumer load. Restructuring has increased the efficiency of these decisions in a number of ways. It has facilitated the increased "geography" of dispatch decisions, which allows costs to decline by using lower-cost resources in one region to displace higher-cost power resources in another.[42] One study of geographic consolidation in New York which also examined the impact of reduced outage rates for nuclear and fossil fuel units, found benefits of between $100 and $200 million per year, which is roughly 5 percent of the system-wide production and fixed operation and maintenance costs.[43] Second, certain long-standing barriers to efficient trade across regions (e.g., "pancaked" layers of transmission rates needed to transport power across multiple regions) have been reduced or eliminated, helping to reduce the overall costs to supply power. Another study of the benefits of the recent expansion of

PJM to include the three Midwest utilities (AEP, ComEd, and DPL) found annual benefits of about $70 million in PJM and about $85 million when including regions outside of PJM.[44]

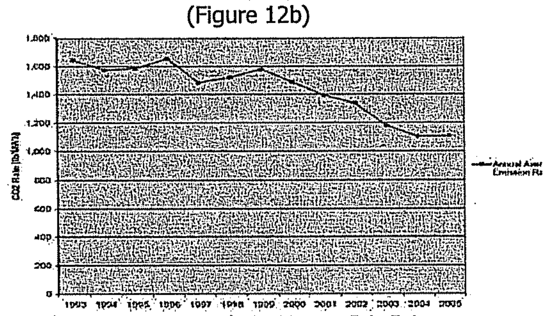
Other benefits have been attributed to improvements in wholesale electricity markets. Adding newer more efficient power production technology and dispatching the system more efficiently has led to reductions in air emissions from power plants in some competitive electric markets, as noted in studies of New England.[45] There, the region increased its power plant capacity by more than 40 percent (i.e., by nearly 9,800 MW) over the period from 1999 through 2005, with corresponding improvements in heat rates (with lower heat rate reflecting less fuel used to produce power) and overall emissions of carbon dioxide (as shown in Figures 12a and 12b, below).

Figure 12
Recent Improvements in Power Plant Efficiency & Emissions: New England Example

Heat Rate (MBtu per MWh) '99-'05
(Figure 12a)



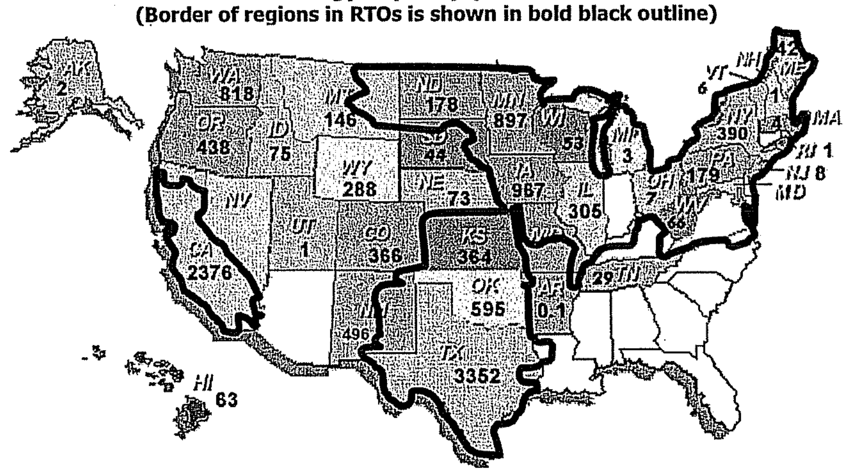
Emissions of CO2 (lb. per MWh) '93-'05
(Figure 12b)



Source: ISO-NE (2007), 2005 New England Marginal Emission Rate Analysis, Figures 5.1, 5.4.
Figures show the historically calculated heat rates and CO2 emissions of the marginal generator in all hours of the year.

In the past decade, renewable power resources (like wind projects) have been added principally in parts of the country served by RTO-administered markets, in large part because of the much-more-favorable transmission policies that enable suppliers to obtain delivery capacity, the visibility of prices by location and time of day, and the ability to sell into spot markets and/or multiple buyers. (See Figure 13.)

Figure 13:
Total Installed U.S. Wind Energy Capacity (MW in each state as of June 2007
(Border of regions in RTOs is shown in bold black outline)



Source: http://www.awea.org/utility/wind_overview.html (total wind capacity = 12,634 MW as of June 30, 2007)
http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp (RTOs as of September 2007)

Another way that competitive power markets have led to innovation, efficiencies, environmental benefits, and reliable power supply is through "demand response." For example, on August 8th, 2007, retail customers in the PJM region voluntarily reduced their demand by 1,945 MW (roughly equivalent in size to two large nuclear power plants) in response to real-time price signals in PJM's wholesale market; these customers were participants in PJM's "demand response" program which allows these customers to be paid the same amount for reducing demand for electricity as generators are paid for supplying electricity.[46] Had these customers not provided power to PJM, other more expensive power supplies would have had to be dispatched, or PJM might have had to resort to involuntary disruptions of service to customers. PJM's wholesale market, like those in other regions like New England, New York, the Midwest ISO region, and California, provides the type of wholesale price transparency that enables such customer-response programs to operate. Further improvements in retail price transparency (allowing many customers to see prices as they change over time at different times of day), would further enhance these efficiency gains. The benefits associated with price transparency, improved access to transmission, and other effects have been identified, although (for many important technical reasons) it is exceedingly difficult to quantify these effects with precision.[47]

Of course, these benefits have been accompanied by incremental administrative costs incurred to start up RTOs and the markets they administer. These costs have ranged from $55 million for New England, to $137 million and $140 million for Texas and for PJM, respectively.[48] Recent indications are that as RTOs mature, their administrative costs have seemed to level off.[49] PJM, for example, the largest market, has recently begun to provide service under tariffs that involve commitments not to increase RTO administrative costs. Notably, one of the activities supported in these administrative costs at RTOs is a type of highly visible and active market monitoring function. Such functions are much more difficult to implement in bilateral markets (and therefore tend not to exist in the same way) without the kind of price transparency existing in RTO-administered markets.[50]

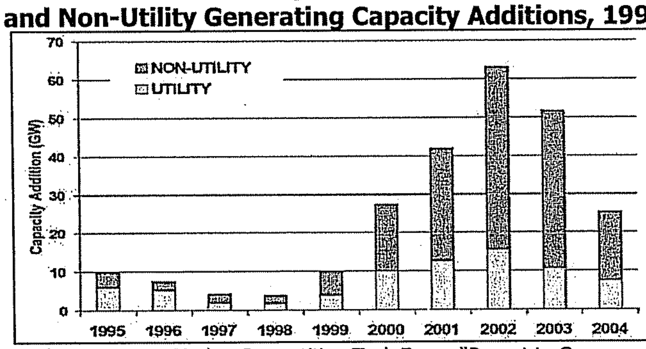
5. CONSUMERS AND SUPPLIERS HAVE BOTH SEEN BENEFITS.

Anyone who has studied the question of "who benefits" as a result of the introduction of competition in the electric industry over the past decades finds the technical and conceptual challenges daunting, to say the least. For example, a federal task force established by the Energy Policy Act of 2005 to "conduct a study and analysis of competition within the wholesale and retail market for electric energy in the United States"[51] avoids drawing bottom-line conclusions on this particular question,[52] in no small part due to the technical difficulties in doing so. As hard as it is to estimate "societal" benefits and costs associated with restructuring the electric industry, it is still more difficult to determine how (and whether) the net benefits of such reforms are shared across different parties — consumers, suppliers, investors, utilities, and so forth.

Clearly, many large sophisticated consumers of power who now arrange for their own electricity supplies have found it beneficial to have that option, even if they do not like the fact that electricity prices have increased in recent years. Anecdotal evidence suggests significant benefits to large, sophisticated electricity customers (like universities and other educational institutions, hospitals, hotels, factories, food stores, commercial office buildings, large retail chains), helping them control their costs and the prices of goods and services they provide to their own customers.[53]

Consumers have benefited from changes in the industry that have imposed greater risks on investors than was the case under traditional cost-based rate regulation. As shown in Figure 14, the vast majority of investment in generating units over the decade since 1995 has been made by non-utility entities,[54] with investors bearing risks of cost overruns and surplus capacity. Competitive market structures typically provide no assurances about future prices for power generated, so owners of such generating facilities are at risk to recover a return of and on their investment through competitive markets. This contrasts sharply with investment patterns in the prior decades, when most of the capacity additions were made by regulated electric utilities.[55] While utilities had to demonstrate that their investments were prudent, once such approvals were in hand, consumers have tended to repay for such investment costs, without regard to power plant operational performance.[56]

Figure 14
Utility and Non-Utility Generating Capacity Additions, 1995-2004



Source: Electric Energy Market Competition Task Force, "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy, Pursuant to Section 1815 of the Energy Policy Act of 2005," page 35, using FERC analysis of Platts PowerDat data.

As a result of these changes, for the most part, consumers have not borne the financial burden of the industry's over-supply of generating capacity that existed in many parts of the U.S. after the massive infusion of new generating capacity additions since 2000; investors have borne the cost of this surplus investment.[57] As noted previously, a rough, conservative estimate of the capital costs of the capacity added during 2000 through 2005 is $99 billion.

Clearly, some investors have done well under competition, while others have not. For example, a number of competitive power suppliers that have investments in low-cost power production facilities in RTO-administered markets (e.g., PJM, NYISO, ISO-NE, Texas) have seen significant returns in recent years, as high natural gas prices have driven up the prices in (and therefore the revenues for sales into) these wholesale spot markets. Much of this capacity — older and relatively efficient nuclear power plants, coal-fired power plants, and hydroelectric facilities — was acquired by investors during the utility divestitures and/or asset spin-offs that occurred over the past decade as part of restructuring plans. As such, these assets are not a part of the utility rate base where investment costs are recovered in regulated retail rates. Rather, revenues in markets are necessary to cover investment, operating and maintenance, fuel purchases and all other costs for such plants. While information on shareholder profits tied to individual power plants in competitive markets tends not to be publicly available, one study of profits earned by companies owning unregulated generating capacity in PJM indicated that returns have been higher than companies that remained entirely regulated.[58] Many of these companies are embarking on major capital investment programs for energy facilities.

Many investors in some regional markets — notably the Northeast — have also experienced relatively lean periods, as surplus capacity conditions and high fuel prices led to lower-than-anticipated utilization and poor financial performance for many new plants. Many of the competitive power generators operating in restructured markets were forced into bankruptcy after 2000, and others had speculative credit ratings for a number of years before restructuring their businesses more recently.[59] As market conditions have improved, some of these companies have reemerged from bankruptcy and restored some of their market value.[60]

So clearly, as in all markets, some investors have done well, and others less well. Some companies went through distressing periods, and disappeared altogether. In most regions — with the possible exception of California during the 2000-2001 electricity crisis — consumers were shielded from the effects of bankruptcies as power plants were required to remain operating even during periods of non-payment and bankruptcy to provide power supplies to homes, offices, hospitals, schools, and factories.

6. IT'S NOT HARMFUL TO CONSUMERS TO HAVE INVESTORS SEEKING ADEQUATE RETURNS IN THE ELECTRIC INDUSTRY. IT'S HOW THIS EXTREMELY CAPITAL-INTENSIVE INDUSTRY FINDS NECESSARY RESOURCES FOR RELIABILITY.

In the U.S. most — although not all — electricity is supplied by shareholder-owned companies. This means that a substantial portion of this extremely capital-intensive industry is supported by private investors. Stated otherwise, consumers around the country depend on the active interest and financial motivations of private investors. It is not a bad thing for electricity consumers, therefore, that investors find favorable returns in the electric industry. Given the future capital requirements needed in the electric industry, this will continue to be an important element of assuring reliable supplies of power in the future.

While 80 percent of generating capacity is owned by investor-owned companies — whether by utilities (40 percent) or by non-utility generators (40 percent) — not all of the power supplied in the US comes from privately owned companies. As an imprecise estimate, if 80 percent of the new electric investment required in upcoming years — whether for power plants, transmission lines, distribution systems, energy efficiency measures, other green technologies and pollution control equipment, advanced metering systems — were to come from private investors, this could amount to several hundred billion dollars, give or take many millions.[61] Needless to say, this is a capital intensive industry. For the U.S. electric industry to attract those kinds of investment dollars in future years — and for American consumers to get the value of the power supplied through those new investments — it will be extremely important to offer attractive returns. This will be essential, whether a particular region adopts a competitive or a regulated industry model.

7. NEITHER REGULATION NOR COMPETITION IS PERFECT. HOWEVER, LONG-TERM CAPITAL INVESTMENT WILL BE ATTRACTED TO PLACES WHERE THERE IS A STABLE REGULATORY FRAMEWORK.

Everyone who pays attention to issues in the electric industry has a running list of problems they've come across over the years. In recent years, in spite of the differences among the lists, many of them seem to have one thing in common: Either implicitly or explicitly, they tend to compare the industry as it exists in a real time and place with some idealized notion of what things would be like "if only" one or another thing occurred. These "if only" worlds tend to be idealized versions of realities the list-maker would like to see.

In the mid-1990s, when regulated prices seemed high and out of control, many observers envisioned what prices might be like in an idealized version of a market place. The idea was to tame costs and send better incentives for risk and reward through introduction of market forces into the electric industry. In many places — especially the ones with highest rates — the industry was restructured, with the changes accomplished through a myriad of compromises that seemed practical and necessary at the time but ended up with a variety of shortcomings in hindsight. The results are somewhat less than the idealized competitive outcomes that were imagined a decade ago, and have led to hybrid "market" designs in many places that fall somewhere between regulation and competition. While certainly some markets have developed more quickly and better reflect these idealized competitive outcomes than others, as a nation we learned that in some regions at least, the bargains and compromises produced some outcomes we never envisioned and clearly haven't liked.

Now, frustrated with today's high electricity rates in those regions, many people question whether the right road was taken and what reforms are now needed to bring things back on track. Some suggest a return to what they view as a more protective set of arrangements they associate with regulation of the past. With this in mind, however, it is worthwhile remembering that the efforts to restructure the industry a decade ago stemmed from desires to protect consumers from absorbing so much of utilities' investment risk.

Traditional regulation has had its notorious problems, just as today's version of competition has its own. Many scholars and industry experts have studied these issues, and most tend to conclude that we should remember that "in the good old days," we did not have perfect regulation any more than we have perfect competition today.[62] Today's debates that critique the imperfections of one approach or another could benefit from reminders that neither is ever as perfect as we imagine when we're comparing the realities we know with the "if only" reforms we're championing.

One of the challenges in this particular industry is that — for better or for worse — it is neither a pure monopoly, warranting regulation of all aspects of the industry, nor is it a pure market, allowing the full unleashing of market forces. Notably, even if it can be helpful to rely on market forces when we think it's useful, we can't seem to help ourselves from trying to fix things (like high prices) when they occur. This situation poses a fundamental challenge for the industry, allowing us to remain somewhere between a product with many commodity-like features and yet retaining a special character that causes politicians to want to intervene when markets are behaving in ways we find uncomfortable.

In light of this, a useful foundation for constructive discussions in this industry is the notion that neither regulation nor competition is perfect. This provides a basis for a reality-based dialogue — one that gravitates towards finding improvements in industry approaches in place in different regions (as described in the next section), rather than attempts to throw out the current industry model in hopes that the alternative will be something better. This will support the kind of stable regulatory environments that investors find attractive.

8. MARKET DESIGN ACTUALLY MATTERS, AND IS STILL EVOLVING.

While today's electricity markets are neither perfect nor fundamentally flawed,[63] there are still important elements of market design that would improve their performance. While the issues vary from region to region, and across retail and wholesale markets, there is hardly a regulator, a market administrator, a market participant, or an academic scholar familiar with wholesale and retail power markets in the U.S. who doesn't have ideas of how to improve their performance. FERC has many of these improvements actively on its radar screens.[64] And in states that have not aggressively restructured their electric industry, consumers would likely benefit from the introduction of greater competitive processes.

In regions with organized wholesale markets, for example, the suggested improvements differ by region, but there are some common themes. These include: [65] implementing clear capacity obligations and forward capacity markets (and/or allowing energy prices to reflect the "value of lost load"); further refining and deepening the demand-response side of the market; improving long-term regional transmission planning; allowing long-term financial transmission rights; improving specific ancillary service markets; establishing more precise and consistent definitions of what constitutes workably competitive markets, and sharing best practices for monitoring and mitigating markets consistent with those definitions; improving various "seams" issues at the borders of markets; allowing long-term contracting in ways that align well with organized market design; assuring greater information sharing; improving price signals to retail consumers so that many fewer see average prices in all hours; and better managing the costs to administer wholesale markets.

In regions with regulated vertically integrated utilities, improvements to wholesale markets tend to include: adopting better (e.g., more rigorous, disciplined and independently overseen) competitive resource solicitations to assure least-cost supply additions; assuring non-discriminatory access to transmission; improving regional transmission planning; designing more transparency in the price terms of bilateral contracts; using locational pricing as a tool for planning or for encouraging greater demand response, even if not an element of market structure *per se*; developing long-term transmission rights; developing more sophisticated means to hedge price risks; adopting regulatory policies that align utilities' financial incentives with adoption of cost-effective energy efficiency measures; and vigorous regulatory pursuit of instances of manipulation of prices in energy trading markets.

FERC and many states have had a number of these issues on their agendas for some time. There is strong support, for example, for ensuring that strong market oversight is needed in all regions, to build confidence that markets are functioning — whether organized or bilateral. There is strong agreement that it would be useful to encourage the development of more sophisticated financial markets to allow market participants to better hedge price risks — as has occurred in other energy markets. There are suggestions that FERC should use its rate authority over transmission so that all users of transmission in interstate commerce should pay the FERC-approved rates for transmission, regardless of whether transmission and electricity sales are bundled or not.[66]

Some industry observers are looking for much-more far-reaching changes, especially in state forums. Ever since electricity prices began to rise more visibly a few years ago, some "to do" lists include changes that *turn* or *reverse* direction, rather than make incremental changes. There are those in some restructured states that want to go back to traditional regulation, or to insert elements familiar to the regulated model into the state's industry structure. Some of these changes are certainly possible. Some of the changes being proposed are not sensible, however, because they risk creating an inconsistent set of messages to market participants about market rules and regulations, with the result of undermining the benefits of market forces and unduly shifting risk to consumers. While it is likely that all regions will retain some degree of hybrid forms, some combinations of pieces work together while others do not.

Stepping back from the detail of changes recommended in one place or another, it is useful to recall the "law of the instrument." Hammers are useful for solving some problems, but not others. We know from all sorts of examples in our daily lives, we can sometimes make things worse when we use the wrong tool or part to fix a problem. We may have in mind a regulatory remedy to try to fix a market design, but sometimes the details of how well the "fix" fits with other aspects of the market matter in terms of whether we'll end up with something better than we started. Just because you have some Toyota auto parts lying around doesn't mean that they'll work if you install them in the Prius. In the electric industry with its technical complexity, it's hard to adopt things that make things better, and unfortunately, it's often easier to make things worse.

The point is that in this industry, deciding whether a proposed remedy "fits" is sometimes just as important a decision as whether to do something at all. Policy makers should take care to look for regulatory stability and to choose their policy instruments with care. This admonition applies equally to states that have or have not adopted competitive industry structures.

States that have retained their traditional vertically integrated industry structures, for example, would be wise to adopt policies that afford their consumers the benefits of market forces. An illustration of this would be to adopt well-designed and disciplined competitive procurement processes that bind the utilities' plans and proposals to the same regulatory requirements as those to which third-party suppliers are held. Utilities are typically required to use competitive procurements for a wide variety of services (including contracting for goods and services), but typically are not required by regulators to submit binding bids covering the price and other terms at which they propose to supply new generating resources in the future. Doing so could introduce the discipline required of others when they submit their bids, and would protect consumers from cost overruns that often accompany large-scale construction programs not obliged to live within "not to exceed" cost caps.[67]

States with retail choice, on the other hand, would be wise to resist the temptation to add policies and regulatory approaches (such as an over-reliance on long-term power contracts, integrated resource planning or other complex resource portfolio obligations and responsibilities for local distribution utilities) that are better suited to a regulated industry framework in which retail consumers are not permitted to shop for power from an alternative electricity supplier. Imposing such obligations that shift financial and economic risk to consumers, while continuing to allow those customers to migrate to other suppliers seems like a formula for problems to arise in the future, should economic conditions change leaving the utilities' supplies priced above market rates.

Either type of regulatory environment can support policies that promote more aggressive targets for cost-effective energy efficiency, by the way, although the policies adopted in the two kinds of states should be mindful to design policies that align well with the incentives built into the overall industry structure.

9. TECHNOLOGY DOESN'T JUST HAPPEN IN THIS INDUSTRY WITHOUT THE INCENTIVES EMBEDDED IN MARKET RULES.

The electric industry is inherently technology-based. It has always operated through complex, enormously technical, engineered systems of generators, transmission lines, distribution systems, and a variety of control technologies. In some respects, the industry relies on tried-and-true technologies: a large portion of the power system's physical assets are older than the people running them. But in its highly interconnected systems today, the industry depends on modern technologies. And our economy with its increasingly high degree of reliance on electronic systems depends on assurance of adequate infrastructure and highly-reliable system operations into the future.

A common plea in this industry is that new technology is needed. New types of power plants are necessary for assuring that the next cohort of long-lived power plant investments are clean and efficient, so that (among other things) the carbon emissions from the electric industry begin to decline in ways that address the requirements of climate change. Technology is also required — and already available — for enhanced, more reliable and more secure transmission investments, allowing for a more robust electric system that positions the U.S. for the needs of the 21st century. Additionally, many of the technologies for enabling customers to better manage and make efficient use of electricity are already known, but have only been deployed in very limited contexts.

Achieving the economic, reliability and environmental benefits of technology adoption is critically important for the country, but depends upon the kinds of significant investment described above, and the kinds of paradigm shift described below. It won't just happen without the adoption of public policies and corporate decisions by industry leaders that result in greater spending on research and development and adoption of advanced technology.

10. CONSUMERS WILL BE BETTER ABLE TO REALIZE THE FULL BENEFITS OF COMPETITIVE WHOLESALE MARKETS IF THEY ARE BROUGHT OUT OF THE DARK.

As Americans look forward to continuing to enjoy the benefits of modern society, including the values afforded by reliable and cleaner energy supplies, it will be useful — if not necessary — to begin to make electricity more visible. Most customers — and virtually all small electricity consumers — only see average prices and billing statements showing only monthly energy use. Most consumers have no idea that it costs more to provide them with power in the middle of the day than during the evening hours, with prices spiking during the hottest hours of the year. Most customers do not know which appliance or electronic equipment uses more electricity than others. Few consumers are aware that many appliances that are turned off still draw electricity, or that many of those cell-phone chargers draw power around the clock whether or not the phone is in the docking station. Most electricity consumers — except perhaps those large electricity users for whom electricity constitutes a major budget item — simply make little connection between their patterns of electricity use and the size of their electricity bills.

Given the realities of today's electricity supply — that it is not cheap — Americans would benefit greatly by being brought out of the dark. Consumers' demand is driving investment requirements and costs to provide power. Consumers could better manage their own electricity bills if more light were shed on electricity realities.

There are ways to do this with technology, much of which already exists but awaits the regulatory incentives to be deployed into the hands of consumers. There are advanced meters and other "smart" equipment that allow customers to see how much it costs to supply power to different appliances at different times of day. There are devices and service providers who can offer relatively seamless ways to better manage customers' usage patterns — such as through cycling of air conditioners in ways that reduce the usage of a city's worth of air conditioners (and thus a significant amount of power requirements) without reducing comfort or convenience. Those who sign up can receive a check for their savings. Large sophisticated users of electricity are already adopting such devices and other ways to manage electricity and save money.[68] But small users who are shielded from knowledge of the prices to supply power at different times of day have weak (if any) motivation to pursue such devices. So, the technology may be there to keep them informed, but there is insufficient motivation to adopt it.

Enabling this kind of customer response to market conditions is critical to the performance of markets themselves, as well as to the ability of consumers to manage their energy use and electricity bills. The value of harnessing price signals to help supply resources to the system and to discipline prices through the operation of both supply and demand has been seen in recent years in many RTO-administered wholesale markets. This was noted previously with regard to the 1,945 MW of "customer-supplied" capacity provided through demand response program participants in PJM on August 8th, 2007. The NYISO operates demand-response programs in which (as of April 2007) approximately 2,000 customers had registered to provide demand-response capacity totaling approximately 1,600 MW.[69] As of August 2007, ISO-NE had registered 2,031 demand response "assets," totaling 1,149 MW,[70] equivalent to 4 percent of New England's highest electricity peak use (28,130 MW, which occurred in the summer of 2006).[71] It is no accident that these programs have moved quite aggressively in these markets in recent years, since the transparency of hourly wholesale prices has enabled the possibility of customers seeing electricity prices and making decisions for themselves about whether they prefer to curtail their usage when prices hit a particular threshold. Without this kind of price transparency — something that typically does not exist in regions without RTOs — these markets are significantly impeded and customers (those who participate in the programs, as well as other non-participants) would be paying much more for their electricity bills.[72]

In the future, leaders would do well to allow for the blinders to be taken off of consumers. This doesn't mean that everyone will have to move electricity issues to the top of their agenda. It does mean, however, that electricity has to be more visible in terms of prices, sending different kinds of messages to consumers than they get when they simply open the bill at the end of the month. Electricity is not cheap; it is more expensive at certain times of day. And electricity use can be *much better* managed, not just by large consumers but by smaller ones as well. Consumers can be empowered in terms of having better control over their electricity bills; but they won't be able to become empowered if they are kept in the dark and protected from the truth that electricity is more expensive and likely to remain that way for the foreseeable future.

Sending this message is essential, requires gumption, and needs to occur whether a region has adopted a competitive industry model or retained vertically-integrated monopoly utilities. It also requires recognition that in the electric industry — like so many other aspects of our economy — there are strengths in the competitive market structure, with benefits for consumers.

CONCLUSION

As much as one would like to conclude otherwise, relatively high electricity prices are likely to be the "new normal" in the electric industry. This is our new reality — whether consumers are served in regions with vertically integrated electric utilities under cost-based regulation, or in ones relying substantially on markets. This reality stems from fundamental economic forces tied to global markets for fossil fuels and other products, and to the need to address other critical economic and social challenges such as continued demand for power, aging infrastructure and global warming. There is nothing fun about any of this, but it is not entirely a "bad news" story.

Electricity continues to fuel a national economy that is increasingly dependent upon machines, systems, tools, and devices that rely on electricity. Americans enjoy some of the most reliable electricity supplies available anywhere in the world. Presuming a degree of regulatory and policy stability going forward, we can expect private investors to supply capital for the grid, for greater improvements in energy efficiency and in power production facilities. We can look forward to an electric sector producing lower pollution levels than in the past. All of this is good for consumers.

Moreover, by better use of market mechanisms, consumers may be better positioned than in the past to determine how much and when they use electricity. Many large and sophisticated customers are already taking advantage of systems and services to help them manage their electricity use and electricity bills. Other electricity users, including smaller commercial and residential consumers, may soon become more "empowered" to manage their supplies.

But to do so, policy makers will need to think differently about electricity. While it is a noble instinct of policy makers to want to protect consumers from surprises, from wrong deeds, and from flaws in the market place, it is another thing to want to keep consumers in the dark and to try to intervene to fix things with policy changes whenever prices move in unpleasant directions. Consumers will benefit from knowing the realities of the outlook for electricity supplies, so that they can make their own plans and actions to manage their bills as best they can. Part of helping consumers get there will be for policy makers to adopt policies giving consumers the tools they need — improved information, pricing signals and service provisions that overcome the "invisibility" inherent in today's electricity system. Many of these, in turn, are aided by competitive elements in the industry that allow for real-time pricing, innovation and a customer orientation.

Part of helping consumers is also applying care when adopting "fixes," so that the cure doesn't end up being worse than the disease. For an industry as complex as the electric industry, it seems particularly prudent to allow further evolution in the paths being taken in different parts of the country. This kind of regulatory stability — in the regions with vertically-integrated utilities, and in the regions with more competitive industry structures — will go a long way to providing the environment that will support our shared goals for an efficient, reliable and environmentally acceptable electricity system.

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ABOUT THE AUTHOR

Dr. Susan F. Tierney, a Managing Principal at Analysis Group in Boston, is an expert on energy policy, regulation and economics. Her focus is on the electric and gas industries. A consultant for a dozen years, she previously served as the Assistant Secretary for Policy at the U.S. Department of Energy (appointed by President Clinton), the Secretary for Environmental Affairs in Massachusetts (appointed by Governor Weld), Commissioner at the Massachusetts Department of Public Utilities (appointed by Governor Dukakis), and executive director of the Massachusetts Energy Facilities Siting Council. Prior to joining Analysis Group, she was Senior Vice President at Lexecon. She taught at the University of California at Irvine, and earned her Ph.D. and Masters. degrees in regional planning at Cornell University. In addition to authoring many articles and reports, she has participated as an expert and advisor in regulatory proceedings before state and federal agencies and legislatures, in civil litigation cases, in arbitrations, negotiations, mediations, and in business consulting engagements, for clients in business, industry, government, non-profit and other organizations. She serves on a number of boards of directors and advisory committees, including the National Commission on Energy Policy, and the National Academy of Sciences Committee on Enhancing the Robustness and Resilience of Electrical Transmission and Distribution in the United States to Terrorist Attack. She is a director of Renegy Inc. (formerly Catalytica Energy Systems, Inc.); chair of the Board of the Energy Foundation; chair of the Board of Clean Air – Cool Planet; a director of the Northeast States Clean Air Foundation, and a director of the Climate Policy Center; a member of the Advisory Council of the National Renewable Energy Laboratory, the Massachusetts Renewable Energy Trust Advisory Council, the Environmental Advisory Council of the New York Independent System Operator, and the WIRES' Blue Ribbon Commission on Cost-Allocation Issues for Transmission Investment. She chaired the Massachusetts Ocean Management Task Force, and authored the report on Liquefied Natural Gas to the Massachusetts Legislature's Special LNG Commission. Previously, she served as Director on the board of the Electric Power Research Institute and a member of the ISO-New England's Advisory Council.

ENDNOTES

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[1] Source: Energy Information Administration ("EIA") "826" data, www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

[2] In 2006, 41 percent of retail electricity sales in the U.S. were in states that had restructured their electric industries. EIA, 826 retail sales data (in megawatt-hour ("Mwh")) for 2006, for the following states (and the District of Columbia ("D.C.")), as compared to total retail Mwh sales in the U.S.: Arizona, Connecticut, D.C., Illinois, Maine, Massachusetts, Maryland, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, Virginia.

[3] These data are average nominal electricity prices for all customer classes of electricity. Data source: EIA, Form 826 Data (using average annual retail electricity price (cents-per-kilowatthour) for all years except 2007 (for which the data represent the average for the January 2007-April 2007 period).

[4] EIA, http://www.eia.doe.gov/cneaf/electricity/epa/figes1.html .

[5] In recent years, many analysts and scholars have studied the relationship between fossil fuel prices and electricity prices. For example, analyzing several decades of annual price data for natural gas and electricity, MIT's Paul Joskow found that there is a close historical relationship between fuel costs and residential and industrial electricity prices. *See*, Joskow (2006). Young Yoo and Bill Meroney from the staff of the Federal Energy Regulatory Commission found relatively strong explanations for electricity prices increases based on changes in natural gas prices. (Yoo and Meroney (2005), analyzing daily prices in New England (2000 to 2003) and New York (2001-2003).) Ken Rose (2007) observes that natural gas prices have played a role in explaining electricity price changes. Rose states that there are other important factors in explaining prices, including the level of customer load (with high prices reflecting high periods of customer demand for gas and electricity during different seasons, and the existence of different generating technologies (with different power production efficiencies) as well). Greg Basheda et. al. (The Brattle Group), also find that *"Fuel and Purchased Power Cost Increases Have Been Enormous and Are the Largest Cause of Recent Electric Cost Increases.* On an industry-wide basis, our analysis finds that fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the cost of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Basheda et. al., page 2.)

[6] EIA, Coal prices delivered to the power sector. Delivered Price for 1990-2004 from EIA State Data Tables, United States Table 6; for 2005-2006 from June 2007 Electric Power Monthly, Table 4.1.

[7] An actual increase of 65,529 MW occurred from 680,941 MW (in 2000) to 746,470 MW (in 2005). Peak demand in 2007 was expected to be approximately, 760,840 MW in the U.S. Thus, an increase of approximately 80,000 MW was expected from 2000 through 2007. To put that in context, Texas' peak demand in the summer of 2006 was over 62,339 MW. Sources: EIA, Electric Power Annual (2006), Table ES1; North American Electricity Reliability Council, Long-Term Reliability Assessment, 2007, Table 32, ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2007.pdf, and NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), page 11.)

[8] In ERCOT (the electrical system of Texas), summer peak demand was 62,339 MW in 2006. NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), page 11.

[9] This "one large power plant a week" statement is based on the following: there are 392 weeks from the start of 2000 through July of 2007; Actual net additions of capacity in the US from the end of calendar year 1999 (i.e., the start of 2000) to August 2007 was approximately 210,480 MW. Dividing 210,480 MW by 392 weeks is 536 MW per week, equivalent to a medium-to-large power plant. EIA, Electric Power Annual (2006), Table 2.1 for end of year 1999 (785,927 MW), For capacity in August 2007 (996,410 MW): EIA, Electric Power Monthly, October 2007, Table ES3. New and Planned U.S. Electric Generating Units by Operating Company, Plant and Month, 2007 – 2008. http://www.eia.doe.gov/ cneaf/electricity/epm/epmxlfilees3.xls (accessed 10-21-07).

[10] Because most of this investment was made by non-regulated power companies, the actual investment costs are not publicly available. This rough calculation is based on the following: Assumed capital costs of $550/kW for combined cycle power plants, and $325/kW for combustion turbine power plants. These two technologies accounted for most of the power plant capacity added during calendar years 2000-2007. This capital cost estimates were from RDI's Outlook for Power in North America 1999 Annual Addition (2000). The estimate of capital costs here is based on these numbers, assuming 2/3rd of the capacity added was combined cycle capacity, and the other 1/3rd was combustion turbine capacity. By contrast, more recent estimates of capacity costs are

much higher. For example, 2001 estimates of capital costs were as follows: $616/kW to $800/kW for combined cycles, and CT (2001) of $400/kW to $600/kW for combustion turbines (from Barmack, Kahn, Tierney). A recent estimate of capital costs in 2007 is $800/kW to $1000/kW for combined cycles, and $500/kW to $700/kW (from ISO-NE Scenario Planning Initiative). These more recent capital-cost estimates were not used in this calculation. Sources: EIA, Electric Power Annual 2006, Table ESI; RDI - Outlook for Power in North America - 1999 Annual Edition; Barmack, Kahn, Tierney (2006); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/apr302007/assumptions.pdf; U.S. Electric Energy Market Competition Task Force, Report (2007), page 39.

[11] Smith, Rebecca. "Court Decisions May Aid Some Utility Profits in Long Term." The Wall Street Journal Online. April 3, 2007. Available at: http://online.wsj.com/article/SB117556293661557706.html?mod=US-Business-News. Accessed August 24, 2007.

[12] NERC, "2006 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2006), page 15. This reflects additions of power lines at 230 kV and higher voltage levels.

[13] Utilities' investments levels were $14.1 billion in 2000, and $15.8 billion in 2003. These figures are for shareholder-owned electric utilities. Edison Electric Institute, http://www.eei.org/industry_issues/energy_infrastructure/transmission/Transmission-Investment-Expenditures.pdf (accessed July 28, 2007).

[14] EIA, Annual Energy Outlook 2007, page 41. As reported in the New York Times, " 'There's massive inflation in copper and nickel and stainless steel and concrete,' said John Krenecki, president and chief executive of GE Energy....'There's real sticker shock out there,' Randy H. Zwirn, president of the Siemens Power Generation Group, said in an interview. He estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 percent to 30 percent. Part of the problem is huge price increases for the raw materials that plants are made from, including copper and nickel, which is what makes steel stainless. But the cost of finishing those commodities into components is also rising. 'There's a lack of production and manufacturing facilities in this country, and that may be partly to blame,' said Jason Makansi, a consultant with Pearl Street, a consulting firm in St. Louis that specializes in electric utilities. But, he said, 'the bigger culprit is the incredible demand in China and the rest of Asia.'.... Siemens, a supplier, gave some examples for a typical combined-cycle natural gas power plant, one that burns the fuel in a gas turbine to drive one generator, then makes steam from the exhaust to drive a second generator. The high-pressure piping for steam, used on a 293-megawatt plant, is up about 60 percent in the last two years, to about $1.12 million, according to the company. The equipment that uses exhaust heat to make steam, used at a 590-megawatt plant, is up about 40 percent in the last two years, $15.1 million in April of this year vs. $10.7 million in May 2005, according to Siemens. Simply moving a 435,000-pound turbine for a 198-megawatt plant from factory to the plant site now runs about $100,000, according to Siemens, up from about $50,000 two years ago." Matthew Wald, "Costs Surge For Building Power Plants," NY Times, July 10, 2007.

[15] EIA, Annual Energy Outlook 2007, page 36.

[16] The U.S. government has recently estimated that average "residential electricity prices are projected to increase by 2.9 percent in 2007 and by a slightly lower rate of 2.4 percent in 2008." EIA, Short Term Energy Outlook – July 2007, page 6. These projections are tied in large part to expected prices for fossil fuel prices, which are expected to remain high in the near term or longer term. According to EIA estimates, long-term electricity prices "follow the prices of fuels to power plants in the reference case, falling initially as fuel prices retreat after the rapid increases of recent years and then rising slowly. From a peak of 8.3 cents per kilowatthour (2005 dollars) in 2006, average delivered electricity prices decline to a low of 7.7 cents per kilowatthour in 2015 and then increase to 8.1 cents per kilowatthour in 2030. In the *AEO2006* reference case, with lower expectations for delivered fuel prices and the added costs of maintaining reliability, electricity prices increased to 7.7 cents per kilowatthour (2005 dollars) in 2030. Without adjustment for inflation, average delivered electricity prices in the *AEO-2007* reference case are projected to reach 13 cents per kilowatthour in 2030." EIA, Annual Energy Outlook 2007, pages 5-6. EIA's long-term price outlook for fossil fuels indicates the following for each fuel: Petroleum: long-term oil prices are likely to remain high, if slightly lower than in the past two years: "from a 2006 average of more than $69 per barrel ($11.56 per million Btu) to just under $50 per barrel ($8.30 per million Btu) in 2014 as new supplies enter the market, then rises slowly to about $59 per barrel ($9.89 per million Btu) in 2030." Natural Gas: "The average U.S. wellhead price for natural gas in the *AEO2007* reference case declines gradually from the current level, as increased drilling brings on new supplies and new import sources become available. The average price falls to just under $5 per thousand cubic feet in 2015 (2005 dollars), then rises gradually to about $6 per thousand cubic feet in 2030 (equivalent to $9.63 per thousand cubic feet in nominal dollars). Imports of liquefied natural gas (LNG), new natural gas production in Alaska, and production from unconventional sources in the lower 48 States are not expected to increase sufficiently to offset the impacts of resource decline and increased demand." Coal: As a result of higher minemouth prices and higher transportation costs for coal, the "average delivered price of coal to power plants is projected to increase from $1.53 per million Btu ($30.83 per short ton) in 2005 to $1.69 per million Btu ($33.52 per short ton) in 2030 in 2005 dollars, 7.0 percent higher than in the *AEO2006* reference case. In

nominal dollars, the average delivered price of coal to power plants is projected to reach $2.72 per million Btu ($53.98 per short ton) in 2030." EIA, Annual Energy Outlook 2007, pages 4-5.

17 EIA's Annual Energy Outlook (2007) "assumes that, for the purposes of long-term planning in the energy industries, costs will revert to the stable or slightly declining trend of the past 30 years." (page 36). Further, a "total of 258 gigawatts of new capacity is expected between 2006 and 2030, representing a total investment of approximately $412 billion (2005 dollars). If construction costs were 5 to 10 percent higher than assumed in the reference case, the total investment over the period could increase by $21 billion to $41 billion." EIA, Annual Energy Outlook 2007, page 41.

18 "All told, investment in the transmission system is projected to add more than 7,122 miles of new transmission through 2009, and nearly 12,484 miles added during the 2005-2014 time period....Averaging $14 billion per year over the next 10 years, expected distribution investment is almost triple the size of projected transmission spending." Edison Electric Institute, "New Investments for Transmission and Distribution Systems Are Needed," September 2006.

19 These are estimates of annual costs to comply with the Clean Air Interstate Rule, the Clean Air Mercury Rule, and the Clean Air Visibility Rule, parts of which begin to go into effect in 2010 with several compliance phases in the subsequent years. These annual costs compare to projected health benefits of approximately $63 to $72 billion in 2010 and $91 to $106 billion in 2015. The net present value of capital investment in pollution controls is estimated to be approximately $19.8, with costs for investment in both pollution controls and generating capacity to make up power production needs totally $23 billion (1999 dollars). (EPA, October 2005), http://www.epa.gov/airmarkets/progsregs/cair/docs/cair_ camr_cavr.pdf, page 30.

20 Brattle Group, "The Economics of U.S. Climate Policy: Impact on the Electric Industry," prepared in collaboration with FPL Group, March 2007, page 8. Notably, the costs associated with a carbon control program represent a way to internalize into the price of coal-fired power production the costs imposed as a result of burning this cheaper fuel in power plants.

21 Per-capita consumption of electricity among Americans increased by 13 percent from 1990 to 2003 (the most recent data available). (13242.8 kwh per person per year in 2003, as compared to 11687.2 kwh per person in 1990). Source: Basheda et. al., "Why are Electricity Prices Increasing?" 2007, Appendix A.

22 It is not hard to overstate the inherent difficulty that exists in studying these issues. Any attempts to assess empirically the impact of restructuring on consumer electricity rates must address a number of issues that complicate such an analysis. "The electric industry" varies for electric utilities within states, across states within regions, and even customer classes within individual utilities. Some states started restructuring under conditions of surplus capacity; others did just the opposite. Some had short-lived rate freezes; other still have them in place. Some allowed for retail customer choice for several years, and then switched gears. Some allow pass-through of fuel costs and expenses on a quarterly basis; others allow such costs to be recovered only if there are extraordinary increases. Some have long-term fuel contracts supporting a significant portion of fuel supply; others have contracts whose prices are indexed continuously to changing prices. Some RTOs have experienced several phases of market design since they began operation; others have just recently started to operate their markets. Even with a single RTO, the changes in market rules over time have created different types and degrees of incentives.

All in all, even if one wanted to conduct a carefully designed study of the effects of fuel prices, or the impact of restructuring, or one or another other factor of interest, it would be difficult at best to do so. Analyses of the performance of restructuring must be careful not to lump together the early and widely recognized failures of the restructuring in California with the more successful development of centralized markets in eastern RTOs. And in the end, it is worth recalling that the initiatives for restructuring the electric industry were largely embarked upon as a way to reduce rates — but to do so relative to what prices would otherwise be in the absence of restructuring. Neither approach to structuring the electric industry — whether traditional regulation or competitive approaches — can assure "lower" rates in absolute terms. There is ample support for that proposition.

Sufficient information exists, also, to encourage thoughtful observers to avoid cherry-picking data points and drawing sweeping generalizations from them. For example, comparisons of rates between 2005 and 2006 do not become a reliable basis for assessments of the success or failure of restructuring, particular when changes in rates between these years reflect the expiration of rate caps that have artificially kept prices below market rates and may well have kept rates below those that consumers would have faced under the traditional cost-of-service models. Similarly, anecdotes reporting dramatic changes in consumer rates may misrepresent the impact of restructuring if they fail to consider the stringency of those caps and the level of rates that would have prevailed had consumers continued to be served by the cost-of-service regulated utilities, or even ignore the reality of significant rate increase in historical periods when large utility investments with cost-overruns began to roll into traditional rates or when significant increases in fuel prices rolled into rates on a dollar-for-dollar basis under fuel-adjustment clauses.

[23] Retail choice commenced in different years in the states that adopted it. For example, several states began retail choice in 1997. The end date April 2007 is the last full calendar month for which data were available as of the writing of this report

[24] Over this period, average retail prices in states that restructured their electric industries rose 30 percent, compared to 26 percent in the states that retained traditional regulation

[25] The RTOs (CAISO, PJM, NYISO, ISO-New England, ERCOT, SPP, and MISO) were actually established in different years after that. The end date April 2007 is the last full calendar month for which data were available as of the writing of this report.

[26] A number of studies have attempted to control for such state-by-state or utility-by-utility differences, and thus provide an estimate of the impact of restructuring holding all of these other factors constant. Joskow, for example, controls for fuel prices, the type of generation technologies relied upon, and average customer size when analyzing consumer rates from 1970 to 2003. (Joskow (2006). Joskow also controls for the average return on utility bonds, which do not vary across states, and the share of electricity generation from facilities that sell their power through terms regulated by the Public Utilities Regulatory Policies Act (or, PURPA).) Joskow found that industry restructuring leads to a 5-to-10-percent decrease in prices to residential customers (and about 5 percent to industrial customers), while wholesale competition leads to a roughly 1-to-0.5-percent reduction in residential prices for each 10-percent increase in power supplied by independent power producers. (Wholesale competition is measured by the share of electricity provided by independent power producers, rather than in relationship to participation in centralized RTO/ISO markets.) Another recent study by Harvey, McConihe, and Pope found that participation in the centralized New York ISO and PJM markets reduced average rates by $0.50 to $1.80 per megawatt-hour. (Harvey, McConihe, and Pope (2006).) These studies, however, represent a starting point, rather than the final word regarding analysis of the impact of electric industry restructuring on consumer rates. Joskow acknowledges that his study is "the first, admittedly crude, empirical analysis to examine more systematically the effects of cost drivers and competitive policy reforms on retail prices across states and over time." (Joskow, 2006, page 28.) The Harvey, McConihe, and Pope study examines only a fraction of market entities (municipal utilities and cooperatives) within two similar RTO/ISO markets (NYISO and PJM). (Harvey, McConihe, and Pope (2006).) Further, several other studies have concluded that restructuring has either increased or had no effect on consumer rates. (Taber et al. (2006) find that deregulation increases prices in certain ISO markets, although the study suffers from a number of methodological and sample issues that make results suspect. Fagan (2006) finds that restructuring did not have a statistically significant impact on price to industrial consumers.) Consequently, despite the many promising signals including demonstrated reductions in costs and reliable statistical analyses finding reductions in consumer rates, further analysis is needed before definitive conclusions can be reached about the impact of restructuring on consumer electricity prices. Even so, these studies provide useful support for the notion that restructuring has not been the spoiler often pointed to by its critics.

[27] Data reflect prices as the end of 2006 (2006 data from EIA, Form 876 data)

[28] In 1996, the 19 states (including DC) with above-average electricity rates were (in order, from highest to lowest): Hawaii, New Hampshire, New York, Connecticut, New Jersey, Rhode Island, Alaska, Massachusetts, Vermont, California, Maine, Pennsylvania, Illinois, Arizona, DC, Florida, Michigan, Maryland, and Delaware. In 2006, the higher-than-average-priced states included all of those states (except Pennsylvania, Illinois, Arizona, and Michigan), as well as Texas and Nevada. Note that two high-priced states in 1996 and that restructured their electric industries after then were Pennsylvania and Illinois; both of these were still under rate caps at the end of 2006, and had relatively low rates at the end of 2006. All of the high-priced states except Hawaii and Alaska, Florida, and Delaware restructured their electric industries during the past decade. Note that two high-priced states in 1996 and that restructured their electric industries after then were Pennsylvania and Illinois; both of these were still under rate caps at the end of 2006, and had relatively low rates at the end of 2006. 1996 and 2006 data from EIA, Form 876 data.

[29] Except Hawaii, Alaska, Florida, and Delaware.

[30] Texas, Ohio, Montana, and Virginia also restructured their electric industries.

[31] These percentages are calculated as the ratio of the average price in restructured states to the average electricity price in non-restructured states. Restructured states were considered to be: Arizona, Connecticut,

District of Columbia, Illinois, Maryland, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Data are from EIA, Form 876 data.

[32] This trend has also been observed in the research carried out by Howard Axelrod, David DeRamus and Collin Cain and published in "The Fallacy of High Prices," *Public Utilities Fortnightly* (November 2006), page 59: "Perhaps even more interesting has been the effect of competition on regional price differentials. While a number of important factors — including fuel mix, labor costs, taxes, and cost of living — drive regional electricity prices, the gap between the PJM area, traditionally a high-cost area, and the Southeast, traditionally a low-cost area, has been shrinking. Our research shows that retail rates in five Southeastern states [footnote in original] rose 23.7 percent from 1998 to 2005, while rates in four "classic" PJM states [footnote in original] rose only 7.8 percent over that same period.[footnote in original] The 7.8 percent increase for the PJM states reflects continued rate caps for some customers in 2005, but the corresponding increase for New Jersey, which has had retail electricity rates set competitively since 2003,was just 9.6percent (*see Fig. 3*). There are limits to how far one can extend such a comparative analysis of rates across different regions of the country. ... For example, the state of Maryland recently was engulfed in a significant political controversy when bids to provide standard-offer service to Baltimore Gas & Electric (BG&E) residential customers were 72 percent higher than the then current retail rates, which had been frozen since 1999 at a 6.5 percent discount to rates in effect since 1993. Obviously, if one were to compare Maryland's retail electric prices with prices in the Pacific Northwest (PNW), one would observe that PNW retail prices are significantly lower. Does that prove that there are not any benefits from competition? The answer is clearly no, since prices in the PNW reflect abundant, federally subsidized hydroelectric capacity not available in Maryland, which makes direct price comparisons between the two regions irrelevant and misleading. To account for the difficulties inherent in a cross-regional comparison, we performed an econometric analysis of the effects of competition over a broad cross-section of the United States, using data for the years 1980 through 2004 for all states east of the Mississippi to estimate the effects of wholesale competition and state restructuring on the retail cost of electricity. We controlled for a number of factors influencing electricity prices, including generation mix, concentration of independent power producers, and capital costs. This specification of an econometric model allows us to derive a preliminary estimate of the benefits of wholesale competition and retail access, controlling for differences in fuel mix and other factors. Again, it is our view that a more robust estimate of the benefits of competition will require additional time, as many of the benefits of competition are inherently long-term in nature. Nevertheless, despite the relatively short time period since electricity restructuring was implemented, our econometric analysis indicates that the introduction of wholesale competition has resulted in an average reduction in the price of electricity by $6.50/MWh for all retail customers. Considering Maryland alone, as the state in which recent price increases arguably have caused the most political controversy, our analysis shows that the benefits of wholesale competition to Maryland consumers are more than $300 million per year."

[33] Many observers have commented on the fact that states adopted a complex and often internally inconsistent packages of policies when they adopted as part of the "restructuring" package, with some of these policies – such as multi-year retail rate freezes established at levels below prevailing prices in markets – inhibiting the ability of competitive retail markets to develop over time. On the other hand, such policies were part of the political bargains made to assure decision makers that there would be benefits for all consumers associated with adoption of policies to restructure the industry. See, for example, Ashley Brown, "Retail Procurement: Default Service vs. Monopoly Service Considerations," Presentation to Harvard Electricity Policy Group, October 5, 2007.

[34] See, for example, the November 2005 letter from seven companies (including Federated Department Stores, WalMart, 7-Eleven, and JC Penny) representing nearly 14,000 facilities and over $2 billion in annual electricity costs as commercial consumers of electricity. http://www.competecoalition.com/1115comments.pdf

[3535] The U.S. Electric Energy Market Competition Task Force's Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (April 2007) provides a good summary of the difficulties experienced in many "retail choice" states in implementing workable competitive markets for small electricity customers.

[36] By comparison, under traditional regulation utilities typically do not share in any of the financial gains from improved operating efficiencies. Under cost-of-service regulation, utilities generally recover their operating expenses but are not allowed to share in the savings they might create by increasing operating efficiency to reduce fuel costs or reducing other components of costs. While utilities might be able to share in some savings under certain circumstances (e.g., incentive regulation or due to lags between regulatory proceedings), the fact that savings are shared and often transitory create only partial incentives for utilities to undertake actions to improve plant productivity. Incentive regulation, which allows regulated utilities to share in the savings produced when plants exceed pre-determined performance benchmarks, creates similar incentives to those created by plant divestment. Lags between regulatory proceedings may allow regulated utilities to profit from cost savings until they are incorporated into rates in future periods.)

[37] One of the techniques used in many states to enhance such incentives for competition was divestiture of power plants, which in some cases allowed for firms to specialize in the operation of particular types of facilities (such as nuclear plant operations).

[38] Bushnell and Wolfram (2005).

[39] Global Energy Decisions (2005); Barmack, Kahn, and Tierney (2006). *See*, also, Cain and Lesser (2007), who found a 5- percent improvement in nuclear output, with a total efficiency benefit in PJM East's region of approximately $450 million in annual savings.

[40] Fabrizio, Rose and Wolfram (2006). *See*, also, Shanefelter (2006). For example, one study estimated improvements in fossil-fuel plant efficiency of roughly 2 percent, while another study found reductions in labor and operations costs of 3 to 5 percent. (Bushnell and Wolfram (2006) estimate approximately a 2 percent improvement in plant heat rates, which Wolfram (2003) estimates would generate savings of roughly $3.5 billion annually. Fabrizio, Rose and Wolfram (2006) estimate a 3 to 5 percent reduction in labor and operations costs, which, based on estimates provided by Wolfram (2003), would produce savings of at least $1 billion annually.) Improvements in the operation of nuclear facilities — where availability and output are estimated to have increased by 10 percent — appear to be largely the result of such consolidation. Although these improvements may not appear dramatic, when aggregated across all facilities, the combined annual savings could be in the billions of dollars.

[41] For example, Tierney and Kahn (2007) estimate the savings from increased plant availability in addition along with savings from other elements of restructuring, such as the consolidation of the multiple geographic areas that had previously used for economic plant dispatch.

[42] Restructuring has facilitated geographic consolidation in a number of ways. One is through the integration of dispatch (or, "unit commitment") decisions that had previously been made within individual sub-regions, such the integration of New York Power Pool sub-regions into the New York ISO. Geographic consolidation also includes integration of regions that were previously in separate RTO/ISOs or dispatch zones, such as the formation of PJM and the recent integration of American Electric Power ("AEP"), Commonwealth Edison ("ComEd"), and Dayton Power and Light ("DPL").

[43] Tierney and Kahn (2007).

[44] Global Economic Decisions (2005). The $85 million annual savings reflects savings across the entire Eastern Interconnect, which spans the majority of the eastern and mid-west states.

[45] For example, Souce: ISO-NE, Capacity Energy Loads and Transmission Reports ("CELT" Reports) for each year from 1999 through 2006. Capacity data in the table in SECTION I - Summaries Summer - NEPOOL and Total New England August Capabilities and Summer Peak Load Forecast (MW).

[46] http://www.pjm.com/contributions/news-releases/2007/20080810-demand-response-record.pdf

[47] See Electric Energy Market Competition Task Force, Appendix C. "The Task Force reviewed roughly 30 cost-benefit analyses [of electric industry restructuring developments] in an attempt to better understand what they reveal. Based on this review, together with a review of the recent DOE Report (J. Eto, B. Lesieutre, and D. Hale, "A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies" (December 2005) [hereinafter Eto]), the Task Force has made the following observations: (1) Many of the existing studies address only the benefits of restructuring proposals. ...(2) The benefits associated with some of the most significant motivations behind restructuring — the maintenance of system reliability and the facilitation of lowest-cost electricity production (via incentives for innovation and low-cost construction) - are very difficult to quantify using current technology and are often left out of benefit assessments. "It is important that technically limited studies not be interpreted to suggest that impacts that they do not analyze are not significant." Eto at 21. (3) Existing methods and models used to estimate benefits are limited in what they can measure. ...(4) Modeling energy transmission and markets necessarily requires making a great deal of assumptions given the significant limitations in data needed to "feed" these models. Thus, outputs of RTO modeling attempts vary widely based on the assumptions made by the parties doing the modeling — assumptions as to transmission configurations, weather, imports/exports, market behaviors, generation costs, etc. ...(5) Another limitation of the studies is that they often only estimate the benefits to society as a whole. Determining the distribution of benefits and costs - who wins and who loses, or who wins the most - is an important piece of the decision making puzzle. Unfortunately, it is much more difficult to measure the distribution of benefits than it is total social costs. ...(6) Characteristics of the best restructuring cost-benefit studies, given existing technology/data, include: Provision of clear and precise descriptions of assumptions, data sources, methods and technical detail; Where econometric models are used, study write-ups should provide regression methods and equations, goodness of fit measures,

and results of any tests done to detect analytical flaws; An attempt to address all potential costs and benefits; An effort to address the distribution of impacts."

See also the analysis of John Kwoka, "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies," Prepared for the American Public Power Association, November 2006.

[48] Tabors Caramanis & Associates. "RTO West Benefit/Cost Study: Final Report Presented to RTO West Filing Utilities. March 11, 2002.

[49] See ISO/RTO Council, "The Value of Independent Regional Grid Operators," November 2005. The report states on page 37 that "Thus, industry average costs per MWh have been fl at since 2003." The data for the individual ISO/RTOs are shown in Appendix A, which states that "Figure A-1 shows ISO/RTO costs as a function of revenue requirement per unit of load served. This shows that while per-unit costs increased in the early years as each ISO/RTO began building its capabilities and experience, those costs have leveled off or dropped as the organizations and their offerings are stabilizing. It also shows a marked distinction between the ISOs and RTOs serving relatively smaller footprints and loads (New England, New York and California) relative to those providing grid and market services to large footprints and loads (ERCOT, Midwest ISO and PJM)." Page 43.

[50] In a recent report exploring different methods for monitoring wholesale power market monitoring in the Western Interconnection outside of California and Alberta, the authors noted the following: "By market monitoring, we mean the systematic analysis of market behavior and outcomes to identify behavior that is inconsistent with well-functioning competitive markets. Such behavior may include the exercise of market power, e.g., withholding supply from the market in order to raise price. [footnote in the original] In the U.S., Regional Transmission Organizations (RTOs) with "Day 2" functions [footnote in the original] generally have dedicated market monitoring functions. The market monitors may be RTO staff members, independent consultants, or both. The Federal Energy Regulatory Commission (FERC) treats applications to sell at market-based rates from suppliers in markets with the full complement of "Day 2" functions, including formal market monitoring, more leniently than other applications. [footnote in the original] While we fully acknowledge the wide range of views on the costs and benefits of RTOs, it is simply a fact that market monitoring in RTOs is easier—primarily because of the voluminous amounts of data produced in the centralized "Day 2" markets administered by RTOs. RTO market monitors typically have access to data on the hourly operations of individual units, their bids into various centrally administered, bid-based markets —including markets for both energy and ancillary services, estimates of units' variable costs, hourly prices at multiple locations and for multiple products, detailed information on transmission constraints, and other data not typically available in non-Day 2 RTOs and other bilateral markets, such as exist in the Western United States. Because of the absence of publicly and/or centrally collected data for the Western U.S. wholesale power markets outside of California, it is generally infeasible to replicate the analyses performed by market monitors in Day 2 RTOs. [footnote in the original] Therefore, it is necessary to approach market monitoring in a different way than has been done in organized markets." This particular article examines, among other methods, the use of econometric models to assist in informing observers about the performance of wholesale markets in the West. See, Matthew Barmack, et. al (2006) "A Regional Approach to Market Monitoring in the West," Lawrence Berkeley National Laboratory (October 2006), page 1.

[51] Energy Policy Act of 2005, Section 1815.

[52] Electric Energy Market Competition Task Force, "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy, Pursuant to Section 1815 of the Energy Policy Act of 2005," April 2007, page 92.

[53] See, for example, the November 2005 letter from seven companies (including Federated Department Stores, WalMart, 7-Eleven, and JC Penny) representing nearly 14,000 facilities and over $2 billion in annual electricity costs as commercial consumers of electricity. http://www.competecoalition.com/1115comments.pdf Another anecdotal example can be found in a recent presentation by a provider of "total energy management" services (Enernoch) who recently listed its customers as including such companies as Xerox, Kraft, Corning, Dresser-Rand, SBC, Pitney Power, Level 3 Communications, GE, AT&T, Adobe, Tufts, MIT, Albertsons, Stop LL& Shop, Big Y, Price Chopper, Partners Health Car, Pfizer, Westin Hotels, Marriott Hotels, Sheraton Hotels, Hampton Inn and Suites, Hilton Hotels, and a wide variety of cities, towns and state governments. Tim Healy, Enernoch, "Demand Response: An Underutilized Capacity Resource Whose Time is Now," presentation to the Harvard Electricity Policy Group, *March 2, 2006,* http://www.ksg.harvard.edu/hepg/Papers/Healy_Demand_Response_0306.pdf

[54] As of 1991, 91 percent of U.S. power was produced at plants owned by regulated electric utilities. By contrast, between 1996 and 2004, roughly 74 percent of electricity capacity additions were made by non-utility power producers. Electric Energy Market Competition Task Force Report, page 35.

[55] Electric Energy Market Competition Task Force Report, page 35.

[56] Electric Energy Market Competition Task Force Report, page 35.

[57] One study of a region (New England) with a substantial post-2000 investment boom compared system power production and investment costs against a counterfactual scenario in which such capacity surplus had not occurred (i.e., under a supposed case in which traditional regulation had occurred). The study estimated that the addition of the more efficient generating capacity in New England produced modest long-term system benefits for the region, and at-least short-term transfers of benefits from investors to consumers. Barmack, Kahn, Tierney (2006).

[58] Edward Bodmer, "The Electric Honeypot: The Profitability of Deregulated Electric Generation Companies," prepared for APPA (January 2007).

[59] Mirant Corporation declared bankruptcy in 2003 (See Mirant Corporation 10-K For the Fiscal Year Ended December 31, 2003). NEGT (formerly PG&E NEG) filed for Chapter 11 bankruptcy protection on July 8, 2003 (See PG&E Corporation 10-K For the Fiscal Year Ended December 31, 2003). On May 14, 2003 NRG and 25 direct and indirect wholly-owned subsidiaries commenced voluntary petitions under chapter 11 of the US bankruptcy code (See NRG Energy, Inc. 10-K For the Fiscal Year Ended December 31, 2003). Calpine filed for bankruptcy protection in December 2005. (http://www.cfo.com/article.cfm/5347314, accessed August 25, 2007.) AES Corp had its credit rating downgraded by Moody's from Baaa3 to Ba1 on May 26, 1999, from Ba1 to Ba3 on June 27, 2002, and from Ba3 to B3 on October 11, 2002. Standard and Poor's downgraded AES Corp from BB to BB- on June 6, 2002 and from BB- to B+ on October 3, 2002. AES Corp's credit ratings have subsequently increased from both rating agencies. (Source: Bloomberg, accessed on August 24, 2007)

[60] For example, NRG emerged from bankruptcy on December 5, 2003. The company now states that it has "a significant presence in major competitive power markets in the United States" and that it plans to "maintain and enhance the Company's position as a leading wholesale power generation company in the United States." (See NRG Energy, Inc. 10-K For Fiscal Year Ended December 31, 2006)

[61] This is a back-of-the-envelope calculation based on the EIA estimate of $412 billion estimated to be needed for new power generation investment (between 2006 and 2030), the $14 billion per year expected for distribution systems ("triple the size of projected transmission spending"), and the scores of billions of dollars of investment in pollution control costs associated with existing federal air regulations. See the discussion and references in the section above titled "1. Electricity is not too cheap to meter."

[62] See, for example, the recent paper by Lester Lave et al., "Deregulation/Restructuring, Where Should We Go from Here?" (7-18-07), and Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007). See also, the separate comments of Linda G. Stuntz, John Rowe/Elizabeth Moler, presented to the FERC Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, February 27, 2007.

[63] Saying that power markets are not perfect is different from saying that they are fundamentally flawed. As observed by Paul Joskow of MIT in February 2007, "The markets in the Northeast and Midwest organized around an LMP model and managed by an Independent System Operator (ISO) now work very well in almost all dimensions. These markets are extremely competitive under almost all contingencies. The wise use of independent market monitors and thoughtful market power mitigation mechanisms have largely mitigated potential market power problems when the few remaining contingencies arise. No market is textbook perfectly competitive and it is unreasonable to set that goal as a standard for wholesale electricity markets to meet." Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007). Additionally, pursuant to FERC requirements (and state requirements in the case of ERCOT), the various RTOs have market monitors to watch and evaluate the performance of markets, to screen conditions and look for anomalous behavior or pricing outcomes, and to flag problems for regulatory investigation when problems are detected, and to screen conditions. Tierney and Hibbard, Market Monitoring at U.S. RTOs: A Structural Review, March 2007.

[64] See, for example, FERC Order 890, 18 CFR Parts 35 and 37 (Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890) Preventing Undue Discrimination and Preference in Transmission Service (Issued February 16, 2007); and FERC's Advanced Notice of Proposed Rulemaking, "Wholesale Competition in Regions with Organized Electric Markets, AD07-7-000 (Item E-3), dated June 21, 2007.

[65] This list of suggestions is based on a variety of sources, including comments made by participants at FERC conferences on wholesale market performance. See, for example the comments of John Shelk of the Electric Power Supply Association (http://www.ferc.gov/EventCalendar/Files/20070228110115-Shelk,%20EPSA.pdf.), William Massey of Covington & Burling (http://www.ferc.gov/EventCalendar/Files/20070314144339-Massey,%20Covington%20&%20 Burling.pdf.), John Rowe and Elizabeth Moler of Exelon (http://www.ferc.gov/EventCalendar/Files/20070227090732-Moler%20and%20Rowe,%20Exelon.pdf), and Paul

Joskow of MIT (http://www.ferc.gov/EventCalendar/Files/ 20070228090000-Joskow,%20MIT.pdf). (All accessed August 25, 2007).

[66] See comments of Linda G. Stuntz, at FERC Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, February 27, 2007. See also Baldick, et. al. (2007), "A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles."

[67] And doing so would be consistent with the decades-old advice of Professor James Bonbright — often considered one of the "grandfathers" of principles of regulation of utilities — that the purpose of regulation is to replicate the results that the competitive market system would achieve in the way of reasonable prices and profits: "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charges rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute." See James Bonbright (1966) page 3, as quoted in Roger A. Morin, Ph.D., *New Regulatory Finance,* Public Utilities Reports, Inc., 2006 (page 1).

[68] One demand-response provider company, Enernoc, indicated in 2006 that its customers for "total energy management" programs include a "who's who" of large industrial firms, commercial office buildings, educational, groceries, department stores, health care facilities, hospitality and other light industrial facilities. See http://www.ksg.harvard.edu/hepg/Papers/Healy_Demand_Response_0306.pdf

[69] David Lawrence, "NYISO's Demand Response Programs," Presentation to the New York Market Operating Committee, 2007, http://www.nyiso.com/public/webdocs/services/market_training/workshops_courses/nymoc/demand_response 0507.pdf

[70] http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2007/aug12007/intro_dr_working_ group _meeting_08_01_2007.ppt#280,3,Demand Response (as of August 1, 2007).

[71] http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf, page 4.

[72] See, for example, the study of the Community Energy Cooperative (of the Center for Neighborhood Technology) which calculated that as more customer loads participate in demand-response programs, the savings to other, non-participating programs increase as well, due to reduction in wholesale market prices and price volatility, avoidance of electric utility costs, and mitigation of market power. Anthony Star, "Can Real-Time Pricing Be The Real Deal?", presentation to the Harvard Electricity Policy Group, Community Energy Cooperative, March 15, 2007. http://www.ksg.harvard.edu/hepg/Papers/star_demand_31507.pdf

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 915

Exhibits in Support
Of Opening Testimony

June 4, 2010

Case Nos. 03-E-0765
02-E-0198
03-G-0766

ROCHESTER GAS AND ELECTRIC CORPORATION

REBUTTAL TESTIMONY OF ROBERT G. ROSENBERG

January 15, 2004

REBUTTAL TESTIMONY OF ROBERT G. ROSENBERG

I. INTRODUCTION

Q. Are you the same Robert G. Rosenberg who previously submitted pre-filed direct testimony in these proceedings?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is two-fold. First, I will present rebuttal to the testimony submitted by Department of Public Service Staff ("Staff") witness Brian Summers concerning the estimation of the cost of equity ("COE") of Rochester Gas and Electric Corporation (hereinafter referred to as "RG&E" or the "Company"). I demonstrate that, adjusting Mr. Summers's analyses for errors and deficiencies that I discuss in my rebuttal, the Staff 9.5% return on equity ("ROE") recommendation should be corrected to 10.68%. Second, I will update my direct testimony by examining the change in interest rates between the recent six-month period and the six-month period of analysis employed in my direct testimony. In addition, I will rebut Mr. Ansaldo's testimony regarding the common equity ratio as part of the Capital Structure Panel.

II. REBUTTAL TO THE COE ANALYSES OF MR. SUMMERS

Q. Would you briefly describe the COE testimony of Mr. Summers?

A. Mr. Summers performs two cost of equity calculations—a discounted cash flow ("DCF") and a Capital Asset Pricing Model ("CAPM")—on a group of nine electric utilities (the same proxy group that I use) and, after certain adjustments, derives a recommended ROE of 9.5% for RG&E. As noted at page 4 of Mr.

REBUTTAL TESTIMONY OF ROBERT G. ROSENBERG

Ansaldo's testimony, this recommended ROE assumes the sale of the Company's R.E. Ginna Nuclear Power Plant ("Ginna"), which would leave RG&E with minimal generation assets. Mr. Ansaldo further recommends that if Ginna is not sold, the Commission should use an 11% ROE and a 50% equity ratio for generation assets.

Mr. Summers's first calculation was a two-stage DCF analysis that produced a 9.98% COE estimate. His second calculation was a CAPM analysis that produced a COE estimate of 8.80%. He weighted these results two-thirds DCF and one-third CAPM to produce a COE estimate for his proxy group of 9.58%, which he rounds to 9.6%. Mr. Summers then reduces this proxy group COE by 30 basis points to 9.3% to account for the proxy companies having some unregulated business. Mr. Summers then performs a Hamada Adjustment to adjust the COE estimate for the fact that RG&E has a different common equity ratio from the proxy group for which he derived the base COE. Mr. Summers adds a 20-basis point increment to the COE as a result of the Hamada Adjustment, producing his recommended COE figure of 9.5%.

Q. Should Mr. Summers have excluded any DCF results from his COE determination?

A. Yes. Mr. Summers calculated a DCF COE estimate of only 6.61% for CH Energy. The recent yield on A-rated utility bonds was 6.50%--virtually identical to Mr. Summers's DCF COE estimate for that company. It is nearly universally agreed that the COE does, and should, exceed the cost of debt. When a COE estimate is just about equal to the level of bond yields, this is clearly an understated estimate and should be discarded.[1] Excluding the CH Energy DCF COE estimate, the median COE estimate for the proxy group increases from 9.98% to 10.66%.

Q. Would you comment on Mr. Summers's estimate of the expected market risk premium used in the CAPM calculation?

A. At pages 3-4, Mr. Summers claims to use the Generic Financing Proceeding (Case 91-M-0509) methodology, as recommended by the ALJs in their Recommended Decision in that case. However, although the ALJs used an Ibbotson-based risk premium in their Recommended Decision, Mr. Summers, inconsistent with his claim, uses a different input—based on a projection made by Merrill Lynch.[2] In the March 7, 2003 Commission Order in the last RG&E rate cases (Cases 02-E-0198 and 02-G-0199) the Commission averaged the historic Ibbotson risk premium with a more recent estimate of the risk premium. In my direct testimony, on page 27, I indicated that the Ibbotson risk premium was 7.0%. Using this risk premium and Mr. Summers's other inputs for the CAPM (an average beta of 0.63 and a risk-free rate of 4.44%), the traditional and zero-beta

[1] The Federal Energy Regulatory Commission ("FERC") in Opinion No. 445 re Southern California Edison Company, July 26, 2000, 92 FERC ¶ 61,070, deleted a cost of equity estimate even somewhat above the concurrent bond yield. FERC indicated at page 27 of that Opinion that: "Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case." FERC excluded this outlier from its calculation of the cost of equity.

[2] The Merrill Lynch publication employed by Mr. Summers shows that, using the same methodology that produced the return on the market estimate employed by Staff, the required ROE for electric utilities was estimated to be only 6.0%--unreasonably low given that recent A-rated utility bond yields have averaged about 6.5%. This suggests that the market return estimate used by Staff may be similarly understated.

CAPM COE estimates would be 8.85% and 9.50%, respectively. Thus, average of the Ibbotson-based CAPM COE calculations is 9.18%.

Averaging this Ibbotson-based 9.18% CAPM estimate with the Staff 8.80% CAPM estimate produces a CAPM COE estimate of 8.99%—19 basis points higher than that determined by Mr. Summers when he did not include the Ibbotson estimate.

Q. What is the COE that results from these corrections to Staff's methodology?

A. Weighting the 10.66% corrected DCF COE estimate derived earlier by two-thirds and the 8.99% CAPM COE estimate derived above by one-third, the Staff COE for RG&E, before adjustments, would be 10.1%—50 basis points higher than the 9.6% figure derived by the Staff, before adjustments.

Q. Would you comment on Mr. Summers's equity ratio adjustment to the COE?

A. Mr. Summers applies what is known in New York as the "Hamada Adjustment." This adjustment is performed in order to estimate the change in the COE required by employing an equity ratio for the utility in question that differs from the equity ratio of the proxy group used to determine the COE. The formula for calculating the Hamada Adjustment is shown below:

$$B_L = B_U + B_U(1-T)\frac{D}{E}$$

where:

B_L = the levered beta (*i.e.*, the actual beta observed in the marketplace reflecting the presence of debt; this is the Value Line reported beta)

B_U = the unlevered beta (*i.e.*, what a company's beta would be if it had no debt)

T = the tax rate

D = the percent debt in the capital structure

E = the percent common equity in the capital structure

Q. How is the Hamada Adjustment performed?

A. The Hamada Adjustment is performed as follows: (1) calculate the unlevered beta using the leverage of the proxy group that Staff employed to determine its base COE, and then (2) relever this unlevered beta at the 40% common equity ratio Staff recommends for RG&E in these proceedings. One then calculates the differential between the new, relevered beta (based on the Staff recommended 40% equity ratio) and the original levered beta (based on the 47.26% common equity ratio of the Staff proxy group).

Below, I show the calculation of the unlevered beta:

<u>Calculating the Unlevered Beta (B_U)</u>

$$B_L = B_U + B_U(1\text{-}T)\frac{D}{E}$$

$$.63 = B_U + B_U(1\text{-}.35)\frac{52.74}{47.26}$$

$$B_U = .365$$

Note that my calculation of the unlevered beta is similar to that of the Staff, except for rounding differences (see STEP 1 on Exhibit___(BMS), page 3). However, after this point, the Staff performs a series of steps that produce an incorrect, understated adjustment to the COE which fails to adequately reflect the cost of increased leverage.

Q. Please explain the errors in Staff's methodology.

A. Staff calculates how much the COE would change between (1) the level of the proxy group with its current equity ratio and (2) the level of the proxy group assuming a 100% equity ratio. Staff calculates this differential to be 178 basis points (see STEP 3 on Exhibit___(BMS), page 3). Mr. Summers then divides the 178 basis-point COE differential by the 53 percentage point change in the equity ratio (between **47%** and **100%**) in order to derive an estimate of how much the COE changes for each 1 percentage point change in the common equity ratio between **47%** and **100%** (see STEP 4 on Exhibit___(BMS), page 3). This is the step where Mr. Summers goes wrong.

Q. Why is this step in Mr. Summers's calculation wrong?

A. We are not interested in the COE effect of an equity ratio going from 47% to 100%. We are interested in the COE effect of an equity ratio going from 47.26% to 40%. Changes in the COE are not linear with changes in the equity ratio. Below, I show the effect on beta (*i.e.*, the relevered beta) of assuming equity ratios different from the 47.26% actual level of the proxy group:

Equity Ratio	Relevered Beta
100	0.365
90	0.391
80	0.424
70	0.467
60	0.523
50	0.602
40	0.721
30	0.919
20	1.314
10	2.500

From the above data one can see that a 10 percentage point change in the equity ratio between, say, 90% and 100% produces a small change in beta of .026 (.391 - .365 = .026). However, a 10 percentage point change in the equity ratio between, say, 30% and 40% produces a different, much larger .198 change in beta (.919 - .721 = .198). Staff has ignored the nonlinear effects on beta of changes in the equity ratio thereby substantially understating the COE differential associated with a common equity ratio differential. The correct way to use the Hamada Adjustment is to measure the change in beta and COE when the equity ratio is changed from the 47.26% actual level of the proxy group to the 40.0% level recommended by Staff for RG&E.[3]

Q. Will you illustrate the proper way to perform the Hamada Adjustment for the 40% equity ratio that Staff recommends for RG&E?

[3] Mr. Summers, himself, performed the Hamada Adjustment in the same manner as demonstrated below in his testimonies concerning Warwick Valley Telephone Company, Case 90-C-1039 and Sherwood Water Corporation, Case 29390.

A. Below I show a relevering calculation where the relevered beta is calculated using a common equity ratio of 40%:

<u>Calculating the Relevered Beta Assuming a 40% Equity Ratio</u>

$$B_L = B_U + B_U(1\text{-}T)\frac{D}{E}$$

$$B_L = .365 + .365\,(1\text{-}.35)\frac{60}{40}$$

$$B_U = .72$$

As indicated above, the relevered beta (at a common equity ratio of 40%) is 0.72. Thus, the difference in beta between the original beta of 0.63 at an equity ratio of 47.26% and a relevered beta of 0.72 at an equity ratio of 40% is 0.09 (0.72 – 0.63 = 0.09). Multiplying this by the Staff market risk premium of 6.50%, the increase in the COE associated with a reduction in the common equity ratio from 47.26% down to 40.00% is 58 basis points (.09 x 6.50 = .58). This adjustment of 58 basis points should be added to the derived COE in place of the understated adjustment of 20 basis points that Mr. Summers employs.

Q. Do you have any comment on Mr. Summers's adjustment for unregulated assets?

A. Yes, I do. Staff employs a DCF method and a CAPM method and weights the results two-thirds and one-third, respectively, in reaching its weighted COE in this proceeding. Below, I show individual-company weighted COE results ranked by the Staff residual asset ratio, which Staff takes as a proxy for unregulated operations:

	Weighted COE 2/3 DCF 1/3 CAPM	Staff Residual Asset Ratio
MGE Energy	10.95 %	3.9 %
NSTAR	8.95	5.0
Consolidated Edison	8.61	12.7
Southern Company	10.88	13.5
SCANA	9.33	17.2
Vectren	10.72	18.1
Wisconsin Energy	9.53	22.1
CH Energy Group	7.47	27.7
FPL Group	10.89	40.4

One would expect that if unregulated operations had a clear effect on proxy group company COE calculations, then higher residual asset ratios would be associated with higher COE estimates. There is no such pattern in the results summarized above. In fact, the correlation between the COE and the residual asset ratio is zero—there is no relationship at all between a company's level of unregulated operations and the COE estimates calculated for individual companies. Note that the company with the lowest residual asset ratio (MGE Energy) has the highest COE estimate of the group! While, admittedly, some of the lack of correlation could be due to the vagaries of individual-company COE estimates, the fact that no relationship whatsoever between the level of unregulated operations and the COE was found implies that the calculational basis for Staff's adjustment for unregulated operations has not been established. Furthermore, it should be noted that no Staff witness proposed a similar adjustment in the last RG&E rate cases when it filed testimony a little more than a year ago.

Q. Based on the above analyses and discussion, what is the corrected Staff ROE?

A. Using the corrected COE of 10.1% and the corrected Hamada Adjustment of 0.58% produces an ROE of 10.68%.

III. CHANGES IN INTEREST RATES

Q. What are the changes in interest rates since you presented your direct testimony?

A. I examined changes in interest rates between the recent six-month period (ended December 2003) and the six-month period used in my direct testimony (ended February 2003). Long-term Treasury bonds averaged 5.02% for the six-month period in my direct testimony and have averaged 5.21% for the six months ended December 2003—an increase of 19 basis points. A-rated utility bond yields, per Moody's, averaged 7.09% for the six-month period used in my direct testimony. In the recent six-month period, A-rated utility bond yields averaged 6.50%--a decline of 59 basis points. Changes in the COE may not mirror changes in interest rates one a one-for-one basis. While the change in utility bond yields may be a more relevant indicator, the two interest rates cited above have gone in different directions. Based on the above comparisons, I recommend that RG&E be allowed an ROE of 11.25%--down 25 basis points from the recommendation in my direct testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 916

Exhibits in Support
Of Opening Testimony

June 4, 2010

THE EFFECT OF THE FIRM'S CAPITAL STRUCTURE ON THE SYSTEMATIC RISK OF COMMON STOCKS

ROBERT S. HAMADA*

I. INTRODUCTION

ONLY RECENTLY has there been an interest in relating the issues historically associated with corporation finance to those historically associated with investment and portfolio analyses. In fact, rigorous theoretical attempts in this direction were made only since the capital asset pricing model of Sharpe [13], Lintner [6], and Mossin [11], itself an extension of the Markowitz [7] portfolio theory. This study is one of the first empirical works consciously attempting to show and test the relationships between the two fields. In addition, differences in the observed systematic or nondiversifiable risk of common stocks, β, have never really been analyzed before by investigating some of the underlying differences in the firms.

In the capital asset pricing model, it was demonstrated that the efficient set of portfolios to any individual investor will always be some combination of lending at the risk-free rate and the "market portfolio," or borrowing at the risk-free rate and the "market portfolio." At the same time, the Modigliani and Miller (MM) propositions [9, 10] on the effect of corporate leverage are well known to the students of corporation finance. In order for their propositions to hold, personal leverage is required to be a perfect substitute for corporate leverage. If this is true, then corporate borrowing could substitute for personal borrowing in the capital asset pricing model as well.

Both in the pricing model and the MM theory, borrowing, from whatever source, while maintaining a fixed amount of equity, increases the risk to the investor. Therefore, in the mean-standard deviation version of the capital asset pricing model, the covariance of the asset's rate of return with the market portfolio's rate of return (which measures the nondiversifiable risk of the asset—the proxy β will be used to measure this) should be greater for the stock of a firm with a higher debt-equity ratio than for the stock of another firm in the same risk-class with a lower debt-equity ratio.[1]

This study, then, has a number of purposes. First, we shall attempt to link empirically corporation finance issues with portfolio and security analyses through the effect of a firm's leverage on the systematic risk of its common

* Graduate School of Business, University of Chicago, currently visiting at the Graduate School of Business Administration, University of Washington. The research assistance of Christine Thomas and Leon Tsao is gratefully acknowledged. This paper has benefited from the comments made at the Finance Workshop at the University of Chicago, and especially those made by Eugene Fama. Remaining errors are due solely to the author.

1. This very quick summary of the theoretical relationship between what is known as corporation finance and the modern investment and portfolio analyses centered around the capital asset pricing model is more thoroughly presented in [5], along with the necessary assumptions required for this relationship.

stock. Then, we shall attempt to test the MM theory, or at least provide another piece of evidence on this long-standing controversial issue. This test will not rely on an explicit valuation model, such as the MM study of the electric utility industry [8] and the Brown study of the railroad industry [2]. A procedure using systematic risk measures (β s) has been worked out in this paper for this purpose.

If the MM theory is validated by this procedure, then the final purpose of this study is to demonstrate a method for estimating the cost of capital of individual firms to be used by them for scale-changing or nondiversifying investment projects. The primary component of any firm's cost of capital is the capitalization rate for the firm if the firm had no debt and preferred stock in its capital structure. Since most firms do have fixed commitment obligations, this capitalization rate (we shall call it $E(R_A)$; MM denote it ρ^τ) is unobservable. But if the MM theory and the capital asset pricing model are correct, then it is possible to estimate $E(R_A)$ from the systematic risk approach for individual firms, even if these firms are members of a one-firm risk-class.[2]

With this statement of the purposes for this study, we shall, in Section II, discuss the alternative general procedures that are possible for estimating the effect of leverage on systematic risk and select the most feasible ones. The results are presented in Section III. And finally, tests of the MM versus the traditional theories of corporation finance are presented in Section IV.

II. Some Possible Procedures and the Selected Estimating Relationships

There are at least four general procedures that can be used to estimate the effect of the firm's capital structure on the systematic risk of common stocks. The first is the MM valuation model approach. By estimating ρ^τ with an explicit valuation model as they have for the electric utility industry, it is possible to relate this ρ^τ with the use of the capital asset pricing model to a nonleveraged systematic risk measure, ${}_A\beta$. Then the difference between the observed common stock's systematic risk (which we shall denote ${}_B\beta$) and ${}_A\beta$ would be due solely to leverage. But the difficulties of this approach for all firms are many.

The MM valuation model approach requires the specification, in advance, of risk-classes. All firms in a risk-class are then assumed to have the same ρ^τ—the capitalization rate for an all-common equity firm. Unfortunately, there must be enough firms in a risk-class so that a cross-section analysis will yield statistically significant coefficients. There may not be many more risk-classes (with enough observations) now that the electric utility and railroad industries have been studied. In addition, the MM approach requires estimating expected asset earnings and estimating the capitalized growth potential implicit in stock prices. If it is possible to consider growth and expected earnings without having

2. It is, in fact, this last purpose of making applicable and practical some of the implications of the capital asset pricing model for corporation finance issues that provided the initial motivation for this paper. In this context, if one is familiar with the fair rate of return literature for regulated utilities, for example, an industry where debt is so prevalent, adjusting correctly for leverage is not frequently done and can be very critical.

to specify their exact magnitude at a specific point in time, considerable difficulty and possible measurement errors will be avoided.

The second approach is to run a regression between the observed systematic risk of a stock and a number of accounting and leverage variables in an attempt to explain this observed systematic risk. Unfortunately, without a theory, we do not know which variables to include and which variables to exclude and whether the relationship is linear, multiplicative, exponential, curvilinear, etc. Therefore, this method will also not be used.

A third approach is to measure the systematic risk before and after a new debt issue. The difference can then be attributed to the debt issue directly. An attractive feature of this procedure is that a good estimate of the market value of the incremental debt issue can be obtained. A number of disadvantages, unfortunately, are associated with this direct approach. The difference in the systematic risk may be due not only to the additional debt, but also to the reason the debt was issued. It may be used to finance a new investment project, in which case the project's characteristics will also be reflected in the new systematic risk measure. In addition, the new debt issue may have been anticipated by the market if the firm had some long-run target leverage ratio which this issue will help maintain; conversely, the market may not fully consider the new debt issue if it believes the increase in leverage is only temporary. For these reasons, this seemingly attractive procedure will not be employed.

The last approach, which will be used in this study, is to assume the validity of the MM theory from the outset. Then the observed rate of return of a stock can be adjusted to what *it would have been* over the same time period had the firm no debt and preferred stock in its capital structure. The difference between the observed systematic risk, ${}_B\beta$, and the systematic risk for this adjusted rate of return time series, ${}_A\beta$, can be attributed to leverage, if the MM theory is correct. The final step, then, is to test the MM theory.

To discuss this more specifically, consider the following relationship for the dollar return to the common shareholder from period t − 1 to t:

$$(X - I)_t(1 - \tau)_t - p_t + \Delta G_t = d_t + cg_t \tag{1}$$

where X_t represents earnings before taxes, interest, and preferred dividends and is assumed to be unaffected by fixed commitment obligations; I_t represents interest and other fixed charges paid during the period; τ is the corporation income tax rate; p_t is the preferred dividends paid; ΔG_t represents the change in capitalized growth over the period; and d_t and cg_t are common shareholder dividends and capital gains during the period, respectively.

Equation (1) relates the corporation finance types of variables with the market holding period return important to the investors. The first term on the left-hand-side of (1) is profits after taxes and after interest which is the earnings the common and preferred shareholders receive on their investment for the period. Subtracting out p_t leaves us with the earnings the common shareholder would receive from currently-held assets.

To this must be added any change in capitalized growth since we are trying to explain the common shareholder's market holding period dollar return. ΔG_t

must be added for growth firms to the current period's profits from existing assets since capitalized growth opportunities of the firm—future earnings from new assets over and above the firm's cost of capital which are already reflected in the stock price at $(t-1)$—should change over the period and would accrue to the common shareholder. Assuming shareholders at the start of the period estimated these growth opportunities on average correctly, the expected value of ΔG_t would not be zero, but should be positive. For example, consider growth opportunities five years from now which yield more than the going rate of return and are reflected in today's stock price. These growth opportunities will become one year closer to fruition at time t than at time $t-1$ so that their present value would become larger. ΔG_t then represents this increase in the present value of these future opportunities simply because it is now four years away rather than five.[3]

Since the systematic risk of a common stock is:

$$_B\beta = \frac{\operatorname{cov}(R_{B_t}, R_{M_t})}{\sigma^2(R_{M_t})} \tag{2}$$

where R_{B_t} is the common shareholder's rate of return and R_{M_t} is the rate of return on the market portfolio, then substitution of (1) into (2) yields:

$$_B\beta = \frac{\operatorname{cov}\left[\dfrac{(X-I)(1-\tau)_t - p_t + \Delta G_t}{S_{B_{t-1}}}, R_{M_t}\right]}{\sigma^2(R_{M_t})} \tag{2a}$$

where $S_{B_{t-1}}$ denotes the market value of the common stock at the beginning of the period.

The systematic risk for the same firm over the same period *if* there were no debt and preferred stock in its capital structure is:

$$_A\beta = \frac{\operatorname{cov}(R_{A_t}, R_{M_t})}{\sigma^2(R_{M_t})}$$

$$= \frac{\operatorname{cov}\left[\dfrac{X(1-\tau)_t + \Delta G_t}{S_{A_{t-1}}}, R_{M_t}\right]}{\sigma^2(R_{M_t})} \tag{3}$$

where R_{A_t} and $S_{A_{t-1}}$ represent the rate of return and the market value, respectively, to the common shareholder if the firm had no debt and preferred stock. From (3), we can obtain:

$$_A\beta S_{A_{t-1}} = \frac{\operatorname{cov}[X(1-\tau)_t + \Delta G_t, R_{M_t}]}{\sigma^2(R_{M_t})} \tag{3a}$$

3. Continual awareness of the difficulties of estimating capitalized growth, or changes in growth, especially in conjunction with leverage considerations, for purposes such as valuation or cost of capital is a characteristic common to students of corporation finance. This is the reason for the emphasis on growth in this paper and for presenting a method to neutralize for differences in growth when comparing rates of return.

Next, by expanding and rearranging (2a), we have:

$$_{B}\beta S_{B_{t-1}} = \frac{\text{cov}\,[X(1-\tau)_t + \Delta G_t, R_{M_t}]}{\sigma^2(R_{M_t})} - \frac{\text{cov}\,[I(1-\tau)_t, R_{M_t}]}{\sigma^2(R_{M_t})} - \frac{\text{cov}\,(p_t, R_{M_t})}{\sigma^2(R_{M_t})} \tag{2b}$$

If we assume as an empirical approximation that interest and preferred dividends have negligible covariance with the market, at least relative to the (pure equity) common stock's covariance, then substitution of the LHS of (3a) into the RHS of (2b) yields:[4]

$$_{B}\beta S_{B_{t-1}} = {}_{A}\beta S_{A_{t-1}} \tag{4}$$

or

$$_{A}\beta = \left(\frac{S_B}{S_A}\right)_{t-1} {}_{B}\beta \tag{4a}$$

Because $S_{A_{t-1}}$, the market value of common stock *if* the firm had no debt and preferred stock, is not observable since most firms do have debt and/or preferred stock, a theory is required in order to measure what this quantity *would have been* at $t-1$. The MM theory [10] will be employed for this purpose, that is:

$$S_{A_{t-1}} = (V - \tau D)_{t-1}. \tag{5}$$

Equation (5) indicates that if the Federal government tax subsidy for debt financing, τD, where D is the market value of debt, is subtracted from the observed market value of the firm, V_{t-1} (where V_{t-1} is the sum of S_B, D and the observed market value of preferred), then the market value of an unleveraged firm is obtained. Underlying (5) is the assumption that the firm is near its target leverage ratio so that no more or no less debt subsidy is capitalized already into the observed stock price. The conditions under which this MM relationship hold are discussed carefully in [4].

It is at this point that problems in obtaining satisfactory estimates of $_{A}\beta$ develop, since (4) theoretically holds only for the next period. As a practical matter, the accepted, and seemingly acceptable, method of obtaining estimates of a stock's systematic risk, $_{B}\beta$, is to run a least squares regression between a stock's and market portfolio's *historical* rates of return. Using past data for $_{B}\beta$, it is not clear which *period's* ratio of market values to apply in (4a) to estimate the firm's systematic risk, $_{A}\beta$. There would be no problem if the market value ratios of debt to equity and preferred stock to equity remained relatively stable over the past for each firm, but a cursory look at these data reveals that this is not true for the large majority of firms in our sample. Should we use the market value ratio required in (4a) that was observed at the start of our regression period, at the end of our regression period, or some kind of average over the period? In addition, since these different observed ratios will give us different estimates for $_{A}\beta$, it is not clear, without some criterion, how we should select from among the various estimates.

4. This general method of arriving at (4) was suggested by the comments of William Sharpe, one of the discussants of this paper at the annual meeting. A much more cumbersome and less general derivation of (4) was in the earlier version.

It is for this purpose—to obtain a standard—that a more cumbersome and more data demanding approach to obtain estimates of $_A\beta$ is suggested. Given the large fluctuations in market leverage ratios, intuitively it would appear that the firm's risk is more stable than the common stock's risk. In that event, a leverage-free rate of return time series for each firm should be derived and the market model applied to this time series directly. In this manner, the beta coefficient would give us a *direct* estimate of $_A\beta$ which can then be used as a criterion to determine if any of the market value ratios discussed above can be applied to (4a) successfully.

For this purpose, the "would-have-been" rate of return for the common stock if the firm had no debt and preferred is:

$$R_{A_t} = \frac{X_t(1-\tau)_t + \Delta G_t}{S_{A_{t-1}}}. \tag{6}$$

The numerator of (6) can be rearranged to be:

$$X_t(1-\tau)_t + \Delta G_t \equiv [(X-I)_t(1-\tau)_t - p_t + \Delta G_t] + p_t + I_t(1-\tau)_t.$$

Substituting (1):

$$X_t(1-\tau)_t + \Delta G_t = [d_t + cg_t] + p_t + I_t(1-\tau)_t.$$

Therefore, (6) can be written as:

$$R_{A_t} = \frac{d_t + cg_t + p_t + I_t(1-\tau)_t}{S_{A_{t-1}}}. \tag{7}$$

Since $S_{A_{t-1}}$ is unobservable for the firms with leverage, the MM theory, equation (5), will be employed; then:

$$R_{A_t} = \frac{d_t + cg_t + p_t + I_t(1-\tau)_t}{(V-\tau D)_{t-1}}. \tag{8}$$

The observed rate of return on the common stock is, of course:

$$R_{B_t} = \frac{(X-I)_t(1-\tau)_t - p_t + \Delta G_t}{S_{B_{t-1}}} = \frac{d_t + cg_t}{S_{B_{t-1}}}. \tag{9}$$

Equation (8) is the rate of return to the common shareholder of the same firm and over the same period of time as (9). However, in (8) there are the underlying assumptions that the firm never had any debt and preferred stock and that the MM theory is correct; (9) incorporates the exact amount of debt and preferred stock that the firm actually did have over this time period and no leverage assumption is being made. Both (8) and (9) are now in forms where they can be measured with available data. One can note that it is unnecessary to estimate the change in growth, or earnings from current assets, since these should be captured in the market holding period return, $d_t + cg_t$.

Using CRSP data for (9) and both CRSP and Compustat data for the components of (8), a time series of yearly R_{A_t} and R_{B_t} for $t = 1948$-1967 were derived for 304 different firms. These 304 firms represent an exhaustive sample of the firms with complete data on both tapes for all the years.

Staff/916
Storm/7

A number of "market model" [1, 12] variants were then applied to these data. For each of the 304 firms, the following regressions were run:

$$R_{Ait} = {}_A\alpha_i + {}_A\beta_i R_{Mt} + {}_A\epsilon_{it} \tag{10a}$$

$$R_{Bit} = {}_B\alpha_i + {}_B\beta_i R_{Mt} + {}_B\epsilon_{it} \tag{10b}$$

$$\ln(1 + R_{Ait}) = {}_{AC}\alpha_i + {}_{AC}\beta_i \ln(1 + R_{M_t}) + {}_{AC}\epsilon_{it} \tag{10c}$$

$$\ln(1 + R_{Bit}) = {}_{BC}\alpha_i + {}_{BC}\beta_i \ln(1 + R_{M_t}) + {}_{BC}\epsilon_{it} \tag{10d}$$

$$i = 1, 2, \ldots, 304$$
$$t = 1948\text{-}1967$$

where R_{M_t} is the observed NYSE arithmetic stock market rate of return with dividends reinvested, α_i and β_i are constants for each firm-regression, and the usual conditions are assumed for the properties of the disturbance terms, ϵ_{it}. Equations (10c) and (10d) are the continuously-compounded rate of return versions of (10a) and (10b), respectively.[5]

III. The Results

An abbreviated table of the regression results for each of the four variants, equations (10a)-(10d), summarized across the 304 firms is shown in Table 1.

The first column designated "mean" is the average of the statistic (indicated by the rows) over all 304 firms. Therefore, the mean ${}_A\hat{\alpha}$ of 0.0221 is the intercept term of equation (10a) averaged over 304 different firm-regressions. The second and third columns give the deviation measures indicated, of the 304 point estimates of, say, ${}_A\hat{\alpha}$. The mean standard error of estimate in the last column is the average over 304 firms of the individual standard errors of estimate.

The major conclusion drawn from Table 1 is the following mean β comparisons:

$${}_B\hat{\beta} > {}_A\hat{\beta}, \text{ i.e., } 0.9190 > 0.7030$$

$${}_{BC}\hat{\beta} > {}_{AC}\hat{\beta}, \text{ i.e., } 0.9183 > 0.7263.$$

The directional results of these betas, assuming the validity of the MM theory, are not imperceptible and clearly are not negligible differences from the investor's point of view. This is obtained in spite of all the measurement and data problems associated with estimating a time series of the RHS of (8) for

5. Because the R_{M_t} used in equations (10) is defined as the observed stock market return, and since adjusting for capital structure is the major purpose of this exercise, it was decided that the same four regressions should be replicated on a leverage-adjusted stock market rate of return. The major reason for this additional adjustment is the belief that the rates of return over time and their relationship with the market are more stable when we can abstract from all changes in leverage and get at the underlying risk of all firms.

For the 221 firms (out of the total 304) whose fiscal years coincide with the calendar year, average values for the components of the RHS of (8) were obtained for each year so that R_{M_t} could be adjusted in the same way as for the individual firms—a yearly time series of stock market rates of return, if all the firms on the NYSE had no debt and no preferred in their capital structure, was derived. The results, when using this adjusted market portfolio rate of return time series, were not very different from the results of equations (10), and so will not be reported here separately.

TABLE 1
SUMMARY RESULTS OVER 304 FIRMS OF EQUATIONS (10a)-(10d)

	Mean	Mean Absolute Deviation*	Standard Deviation	Mean Standard Error of Estimate
${}_{A}\hat{\alpha}$	0.0221	0.0431	0.0537	0.0558
${}_{A}\hat{\beta}$	0.7030	0.2660	0.3485	0.2130
${}_{A}\hat{R}^2$	0.3799	0.1577	0.1896	
${}_{A}\hat{\rho}$	0.0314			
${}_{B}\hat{\alpha}$	0.0187	0.0571	0.0714	0.0720
${}_{B}\hat{\beta}$	0.9190	0.3550	0.4478	0.2746
${}_{B}\hat{R}^2$	0.3864	0.1578	0.1905	
${}_{B}\hat{\rho}$	0.0281			
${}_{AC}\hat{\alpha}$	0.0058	0.0427	0.0535	0.0461
${}_{AC}\hat{\beta}$	0.7263	0.2700	0.3442	0.2081
${}_{AC}\hat{R}^2$	0.3933	0.1586	0.1909	
${}_{AC}\hat{\rho}$	0.0268			
${}_{BC}\hat{\alpha}$	−0.0052	0.0580	0.0729	0.0574
${}_{BC}\hat{\beta}$	0.9183	0.3426	0.4216	0.2591
${}_{BC}\hat{R}^2$	0.4012	0.1602	0.1922	
${}_{BC}\hat{\rho}$	0.0262			

* Defined as: $\dfrac{\sum_{i=1}^{N}|x_i - \bar{x}|}{N}$, where $N = 304$. $\hat{\rho}$ = first order serial correlation coefficient.

each firm. One of the reasons for the "traditional" theory position on leverage is precisely this point—that small and reasonable amounts of leverage cannot be discerned by the market. In fact, if the MM theory is correct, leverage has explained as much as, roughly, 21 to 24 per cent of the value of the mean β.

We can also note that if the covariance between the asset and market rates of return, as well as the market variance, was constant over time, then the systematic risk from the market model is related to the expected rate of return by the capital asset pricing model. That is:

$$E(R_{A_t}) = R_{F_t} + {}_{A}\beta[E(R_{M_t}) - R_{F_t}] \quad (11a)$$

$$E(R_{B_t}) = R_{F_t} + {}_{B}\beta[E(R_{M_t}) - R_{F_t}] \quad (11b)$$

Equation (11a) indicates the relationship between the expected rate of return for the common stock shareholder of a debt-free and preferred-free firm, to the systematic risk, ${}_{A}\beta$, as obtained in regressions (10a) or (10c). The LHS of (11a) is the important ρ^{τ} for the MM cost of capital. The MM theory [9, 10] also predicts that shareholder expected yield must be higher (for the same real firm) when the firm has debt than when it does not. Financial risk is greater, therefore, shareholders require more expected return. Thus, $E(R_{B_t})$ must be greater than $E(R_{A_t})$. In order for this MM prediction to be true, from (11a) and (11b) it can be observed that ${}_{B}\beta$ must be greater than ${}_{A}\beta$, which is what we obtained.

Using the results underlying Table 1, namely the firm and stock betas, as the

Staff/916
Storm/9

criterion for selecting among the possible observed market value ratios that can be used, if any, for (4), the following cross-section regressions were run:

$$({}_{B}\beta)_i = a_1 + b_1 \left(\frac{S_A}{S_B} {}_{A}\beta \right)_i + u_{1i} \qquad i = 1, 2, \ldots, 102 \qquad (12a)$$

$$({}_{BO}\beta)_i = a_2 + b_2 \left(\frac{S_A}{S_B} {}_{AO}\beta \right)_i + u_{2i} \qquad i = 1, 2, \ldots, 102 \qquad (12b)$$

$$({}_{A}\beta)_i = a_3 + b_3 \left(\frac{S_B}{S_A} {}_{B}\beta \right)_i + u_{3i} \qquad i = 1, 2, \ldots, 102 \qquad (13a)$$

$$({}_{AO}\beta)_i = a_4 + b_4 \left(\frac{S_B}{S_A} {}_{BO}\beta \right)_i + u_{4i} \qquad i = 1, 2, \ldots, 102 \qquad (13b)$$

Because the preferred stock market values were not as reliable as debt, only the 102 firms (out of 304) that did not have preferred in any of the years were used. The test for the adequacy of this alternative approach, equation (4), to adjust the systematic risk of common stocks for the underlying firm's capital structure, is whether the intercept term, a, is equal to zero, and the slope coefficient, b, is equal to one in the above regressions (as well as, of course, a high R^2)—these requirements are implied by (4). The results of this test would also indicate whether future "market model" studies that only use common stock rates of return without adjusting, or even noting, for the firm's debt-equity ratio will be adequate. The total firm's systematic risk may be stable (as long as the firm stays in the same risk-class), whereas the common stock's systematic risk may not be stable merely because of unanticipated capital structure changes—the data underlying Table 3 indicate that there were very few firms which did not have major changes in their capital structure over the twenty years studied.

The results of these regressions, when using the average S_A and average S_B over the twenty years for each firm, are shown in the first column panel of Table 2. These regressions were then replicated twice, first using the December 31, 1947 values of S_{A_i} and S_{B_i} instead of the twenty-year average for each firm, and then substituting the December 31, 1966 values of S_{A_i} and S_{B_i} for the 1947 values. These results are in the second and third panels of Table 2.[6]

From the first panel of Table 2, it appears that this alternative approach via (4a) for adjusting the systematic risk for the firm's leverage is quite

6. The point should be made that we are not merely regressing a variable on itself in (12) and (13). (12a) and (12b) can be interpreted as correlating the ${}_{B}\beta_i$ obtained from (10b) and (10d)—the LHS variable in (12a) and (12b)—against the ${}_{B}\beta_i$ obtained from rearranging (4)—the RHS variable in (12a) and (12b)—to determine whether the use of (4) is as good a means of obtaining ${}_{B}\beta_i$ as the direct way via the equations (10). We would be regressing a variable on itself only if the ${}_{A}\beta_i$ were calculated using (4a), and then the ${}_{A}\beta_i$ thus obtained, inserted into (12a) and (12b).

Instead, we are obtaining ${}_{A}\beta_i$ using the MM model in *each* of the twenty years so that a leverage-adjusted 20 year time series of R_{A_i} is derived. Of course, if there were no data nor measurement problems, and if the debt-to-equity ratio were perfectly stable over this twenty year period for each firm, then we should obtain perfect correlation in (12a) and (12b), with $a = 0$ and $b = 1$, as (4) would be an identity.

Staff/916
Storm/10

TABLE 2

RESULTS FOR THE EQUATIONS (12a), (12b), (13a), AND (13b)*

	Using 20-Year Average for $\left(\frac{S_A}{S_B}\right)_i$			Using 1947 Value for $\left(\frac{S_A}{S_B}\right)_i$			Using 1966 Value for $\left(\frac{S_A}{S_B}\right)_i$		
	a	b	R^2	a	b	R^2	a	b	R^2
Eq. (12a)	−0.022 (0.021)	1.062 (0.021)	0.962	0.150 (0.048)	0.842 (0.045)	0.781	0.085 (0.041)	0.905 (0.038)	0.849
	constant suppressed	1.042 (0.009)	0.962	constant suppressed	0.966 (0.021)	0.781	constant suppressed	0.976 (0.017)	0.849
Eq. (12b)	−0.003 (0.013)	1.016 (0.013)	0.984	0.159 (0.047)	0.816 (0.044)	0.773	0.124 (0.037)	0.843 (0.034)	0.859
	constant suppressed	1.014 (0.005)	0.984	constant suppressed	0.952 (0.019)	0.773	constant suppressed	0.947 (0.015)	0.859

	Using 20-Year Average for $\left(\frac{S_B}{S_A}\right)_i$			Using 1947 Value for $\left(\frac{S_B}{S_A}\right)_i$			Using 1966 Value for $\left(\frac{S_B}{S_A}\right)_i$		
	a	b	R^2	a	b	R^2	a	b	R^2
Eq. (13a)	0.030 (0.016)	0.931 (0.017)	0.969	0.112 (0.028)	0.843 (0.030)	0.888	0.080 (0.027)	0.898 (0.030)	0.902
	constant suppressed	0.960 (0.007)	0.969	constant suppressed	0.948 (0.015)	0.888	constant suppressed	0.976 (0.014)	0.902
Eq. (13b)	0.007 (0.010)	0.979 (0.011)	0.988	0.119 (0.026)	0.852 (0.028)	0.902	0.063 (0.026)	0.942 (0.029)	0.911
	constant suppressed	1.004 (0.012)	0.911	constant suppressed	0.967 (0.013)	0.902	constant suppressed	1.005 (0.012)	0.911

* Standard error in parentheses.

satisfactory (at least with respect to our sample of firms and years) only if long-run averages of S_A and S_B are used. The second and third panels indicate that the equations (8) and (10) procedure is markedly superior when only one year's market value ratio is used as the adjustment factor. The annual debt-to-equity ratio is much too unstable for this latter procedure.

Thus, when forecasting systematic risk is the primary objective—for example, for portfolio decisions or for estimating the firm's cost of capital to apply to prospective projects—a long-run forecasted leverage adjustment is required. Assuming the firm's risk is more stable than the common stock's risk,[7] and if there is some reason to believe that a better forecast of the firm's future leverage can be obtained than using simply a past year's (or an average of past years') leverage, it should be possible to improve the usual extrapolation forecast of a stock's systematic risk by forecasting the total firm's systematic risk first, and then using the independent leverage estimate as an adjustment.

IV. Tests of the MM vs. Traditional Theories of Corporation Finance

To determine if the difference, ${}_B\beta - {}_A\beta$, found in this study is indeed the correct effect of leverage, some confirmation of the MM theory (since it was assumed to be correct up to this point) from the systematic risk approach is needed. Since a direct test by this approach seems impossible, an indirect, inferential test is suggested.

The MM theory [9, 10] predicts that for firms in the same risk-class, the capitalization rate if all the firms were financed with only common equity, $E(R_A)$, would be the same—regardless of the actual amount of debt and preferred each individual firm had. This would imply, from (11a), that if $E(R_A)$ must be the same for all firms in a risk-class, so must ${}_A\beta$. And if these firms had different ratios of fixed commitment obligations to common equity, this difference in financial risk would cause their observed ${}_B\beta$s to be different.

The major competing theory of corporation finance is what is now known as the "traditional theory," which has contrary implications. This theory predicts that the capitalization rate for common equity, $E(R_B)$, (sometimes called the required or expected stock yield, or expected earnings-price ratio) is constant, as debt is increased, up to some critical leverage point (this point being a function of gambler's ruin and bankruptcy costs).[8] The clear implication of this constant, horizontal, equity yield (or their initial downward sloping cost of capital curve) is that changes in market or covariability risk are assumed not to be discernible to the shareholders as debt is increased. Then the traditional theory is saying that the ${}_B\beta$s, a measure of this covariability risk, would be the same for all firms in a given risk-class irregardless of differences in leverage, as long as the critical leverage point is not reached.

Since there will always be unavoidable errors in estimating the β's of indi-

7. A faint, but possible, empirical indication of this point may be obtained from Table 1. The ratio of the mean point estimate to the mean standard error of estimate is less for the firm β than for the stock β in both the discrete and continuously compounded cases.

8. This interpretation of the traditional theory can be found in [9, especially their figure 2, page 275, and their equation (13) and footnote 24 where reference is made to Durand and Graham and Dodd].

Staff/916
Storm/12

TABLE 3
INDUSTRY MARKET VALUE RATIOS OF PREFERRED STOCK (P) AND DEBT (D) TO COMMON STOCK (S)

Industry Number	Industry	Number of Firms		P/S			D/S			$\frac{P+D}{S}$	
20	Food and Kindred Products	30	Mean*		0.22			0.81			1.04	
			ROM**	0.00		1.18	0.00		3.55	0.00		4.13
			ROCR***	0.00		2.52	0.00		8.10	0.00		10.01
28	Chemicals and Allied Products	30	Mean		0.07			0.25			0.33	
			ROM	0.00		0.51	0.00		0.90	0.00		1.20
			ROCR	0.00		1.54	0.00		2.07	0.00		2.92
29	Petroleum and Coal Products	18	Mean		0.06			0.22			0.27	
			ROM	0.00		0.26	0.00		0.55	0.03		0.57
			ROCR	0.00		0.83	0.00		1.54	0.00		2.30
33	Primary Metals	21	Mean		0.14			0.54			0.68	
			ROM	0.00		1.31	0.00		1.95	0.00		3.04
			ROCR	0.00		4.69	0.00		6.20	0.00		7.49
35	Machinery, except Electrical	28	Mean		0.07			0.33			0.40	
			ROM	0.00		0.49	0.00		1.92	0.00		2.32
			ROCR	0.00		1.28	0.00		6.92	0.00		7.62

TABLE 3 (*Continued*)

Industry Number	Industry	Number of Firms		P/S			D/S			$\frac{P+D}{S}$		
36	Electrical Machinery & Equipment	13	Mean		0.06			0.35			0.41	
			ROM	0.00		0.29	0.00		1.31	0.01		1.33
			ROCR	0.00		1.13	0.00		2.53	0.00		2.53
37	Transportation Equipment	24	Mean		0.08			0.38			0.47	
			ROM	0.00		0.54	0.00		0.93	0.00		1.32
			ROCR	0.00		2.33	0.00		3.76	0.00		6.09
49	Utilities	27	Mean		0.25			1.03			1.28	
			ROM	0.00		0.53	0.49		2.64	0.52		3.12
			ROCR	0.00		3.12	0.12		16.40	0.12		19.52
53	Dep't Stores, Order Houses & Vending Mach. Operators	17	Mean		0.13			0.49			0.62	
			ROM	0.00		0.38	0.01		1.52	0.01		1.87
			ROCR	0.00		1.09	0.00		3.19	0.00		3.66

* "Mean" refers to the average ratio over 20 years and over all firms in the industry.
** "Range of Means" (ROM) refers to the lowest firm's mean (over 20 years) ratio and the highest firm's mean (over 20 years) ratio in the industry.
*** "Range of Company Ranges" (ROCR) refers to the lowest and highest ratio in the industry, regardless of the year.

vidual firms and in specifying a risk-class, we would not expect to find a set of firms with identical systematic risk. But by specifying reasonable a priori risk-classes, if the individual firms had closer or less scattered $_A\beta$s than $_B\beta$s, then this would support the MM theory and contradict the traditional theory. If, instead, the $_B\beta$s were not discernibly more diverse than the $_A\beta$s, and the leverage ratio differed considerably among firms, then this would indicate support for the traditional theory.[9]

In order to test this implication, risk-classes must be first specified. The SEC two-digit industry classification was used for this purpose. Requiring enough firms for statistical reasons in any given industry, nine risk-classes were specified that had at least 13 firms; these nine classes are listed in Table 3 with their various leverage ratios.[10] It is clear from this table that our first requirement is met—that there is a considerable range of leverage ratios among firms in a risk-class and also over the twenty-year period.

Three tests will be performed to distinguish between the MM and traditional theories. The first is simply to calculate the standard deviation of the unbiased β estimates in a risk-class. The second is a chi-square test of the distribution of β's in an industry compared to the distribution of the β's in the total sample. Finally, an analysis of variance test on the estimated variance of the β's between industries, as opposed to within industries, is performed. In all tests, only the point estimate of β (which should be unbiased) for each stock and firm is used.[11]

The first test is reported in Table 4. If we compare the standard deviation of $_{AC}\beta$ with the standard deviation of $_{BC}\beta$ by industries (or risk-classes), we can note that $\sigma(_{AC}\beta)$ is less than $\sigma(_{BC}\beta)$ for eight out of the nine classes. The probability of obtaining this is only 0.0195, given a 50% probability that $\sigma(_{AC}\beta)$ can be larger or smaller than $\sigma(_{BC}\beta)$. These results indicate that the systematic risk of the firms in a given risk-class, if they were all financed only with common equity, is much less diverse than their observed stock's systematic risk. This supports the MM theory, at least in contrast to the traditional theory.[12]

9. The traditional theory also implies that $E(R_A)$ is equal to $E(R_B)$ for all firms. Unfortunately, we do not have a functional relationship between these traditional theory capitalization rates and the measured βs of this study. Clearly, since the $_A\beta$s were obtained assuming the validity of the MM theory, they would not be applicable for the traditional theory. In fact, no relationship between the $_A\beta$ and $_B\beta$ for a given firm, or for firms in a given risk-class, can be specified as was done for the capitalization rates.

10. The tenth largest industry had only eight firms. For our purpose of testing the uniformity of firm βs relative to stock βs within a risk-class, the use of the two-digit industry classification as a proxy does not seem as critical as, for instance, its use for the purpose of performing an MM valuation model study [8] wherein the ρ^τ must be pre-specified to be exactly the same for all firms in the industry.

11. Since these βs are estimated in the market model regressions with error, precise testing should incorporate the errors in the β estimation. Unfortunately, to do this is extremely difficult and more importantly, requires the normality assumption for the market model disturbance term. Since there is considerable evidence that is contrary to this required assumption [see 3], our tests will ignore the β measurement error entirely. But ignoring this is partially corrected in our first and third tests since means and variances of these point estimate βs must be calculated, and this procedure will "average out" the individual measurement errors by the factor 1/N.

12. Of course, there could always be another theory, as yet not formulated, which could be even

TABLE 4
MEAN AND STANDARD DEVIATION OF INDUSTRY β's

Industry Number	Industry	Number of Firms		$_A\beta$	$_B\beta$	$_{AC}\beta$	$_{BC}\beta$
20	Food & Kindred Products	30	Mean β	0.515	0.815	0.528	0.806
			σ(β)	0.232	0.448	0.227	0.424
28	Chemicals & Allied Products	30	Mean β	0.747	0.928	0.785	0.946
			σ(β)	0.237	0.391	0.216	0.329
29	Petroleum & Coal Products	18	Mean β	0.633	0.747	0.656	0.756
			σ(β)	0.144	0.188	0.148	0.176
33	Primary Metals	21	Mean β	1.036	1.399	1.106	1.436
			σ(β)	0.223	0.272	0.197	0.268
35	Machinery, except Electrical	28	Mean β	0.878	1.037	0.917	1.068
			σ(β)	0.262	0.240	0.271	0.259
36	Electrical Machinery and Equipment	13	Mean β	0.940	1.234	0.951	1.164
			σ(β)	0.320	0.505	0.283	0.363
37	Transportation Equipment	24	Mean β	0.860	1.062	0.875	1.048
			σ(β)	0.225	0.313	0.225	0.289
49	Utilities	27	Mean β	0.160	0.255	0.166	0.254
			σ(β)	0.086	0.133	0.098	0.147
53	Department Stores, etc.	17	Mean β	0.652	0.901	0.692	0.923
			σ(β)	0.187	0.282	0.198	0.279

Our second test, the chi-square test, requires us to rank our 300 $_A\beta$s into ten equal categories, each with 30 $_A\beta$s (four miscellaneous firms were taken out randomly). By noting the value of the highest and lowest $_A\beta$ for each of the ten categories, a distribution of the number of $_A\beta$s in each category, by risk-class, can be obtained. This was then repeated for the other three betas. To test whether the distribution for each of the four β's and for each of the risk-classes follows the expected uniform distribution, a chi-square test was performed.[13]

Even with just casual inspection of these distributions of the betas by risk-class, it is clear that two industries, primary metals and utilities, are so highly skewed that they greatly exaggerate our results.[14] Eliminating these

more strongly supported than the MM theory. If we compare $\sigma(_A\beta)$ to $\sigma(_B\beta)$ by risk-classes in Table 4, precisely the same results are obtained as those reported above for the continuously-compounded betas.

13. By risk-classes, seven of the nine chi-square values of $_A\beta$ are larger than those of $_B\beta$, as are eight out of nine for the continuously-compounded betas. This would occur by chance with probabilities of 0.0898 and 0.0195, respectively, if there were a 50% chance that either the firm or stock chi-square value could be larger. Nevertheless, if we inspect the individual chi-square values by risk-class, we note that most of them are large so that the probabilities of obtaining these values are highly unlikely. For all four βs, the distributions for most of the risk-classes are nonuniform.

14. Primary metals have extremely large betas; utilities have extremely small betas.

two industries, and also two miscellaneous firms so that an even 250 firms are in the sample, new upper and lower values of the β's were obtained for each of the ten class intervals and for each of the four β's.

In Table 5, the chi-square values are presented; for the total of all risk-classes, the probability of obtaining a chi-square value less than 120.63 is over 99.95% (for $_{A}\beta$), whereas the probability of obtaining a chi-square value less than 99.75 is between 99.5% and 99.9% (for $_{B}\beta$). More sharply contrasting results are obtained when $_{AC}\beta$ is compared to $_{BC}\beta$. For $_{AC}\beta$, the probability of obtaining less than 128.47 is over 99.95%, whereas for $_{BC}\beta$, the probability of obtaining less than 78.65 is only 90.0%. By abstracting from financial risk, the underlying systematic risk is much less scattered when grouped into risk-classes than when leverage is assumed not to affect the systematic risk. The null hypothesis that the β's in a risk-class come from the same distribution as all β's is rejected for $_{AC}\beta$, but not for $_{BC}\beta$ (at the 90% level). Although this, in itself, does not tell us *how* a risk-class differs from the total market, an inspection of the distributions of the betas by risk-class underlying Table 5 does indicate more clustering of the $_{AC}\beta$s than the $_{BC}\beta$s so that the MM theory is again favored over the traditional theory.

The analysis of variance test is our last comparison of the implications of the two theories. The ratio of the estimated variance between industries to the estimated variance within the industries (the F-statistic) when the seven

TABLE 5
CHI-SQUARE RESULTS FOR ALL β'S AND ALL INDUSTRIES
(EXCEPT UTILITIES AND PRIMARY METALS)

Industry		$_{A}\beta$	$_{B}\beta$	$_{AC}\beta$	$_{BC}\beta$
Food and Kindred	Chi-Square	18.67	11.33	26.00	9.33
	$P\{\chi^2 < \}^* =$	95-97.5%	70-75%	99.5-99.9%	50-60%
Chemicals	Chi-Square	9.33	10.67	12.00	7.33
	$P\{\chi^2 < \} =$	50-60%	60-70%	75-80%	30-40%
Petroleum	Chi-Square	17.56	25.33	18.67	22.00
	$P\{\chi^2 < \} =$	95-97.5%	99.5-99.9%	95-97.5%	99-99.5%
Machinery	Chi-Square	19.14	12.00	24.86	9.14
	$P\{\chi^2 < \} =$	97.5-98%	75-80%	99.5-99.9%	50-60%
Electrical Machinery	Chi-Square	13.92	7.77	12.38	9.31
	$P\{\chi^2 < \} =$	80-90%	40-50%	80-90%	50-60%
Transportation Equipment	Chi-Square	15.17	16.83	13.50	6.83
	$P\{\chi^2 < \} =$	90-95%	90-95%	80-90%	30-40%
Dep't Stores	Chi-Square	14.18	3.59	14.18	3.59
	$P\{\chi^2 < \} =$	80-90%	5-10%	80-90%	5-10%
Miscellaneous	Chi-Square	12.67	12.22	6.89	11.11
	$P\{\chi^2 < \} =$	80-90%	80-90%	30-40%	70-75%
Total	Chi-Square	120.63	99.75	128.47	78.65
	$P\{\chi^2 < \} =$	over 99.95%	99.5-99.90%	over 99.95%	90.0%

* Example: $P\{\chi^2 < 18.67\} = 95\text{-}97.5\%$ for 9 degrees of freedom.

industries are considered (again, the two obviously skewed industries, primary metals and utilities, were eliminated) is less for $_B\beta$ (F = 3.90) than for $_A\beta$ (F = 9.99), and less for $_{BO}\beta$ (F = 4.18) than for $_{AO}\beta$ (F = 10.83). The probability of obtaining these F-statistics for $_A\beta$ and $_{AO}\beta$ is less than 0.001, but for $_B\beta$ and $_{BO}\beta$ greater than or equal to 0.001. These results are consistent with the results obtained from our two previous tests. The MM theory is more compatible with the data than the traditional theory.[15]

V. Conclusions

This study attempted to tie together some of the notions associated with the field of corporation finance with those associated with security and portfolio analyses. Specifically, if the MM corporate tax leverage propositions are correct, then approximately 21 to 24% of the observed systematic risk of common stocks (when averaged over 304 firms) can be explained merely by the added financial risk taken on by the underlying firm with its use of debt and preferred stock. Corporate leverage does count considerably.

To determine whether the MM theory is correct, a number of tests on a contrasting implication of the MM and "traditional" theories of corporation finance were performed. The data confirmed MM's position, at least vis-à-vis our interpretation of the traditional theory's position. This should provide another piece of evidence on this controversial topic.

Finally, if the MM theory and the capital asset pricing model are correct, and if the adjustments made in equations (8) or (4a) result in accurate measures of the systematic risk of a leverage-free firm, the possibility is greater, without resorting to a fullblown risk-class study of the type MM did for the electric utility industry [8], of estimating the cost of capital for individual firms.

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15. All of our tests, it should be emphasized, although consistent, are only inferential. Aside from assuming that the two-digit SEC industry classification is a good proxy for risk-classes and that the errors in estimating the individual βs can be safely ignored, the tests rely on the two theories exhausting all the reasonable theories on leverage. But there is always the use of another line of reasoning. If the results of the MM electric utility study [8] are correct, and if these results can be generalized to all firms and to all risk-classes, then it can be claimed that the MM theory is universally valid. Then our result in Section III does indicate the correct effect of the firm's capital structure on the systematic risk of common stocks.

Staff/916
Storm/18

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CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 917

Exhibits in Support
Of Opening Testimony

June 4, 2010

		PGE's Exhibit 1206: Estimated Earnings Growth Rates					Staff Compound Average Dividend Growth Rates[d/]	Growth Rates: Staff vs. PGE
		Value Line[a/] (a)	Zacks[b/] (b)	Yahoo![b/] (c)	Reuters[b/] (d)	Average[c/] (e)	(f)	(g)
1	Allegheny Energy, Inc.	7.0	16.0	14.0	7.5	11.1	6.9%	-4.2%
2	ALLETE, Inc.	nmf	4.0	4.0	7.0	5.0	2.8%	-2.2%
3	Alliant Energy Corporation	4.5	3.0	4.3	4.0	4.0	4.3%	0.3%
4	Ameren Corporation	1.0	4.0	3.0	4.0	3.0	3.4%	0.4%
5	American Electric Power Co.	3.0	3.3	3.0	4.7	3.5	3.7%	0.2%
6	Avista Corporation	6.5	5.0	5.0	4.5	5.3	5.6%	0.4%
7	Cleco Corporation	9.5	9.0	9.0	9.7	9.3	5.5%	-3.8%
8	CMS Energy Corporation	10.0	5.8	5.6	5.8	6.8	6.5%	-0.3%
9	DPL Inc.	8.5	6.2	7.1	15.0	9.2	4.4%	-4.8%
10	DTE Energy Company	7.5	4.5	3.0	3.5	4.6	4.2%	-0.5%
11	Duke Energy Corporation	5.0	4.3	3.6	3.7	4.2	3.7%	-0.5%
12	Edison International	4.5	5.0	1.0	2.4	3.2	4.2%	1.0%
13	Empire District Electric Co.	6.0	na	6.0	34.0	15.3	3.0%	-12.3%
14	Entergy Corporation	6.0	4.7	6.8	8.5	6.5	4.1%	-2.4%
15	FPL Group, Inc.	8.0	7.8	7.9	7.9	7.9	4.2%	-3.6%
16	Great Plains Energy Inc.	0.5	5.0	5.0	4.8	3.8	4.9%	1.1%
17	Hawaiian Electric Industries, Inc.	7.0	11.3	10.5	3.0	8.0	2.6%	-5.4%
18	IDACORP, Inc.	4.5	5.0	5.0	5.0	4.9	4.0%	-0.9%
19	MGE Energy, Inc.	6.0	5.0	5.0	5.0	5.3	3.1%	-2.2%
20	Northwestern Corporation	9.3	7.7	7.0	na	8.0		
21	OGE Energy Corp.	4.5	6.0	6.0	5.0	5.4	3.4%	-2.0%
22	PG&E Corporation	6.5	7.7	7.3	7.0	7.1	4.9%	-2.2%
23	Pinnacle West Capital Corp.	3.0	8.0	8.0	1.3	5.1	3.0%	-2.1%
24	Portland General Electric	3.5	6.7	6.8	6.3	5.8	4.2%	-1.6%
25	Progress Energy Inc.	6.0	4.5	4.5	5.2	5.0	2.8%	-2.2%
26	Southern Company	4.5	7.6	4.5	5.0	5.4	3.9%	-1.5%
27	TECO Energy, Inc.	4.5	10.8	9.8	7.7	8.2	3.9%	-4.3%
28	UniSource Energy Corporation	17.0	5.0	5.0	na	9.0	5.2%	-3.8%
29	Westar Energy, Inc.	4.5	5.0	3.7	3.9	4.3	3.6%	-0.6%
30	Wisconsin Energy Corporation	8.0	8.3	9.9	8.4	8.7	6.2%	-2.4%
31	Xcel Energy Inc.	6.5	5.7	7.3	6.4	6.5	3.6%	-2.8%
	Average	6.1	6.4	6.1	6.8	6.4	4.2%	-2.2%

Notes and Sources:

a/ Value Line Investment Survey Issue 1 (dated November 27, 2009), the Standard Issue 5 and Small and Mid Cap Issue 5 (dated September 25, 2009) and Issue 11 (dated November 6, 2009).

b/ Sources are analysts' forecasts reported on the Internet on December 18, 2009.

c/ Average of analysts' forecasts including Value Line.

d/ Staff's estimated estimated average dividend growth rates on geometric basis for 2011 - 2025. The underlying rates were used in Staff's multistage DCF models.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 918

Exhibits in Support
Of Opening Testimony

June 4, 2010

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Storm/1

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Rationality and Analysts' Forecast Bias

TERENCE LIM*

ABSTRACT

This paper proposes and tests a quadratic-loss utility function for modeling corporate earnings forecasting, where financial analysts trade off bias to improve management access and forecast accuracy. Optimal forecasts with minimum expected error are optimistically biased and exhibit predictable cross-sectional variation related to analyst and company characteristics. Empirical evidence from individual analyst forecasts is consistent with the model's predictions. These results suggest that positive and predictable bias may be a rational property of optimal earnings forecasts. Prior studies using classical notions of unbiasedness may have prematurely dismissed analysts' forecasts as being irrational or inaccurate.

A LARGE BODY OF RESEARCH has examined the properties of financial analysts' earnings forecasts within the context of the rational expectations hypothesis. Earnings estimates from brokerage firms are systematically collected by services such as I/B/E/S, Zacks, Standard and Poor's, and First Call, and are routinely held to the "market test" every three months. Because analysts' livelihoods depend on the accuracy of their forecasts, it seems reasonable to treat these forecasts as if they were the analysts' best expectations.

Prior empirical evidence suggests that analysts' forecasts of corporate earnings do not meet the classical standards of the rational expectations hypothesis. Earnings forecasts have been found to be positively biased,[1] and the extent of bias is predictable from publicly available information.[2]

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[1] Abarbanell (1991), Brown, Foster, and Noreen (1985), and Stickel (1990), using Value Line, I/B/E/S, and Zacks data sources, respectively, find that analysts' earnings forecasts are systematically overoptimistic.

[2] Abarbanell and Bernard (1992) and Klein (1990) show that analysts fail to incorporate information in past earnings announcements and stock returns, respectively; Das, Levine, and Sivaramakrishnan (1998), Ackert and Athanassakos (1997), and Han, Manry, and Shaw (1998) document that companies with greater past earnings variability or earnings forecast uncertainty are associated with more optimistic bias; Peters (1993) finds that positive earnings surprises (underestimated earnings) occur less frequently among small stocks.

In this paper, I argue that the unbiasedness of forecasts need not mean they are best or most accurate. Statistically optimal forecasts, in the sense of minimum expected squared error, may be positively and predictably biased. Consider an environment in which professional financial analysts have been delegated the task of producing accurate forecasts of company earnings. The company's management is a key source of nonpublic company information, and managers prefer favorable forecasts because these support higher capital market valuations and, hence, their compensation levels. They may limit or eliminate an analyst's flow of information if the analyst issues unfavorable forecasts, even if these are justified.[3] In this environment, analysts optimally report biased estimates. Positive bias in their estimates acts to decrease mean squared error—which can be decomposed into a squared bias and a variance term—by reducing forecast variance through improved access to managers' information. The optimal forecast under this quadratic loss criterion also exhibits predictable cross-sectional variation in the extent of bias that can be empirically tested. Specifically, companies with more uncertain information environments and analysts for whom building management access is more important are predicted to be associated with more optimistic forecasts.

These results are based on the simple argument that analysts seek to minimize forecast error. They do not draw on alternative hypotheses that have been suggested to explain analysts' seemingly "irrational" behavior. These explanations can be loosely divided into two groups. One argues that analysts face conflicting incentives, such as investment banking relationships or reputation concerns, which are incompatible with producing accurate forecasts. Michaely and Womack (1999) and Dechow, Hutton, and Sloan (1998) suggest that analysts employed by brokerage firms who also have underwriting relationships with the company they follow may have an economic incentive to issue more favorable recommendations or earnings growth forecasts. Scharfstein and Stein (1990) and Laster, Bennett, and Geoum (1996) develop models of how analysts may deliberately report earnings forecasts that are closer to or further from the consensus because of career concerns; however, these models do not explain why estimates are systematically overoptimistic. The second group of explanations draws from the psychology literature to suggest that analysts suffer from cognitive failures. De Bondt and Thaler (1990) argue that analysts have a behavioral tendency to overreact and form expectations that are too extreme. On the other hand, Mendenhall (1991), Abarbanell and Bernard (1992), and Klein (1990) show that analysts appear to underreact to information in past quarterly earnings and past stock returns. Easterwood and Nutt (1999) reconcile these two sets of findings by demonstrating that analysts underreact to negative earnings news but overreact to positive news, and hence appear systematically optimistic.

[3] For example, in the *Wall Street Journal*, Siconolfi (1995) writes "it's a fact of life among Wall Street securities analysts: bash a company in a research report and brace for the deep freeze."

Related empirical work by Das, Levine, and Sivaramakrishnan (1998) and Francis and Philbrick (1993) finds that earnings estimates from the Value Line ratings service are more positively biased for companies with greater historical earnings variability or that had a sell rating respectively, which can be interpreted to be consistent with analysts seeking to cultivate management access. My study examines a larger and longer survey of earnings estimates collected by I/B/E/S, and proposes and tests a wider set of predicted cross-sectional relationships between forecast bias and company and analyst characteristics.

This paper is organized as follows. In Section I, I develop more formally how analysts trade off bias for precision when forming minimum-error forecasts of earnings. Section II describes the data sample of individual analysts' forecasts. I identify and exclude from the sample those forecasts that are stale, affected by large discretionary accounting charges, or associated with underwriting relationships. The main empirical analysis presented in Section III shows that the cross-sectional variation in forecast bias is consistent with the model's predictions. Section IV concludes, and discusses implications from these results for tests of analysts' rationality and the predictability of forecast bias.

I. Rational Bias

In this section, I propose a quadratic-loss utility function to characterize earnings forecasting. My main thesis is that biased forecasts may be optimal under the simplest, natural assumption that analysts have been delegated the task of producing accurate estimates of company earnings.

Formally, assume the analyst observes a noisy private signal, I, of earnings, X, through research, company visits, and contact with the company's managers. The analyst produces a forecast, $\hat{X}$, that minimizes the conditional expected squared error, which can be decomposed into a squared mean bias and a variance term

$$\mathrm{Min}_{\hat{X}} E[(\hat{X}-X)^2|I] \equiv \mathrm{Min}_b\, b^2 + \mathrm{Var}(X|I), \tag{1}$$

where b is the (conditional) bias $\hat{X} - E[X|I]$.

To parameterize this model, let actual earnings X be a normal random variable with unconditional mean 0 (without loss of generality) and precision (the inverse of variance) τ_0. The noisy private signal the analyst observes is $I = X + \epsilon$. ϵ is a normal random variable with mean 0 and precision $\tau(b)$, which is a positive, concave function of bias b: This captures the key assumption that the analyst, in publishing a positively biased forecast, can generate more precise private information about the company's actual earnings. With these assumptions, the analyst's quadratic-loss utility function can be rewritten as

$$\mathrm{Min}_b\, b^2 + \frac{1}{\tau_0 + \tau(b)}. \tag{2}$$

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The first-order condition characterizing the optimal forecast is

$$b = \frac{\tau'(b)}{2(\tau_0 + \tau(b))^2}. \tag{3}$$

Because τ' is positive, the minimum-error forecast is positively biased.[4] Only in the degenerate case where forecast bias and precision are unrelated ($\tau' \equiv 0$ when management access is useless) would the optimal forecast bias be zero. A static analysis of the first-order condition suggests the following two empirically testable propositions.

PROPOSITION 1: *If earnings are less predictable (τ_0 is small), then bias b increases (because $\delta b/\delta\tau_0 < 0$). When public information about the company's earnings prospects is less readily available, an analyst has more to benefit informationally when trading off some positive bias to gain management access. Companies for whom uncertainty about earnings is greater, or are likely to have poorer financial disclosures, should have more optimistically biased earnings forecasts.*

PROPOSITION 2: *Greater optimism is observed if cultivating management relations is more important for obtaining information (i.e., $\tau'(b) \gg 0$). Analysts employed by smaller regional brokerage firms who have fewer resources, or are junior in tenure and have to build access, are likely to be more reliant on management relations to gain company information.*

The model implies that analysts' forecasts are optimistically and rationally biased. Optimality conditions suggest that the extent of forecast bias can be related to characteristics of the followed company or the analyst. In the next sections, I construct proxies of uncertainty or poor financial disclosure for a company (such as size, coverage, volatility, and past performance) and the importance of management access for an analyst (such as brokerage firm size and experience), and test their predicted relationships with the extent of bias.

II. Data

Forecasts of quarterly earnings reported by analysts at over 300 brokerage firms are extracted from the I/B/E/S Detail files. Each observation represents an individual forecast and contains the company ticker, broker identifier, analyst identifier, earnings estimate, and forecast date. I/B/E/S attempts to retain analyst identifier codes as an analyst moves from broker to broker. Additionally, an analyst/broker names translation file was ob-

[4] This result that a biased estimator can possess the desirable property of having lower sampling error has several analogies in the field of statistical decision theory and econometrics. For example, James and Stein (1961) derive a biased estimator in a linear multiple regression setup that dominates the conventional unbiased least squares-maximum likelihood estimator under a squared loss criterion.

tained from I/B/E/S by special permission. The sample is drawn from the first quarter of 1984 to the fourth quarter of 1996, which provides 52 consecutive quarters of data. This long time span should reduce the sensitivity of my results to aggregate shocks, as discussed in O'Brien (1994).

For comparability with prior literature, I extract and match actual earnings (before extraordinary items) from COMPUSTAT's Industrial Quarterly files, stated on the same primary or diluted per-share basis as the I/B/E/S forecasts.[5] Stock prices, returns, and market capitalization information are obtained from CRSP. To reduce heteroskedasticity across stocks, forecasts (and forecast errors) are expressed as a percentage of the beginning-of-quarter stock price. I exclude companies with a stock price less than 5 dollars (because I do not want a stock price that is too small to enter into the denominator), or whose forecast error exceeds 10 dollars (which probably resulted from a data input error).

A. Forecast Recency

My preliminary analysis addresses the effects of forecast recency, discretionary accounting charges, and underwriting relationships. First, I define the consensus forecast bias for a company in a quarter as the median of all brokers' latest unrevised estimate of the company's earnings quarter, submitted no more than three months prior to quarter end, minus actual earnings from COMPUSTAT and expressed as a percentage of adjusted stock price. This "timely" composite of estimates[6] is motivated by Brown (1991) who shows that earnings forecast accuracy can be improved by discarding old earnings estimates. Furthermore, these unrevised estimates are more likely to be the forecasts actually held to a market test. Figure 1 shows that a rule requiring three months' recency is appropriate for screening out stale forecasts. Forecast bias decreases with recency, consistent with prior studies such as Kang, O'Brien, and Sivaramakrishnan (1994). The rate of decrease becomes steepest around 55 trading days prior to quarter end, which coincides with more rapid analyst forecast revisions as the prior quarter's earnings are announced.

B. Special Item Charges

I/B/E/S analysts forecast earnings from continuing operations, after discontinued operations, extraordinary charges, and other non operating items have been backed out. This usually corresponds to what GAAP calls "income before extraordinary items." However, I/B/E/S provides no specific instructions to individual analysts about the treatment of noncontinuing items. "Special items" are above-the-line accounting charges (usually large

[5] Although I/B/E/S also supplies reported earnings, Philbrick and Ricks (1991) identify possible misalignment problems in this data file.

[6] This may differ from the Summary median estimate reported by I/B/E/S each month, because I/B/E/S calculates its summaries at fixed dates in the middle of each month and does not discard stale estimates.

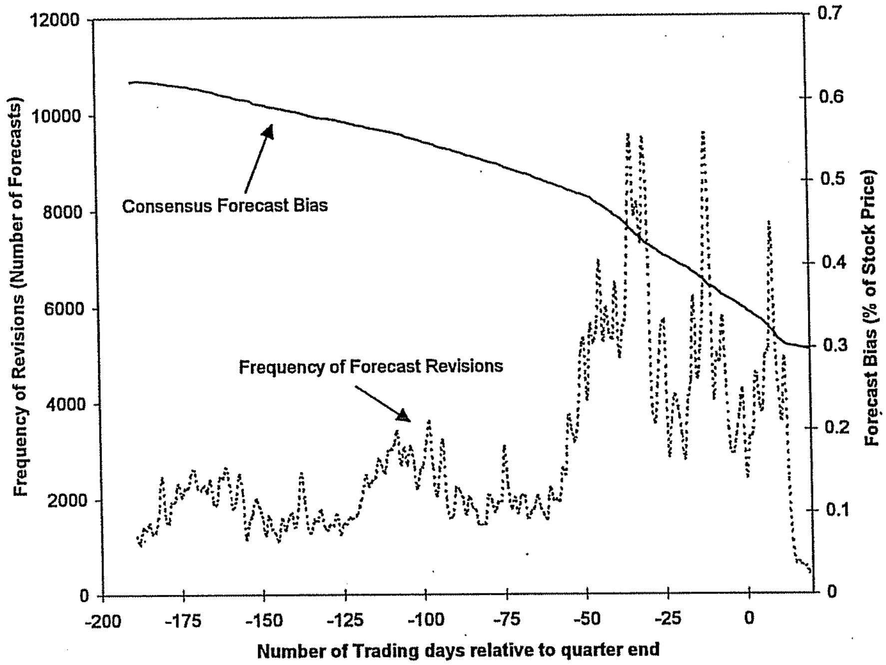

Figure 1. Forecast bias, frequency of revisions, and forecast horizon. This figure plots the average consensus forecast bias and the frequency of forecast revisions from −190 trading days through +20 trading days relative to a forecasted quarter's fiscal end date. The consensus forecast bias is the median of all brokers' latest forecasts available that day minus actual earnings, expressed as a percentage of stock price. The sample period is from 1984 to 1996.

asset write-offs or restructuring expenses) that can be taken at the discretion of management, and reported by COMPUSTAT in pretax EPS before extraordinary items and discontinued operations. Philbrick and Ricks (1991) report that I/B/E/S forecasts appear to exclude special items, while I/B/E/S reported earnings are inconsistent in the treatment of such items. Large discretionary accounting charges may generate extreme negative earnings that skew measures of overall forecast bias. Following Keane and Runkle (1998), I eliminate those observations with large special items charges, reasoning that it is difficult to unbiasedly determine what the analysts are trying to predict for these cases.

Table I shows that the majority of special items are negative charges to income, with a mean (median) of −1.81 (−0.36) percent of price. This reflects the conservative nature of accounting: Management can take large discretionary write-downs, but assets cannot be written up. Special items charges also occur more frequently in the fourth fiscal quarter.

If we remove all observations with nonzero special items, average forecast bias would still be positive, but reduced by half from 0.46 percent to 0.23 percent of stock price. Hence discretionary accounting charges cannot solely explain why earnings forecasts are positively biased on average. Most of this

Table I

Special Items Charges

Panel A reports the distribution of nonzero special items charges, as a percentage of stock price, in the pooled sample of companies between March 1984 and December 1996, by fiscal quarter. The sample excludes companies with a stock price less than five dollars. Panel B describes the distribution of consensus forecast bias in the pooled sample, after excluding outlier observations with large special items charges. Outliers are those observations for which special items charges (as a percentage of stock price) exceed a multiple of the standard deviation, σ, of the consensus forecast bias for all observations that have no special items charges. From the last line of this panel, $\sigma = 2.48$ percent of stock price in the sample. Consensus forecast bias is the median of all brokers' latest estimate of a company's earnings in a quarter, submitted no more than three months prior to quarter end, minus actual earnings, expressed as a percentage of adjusted stock price at the beginning of the quarter.

Panel A: Distribution of Special Items

Fiscal Qtr	N	No. Nonzero Special Items	Mean	Std.	Percentile 25	Percentile 50	Percentile 75
1	23,752	2,063	−0.42	5.68	−0.87	−0.10	0.51
2	25,479	2,730	−1.21	5.94	−1.52	−0.23	0.32
3	26,335	3,107	−1.83	7.09	−1.98	−0.31	0.20
4	27,676	5,383	−2.63	7.48	−3.04	−0.69	0.04
All	103,242	13,283	−1.81	6.88	−2.06	−0.36	0.20

Panel B: Consensus Forecast Bias, Excluding Large Special Items

Exclude	N	Mean	Std.	Skew	Percentile 25	Percentile 50	Percentile 75	% Pos.	% Neg.
None	103,242	0.46	3.38	8.88	−0.19	0.00	0.39	49.0	43.6
$\geq \pm 4\sigma$	102,227	0.33	2.60	9.65	−0.19	0.00	0.37	48.7	43.9
$\geq \pm 3\sigma$	101,854	0.31	2.56	9.91	−0.19	0.00	0.37	48.6	44.0
$\geq \pm 2\sigma$	101,121	0.28	2.50	10.38	−0.19	0.00	0.35	48.3	44.2
$\geq \pm 1\sigma$	99,549	0.25	2.45	10.94	−0.19	0.00	0.33	47.9	44.5
All	89,959	0.23	2.48	11.31	−0.19	0.00	0.30	46.8	45.2

reduction in bias comes from eliminating the largest special item charges. Eliminating the 3,693 observations (roughly one-quarter of all occurrences) with special items larger than one standard deviation of forecast bias brings mean bias down to 0.25 percent of stock price, with a standard deviation of 2.45 percent.[7] This is a reasonable cutoff for removing influential cases of special items charges, and the remainder of my analysis uses this truncated sample; the results are not affected by deleting all observations of nonzero special items.

[7] By comparison, the consensus forecast bias of the full sample computed using I/B/E/S actuals had an approximately identical mean (0.32 percent of price) but higher standard deviation (7.61 percent of price).

Table II

Forecast Bias of Lead Underwriter and Other Analysts

This table reports the average consensus forecast bias, over all company-quarters, of lead underwriter minus other analysts, expressed as a percentage of the beginning-of-quarter stock price. The consensus forecast bias of lead underwriter analysts is the median of the latest forecasts from brokers who were also lead underwriters for a secondary equity offering issued within a specified window relative to the quarter-end date. The consensus forecast bias of other analysts is the median of the latest forecasts from brokers who were not lead underwriters. The sample includes companies with fiscal quarter-end dates between March 1984 and December 1996, and excludes companies with a stock price less than five dollars.

Fiscal Quarter-end Relative to Issue Date, in Months	No. Companies	Bias of Lead Underwriter Analysts Minus Bias of Other Analysts (*t*-statistic)
−48 to −42	498	0.01 (0.19)
−42 to −36	599	0.03 (0.92)
−36 to −30	655	0.01 (0.38)
−30 to −24	787	0.01 (0.43)
−24 to −18	916	0.04 (1.39)
−18 to −12	1,002	−0.03 (−1.18)
−12 to −6	1,202	−0.01 (−0.52)
−6 to 0	1,349	0.03 (1.15)
0 to +6	2,088	−0.02 (−1.57)
+6 to +12	2,373	0.01 (0.51)
+12 to +18	2,314	−0.02 (−1.20)
+18 to +24	2,100	0.01 (0.96)
+24 to +30	1,925	0.02 (1.05)
+30 to +36	1,841	−0.01 (−0.66)
+36 to +42	1,652	−0.03 (−2.21)
+42 to +48	1,475	−0.03 (−1.63)

C. Underwriting Relationships

Some of the I/B/E/S forecasts may be from analysts whose brokerage firms have underwriting relationships with the followed company. Michaely and Womack (1999) suggest that analysts working for the lead underwriter have an economic incentive to promote the stock, because the lead investment bank is most involved in "building the book" of committed investors and marketing the IPO. On the other hand, Allen and Faulhaber (1989) argue that investment bankers will have superior information gained through the due diligence process. Also, companies may disclose more information to mitigate the information asymmetry associated with the negative signal of a securities offering. These studies suggest that forecasts from lead underwriter analysts may possess different properties and should be excluded from the main sample.

I identify public equity offerings, issue dates, and lead underwriter investment banks from the Securities Data Company (SDC) database. Analysts employed by an investment bank (or subsidiary or the parent of the bank) acting as the lead manager for the offering are classified as "lead underwriter analysts." Table II examines the average difference between the forecast bias of "lead underwriter analysts" and "other analysts," for four years around a seasoned equity offering. In none of the six-month periods around the issue date is the difference significantly greater than zero. This finding is consistent with Lin and McNichols (1998), who document that although lead underwriter analysts tend to issue more optimistic recommendations, their earnings forecasts are not any more biased. Because quarterly earnings estimates can be easily evaluated, perhaps analysts tend to promote stocks more through subjective recommendations or longer-term forecasts instead.

The most positive difference in bias appears at 24 months prior (0.04 percent of stock price) and 30 months after (0.02 percent) an equity issue date. I exclude all forecasts from lead underwriter analysts for quarter-end dates that fall within this four-and-a-half-year window. In the cross-sectional tests, I also require that price data be available for one year prior to the beginning of the fiscal quarter, hence eliminating all forecasts for 15 months after new listings as well. My results are insensitive to changing this window to four years before and after the issue date, or to excluding all companies within two years of an equity issue (not reported for brevity).

III. Empirical Results

A. Company Characteristics

The first set of empirical tests examine the cross-sectional variation of forecast bias across company characteristics. Proposition 1 states that companies with more informational uncertainty should be associated with more optimistically biased forecasts. The general information environment is likely to be richer for companies that are larger[8] and covered by more analysts. I also examine measures of company uncertainty based on historical earnings and recent stock price volatility. For every company in each quarter, I compute the market capitalization (LNSIZE); number of analysts providing annual earnings forecasts[9] (LNCOVER); historical earnings variability (EPSVAR); and the standard deviation of weekly[10] excess stock returns (SIGMA) that represents a more timely capital markets-based measure of company-specific uncertainty.

Earnings uncertainty is also likely to be greater when companies are sitting on bad news, as managers tend to be less forthcoming. In contrast, when companies have good news, managers have every incentive to push

[8] See Ho and Michaely (1988). The FASB's and SEC's disclosure requirements also suggest that disclosure costs are decreasing in company size. For example, the SEC has separate 10K and 10Q filing requirements for small companies, to facilitate the access of small business issuers to the public markets.

[9] Although my study focuses on quarterly earnings forecasts, the number of analysts providing forecasts of annual (FY1) earnings is a better measure of analyst coverage, as some analysts who provided annual forecasts did not provide quarterly estimates, particularly in the earlier part of the sample period.

[10] As in Adamek et al. (1998), I use weekly returns based on Wednesday-to-Wednesday closing prices to mitigate nonsynchronous trading or bid-ask bounce effects inherent in daily prices. A one-year estimation period was chosen to provide a reasonable number of observations.

this news out to investors as quickly as possible. Consistent with this view, Hong, Lim, and Stein (2000) show that stock price momentum effects are stronger and more persistent for poor performers, indicating that bad news diffuses more slowly than good news to the investing public. Lang and Lundholm (1993) find that analysts' ratings of companies' disclosures are lower for poor-performing companies. After past earnings disappointments (i.e., past positive forecast bias PREVBIAS) or stock price declines (negative ALPHA), analysts would want to report more positively biased forecasts and appear to not fully revise their earnings estimates downwards.

Finally, the dependent variable, consensus forecast bias (BIAS), is expressed as a percentage of adjusted stock price 12 months prior to the beginning of the quarter. I use a "stale" stock price to reduce any endogeneity effects with the other company characteristic variables. The conclusions are not changed if contemporaneous prices or fundamental values are used. To mitigate the effects of outliers, all observations in the tail 2.5 percent of BIAS values each quarter are excluded.

To examine the univariate relationships, I form quintile portfolios of companies by ranking on each company characteristic every quarter. The average consensus forecast bias is computed for each group, and the time series means and standard errors are reported in Table III. Because I expect bias to be negatively related to ALPHA, LNSIZE, and LNCOVER, I rank companies in descending order for these characteristics (as indicated by a "minus" prefix in the table), so that, for example, the largest company is in quintile 1 and the smallest in quintile 5.

For (minus) ALPHA, the relationship is approximately flat in the first 2 quintiles, and is most positive for quintiles 3–5—the stocks that had performed most poorly. PREVBIAS shows more of an increasing relationship across all quintiles, and is also steepest in quintiles 4 and 5. This is consistent with the "underreaction effect" found by prior studies, but this effect is asymmetric. When a company is sitting on bad news, maintaining optimism and management access is likely to be more important; hence analysts appear to underreact more to negative information.

The sorts on (minus) SIZE, (minus) LNCOVER, EPSVAR, and SIGMA show similar patterns. Their relationships with forecast bias are generally increasing, and most of the positive bias is concentrated in quintiles 4 and 5—the smallest or most volatile companies. The correlation for EPSVAR is weak;[11] because this variable estimates historical earnings variability from a small number of data points and does not reflect other more current sources of information, it may not be as good a measure of current company uncertainty.

Table IV reports the results from a multivariate regression analysis of consensus forecast bias on company characteristic variables LNSIZE, SIGMA, PREVBIAS, and ALPHA. The preliminary analysis in Table I suggests the inclusion of a dummy variable to account for fiscal fourth quarter effects (when more discretionary charges are likely to be taken). Separate quarterly

[11] In additional sensitivity tests, not reported for brevity, measuring historical earnings variability over 4 or 12 trailing quarters yielded similar conclusions.

Table III

Consensus Forecast Bias, Grouped by Company Characteristics

This table reports the time-series mean (standard error) from March 1984 to December 1996 of the quarterly consensus forecast bias for each quintile of companies, regrouped each quarter by a company characteristic. As negative relationships with ALPHA, LNSIZE, and LNCOVER are expected, companies are sorted in descending order with respect to these characteristics (and indicated by a "minus" prefix in the table) to facilitate comparison across characteristics. Consensus forecast bias is the median of all brokers' latest estimate of a company's earnings in a quarter, submitted no more than three months prior to quarter end, as a percentage of adjusted stock price 12 months prior to the beginning of the quarter. Forecasts from lead underwriter analysts are excluded. Sample excludes companies that do not have quarter-end dates in March, June, September or December; with stock price less than five dollars; have large special item charges; or whose consensus forecast bias is in the extreme 2.5 percent tails in a quarter. Company characteristics are: ALPHA: the intercept from a market model regression of weekly stock returns on weekly value-weighted market returns, over the year ending at the beginning of the quarter; PREVBIAS: the consensus forecast bias from the prior quarter, as a percentage of stock price 12 months prior to the beginning of the forecasted quarter; LNSIZE: the log market capitalization 12 months prior to the beginning of the quarter; LNCOVER: the log of one plus the number of analysts providing annual FY1 earnings estimates lagged 12 months from the beginning of the quarter; SIGMA: the standard deviation of the residuals from a market model regression of weekly stock returns on weekly value-weighted market returns, over the year ending at the beginning of the quarter; EPSVAR: the standard error from a trend regression of quarterly earnings (as a percentage of stock price) from nine through two quarters (total of eight quarters) prior to the current quarter, scaled by adjusted stock price at the beginning of the quarter.

	Quintile						Average No. Companies per Quarter
Grouped by	1	2	3	4	5	All	
(minus) ALPHA	0.06	0.09	0.12	0.17	0.30	0.15	1,333
	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	
PREVBIAS	−0.08	0.01	0.10	0.21	0.49	0.15	1,243
	(0.02)	(0.01)	(0.01)	(0.02)	(0.03)	(0.02)	
(minus) LNSIZE	0.08	0.11	0.14	0.18	0.22	0.15	1,333
	(0.01)	(0.02)	(0.02)	(0.02)	(0.03)	(0.02)	
(minus) LNCOVER	0.09	0.11	0.14	0.17	0.22	0.15	1,333
	(0.01)	(0.01)	(0.02)	(0.02)	(0.03)	(0.02)	
SIGMA	0.08	0.08	0.12	0.19	0.27	0.15	1,333
	(0.01)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	
EPSVAR	0.10	0.14	0.12	0.15	0.20	0.14	1,163
	(0.01)	(0.02)	(0.02)	(0.02)	(0.03)	(0.02)	

cross-sectional regressions are run and statistical inference is drawn from the time series of the coefficients. To account for intertemporal dependence in the quarterly coefficient estimates, the time series standard errors are computed using a Newey–West procedure with four lags.

The estimated coefficients are all of the predicted sign, and are consistent with the results from the univariate portfolio sorts. Forecast bias is greatest for companies that are small, are more volatile, experienced prior negative earnings surprise, or experienced poor past stock returns. Similar results are obtained in subperiods and size-based subsamples. Adding control re-

Table IV
Regression of Consensus Forecast Bias on Company Characteristics

This table reports the time-series average of the estimated coefficients (autocorrelation-consistent time-series t-statistics in parentheses) from quarterly cross-sectional regressions of consensus forecast bias on company characteristics, between March 1984 and December 1996. Forecasts from lead underwriter analysts are excluded, as are companies that do not have quarter-end dates in March, June, September, or December; with a stock price less than five dollars; that have large special item charges; or whose consensus forecast bias is in the extreme 2.5 percent tails in a quarter. Variable definitions are as in Table III. D_{4Q} is a dummy variable indicating a fiscal fourth quarter; D_{sic} are industry dummy variables based on two-digit SIC codes; BP is the book-to-price ratio lagged 12 months from the beginning of the quarter. The cross-sectional regression equation estimated each quarter t across companies indexed by i is

$$BIAS_{it} = \hat{\beta}_0 + \hat{\beta}_1 LNSIZE_{it} + \hat{\beta}_2 SIGMA_{it} + \hat{\beta}_3 PREVBIAS_{it} + \hat{\beta}_4 ALPHA_{it} + \hat{\beta}_5 D4Q_{it} + \hat{\varepsilon}_{it}$$

	LNSIZE	SIGMA	PREVBIAS	ALPHA	D_{4Q}	BP	LNCOVER	EPSVAR	D_{sic}
Full period	−0.0252	0.0242	0.0443	−0.1322	0.0196				
1984–1996	(−4.25)	(4.22)	(8.58)	(−12.38)	(0.74)				
Subperiod	−0.0353	0.0375	0.0552	−0.1558	−0.0040				
1984–1990	(−4.27)	(5.35)	(9.54)	(−11.44)	(−0.09)				
Subperiod	−0.0135	0.0087	0.0317	−0.1045	0.0472				
1991–1996	(−4.10)	(2.74)	(6.98)	(−10.39)	(4.14)				
Decile 9–10 (L)	−0.0183	0.0208	0.0491	−0.1275	0.0508				
1984–1996	(−2.82)	(5.15)	(6.10)	(−10.95)	(1.62)				
Decile 7–8	−0.0695	0.0291	0.0666	−0.1283	−0.0070				
1984–1996	(−3.75)	(2.92)	(6.61)	(−8.13)	(−0.34)				
Decile 1–6 (S)	−0.0474	0.0289	0.0675	−0.1719	−0.0336				
1984–1996	(−2.81)	(2.07)	(5.08)	(−5.03)	(−0.53)				
Full period (exclude	−0.0252	0.0201	0.0431	−0.1210	0.0101				
all nonzero	(−4.64)	(3.41)	(7.55)	(−11.07)	(0.41)				
special items)									
1984–1996									
NYSE only	−0.0239	0.0327	0.0466	−0.1429	0.0518				
1984–1996	(−3.78)	(4.10)	(5.85)	(−14.29)	(2.35)				
Full period	0.0070	0.0187	0.0391	−0.1186	0.1261	0.0069	−0.0656	0.0137	Yes
1984–1996	(0.30)	(3.64)	(6.53)	(−10.24)	(1.15)	(0.73)	(−2.59)	(1.82)	

gressors for book-to-price, analyst coverage, historical earnings variability, and industry classification eliminates the size effect (probably due to the strong collinearity with the amount of analyst coverage—the correlation of LNSIZE and LNCOVER is 0.8—that enters with a significantly negative coefficient), but the other coefficients remain significant (*t*-statistics greater than 2.59) and with the predicted signs. The EPSVAR coefficient has the predicted positive sign but, as in the univariate case, the relationship is not as strong (*t*-statistic of 1.82).

B. Analyst Characteristics

I next examine the cross-sectional relation between relative forecast bias and analyst characteristics. Proposition 2 suggests that analysts who are less reliant on management relations and access as a source of company information should exhibit less positive bias. Analysts who are employed by large brokerage firms or have more experience are likely to have less need to cultivate management access. Large brokerage firms have superior resources, such as administrative and research support, database access, and better reputation. Companies often covet coverage by a well-known broker, which represents an important marketing tool for reaching institutional investors. I use the number of analysts employed by a brokerage firm within a rolling 12-month prior period as a measure of brokerage firm size. To measure analyst experience, I compare the fiscal end date of the forecast with the date of the analyst's first forecast in the I/B/E/S database.

The data sample comprises the most recent forecast every company-quarter from each analyst, submitted no more than three months prior to quarter end. Following Clement (1997), I exclude forecasts from analyst teams,[12] because we cannot determine the identity or experience of the team members. Companies with two or fewer eligible forecasts in a quarter are dropped. Each analyst's forecast is expressed relative to all analysts who followed the same company in the same quarter. I consider the following analyst characteristic variables, which are also measured relative to all analysts following the same company in the same quarter: the number of analysts employed (DBROKSIZE); analyst experience (DGENEXP); and a control variable for forecast recency (DSTALE).

The number of brokerage firms ranges from 141 at the beginning of my sample to 281 in 1996. Since I/B/E/S only began recording detailed forecast data in 1983, the mean analyst experience in our sample was just 1.5 years in December 1984, but rose to 4.8 years in 1996. Similarly, the range increased over the period: The first and third quartile values of analyst experience were 0.8 and 2.2 years, respectively, at the end of 1984, and 0.7 and 8.5 years, respectively, in 1996.

[12] Analyst teams are those with names in the I/B/E/S analyst/broker translation file that contain an "&," "/," or an industry name.

Table V

Regression of Relative Analyst Bias on Analyst Characteristics

This table reports the time-series average of the estimated coefficients (autocorrelation-consistent time-series t-statistics in parentheses) from quarterly cross-sectional regressions of relative forecast bias on relative analyst characteristics of individual forecasts for quarter-end dates between December 1984 and December 1996. Forecasts from lead underwriters, of analyst teams, reported more than three months prior to quarter end, or having relative bias in the extreme 2.5 percent tails are excluded. The sample also excludes companies that do not have quarter-end dates in March, June, September, or December; with a stock price less than five dollars; having large special item charges; or having two or fewer eligible forecasts per quarter. Analyst characteristics are: RELBIAS: an analyst's latest forecast, submitted no more than three months prior to quarter end, minus actual company earnings, as a percentage of adjusted stock price 12 months prior to the beginning of the quarter, minus the average for analysts following the company in the quarter; DGENEXP: the log of one plus the number of years before the quarter-end date since the analyst first reported an estimate in the I/B/E/S database, minus the average for analysts following the company in the quarter; DSTALE: the quarter-end date minus the submission date of the estimate, expressed as the log of one plus number of years, minus the average for analysts following the company in the quarter; DBROKSIZE: the log of one plus the number of analysts employed by the brokerage firm within 12 months prior to the quarter end, minus the average for analysts following the company in the quarter. The cross-sectional regression equation estimated each quarter t across analysts indexed by i is

$$RELBIAS_{it} = \hat{\beta}_0 + \hat{\beta}_1 DGENEXP_{it} + \hat{\beta}_2 DSTALE_{it} + \hat{\beta}_3 DBROKSIZE_{it} + \hat{\varepsilon}_{it}$$

	DGENEXP	DSTALE	DBROKSIZE
Full period	−0.0028	0.3252	−0.0056
1984–1996	(−1.36)	(5.56)	(−2.95)
Subperiod	−0.0034	0.4143	−0.0027
1984–1990	(−0.84)	(4.73)	(−0.99)
Subperiod	−0.0022	0.2362	−0.0084
1991–1996	(−2.28)	(4.22)	(−5.48)
Decile 10 (Large)	−0.0057	0.2810	−0.0038
1984–1996	(−1.94)	(4.58)	(−1.72)
Decile 9 (Medium)	0.0055	0.4201	−0.0104
1984–1996	(1.54)	(6.14)	(−7.03)
Decile 1–8 (Small)	0.0041	0.4493	−0.0089
1984–1996	(1.19)	(6.78)	(−2.93)
NYSE only	−0.0017	0.3125	−0.0047
1984–1996	(−0.95)	(5.24)	(−2.04)

Table V reports results from a multivariate regression analysis of relative forecast bias on the analyst characteristic variables. To mitigate the effects of outliers, all observations in the tail 2.5 percent of RELBIAS values each quarter are excluded. The number of forecasts each quarter ranges from 2,484 in December 1984 to 8,531 in 1996; prior quarters were dropped because these provide significantly fewer observations. As before, statistical inference is drawn from the time series of estimated coefficients from separate quarterly cross-sectional regressions. Time-series standard errors are computed using a Newey–West procedure with four lags.

Staff/918
Storm/15

The average coefficient for brokerage size is reliably negative[13] as predicted (t-statistic = -2.95). This effect is also observed in a subsample of NYSE-listed stocks only; it is not driven by small brokers who are often market markers for Nasdaq-listed stocks, which may create some conflicts of interest.

The coefficient on DGENEXP is weakly negative, indicating that less experienced analysts tend to be more positively biased, but this relationship is not as reliable. The effect is stronger for large companies, but cannot be detected in smaller companies. The estimated coefficient from the second half-period is stronger in significance, perhaps because our measure of analysts' experience is less accurate in the first subperiod just after I/B/E/S began recording individual analysts' forecasts. Furthermore, once individual forecasts are disseminated, less informed analysts can easily mimic the (more informed) consensus. Hong, Kubik, and Solomon (2000) find that younger analysts issue forecasts later and deviate less from the consensus. Hence forecast recency explains more than the predicted effects from the other characteristics.

IV. Conclusion

Some investigators have interpreted a test of unbiasedness to be necessary for inferring rationality. This paper argues that unbiasedness of forecasts need not mean best or most accurate. Rational analysts who aim to produce accurate forecasts may optimally report optimistically biased forecasts. By trading off bias to improve management access and forecast precision, analysts minimize the expected squared error of their forecasts. The extent of positive bias is predicted by optimality conditions to be larger for companies that have more uncertain information environments, and for analysts who are more reliant on management access as a source of company information.

The empirical evidence presented shows that forecast bias varies predictably across companies and analysts in a manner consistent with this model. I find that proxies for the richness of a company's information environment, such as company size and analyst coverage, are inversely related to forecast bias. To the extent that companies who have performed poorly are associated with more uncertainty or poorer disclosures, analysts following these companies refrain from fully revising their estimates downwards, leading to greater positive bias—the underreaction effect previously documented by other researchers. I also find that a capital markets-based proxy for company-specific uncertainty—the standard deviation of weekly excess stock returns—is positively related to forecast bias. Analysts from smaller brokerage firms or, to a weaker extent, those who have less experience produce more optimistic forecasts.

[13] In a similar spirit, Carleton, Chen, and Steiner (1998) report that regional brokerage firms issue more optimistic equity *recommendations* than national brokerage firms.

Staff/918
Storm/16

Positive and predictable bias may be a fundamental property of statistically optimal earnings forecasts. This result follows from a simple, natural argument that minimizing forecast error is a pervasive component of analysts' utility functions, and does not draw on alternative behavioral explanations such as cognitive failures or conflicting incentives. Prior empirical studies that have evaluated analysts' rationality using classical notions of unbiasedness may have prematurely dismissed analysts' forecasts as being too inaccurate or irrational.

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CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 919

Exhibits in Support
Of Opening Testimony

June 4, 2010

UE 215 PGE

Value Line Earnings Data for Comparable Companies

	2007	2008	Annual Rate of Change 2007-08	2009	Annual Rate of Change 2008-09	Annual Rate of Change 2007-09	Value Line Est. Annual Dividend Growth
Allegheny Energy Inc.	2.42	2.33	-3.7%	2.33	0.0%	-1.9%	25.0%
Allete	3.08	2.82	-8.4%	1.89	-33.0%	-21.7%	1.0%
Alliant Energy Corp	2.69	2.54	-5.6%	1.89	-25.6%	-16.2%	5.5%
Ameren Corp.[2]	2.98	2.88	-3.4%	2.78	-3.5%	-3.4%	-5.5%
American Electric Power Co. Inc.	2.86	2.99	4.5%	2.97	-0.7%	1.9%	2.5%
Avista Corp.	0.72	1.36	88.9%	1.55	14.0%	46.7%	11.5%
Cleco Corp.	1.32	1.70	28.8%	1.76	3.5%	15.5%	6.5%
CMS Energy Corp.	0.64	1.23	92.2%	0.93	-24.4%	20.5%	17.0%
DPL Inc.	1.81	2.12	17.1%	2.01	-5.2%	5.4%	5.5%
DTE Energy Co.	2.66	2.73	2.6%	3.24	18.7%	10.4%	3.0%
Duke Energy Corp.[2]	1.20	1.01	-15.8%	1.13	11.9%	-3.0%	NMF
Edison International	3.32	3.68	10.8%	3.10	-15.8%	-3.4%	4.0%
Empire District Electric Co.	1.09	1.17	7.3%	1.18	0.9%	4.0%	1.0%
Entergy Corp.	5.60	6.20	10.7%	6.30	1.6%	6.1%	4.0%
FPL Group, Inc.	3.27	4.07	24.5%	3.97	-2.5%	10.2%	6.5%
Great Plains Energy Inc.[2]	1.86	1.16	-37.6%	1.03	-11.2%	-25.6%	-2.5%
Hawaiian Electric Industries	1.11	1.07	-3.6%	0.90	-15.9%	-10.0%	0.0%
IDACORP	1.86	2.18	17.2%	2.40	10.1%	13.6%	2.5%
MGE Energy Inc.	2.27	2.38	4.8%	2.21	-7.1%	-1.3%	0.5%
OGE Energy Corp.	2.64	2.49	-5.7%	2.66	6.8%	0.4%	2.5%
PG&E Corp.	2.78	3.22	15.8%	3.15	-2.2%	6.4%	7.5%
Pinnacle West	2.96	2.12	-28.4%	2.45	15.6%	-9.0%	1.0%
Portland General	2.33	1.39	-40.3%	1.40	0.7%	-22.5%	5.5%
Progress Energy Inc.	2.69	2.96	10.0%	3.03	2.4%	6.1%	1.0%
Southern Co.	2.28	2.25	-1.3%	2.32	3.1%	0.9%	4.0%
TECO Energy, Inc.	1.27	0.77	-39.4%	1.00	29.9%	-11.3%	3.0%
UniSource Energy	1.55	0.39	-74.8%	2.70	592.3%	32.0%	10.0%
Westar Energy Inc.	1.84	1.31	-28.8%	1.28	-2.3%	-16.6%	3.5%
Wisconsin Energy Corporation	2.84	3.03	6.7%	3.20	5.6%	6.1%	13.0%
Xcel Energy	1.35	1.46	8.1%	1.49	2.1%	5.1%	3.0%
Mean			1.8%		19.0%	1.5%	4.9%

1. Excludes Northwestern Corp.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 920

Exhibits in Support
Of Opening Testimony

June 4, 2010

Staff/920
Storm/1

92 FERC ¶ 61,070

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 445

Southern California Edison Company

Docket Nos. ER97-2355-000, ER98-1261-000 and ER98-1685-000

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND REVERSING IN PART, INITIAL DECISION

Issued: July 26, 2000

FERC DOCKETED
JUL 26 2000

000727-0463-1

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO.445

Southern California Edison Company

Docket Nos. ER98-2355-000 ER98-1261-000 and ER98-1685-000

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND
REVERSING IN PART, INITIAL DECISION

APPEARANCES

Gary A. Morgans, Bruce J. Barnard, Michael D. Mackness, Jennifer Key, and Edward Twomey for Southern California Edison Company;

Bonnie S. Blair for Cities of Anaheim, Azusa, Banning, Colten and Riverside, California;

Alan I. Robbins, Elisa J. Grammar, and Mark D. Urban for California Department of Water Resources;

Arnold Fieldman, Channing D. Strother, and David B. Brearley for the City of Vernon;

Harvey Y. Morris and Peter Arth, Jr., for Public Utilities Commission of the State of California;

Edward Berlin, David Ruben, and Michael Ward for California Independent System Operator Corporation;

Lisa G. Dowden and Sarah Weinberg for Northern California Power Agency;

Mark D. Parizio for Pacific Gas and Electric Company;

Michael Yuffee and Joel Newton for Sacramento Municipal Utility District;

James D. Pembroke, Wallace L. Duncan, Michael Postar, Lisa Gast, and Diana Mahmud for Transmission Agency of Northern California, The Metropolitan Water District of Southern California, Modesto Irrigation District, City of Santa Clara, California City of Redding, California, M-S-R Public Power Agency, and Trinity County Public Utility District; and

Linda Lee, Stanley A. Berman, Jo Ann Scott, Janet Jones, Laura K. Sheppeard, and Richard L. Miles for the trial staff of the Federal Energy Regulatory Commission

Staff/920
Storm/4

92 FERC ¶ 61,070

UNITED STATES OF AMERICA
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OPINION NO. 445

Southern California Edison Company

Docket Nos. ER97-2355-000, ER98-1261-000 and ER98-1685-000

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND REVERSING IN PART, INITIAL DECISION

Issued: July 26, 2000

000727-0463-1

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert. Jr

Southern California Edison Company

Docket Nos. ER97-2355-000, ER98-1261-000, and ER98-1685-000

OPINION NO.445

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND
REVERSING IN PART, INITIAL DECISION

(Issued July 26, 2000)

I. Introduction

This case is before the Commission on exceptions to an Initial Decision issued March 31, 1999. [1] For the reasons set forth below, we will affirm in part, vacate in part, and reverse in part, the Initial Decision.

II. Procedural Background

On March 31, 1997, Southern California Edison Company (SoCal Edison) filed, in Docket No. ER97-2355-000, a Transmission Owner (TO) Tariff, for utility-specific rates to be charged for transmission service on its facilities under the operational control of the California Independent System Operator (California ISO). In the same filing, SoCal Edison also submitted a Distribution Access (DA) Tariff for transmission service over its distribution facilities that are not part of the California ISO grid. In an order issued by

[1] Southern California Edison Company, 86 FERC ¶ 63,014 (1999) (Initial Decision).

the Commission on December 17, 1997, [2] we accepted SoCal Edison's TO and DA Tariffs, for filing, suspended them, and permitted them to become effective, subject to refund, on the date the California ISO began operation. We also set the proposed tariffs for hearing.

On December 31, 1997, SoCal Edison filed, in Docket No. ER98-1261-000, proposed revisions to its TO Tariff to add a surcharge of $.00009/kWh for a one-year period, to recover $6.7 million in costs associated with its abandoned Devers-Palo Verde 2 project. On January 29, 1998, SoCal Edison filed, in Docket No. ER98-1685-000, proposed revisions to its TO Tariff to correct what it claimed were computational errors and omissions in the development of the rates set for hearing in the December 17 Order. In separate orders issued by the Commission on February 25, 1998, [3] and March 30, 1998, [4] we set SoCal Edison's proposed tariff revisions for hearing and consolidated these filings with SoCal Edison's pending proceeding in Docket No. ER97-2355-000. [5]

Prior to hearing, a number of issues initially set for hearing were resolved. First, the rate-effective period applicable to SoCal Edison's proposed cost-based rates for ancillary services was narrowed by the Commission's ruling in Docket No. ER98-2843-001, in which we granted market-based rate authority to all entities providing ancillary services in California, effective November 3, 1998. [6] As such, SoCal Edison's proposed cost-based rates for ancillary services is this proceeding are only for a locked-in period, April 1, 1998 through November 2, 1998. In addition, the parties filed a stipulation with

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[2]Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,323 (1997) (December 17 Order), order on reh'g, 82 FERC ¶ 61,324 (1998).

[3]California Independent System Operator Corporation, et al., 82 FERC ¶ 61,174 (1998).

[4]San Diego Gas & Electric Company, et al., 82 FERC ¶ 61,324 (1998).

[5]On February 6, 1998, the Chief Administrative Law Judge severed issues concerning non-rate terms and conditions from rate issues, and assigned the SoCal Edison's TO Tariff and DA Tariff filing to the Presiding Judge. See Pacific Gas & Electric Company, et al., 82 FERC ¶ 63,010 (1998).

[6]AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998) (AES).

the Presiding Judge, which the Presiding Judge accepted, fully resolving six issues originally set for hearing. [7]

An evidentiary hearing on all remaining issues commenced on September 15, 1998. Following the hearing and the filing of initial and reply briefs, the Presiding Judge issued the Initial Decision. Briefs on exceptions were filed by SoCal Edison, the Commission's trial staff (trial staff), the California ISO, the Department of Water Resources of the State of California (DWR). Briefs opposing exceptions were filed by SoCal Edison, trial staff, DWR, the Northern California Power Agency (NCPA), the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (Cities), the Public Utilities Commission of the State of California (California Commission), and the City of Vernon (Vernon).

IV. Discussion

A. Issues Identified and Resolved by the Initial Decision

The Initial Decision identified and resolved 17 issues. Of these issues, we will summarily affirm Issue Nos. 1-3, 5, 8, 11-12, 14-15, and 17; and vacate as moot Issue Nos. 9-10, and 13, in part. The remaining issues (Issue Nos. 4, 6-7, 13, and 16) are discussed below.

B. Summary Affirmance Issues

No party excepted to the Presiding Judge's disposition of Issues Nos. 1-3, 5, 14-15, and 17. Specifically, the Presiding Judge ruled (and no party now contests) that: (1) SoCal Edison's reliance on a 45-day cash working capital allowance in rate base is reasonable, subject to the adjustments discussed elsewhere in the Initial Decision (Issue No. 1); (2) SoCal Edison's claimed rate base for plant held for future use, Account 105, (Issue No. 2), [8] and for construction work in progress, Account 107, (Issue No. 3), should be addressed in a compliance filing to be made by SoCal Edison to demonstrate that SoCal Edison's Account 105 and Account 107 costs do not recover costs already included

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[7]Initial Decision, 86 FERC at 65,136 (citing the following issues: abandoned plant; rate base adjustments; South Georgia adjustments; depreciation; revenue credits for wholesale transmission and power sales agreements; and the divisor for wholesale and access charges).

[8]Our ruling includes the requirement that SoCal Edison's compliance filing must demonstrate that such plant is not also recorded in Account 101.

in Account 101, electric plant in service; (3) the California Commission's proposal for the disposition of refunds to retail customers should be followed, in the event a lower transmission revenue requirement than that proposed by SoCal Edison is found just and reasonable (Issue No. 5); (4) the term of the TO Tariff may be superceded by the new California ISO Tariff, but in any event, does not need not be addressed in this proceeding (Issue No 14); (5) SoCal Edison's load dispatching expenses included in Account 561 are incurred by SoCal Edison for the benefit of all users of the transmission system and should therefore be allowed, as claimed (Issue No. 15); and (6) Vernon's proposal allowing ratepayers to recover a share of the gains realized by SoCal Edison from the sale of its oil and gas generating plants was not supported and should be rejected (Issue No. 17).

We find that the Presiding Judge's rulings on these issues were well reasoned and fully supported by the record. Accordingly, these rulings are hereby summarily affirmed. We also summarily affirm the ruling of the Presiding Judge: (1) accepting rolled-in rates for the TO Tariff wholesale access charge (Issue No. 8); (2) rejecting the proposal for time-of-use transmission rates (Issue No. 11); and (3) accepting the DA Tariff rate design (Issue No. 12). We find that the Initial Decision properly decided these issues on the grounds set forth in the Initial Decision. We therefore deny the exceptions on these issues asserted by SoCal Edison (as to Issue No. 8) and DWR (as to Issue Nos. 11-12).

C. Vacated Issues

We will vacate the Initial Decision as to those issues concerning membership rights and incentives to join the California ISO (Issue Nos. 9, 10, and 13). [9] On March 31, 2000, in Docket No. ER00-2019-000, the California ISO filed Amendment No. 27 to its tariff to address these issues. Amendment No. 27 proposes a new methodology for recovering, through a Transmission Access Charge (TAC), the embedded cost of transmission facilities comprising the Califiornia ISO-controlled grid. In our order issued May 31, 2000, we accepted for filing, suspended, and set for hearing the proposed TAC methodology and related tariff revisions. [10] Given these changed circumstances, the issues litigated in this proceeding relating to parties joining the California ISO are rendered moot. Therefore, we will vacate the Initial Decision

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[9] These incentives include, among other things, removal of the self-sufficiency test, which in turn eliminates the Non-Self Sufficiency Access charge.

[10] See California Independent System Operator Corp., 91 FERC 61,205 (2000). We also held the hearing in abeyance pending efforts at settlement and established settlement judge procedures.

regarding these issues, specifically, the appropriate billing determinants to be used for SoCal Edison's Non-Self Sufficient Access charge (Issue No. 9), whether a monthly versus an hourly rate should be used for SoCal Edison's Non-Self Sufficient Access charge (Issue No. 10), and all issues relating to customer credits for participating transmission owners (Participating TOs) (Issue No. 13).[11]

D. Whether the Presiding Judge Properly Determined that Non-Participating TOs Should Receive Credits for their Customer-Owned Transmission Facilities

Initial Decision

At hearing, Vernon and Cities (collectively Municipals) argued that as non-Participating TOs they should receive network customer credits against their Access Charges for their transmission facilities that are integrated with SoCal Edison's transmission system. Prior to restructuring, the creation of the California ISO, and SoCal Edison's filing of its TO Tariff, the Municipals were receiving an implicit credit for their customer-owned transmission facilities under their Intergrated Operating Agreements (IOAs) through hub and spoke pricing. In late 1996 and early 1997, as a result of the California restructuring process, the parties negotiated Restructuring Agreements, creating the current Transmission Service Agreements (TSAs), and terminated the IOAs. Under the TSAs, Municipals still pay for transmission solely within SoCal Edison's 230 kV hub network and not for SoCal Edison's spokes which generally parallel Municipals' transmission facilities. At hearing, Municipals argued that after their TSAs expire it will be unfair to take service under the TO Tariff using rolled-in pricing.[12]

SoCal Edison, the California ISO, and trial staff disagreed, relying on Florida Municipal Power Agency v. Florida Power & Light Company[13] and Orders Nos. 888 and 888-A. These parties argued that the Municipals' facilities are not integrated with the California ISO-controlled grid, which now includes SoCal Edison's transmission facilities, and therefore network customer credits should be denied. They further argued

[11] That portion of Issue No. 13 which addresses credits for non-participating TO's has not been rendered moot. The exceptions raised with respect to this issue, therefore, are addressed below.

[12] The TSA expiration dates differ for each agreement, with some TSAs terminating as early as December 31, 2002.

[13] 67 FERC ¶ 61,167 (1994) (FMPA), reh'g denied, 74 FERC ¶ 61,006 (1996).

that the only relevant test for integration under the restructured California ISO framework is if the California ISO has operational control and scheduling rights for the use of the transmission facilities.

The Presiding Judge rejected these arguments and found that the Municipals' facilities provide substantial support to the California ISO-controlled grid and that the Municipals act functionally as network service customers, meeting the Commission's requirements for network customer credits. On the matter of whether the Municipals should receive a network customer credit as Non-Participating TOs, the Presiding Judge found that the elimination of the implicit credits with the expiration of the TSAs would be unjust and unreasonable. The Presiding Judge ruled that SoCal Edison must modify the proposed wholesale wheeling access charge to permit the Municipals to pay hub-only costs instead of rolled-in costs once their TSAs expire.

Exceptions

SoCal Edison, the California ISO and trial staff filed exceptions. SoCal Edison and trial staff argue that the rates and term of the TSAs were the result of negotiation by the affected parties for the purpose of implementing restructuring, and that the Initial Decision has the effect of improperly extending these existing agreements beyond their negotiated contract terms. SoCal Edison also argues that the Presiding Judge's ruling on this issue undermines the ruling accepting rolled-in rates by making exceptions for the Municipals. Finally, SoCal Edison contends that the continuation of the TSAs beyond their negotiated terms unduly discriminates against the other users of the transmission system, including SoCal Edison's retail customers, who will have to pay higher rates when the current TSAs expire for the same service.[14]

The California ISO adds that because no party to this proceeding proposed continuation of the sub-functional (hub and spoke) rates, they were not a subject of discussion during the hearing, and there is no record evidence of the impact of such rates on other market participants. The California ISO concludes that under these circumstances, the justness and reasonableness of these rates was unsupported.

Cities and Vernon oppose these exceptions. Cities states that the Initial Decision does not extend the Cities' current contract rights, nor does the Initial Decision rely on the TSAs in reaching the conclusion that credits for the Municipals are appropriate. Cities argue that the Presiding Judge's findings were based on proper ratemaking principles and are independent of the contractual arrangements embodied in the TSAs and Restructuring

[14] SoCal Edison's Brief on Exceptions, at pp. 62-65.

Agreements. Vernon adds that SoCal Edison has proposed a new rate methodology in this proceeding which the Presiding Judge modified to grant customer credits. Vernon also disagrees with the assertions made by SoCal Edison and trial staff that the Presiding Judge has extended the existing contracts beyond their negotiated term, stating that the Presiding Judge's determination has only modified the proposed rates to incorporate the previous TSA's sub-functional rates.

Discussion

Although we have vacated the issue of customer credits for Participating TOs due to the ISO's TAC filing, in Docket No. ER00-2019-000, specifically the proposal to eliminate the non-self sufficiency test, [15] we will discuss here the issue of customer credits for non-Participating TOs.

FMPA, Order No. 888, and Order 888-A, all require that for facilities to be considered integrated, the transmission provider must be able to provide transmission service to itself or other transmission customers over these facilities As of the start-up of the California ISO, SoCal Edison no longer served as the transmission provider. Under these circumstances, until and unless the Municipals join the California ISO and turn over control of their facilities to the California ISO, the California ISO can have no operational control over Municipals' facilities. If the California ISO has no operational control over these facilities, it can not use them to provide transmission service to its customers. In fact, the California ISO would not even be able to transmit power over the customer facilities to the Municipals.

The Presiding Judge's ruling gives the benefit of California ISO membership without assigning any corresponding responsibilities to the Municipals. The result of this ruling is that other users of the California ISO grid would pay for the implicit credit, but would not be able to use the facilities. In addition, the Presiding Judge's ruling would require the rolled-in rate for other users to be modified each time a TSA expires, creating a lack of uniformity in rates over several years. In order for the Municipals to receive credits for their facilities, they must join the California ISO and thereby allow scheduling and control of the facilities by the transmission provider.

In addition, we find that the Presiding Judge improperly applied the terms and conditions of a negotiated contract to the proposed wholesale wheeling access charge. As noted by Cities' witness, the parties "mutually agreed in the Restructuring Agreements to terms and conditions under which the IOAs would terminate and the Cities will make the

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[15] See section C supra.

transition to independent operation in the restructured market".[16] The terms and conditions of the Restructuring Agreements were negotiated as a package with the expectation that the Municipals would eventually be able to operate independently. The Presiding Judge's ruling acts to sever the expiration term of the contract from the other terms and conditions mutually agreed upon by the parties, and would have the effect of abrogating the parties' agreement, without a reasonable basis for doing so. Therefore, we reverse the Presiding Judge's ruling that the implicit credit contained in the TSA's should be continued in the wholesale wheeling access charge.

E. Whether the Presiding Judge Properly Determined SoCal Edison's Rate of Return on Common Equity

Initial Decision

The Initial Decision declined to adopt the rate of return on common equity (ROE) proposed by SoCal Edison (11.6 percent) or trial staff (8.71 percent). The Initial Decision also accepted, in part, and rejected, in part, the methodologies used by these parties for calculating their respective ROEs. Based on the Presiding Judge's application of a two-stage discounted cash flow (DCF) formula which the Presiding Judge found to be consistent with the Commission's recent precedents in natural gas pipeline company cases,[17] the Presiding Judge calculated an ROE for SoCal Edison of 9.68 percent.

The Initial Decision found that the ROE recommendations made by SoCal Edison and trial staff differed significantly, due to the differing methodologies advanced by these parties to calculate SoCal Edison's ROE. These differences included: (1) trial staff's stand alone analysis of SoCal Edison versus SoCal Edison's analysis of a proxy group; (2) trial staff's use of a DCF analysis alone versus SoCal Edison's reliance on a DCF/risk premium analysis; (3) SoCal Edison's reliance on the gross domestic product (GDP) for the long-term growth factor in the DCF analysis versus trial staff's use of DRI industry data; and (4) the use or rejection of adjustments based on flotation costs and risk assessments.

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[16] Vernon's Brief Opposing Exceptions, at pp. 43-44.

[17] Initial Decision, 86 FERC at 65,143, citing Williston Basin Interstate Pipeline Company, 50 FERC ¶ 61,284 (1990) (Williston), vacated on other grounds, 931 F.2d 948 (D.C. Cir. 1991); Northwest Pipeline Corporation, 79 FERC ¶ 61,309 (Opinion No. 396-B), reh'g denied, 81 FERC ¶ 61,036 (1997) (Opinion No. 396-C); and Transcontinental Gas Pipe Line Corporation, 80 FERC ¶ 61,157 (1997) (Opinion No. 414), reh'g, 84 FERC ¶ 61,084 (1998) (Opinion No. 414-A).

The Presiding Judge concluded that in performing the DCF analysis in this case, the proxy group advanced by trial staff was appropriate because it is the Commission's preferred approach for natural gas pipeline companies and because "[t]he same logic should apply to electric companies." [18] The Presiding Judge also held that a DCF analysis rather than a risk premium analysis, or a combination thereof, was appropriate because, among other reasons, it was consistent with Commission policy In addition, the Presiding Judge accepted the use of the Institutional Brokers Estimation System (IBES) growth projections for the short-term growth factor in the DCF model and held that SoCal Edison's recommended use of GDP data, as a long-term growth factor, was appropriate because it was consistent with the Commission's rulings in Williston and Opinion No. 396-B. [19] Finally, the Presiding Judge chose the median return from the zone of reasonableness of the proxy group of companies he relied on to calculate his ROE, without an adjustment for flotation costs, based on his assessment of SoCal Edison's business and financial risks.

Exceptions

Exceptions were filed by SoCal Edison and trial staff. SoCal Edison argues that the Presiding Judge's ROE of 9.68 percent "fails to reflect the significant risks that [SoCal Edison] faces in the restructured electric utility environment, and reduces [SoCal Edison's] ROE substantially below levels previously allowed by the [California Commission] on the same assets for the same service." [20] SoCal Edison also claims that in addition to the DCF model, use of a risk premium analysis is appropriate because: (1) it is widely used and relied upon; and (2) the bond yields, on which the analysis is based, reflect investors' perceptions on a forward-looking basis.

SoCal Edison also objects to the Presiding Judge's rejection of its proxy group. SoCal Edison states that the companies included in trial staff's proxy group, which the Presiding Judge relied upon, have a lower risk profile than SoCal Edison. SoCal Edison also takes issue with the Presiding Judge's reliance on the Commission's natural gas pipeline precedents for the weighting to be given the short and long-term dividend growth rates, as used in the DCF formula to calculate "g." While in these precedents, the

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[18] Id. at 65,141.

[19] The Presiding Judge also determined that the short-term growth component should be given a two-thirds weight, and the long-term component a one-third weight, consistent with the Commission's recent natural gas pipeline company cases.

[20] SoCal Edison's Brief on Exceptions, at 7.

Commission gave a two-thirds weighting to short-term growth and a one third weighting to long-term growth, SoCal Edison claims that the Presiding Judge failed to explain why this same weighting would be appropriate in the case of an electric utility.

Trial staff asserts as error the Presiding Judge's decision not to use the long-range growth forecast of the electric industry's return on total capital, as published by Data Resources Inc. (DRI), for the long-term projection of growth in the DCF model. Trial staff also asserts as error the Presiding Judge's failure to consider company-specific data in the form of a stand-alone DCF in determining SoCal Edison's ROE.

Order Establishing Further Procedures

On September 17, 1999, the Commission issued an "Order Establishing Further Procedures On Issue Of Rate of Return on Common Equity."[21] In the September 17 Order, the Commission held that it would be in the public interest to consider additional arguments in this proceeding on the issue of SoCal Edison's ROE "[i]n light of the possible risks associated with the transfer of operational control of facilities to the California ISO, and the potential increase, since the end of the hearing, in the number of public utilities that face similar risks. . . ." The September 17 Order permitted interested parties to file initial and reply comments on these issues.[22]

Initial Comments

Initial Comments were timely filed by the California Electricity Oversight Board (Board); trial staff; the California Commission; the Sacramento Municipal Utility District (SMUD); and SoCal Edison. In addition, a motion for leave to file initial comments one day out of time was filed by Pacific Gas and Electric Company (PG&E), and motions for late intervention and comments were filed by Edison Electric Institute (EEI), the Electricity Consumers Resources Council (ELCON) and the American Iron and Steel Institute (AISI); and the Midwest ISO Participants (ISO Particpants).[23]

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[21]Southern California Edison Company, 88 FERC ¶ 61,254 (1999) (September 17 Order).

[22]As required by the September 17 Order, Initial Comments were filed on November 1, 1999. Reply Comments were filed December 1, 1999.

[23]Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2000), we will grant the unopposed motions to intervene filed by EEI,
(continued...)

SoCal Edison submits an updated ROE analysis, in its comments, in which it updates both its DCF study as well as its two risk premium analyses. These updated analyses are based on data for the period April 1999 through September 1999 and support, in SoCal Edison's view, an ROE in this case of at least 11.6 percent. SoCal Edison explains that this recommended ROE is based on the high end of the zone of reasonableness indicated by SoCal Edison's DCF analysis and is supported by a finding that SoCal Edison faces significant risks attributable to its joining the California ISO.

In assessing the risks it faces, SoCal Edison asserts that other industries that have experienced similar unbundling and partial deregulation should be studied, including the telecommunications and natural gas pipeline industries. SoCal Edison states that in these industries, there is clear evidence that unbundling one component of a previously integrated company can increase the risk attributable to the other components of the company's business. SoCal Edison also argues that in setting its ROE in this case, the Commission should consider the broader policy issue it discussed in the RTO proceeding, i.e., the option of using ROEs to give electric utilities an incentive to make investments in new transmission facilities.

ISO Participants, PG&E, and EEI argue that higher ROEs for the electric utility industry as a whole are necessary because in the restructured market, electric utilities face an increased risk of non-recovery of their transmission revenue requirements. EEI points out that while higher ROEs may mean higher direct costs for consumers, it will mean an avoidance of the far more significant indirect costs that could be incurred if utilities are not given the proper incentives to participate fully in the restructured market. ISO Participants add that the DCF analyses of integrated electric utilities may not reflect the risks associated with RTOs because the earnings growth forecasts for vertically integrated companies do not reflect transmission-only growth forecasts, nor do they reflect the increased financial and operational risks associated with joining an RTO. PG&E asserts that there are significant regulatory risks associated with a transfer of jurisdiction from the California Commission to the Commission, and that an exclusive reliance on a DCF analysis using electric utilities as a proxy group significantly understates the risks that SoCal Edison faces, because the electric utilities that comprise this proxy group are undergoing so much change at the present time.

Trial staff, the California Commission, the Board, ELCON, and AISI assert a different position on these issues. Trial staff argues that there is no evidence that SoCal

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[23](...continued)
ELCON, AISI, and the ISO Participants. We will also accept the initial comments filed one day out of time by PG&E.

Edison has become exposed to any new risks following the close of the record in this case, and suggests that SoCal will fully recover its stranded generation costs and plans to make significant new generation investments. Trial staff also cites evidence that the stock value of SoCal Edison's parent has and will continue to out-perform the electric utility averages. In addition, trial staff states that SoCal Edison itself has performed well since the advent of retail unbundling and intends to make substantial investments in its transmission and distribution network.[24]

The California Commission and the Board state that any increased risks facing SoCal Edison as a result of its participation in the California ISO were fully addressed by the California legislature in Assembly Bill 1890 (AB 1890), and that SoCal Edison retains the right to file section 205 rate cases at the Commission to recover its transmission revenue requirements.

ELCON, AISI and SMUD agree with the general thrust of these arguments. They argue that SoCal Edison's risks have been significantly reduced since its restructuring, and that its credit rating will actually improve as a result of its membership in the ISO, given its ability to recover its stranded costs. However, because an immediate reduction in ROEs for other utilities may act as a disincentive to their membership in RTOs, ELCON and AISI support the allowance of a grace period, during which utilities joining RTOs will be permitted to retain their current ROEs. SMUD argues that an artificially-inflated ROE is contrary to sound, cost-based ratemaking practices, and believes that SoCal Edison does not have increased risk associated with its participation in the California ISO.

Reply Comments

Reply comments were timely filed by ELCON; SoCal Edison; SMUD; the Metropolitan Water District of Southern California (Metropolitan); the California Commission; and trial staff. Trial staff and SMUD note, in their reply comments, that many of the arguments raised by SoCal Edison and others, in support of raising SoCal Edison's ROE in this case, address issues which have no bearing on the issues identified by the Commission in the September 17 Order. Trial staff further points out that other

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[24]Trial staff does note, however, that following the close of the record in this case, changes in the financial markets have occurred, which would justify an increased ROE for SoCal Edison over the figure advanced by trial staff at hearing. Specifically, the 8.71 percent return initially recommended by trial staff should be adjusted upward to 9.47 percent, based on the updated data on which trial staff relies and the same methodology previously utilized by trial staff's witness.

issues raised by these parties may have a bearing on other utilities or other industries, but have not been shown to have a bearing on the electricity market in California, or on SoCal Edison, specifically. Trial staff also takes issue with SoCal Edison's argument that the California ISO has no financial incentive in maximizing the company's profits. Trial staff claims that this risk, if it existed, would already be reflected in investors' expectations. Metropolitan also asserts that this risk is overstated and that it overlooks the many benefits conferred upon SoCal Edison as a result of its membership in the California ISO.

The California Commission also disputes SoCal Edison's claim that it risks less growth in its regulated business. The California Commission notes that SoCal Edison's own president has forecasted a substantial growth in its service territory. The California Commission also disputes SoCal Edison's claim that a higher ROE is necessary in order to further expand the transmission grid, pointing to other cases approving lower ROEs for utilities who are nonetheless pursuing expansion projects.

In its reply comments, Metropolitan urges the Commission to set SoCal Edison's ROE in this case based solely on SoCal Edison's electric transmission business. Metropolitan also urges the Commission not to use the instant proceeding to announce any new policies regarding appropriate ROEs for utilities who voluntary join an RTO pursuant to Order No. 2000. Metropolitan points out that because the California ISO was not voluntarily established, it does not fit the new paradigm contemplated by Order No. 2000. SMUD concurs with Metropolitan on this point.

ELCON takes issue with EEI's conclusion that restructuring will enhance the risk faced by transmission owners. ELCON asserts, to the contrary, that restructured transmission services, because they will be regulated, will continue to qualify for a fair ROE. ELCON also states that in a restructured environment, transmission owners will no longer be burdened by the substantial risks associated with generation.

SoCal Edison's reply comments take issue with the contention that it is seeking a premium ROE as a reward for its having joined the California ISO. SoCal Edison argues that the ROE it is seeking is fully commenserate with the risks it faces. SoCal Edison also takes issue with those comments addressing such issues as retail restructuring, generation, distribution and stranded cost recovery. SoCal Edison asserts that the issue for review, pursuant to the September 17 Order, are not these issues, but the risk that California ISO membership imposes on SoCal Edison's transmission business.

Discussion

The record in this proceeding was reopened for the purpose of considering additional evidence and arguments on ROE. As noted above, numerous comments were received, including the submission of revised DCF analyses by SoCal Edison and trial staff, and new DCF analyses submitted by SMUD and PG&E. These parties developed their ROE recommendations using either a DCF or a risk premium analysis or a combination of the two. The DCF analyses submitted in the supplemental record are similar to both the DCF analyses submitted by SoCal Edison and trial staff in the original proceeding and the DCF analysis adopted by the Presiding Judge. Each of these analyses relies on a weighted averaging of a short-term and a long-term growth rate, and purports to comply with the Commission's two-step DCF methodology, as set forth in Opinion No. 396-B.

The Commission, to date, has not expressly addressed the differing approaches taken in setting ROEs for gas pipelines and for electric utilities. This proceeding, however, presents the Commission with its first opportunity to calculate an ROE for an electric utility company where the positions advocated by the parties, and the record evidence contains both short-term and long-term growth data, consistent with our latest formulation of a two-step DCF methodology for natural gas pipeline companies. [25] The issue presented here, therefore, is whether the Commission's preferred DCF methodology for natural gas pipeline companies should be applied, without variation, to an electric utility company, in place of the Commission's standard, constant growth DCF model, previously relied upon by the Commission in calculating an ROE for an electric utility company. [26]

As noted above, the Presiding Judge applied the two-step DCF model currently used by the Commission in natural gas pipeline cases, reasoning, among other things, that

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[25] See, e.g., note 10 supra. The Commission's preferred approach in both gas pipeline and electric utility proceedings, is to use a DCF methodology to calculate the ROE. As discussed below, however, the two policies have diverged in how they determine the appropriate growth rate used in the DCF model.

[26] See, e.g., Southern California Edison Company, 56 FERC ¶ 61,003 (Opinion No. 362), order on reh'g, 56 FERC ¶ 61,117 (1991) (Opinion No. 362-A); Connecticut Light & Power Co., 43 FERC ¶ 61,508 (1988), Jersey Central Power & Light Co., 77 FERC ¶ 61, 001 (1996), Southwestern Public Service Co., 83 FERC ¶ 61,138 (1998), Appalachian Power Co., 83 FERC ¶ 61,335 (1998) (Appalachian), and Consumers Energy Co., 85 FERC ¶ 61,100 (1998).

the precedents applicable under Natural Gas Act are equally applicable to a case decided under the Federal Power Act. [27] Rather than adopting this approach, however, we believe that significant differences exist in the electric utility industry and the natural gas pipeline industry which warrant the continued use of different growth rates in the DCF models for each. Accordingly, we will not adopt the Initial Decision's ROE of 9.68 percent and the natural gas pipeline company methodology on which it relies. Instead, we will approve an ROE for SoCal Edison of 11.60 percent, based on the Commission's standard constant growth DCF model, as applied below. Should circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary.

In Opinion No. 396-B, we gave four reasons why the long-term growth of the United States economy as a whole is a reasonable proxy for the long-term growth rate of all firms, including regulated firms in the gas business. [28] First, the record in that case showed that as companies reach maturity over the long-term, their growth slows, and their growth rate will approach that of the economy as a whole. Second, it is reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy. Third, the purpose of using the DCF model approved in Opinion No. 396-B was to approximate the rate of return an investor would reasonably expect from a pipeline company, and no evidence in that record indicated that investors relied upon any of the alternative long-term growth approaches suggested by the parties in that proceeding. Fourth, each of the witnesses in Opinion No. 396-B used the long-term growth of the economy as a whole as confirmation or support for their analyses.

We find that our rationale in Opinion No. 396-B does not support the use of GDP data in developing a growth rate estimate in this proceeding. Unlike the gas pipeline industry, which was nearly through with major restructuring at the time we issued Opinion No. 396-B, on June 11, 1997, the electric industry is just beginning a significant new phase of its restructuring. In particular, SoCal Edison had just begun to restructure from a vertically integrated utility when it made its filing in the instant proceeding. [29] In addition, in contrast to the growth estimates that underlay the two-step approach for gas pipelines, the current growth rate estimates for SoCal Edison are not two to three times

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[27]Initial Decison, 86 FERC at 65,141.

[28]Opinion No. 396-B, 79 FERC at 62,382-83.

[29]SoCal Edison notes, moreover, that the transmission assets which are the subject of this proceeding, were state-regulated assets, until only recently, earning an 11.6 percent ROE. See SoCal Edison's Brief Opposing Exceptions, at p.4.

greater than GDP.[30] Moreover, the use of a two-step approach in natural gas pipeline company cases is supported by the fact that two large investment firms, Merrill Lynch and Prudential Securities, use the long-term growth of the economy as a whole in their analyses of gas pipeline companies. However, Prudential Securities indicates that it treats electric utilities differently from all of the other industrial companies when estimating growth rates.[31]

Trial staff also notes a number of significant differences between the electric and gas industries.[32] Specifically, trial staff notes that gas pipeline companies are similar to other industrial companies in that they have low dividend payout ratios (i.e., low dividend yields) and that they reinvest a high proportion of their earnings into their businesses to promote future growth.[33] By comparison, electric utilities typically have much higher dividend payout ratios (i.e., high dividend yields) as compared to most other industrial companies, including most gas pipeline companies. As a result, electric utilities reinvest less than a third of their earnings.[34]

This distinction between the two industries is critical, because retained earnings are a key source of dividend growth. The higher payout ratios attributable to electric

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[30]See, e.g., Ozark Gas Transmission System, 68 FERC ¶ 61,032 at 61,104-05 (1994) (Ozark) (growth estimates ranging from 8.81 percent to 15.2 percent and GDP estimates of 5.4 percent); Williston Basin Interstate Pipeline Company, 72 FERC ¶ 61,074 at 61,387 (1995) (growth estimates ranging from 8 to 15 percent and GDP estimates of 5.37 percent and 6.33 percent); and Opinion No. 414-A, 84 FERC at 61,427-7 (growth estimates ranging from 8 percent to 15 percent and GDP estimates of 5.45 percent). By comparison, the IBES growth estimate for SoCal Edison is 5.87 percent. See trial staff's Reply Comments, Att. D-1, at p. 1. GDP estimates range from 4.41 percent to 5.2 percent. See Exh. SCE-97, at pp. 5-7.

[31]See Exh. S-2, Schedule 14, at pp. 1-4.

[32]Trial staff's Brief on Exceptions, at pp. 19-21.

[33]Trial staff also points out that industrial companies, on average, had a payout ratio of 29 percent for the period 1994-97 and a forecasted payout ratio of 24 percent for 2002. Exh. S-2, Schedule No. 15, at p. 2. Gas pipelines had a payout ratio of 45 percent for the period 1993-97 and a forecasted payout ratio of 30 percent for 2002. Id., Schedule No. 13.

[34]Electric utilities had an average payout ratio of 71 percent for the period 1993-97, and a forecasted payout ratio of 68 percent for 2002. Id.

utilities cause these companies to have significantly lower expected dividend growth rates than most other industrial companies (including most gas pipeline companies). For example, the record in this case indicates that while the internal growth rate of gas pipelines averaged 6.05 percent from 1993 to 1997, and is projected to be 9.16 percent in 2002, the internal growth rate of electric utilities averaged only 2.51 percent over the same period, and is projected to be 3.86 percent in 2002.[35] While retention ratios for the electric utility industry, as a whole, are projected to increase slightly, in the future, as noted above, the rate of retention is still significantly lower than the average gas pipeline company. For all these reasons, we find that it would be premature, at this time, to incorporate GDP in the DCF model applicable to an electric utility company.

Nor are we convinced that trial staff's proposed use of DRI data is a reliable source for projecting growth, in this case, for SoCal Edison. Trial staff argues that because the DRI data on which it relies is closely related to total return on common equity, it is both more appropriate than GDP for projecting dividend growth for electric utilities and more likely to be used by investors. However, as the Presiding Judge found, DRI's estimate of return on total capital may be depressed by its anticipated write-offs of stranded costs that are incorporated into its forecasts.[36] Moreover, trial staff has not demonstrated that its DRI projection of growth in total capital equates to the measure of "g" on which the DCF model relies, i.e., growth in dividends per share, as we discuss below.

In the past, we have consistently applied a one-step, constant growth DCF model for calculating ROEs for electric utilities. The DCF methodology determines the ROE by summing the dividend yield (with an adjustment for the quarterly payment of dividends) and expected growth rate. The resulting formula is $D/P(1+.5g) + g = k$, where "D/P" is the dividend yield, "g" is the sustainable growth rate of dividends per share, and "k" is the resulting ROE. The sustainable growth rate is calculated by the following formula: $g = br + sv$, where "b" is the expected retention ratio, "r" is the expected earned rate of return on common equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.[37]

Based on the evidence submitted by trial staff in its Initial Comments, we can calculate an ROE for SoCal Edison using this one-step, constant growth DCF

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[35]See id., Schedule Nos. 10 and 13. A company's internal growth rate is computed as the product of its retention rate and its earned return on equity.

[36]Initial Decision, 86 FERC at 65,142; See also Exh. SCE-55, at p. 9.

[37]Connecticut Light & Power Co., 45 FERC ¶ 61,370 at 62,161, n. 15. (1988).

methodology. We turn first to the growth rate, of "g." From Value Line's growth projections for SoCal Edison's parent company, Edison International, a payout ratio can be calculated by dividing forecasted dividends per share by forecasted earnings per share. The payout ratio, for 1999, is 55.38 percent (based on Value Line's forecasts of dividends per share of $1.08, and earnings per share of $1.95); 52.68 percent for 2000 (based on Value Line's forecasts of dividends per share of $1.08, and earnings per share of $2.05), and 52.73 percent for 2003 (based on Value Line's forecasts of dividends per share of $1.16, and earnings per share of $2.20). The average forecasted payout ratio is 53.6 percent. Consequently, the retention ratio, "b," which is 1 minus the payout ratio, is 46.40 percent.

Value Line also forecasts a return on book value for Edison International, the "r" in the "br+sv" equation. For both 1999 and 2000, that return is expected to be 12.5 percent. It is expected to be 11.5 percent for 2003. The average forecasted "r" is 12.17 percent. However, these are forecasted year-end returns which must be adjusted by the growth in common equity for the period to derive an average yearly return. The average yearly return ("r") is thus 12.52 percent. [38]

Because Edison International is not issuing any new common stock, the external growth rate "sv," in the br+sv model, in this case, is zero.

Consequently, "g" may be calculated as "b" (.4640) times "r" (.1252), for a forecasted growth rate of 5.81 percent. By comparison, the IBES growth forecast for Edison International is 5.87 percent. [39] Using both projections, we will frame the zone of reasonableness in this case by combining the average low dividend yield for the six-month period ending August 1999 (3.96 percent), with the low growth rate (5.81 percent) and the average high dividend yield for this period (4.51 percent) with the high growth rate (5.87 percent). [40] The resulting zone of reasonable returns, as adjusted for the quarterly payments of dividends, is 9.89 percent to 10.51 percent.

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[38] In 1998, SoCal Edison's common equity ratio was 37.4 percent, with total capital of $13.6 billion (the equity component was $5.1 billion). For 2003, Value Line forecasts an equity ratio of 46 percent, with total capital of $14.8 billion (the equity component is $6.8 billion). Therefore, the growth in common equity ("G") is 5.9 percent. The adjustment factor -- 2(1+G)/(2+G) is 1.0287, which is applied to the year-end "r".

[39] Trial staff's Initial Comments, Att. D, at p. 1.

[40] Appalachian, 83 FERC at 62,350.

The Supreme Court has provided guidance in two often cited decisions regarding the range of allowed returns that may be permitted in a particular case. In Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,[41] the Court stated that the approved return should be "reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties."[42] In a subsequent case, FPC v. Hope Natural Gas Co.,[43] the Court provided additional guidance on this issue:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[[44]]

Applying these guidelines, we will measure the zone of reasonable returns indicated by the above analysis against a group of proxy companies having corresponding risks. A number of alternative proxy groups were proposed in this case by SoCal Edison, trial staff, SMUD, and PG&E. In the original proceeding and its Initial Comments, SoCal Edison relied on a proxy group of 13 companies with operating revenues of over $1 billion, and a bond rating of "A" or "A+." In its Initial Comments, SoCal Edison also developed an alternative proxy group, based on two criteria: companies located in states in which electric restructuring is at a comparable level to SoCal Edison's own restructuring, and companies having comparable bond ratings.[45] Trial staff, by contrast, chose its four-company proxy group based on the following criteria: (1) bond ratings of "AA-" to "A+"; (2) nuclear generation equal to at least 17 percent of total generation; (3)

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[41]262 U.S. 679 (1923) (Bluefield).

[42]Id. at 693.

[43]320 U.S. 591 (1944) (Hope).

[44]Id. at 603.

[45]SoCal Edison's alternative proxy group consists of Allegheny Energy Inc., MDU Resources Group, New England Electric System, PG&E, Pacificorp, and Sempra Energy.

a Standard & Poors (S&P) business profile of average or above; (4) $3 billion or more in total revenues, for 1996; and (5) an exclusion of any utility involved in any merger activity.

SMUD also calculated a zone of reasonableness based on a six company proxy group and the following seven criteria: (1) common stock actively traded on the open market and reported in the Wall Street Journal: (2) 80 percent of 1998 operating revenues derived from electric utility operations; (3) consistent financial history lasting for at least the last five years; (4) the exclusion of any utility involved in any merger activity or other significant structural change; (5) nuclear energy operations comprising less than 20 percent of generation fuel base; (6) companies paying dividends for the last ten years; and (7) companies whose non-utility revenues are equal to 15 percent, or less, of total operating revenues. PG&E calculated its proposed ROE utilizing a group of natural gas local distribution companies as a proxy group.

The Presiding Judge adopted trial staff's proxy group and we will do the same for the purpose of confirming our DCF analysis for SoCal Edison. As such, we will reject the proxy groups proposed by SoCal Edison, SMUD, and PG&E. As noted by the Presiding Judge, SoCal Edison's 13 company proxy group is based on overly-broad selection criteria without any emphasis on finding companies that are comparable in risk to SoCal Edison. SoCal Edison's alternative proxy group is a closer fit, however, it too lacks the detailed risk analysis of trial staff's comparable group. Several of the companies included by SMUD in its proxy group are insufficient in size relative to SoCal Edison. In addition, unlike SoCal Edison, five of the companies in SMUD's proxy group have no nuclear facilities. Finally, we will reject PG&E's proposed proxy group, given the significant differences between the gas industry and the electric utility industry, as discussed above.

Trial staff's proxy group, by contrast, includes comparable risk companies that are similar to SoCal Edison in size, business profile, and level of nuclear generation. Moreover, two of the four companies in trial staff's proxy group are currently in a Commission-approved ISO -- PG&E and the Constellation Energy Group (the parent company of Baltimore Gas & Electric Company). Thus trial staff's comparable group is the best proxy group to apply the standards enunciated in Bluefield and Hope.

In calculating our comparison group ROE, we will use the same "br + sv" formula, applied above, and the same Value Line source material relied upon above to calculate

SoCal Edison's individual zone of reasonableness.[46] In addition, we will corroborate the calculated growth rate with the forecasted IBES growth rate to set the high and low end of the zone of reasonableness. The results are summarized in the table below:

	avg. low dividend	avg. high dividend	growth rate (br + sv)[47]	growth rate (IBES)	zone of reasonableness
PG&E	3.63	3.88	4.70	6.153[48]	8.42 - 10.15
Constel-lation	5.63	6.16	4.10	3.85	9.59 - 10.39
Duke	3.74	4.14	7.60	8.13	11.48 - 12.44
Southern	4.81	5.35	5.28	5.85	10.22 - 11.36

An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999.[49] Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low end-return cannot be considered reliable in this case. Therefore, excluding this single outlier, the resulting zone of reasonableness for the comparable companies is 9.59 percent to 12.44 percent. The midpoint return is 11.02 percent.

We will next consider where, within this zone of reasonable returns, SoCal Edison's ROE should be set. In making this determination, it is necessary to measure the business and financial risks faced by SoCal Edison relative to the overall risks attributable to the appropriate proxy group of companies. As noted above, a substantial body of evidence has been presented in this case arguing for and against the relative riskiness of a utility transferring its transmission assets to an ISO. In addition, SoCal Edison, trial staff, and SMUD attempted to quantify the potential risks associated with SoCal Edison's

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[46]See trial staff's Initial Comments, Att. D-1, at pp. 12-15.

[47]Both Constellation and Duke are forecasted to issue stock.

[48]Exh. SCE-104, at p. 14 (containing a corrected forecasted growth rate of eight percent rather than 39 percent for the one analyst that was excluded from trial staff's calculation).

[49]Exh. SCE-104, at p. 31.

transfer of assets to the California ISO. However, much of this evidence was disputed by one party or another, or was speculative. In addition, much of the evidence submitted by the parties in their Initial Comments and Reply Comments was tied only tangentially to SoCal Edison.

The revised and updated DCF analyses submitted by SoCal Edison, trial staff and SMUD reflect updated investor expectations for SoCal Edison, which are based on more than a year's worth of operating practice by the California ISO. Given the conflicting evidence in this case on the issue of risk, we find that the updated financial data relied upon above is the best quantifiable measure of the investment communities' current risk assessment for SoCal Edison.

SoCal Edison argues that its risks exceed those of the proxy group based, among other things, on the rating of the comparable group's senior secured debt. Except for two of the five Southern Company subsidiaries, which have the same S&P bond rating as SoCal Edison, the rest of the companies in this proxy group are rated "AA-".[50] SoCal Edison's zone of reasonableness (9.89 - 10.51 percent) places SoCal Edison at the lower end of the zone of reasonableness of the comparable companies. This would be a reasonable result, if SoCal Edison was less risky than the comparable companies. However, based on the higher bond ratings of the comparable companies, we find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group. Therefore, we will establish SoCal Edison's ROE at the midpoint of the upper half of the zone of reasonableness.[51] That zone is 11.02 - 12.44 percent with a midpoint of 11.73. However, because this return exceeds SoCal Edison's own request, we will adjust the indicated return downward to 11.60 percent.

Use of Updated Data

Because capital market conditions may change significantly between the time the record closes and the date the Commission issues a final decision, we have consistently required the use of updated data in setting a company's ROE.[52] Here, however, the re-opened record authorized by the September 17 Order has permitted us to use current data,

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[50]Exh. SCE-102, at p. 18.

[51]See Consumers Energy Company, 85 FERC ¶ 61,100 at 61,364 (1998).

[52]See Appalachian Power Company, 55 FERC ¶ 61,509, order on reh'g, 57 FERC ¶ 61,100 (1991), order on reh'g, 58 FERC ¶ 61,193 (1992).

making any additional updates unnecessary. Consequently, SoCal Edison's ROE will be set at 11.6 percent for the period the rates went into effect and prospectively from the date of this order until SoCal Edison files for a change in its transmission rates.

F. Whether the Presiding Judge Properly Determined the Allocation of Administrative and General Expense and General and Intangible Plant to ISO Transmission

Initial Decision

The Initial Decision found that trial staff's proposed use of labor cost ratios to allocate administrative and general (A&G) and general and intangible plant (G&I) expenses was consistent with the Commission's long-standing policy set forth in Minnesota Power and Light Company,[53] and rejected SoCal Edison's alternative proposal, which relied on a multi-factor allocator. The Initial Decision noted that under SoCal Edison's proposal, A&G and G&I costs would be assigned to generation, ISO transmission, and non-ISO business segments by grouping these costs into one of three cost attribution pools: direct, joint, or common. These costs would then be assigned to the appropriate business segment based on the attribution technique specific to that pool, with the stated objective of limiting the amounts to which general allocation formulas are applied.

The Presiding Judge rejected this approach based, in part, on the Commission's recent reaffirmation of its long-standing use of labor ratios to allocate A&G and G&I expenses.[54] The Presiding Judge also found that while the alternative allocation proposal advanced by SoCal Edison and trial staff lead to different allocations, this difference alone does not prove that one method is superior to the other, nor did it satisfy SoCal Edison's burden of showing that the Commission's existing policy is unjust and unreasonable and that its own proposal was just and reasonable. The Presiding Judge also found that SoCal Edison failed to support its own allocation of its costs, and that the timing of rate cases before this Commission and the California Commission and the restructuring of SoCal Edison's facilities and services did not support the rejection of labor ratios as the preferred allocation methodology.

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[53] 4 FERC ¶ 61,268 (1978).

[54] Initial Decision, 86 FERC at 65,145, citing Portland General Electric Company, 84 FERC ¶ 61,216, at p. 62,004 (1998) and Montana Power Company, 83 FERC ¶ 61,211, at p. 61,935 (1998).

Exceptions

Exceptions were filed by SoCal Edison, in which SoCal Edison renews the arguments presented at hearing concerning the reasonableness of its proposed A&G and G&I allocation methodology. In addition, SoCal Edison states that the Presiding Judge's determination would result in significant under-recovery of its reasonably incurred transmission costs. SoCal Edison contends that the California Commission assumed that these costs would be recovered in transmission rates when the California Commission designed SoCal Edison's state jurisdictional retail rates. SoCal Edison concludes that these costs would be unrecovered due solely to the transfer of jurisdiction over retail transmission from the California Commission to this Commission resulting in an unfair denial of its legitimately-incurred costs.

Trial staff opposes SoCal Edison's exceptions, reiterating its arguments presented at hearing. The California Commission submitted comments stating that SoCal Edison's allegation that the unrecovered costs at issue would "fall through the jurisdictional cracks" is misleading. The California Commission states that Socal Edison filed for and received a resolution action from the California Commission giving SoCal Edison the opportunity to present evidence to the California Commission in order to recover these costs.

Discussions

We will affirm the Initial Decision. The majority of the arguments raised by SoCal Edison on exceptions were presented at hearing and were properly disposed of in the Initial Decision. We also find that the Presiding Judge properly applied the Commission's existing policy for allocating A&G and G&I costs. In addition, the California Commission has made clear in its comments that SoCal Edison has the opportunity, if it so chooses, to seek state jurisdictional review and potential recovery of any non-transmission costs subject to the California Commission's jurisdiction. Given this opportunity, we find that SoCal Edison's claimed inability to recover its legitimately incurred costs, due to changes in jurisdiction, is unfounded.

G. Whether the Presiding Judge Properly Determined that SoCal Edison's Projected 1998 A&G Expenses Should be Rejected in favor of the 1997 Recorded A&G Amounts, as Adjusted

Initial Decision

The Initial Decision rejected SoCal Edison's 1998, Period II test year forecasts to calculate its A&G expenses, adopting instead the California Commission's recommendation, which was based on SoCal Edison's 1997 Form No. 1 A&G data, with an adjustment to account for its divested oil and gas plants. In support of his holding, the Presiding Judge cited Commission precedent for the proposition that Period II adjustments may be based on more recent actual data.[55] The Presiding Judge also found that the use of this data was appropriate in this case given SoCal Edison's restructuring. and because SoCal Edison's Period II projections were poorly founded.

Exceptions

SoCal Edison and trial staff filed exceptions. SoCal Edison cites Commission policy for the proposition that a utility's test year projections must be accepted if found to be reasonable when made, and there is no evidence that it will produce unreasonable results.[56] SoCal Edison argues that the single fact that its 1998 Period II estimate and its 1997 data vary does not demonstrate that its test period estimate was unreasonable when made. Moreover, SoCal Edison points out that its projected 1998 A&G expense level was based on a significant reduction in its 1995 A&G expenses and was a reasonable projection of the cost reductions it anticipated.

Trial staff argues that no showing was made in this case that use of SoCal Edison's 1997 actual costs are representative of the costs that will be incurred by SoCal Edison during the rate-effective period and that these costs, in any event, would have to be adjusted to reflect future operations. Trial staff also objects to the mixing of data from different years for use of Period II data.

The California Commission opposes these exceptions, citing record evidence showing that SoCal Edison knew when they filed their 1998 Period II estimate that (1) staffing reductions decreased their A&G costs by $70 million as recorded in 1997 Form No. 1 data; (2) that the costs of certain terminated programs should be removed from the A&G projection; and (3) that use of inflation-related escalators was not accurate given the multi-year Performance Based Rate (PBR) cost-cutting measures SoCal Edison had committed to hold constant. Because SoCal Edison failed to incorporate these known changes into their projection, the California Commission supports the Presiding Judge's

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[55]Initial Decision, 86 FERC at 65,176, citing Cleveland Electric Illuminating Company, 28 FERC ¶ 63,089 (1984) (Cleveland Electric), aff'd in relevant part, 32 FERC ¶ 61,381 at 61,858 (1985); Southern California Edison Company, 56 FERC ¶ 61,003, at 61,021-24 (1991).

[56]SoCal Edison's Brief on Exceptions, at p. 58, citing Delmarva Power & Light Company, 24 FERC ¶ 61,199 at 61,453 (1983).

finding that the estimates were not reasonable when made. In addition, the California Commission refutes SoCal Edison's interpretation of the case law, stating that in Cleveland Electric adjustments were made to the historic data because that was the only data available at the time, as opposed to this case where 1997 Form No. 1 data is available.

Discussion

None of the exceptions warrant reversing the Presiding Judge's determination in this proceeding that SoCal Edison's Period II estimate is unjust and unreasonable. The Presiding Judge's reasoning that the use of 1997 adjusted Form No. 1 data is more likely to yield just and reasonable results than SoCal Edison's poorly supported Period II estimates is well-supported by the record evidence. The approach adopted by the Presiding Judge is acceptable in this situation because of the unique facts of this case. As noted by the Presiding Judge, SoCal Edison drastically restructured and downsized its previous utility operations, divested substantial generation assets and turned over its transmission facilities to the ISO. Their escalation of 1995 A&G data in this proceeding was unwarranted given the cost cutting incentives under the PBR when SoCal Edison made its test year projections. As noted by the Presiding Judge, So Cal Edison has the burden of showing that its projections were reasonable when made, but it has not done so. Given the unique facts of this case we will affirm the Initial Decision.

H. Whether the Presiding Judge Properly Determined the Level of SoCal Edison's Cost-Based Ancillary Services Rates for the Locked-In Period, April 1, 1998 - November 2, 1998

Initial Decision

The Initial Decision found that SoCal Edison's proposed cost-based bid caps for four ancillary services for the locked-in period April 1, 1998 through November 2, 1998 [57] should not be based on the cost of SoCal Edison's oil and gas generation facilities, as proposed by SoCal Edison, but rather on SoCal Edison's hydro resources, as proposed by trial staff. The Presiding Judge further found that SoCal Edison's proposed bid caps

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[57]The locked-in period was the result of the Commission's ruling in AES, 85 FERC at 61,459-65, in which the Commission granted market-based rate authority to all entities providing ancillary services in the State of California, based on our determination that cost-based bid caps in the ancillary services market were restricting supplies to these markets .

should be based on a trial staff study of 1997 FERC Form 1 data for its Hoover and Big Creek costs.

The bid caps established the maximum amount SoCal Edison could bid in the ISO's ancillary service markets during the period that the cost-based rates were in effect. SoCal Edison's filing states that these proposed rates were an interim measure to continue their existing ancillary services rates until the company completed the market study required for filing for market-based ancillary service rates.[58]

In support of its ruling, the Initial Decision noted trial staff's contention that because these facilities were divested during the period that the proposed ancillary service bid caps were in effect, the rate should be based on SoCal Edison's remaining hydro units. Even though SoCal Edison owned oil and gas-fired generation facilities through part of June 1998, trial staff maintained that SoCal Edison did not use these units for ancillary services during any part of the locked-in period. Only trial staff objected to the continued use of SoCal Edison's rates, maintaining that SoCal Edison's bid caps were in excess of the actual costs of the units that provided the services during the locked-in period.

Exceptions

On exceptions, SoCal Edison argues that its proposed ancillary services bid caps are significantly below the levels that the Commission found to be just and reasonable in AES, and are otherwise fully cost-justified. In particular, SoCal Edison notes that some of the ancillary services it provided during the relevant time period did in fact rely on SoCal Edison's oil- and gas-fired units. Moreover, SoCal Edison argues that its ancillary services sales are subject to the Commission's policy regarding off-system sales, as enunciated in Illinois Power Company,[59] which permits pricing flexibility not necessarily tied to the actual generating resource used to provide the service at issue.

In addition, SoCal Edison takes exception to various methods and calculations of cost used by trial staff to determine alternative ancillary service rates based exclusively on SoCal Edison's individual hydro units. SoCal Edison maintains that its proposed ancillary services bid caps are below costs that it experiences in providing ancillary services from its hydro resources.

[58] SoCal Edison's Transmittal Letter at 18, n. 5.

[59] 57 FERC ¶ 61,213 at 61,699 (1991) (Illinois Power).

Discussion

We find that the Presiding Judge's rejection of SoCal Edison's cost-based ancillary services bid caps, for the locked-in period, is in error. First, we agree with SoCal Edison that its proposed bid caps are cost-justified and consistent with our ruling in Illinois Power. The reasonableness of these rates, moreover, is confirmed by trial staff's own analysis, which would support a maximum rate well above SoCal Edison's proposed bid caps.[60]

We reject trial staff's contention that ancillary service bid caps must reflect the actual costs of the individual unit supplying the ancillary service at the time of sale. The ISO's ancillary services market is based on an auction mechanism in which suppliers submit hourly bids that are put in merit order, with the market clearing price paid to all bidders who are selected. As a result, during the locked-in period, all units which provide ancillary services for that hour receive the market clearing price capped at their respective cost-based bid caps. This market clearing mechanism does not comport with the theory trial staff espouses for tracking the exact costs of the actual generating unit used to supply a particular service.

Given the circumstances of this case and the state of the ISO ancillary services markets during the locked-in period, we reject the Presiding Judge's finding that trial staff's ancillary service bid caps are representative of the ceiling costs of these services during the locked-in period. For the reasons discussed above, we approve SoCal Edison's proposed ancillary service bid caps, as filed.

The Commission orders:

(A) The Initial Decision is hereby vacated in part, affirmed in part, and reversed in part, as discussed in the body of this order.

(B) The motions to intervene filed by EEI, ELCON, AISI, and the ISO Participants are hereby granted, as discussed in the body of this order.

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[60] Trial staff calculated the unit-by-unit costs for SoCal Edison's hydro generation resources, resulting in a maximum capacity charge of $26.02/MW/hr. See Exhibit S-4, at 16-18 and Exh. S8). In contrast, SoCal Edison's proposed ancillary services bid caps ranged from $4.47/MW/hr to $9.55/MW/hr. See TO Tariff and DA Tariff at Original, Sheet Nos. 74 through 78.

(C) SoCal Edison is hereby directed to file, within 45 days of the date of this order, a compliance filing addressing those matters discussed herein. However, if a request for rehearing is pending at the end of the 45 day period, the compliance filing shall be made within 15 days of the date such rehearing is disposed of by the Commission.

By the Commission.

(S E A L)

David P. Boergers

David P. Boergers,
Secretary.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 921

Exhibits in Support
Of Opening Testimony

June 4, 2010

Staff/921
Storm/1

indexArb

Dividend Yield for Stocks in the S&P 500

Updated: Tuesday, May-11-2010
8:30pm ET

- Home Page
- Distant Months Contracts
- IndexArb Values vs. Time
- Stock Performance vs. Indexes
- Capitalization Analysis
- Index Component Weights
- Dividend Analysis
- Fair Value Decomposition
- Yield Curve
- Program Trading Calculator
- Help
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Notes about the following table of dividend yields.

- The "Estimated Dividend" for each stock below is our best estimate of the per share amount that will be paid during the next year, beginning on May-12-2010. Most companies pay dividends on a quarterly frequency; some pay annually or semi-annually. The amount, timing, and growth of each dividend is forecasted from several years of dividend history, provided, of course, that the company has an established track record. Otherwise, the most recent (perceived) dividend policy is extended.
- Internal values have a precision of at least twelve decimal places. Displayed values, however, are rounded to either two or four decimal places.
- Therefore, if you calculate the dividend yield by dividing the estimated dividend by the price using the rounded amounts in the table, you might get slightly different values. The correct values are those that are displayed.
- The table can be sorted by clicking on the column headings of Stock (for an alphabetical listing) or Dividend Yield (for a descending value listing).

The following table is sorted by Dividend Yield.

Stock	Current Price	Estimated Dividend [For the next year]	Dividend Yield (%)	Bar Graph
Frontier Communications	7.78	0.8125	10.44	
Windstream	10.58	1.0000	9.45	
CenturyLink	33.70	2.9000	8.61	
Diamond Offshore Drilling	75.07	6.0000	7.99	
Verizon Communications	28.40	1.9600	6.90	
Reynolds American	54.08	3.6000	6.66	
AT&T	25.64	1.7000	6.63	
Altria	21.59	1.4100	6.53	
Pepco Holdings	16.93	1.0800	6.38	
Health Care REIT	42.91	2.7200	6.34	
Qwest Communications Int'l	5.16	0.3200	6.20	
Progress Energy	40.31	2.4800	6.15	
FirstEnergy	35.87	2.2000	6.13	
Ameren	25.24	1.5400	6.10	
Pinnacle West Capital	35.70	2.1500	6.02	
Pitney-Bowes	24.63	1.4700	5.97	
Duke Energy	16.92	0.9900	5.85	
Cincinnati Financial	27.46	1.5950	5.81	
NiSource	15.89	0.9200	5.79	
Lilly (Eli)	35.28	2.0200	5.73	
Integrys Energy Group	48.57	2.7200	5.60	
CenterPoint Energy	14.18	0.7900	5.57	

Staff/921
Storm/2

HCP	33.76	1.8700	5.54	
PPL	25.60	1.4100	5.51	
Bristol-Myers Squibb	24.37	1.3000	5.33	
Consolidated Edison	44.85	2.3900	5.33	
Southern	34.88	1.8375	5.27	
Donnelley (R.R.)	20.11	1.0400	5.17	
Lorillard	80.66	4.1600	5.16	
SCANA	37.26	1.9050	5.11	
American Electric Power	33.15	1.6900	5.10	
TECO Energy	16.21	0.8200	5.06	
Philip Morris International	48.35	2.4400	5.05	
Exelon	42.68	2.1100	4.94	
ProLogis	12.18	0.6000	4.93	
Microchip Technology	28.71	1.3900	4.84	
XCEL Energy	21.57	1.0100	4.68	
Hudson City Bancorp	13.07	0.6100	4.67	
Merck	33.51	1.5200	4.54	
Pfizer	17.01	0.7600	4.47	
DTE Energy	47.72	2.1200	4.44	
Leggett & Platt	24.14	1.0700	4.43	
Dominion Resources	41.80	1.8500	4.43	
Spectra Energy	22.67	1.0000	4.41	
Ventas	48.68	2.1400	4.40	
Public Serv. Enterprise	31.48	1.3775	4.38	
Paychex	30.25	1.3200	4.36	
NICOR	42.66	1.8600	4.36	
Plum Creek Timber	38.75	1.6800	4.34	
Dupont	38.10	1.6400	4.30	
Entergy	77.63	3.3200	4.28	
Kimberly-Clark	62.79	2.6800	4.27	
People's United Financial	14.71	0.6250	4.25	
PG&E	44.41	1.8550	4.18	
CMS Energy	15.46	0.6400	4.14	
Federated Investors	23.50	0.9600	4.09	
Kraft Foods	30.37	1.2200	4.02	
Northeast Utilities	26.51	1.0438	3.94	
NYSE Euronext	30.72	1.2000	3.91	
Kimco Realty	16.40	0.6400	3.90	
Genuine Parts	42.52	1.6500	3.88	
ONEOK	48.81	1.8800	3.85	
ConocoPhillips	57.28	2.2000	3.84	
FPL Group	52.66	2.0200	3.84	
Waste Management	33.96	1.2850	3.78	
Edison	33.99	1.2800	3.77	

Staff/921
Storm/3

Heinz (H.J.)	46.53	1.7200	3.70
Abbott Labs	49.40	1.8100	3.66
MeadWestvaco	25.26	0.9200	3.64
Chevron	79.70	2.8800	3.61
Block H&R	17.34	0.6000	3.46
Marsh & McLennan	23.17	0.8000	3.45
AvalonBay Communities	103.79	3.5700	3.44
Clorox	63.14	2.1600	3.42
ConAgra Foods	24.36	0.8300	3.41
Coca-Cola	53.61	1.8000	3.36
Sysco	30.38	1.0200	3.36
PPG	66.43	2.2200	3.34
Sempra Energy	47.30	1.5800	3.34
Johnson & Johnson	64.67	2.1600	3.34
Mattel	22.82	0.7600	3.33
Automatic Data Processing	42.50	1.4000	3.29
Public Storage	97.86	3.2000	3.27
McDonalds	70.48	2.3000	3.26
Bemis	28.35	0.9250	3.26
Marathon Oil	31.07	1.0000	3.22
Campbell Soup	35.88	1.1500	3.21
Wisconsin Energy	52.17	1.6700	3.20
Time Warner Cable	50.05	1.6000	3.20
Linear Technology	29.41	0.9400	3.20
Vornado Realty Trust	81.88	2.6000	3.18
Procter & Gamble	62.37	1.9754	3.17
McGraw-Hill	30.06	0.9500	3.16
M&T Bank	88.77	2.8000	3.15
Sara Lee	14.33	0.4500	3.14
Nucor	45.99	1.4400	3.13
Lockheed Martin	83.10	2.6000	3.13
Avon Products	28.79	0.8900	3.09
Intel	22.28	0.6650	2.98
Kellogg	54.38	1.6050	2.95
Chubb	51.40	1.5100	2.94
Allegheny Energy	20.47	0.6000	2.93
V.F.	83.36	2.4400	2.93
Travelers	49.78	1.4400	2.89
PepsiCo	66.55	1.9200	2.89
General Mills	72.32	2.0800	2.88
Raytheon	57.46	1.6450	2.86
Equity Residential	47.33	1.3500	2.85
United Parcel Service	66.99	1.9000	2.84
Northrop Grumman	64.89	1.8400	2.84

Staff/921
Storm/4

Smucker	58.68	1.6500	2.81	
Air Products & Chemicals	71.67	2.0000	2.79	
ExxonMobil	64.46	1.7900	2.78	
Analog Devices	28.86	0.8000	2.77	
Molex	22.15	0.6100	2.75	
Penney (J.C.)	29.07	0.8000	2.75	
McCormick	39.33	1.0800	2.75	
Eastman Chemical	64.59	1.7600	2.72	
Emerson Electric	49.90	1.3550	2.72	
Xilinx	25.06	0.6800	2.71	
Time Warner	31.48	0.8500	2.70	
Constellation Energy Group	35.70	0.9600	2.69	
Baxter	45.50	1.2200	2.68	
Hershey	47.88	1.2800	2.67	
Eaton	75.02	2.0000	2.67	
Colgate-Palmolive	82.83	2.2000	2.66	
Honeywell International	45.85	1.2175	2.66	
Molson Coors	42.19	1.1200	2.65	
Home Depot	35.63	0.9450	2.65	
Simon Property Group	90.62	2.4000	2.65	
Meredith	34.97	0.9250	2.65	
Illinois Tool Works	50.12	1.3000	2.59	
Darden Restaurants	44.73	1.1600	2.59	
Snap-On	46.54	1.2000	2.58	
Republic Services	29.99	0.7700	2.57	
Caterpillar	66.07	1.6900	2.56	
Allstate	32.75	0.8300	2.53	
Supervalu	13.86	0.3500	2.53	
3M	85.04	2.1150	2.49	
Hasbro	41.28	1.0200	2.47	
Boston Properties	81.16	2.0000	2.46	
General Electric	18.00	0.4400	2.44	
Wal Mart	52.46	1.2800	2.44	
United Technologies	73.13	1.7700	2.42	
Boeing	71.42	1.7200	2.41	
General Dynamics	72.65	1.7200	2.37	
Norfolk Southern	59.15	1.3800	2.33	
AFLAC	48.94	1.1400	2.33	
Praxair	80.39	1.8500	2.30	
Williams	21.81	0.5000	2.29	
Sealed Air	21.05	0.4800	2.28	
Archer-Daniels-Midland	27.02	0.6100	2.26	
XL Capital	17.94	0.4000	2.23	
Cardinal Health	35.03	0.7800	2.23	

Staff/921
Storm/5

Yum! Brands	41.81	0.9300	2.22	
International Flavors Fragrance	46.58	1.0300	2.21	
National Semiconductor	14.48	0.3200	2.21	
Limited Brands	27.16	0.6000	2.21	
Stanley Black & Decker	61.45	1.3500	2.20	
Ryder System	46.04	1.0100	2.19	
Brown-Forman (B)	57.58	1.2400	2.15	
Comcast	18.08	0.3890	2.15	
Dow Chemical	27.89	0.6000	2.15	
Hormel Foods	41.04	0.8800	2.14	
Avery Dennison	37.65	0.8000	2.12	
Dover	50.47	1.0700	2.12	
Medtronic	42.67	0.9000	2.11	
IBM	126.89	2.6600	2.10	
Applied Materials	13.36	0.2800	2.10	
Northern Trust	54.45	1.1400	2.09	
EQT	42.13	0.8800	2.09	
Becton Dickinson	74.75	1.5600	2.09	
Invesco	21.19	0.4400	2.08	
International Paper	24.29	0.5000	2.06	
T. Rowe Price	54.04	1.1000	2.04	
Grainger (W.W.)	110.33	2.2400	2.03	
QUALCOMM	37.48	0.7600	2.03	
Texas Instruments	25.65	0.5100	1.99	
Deere	59.46	1.1800	1.98	
Masco	15.12	0.3000	1.98	
ITT	52.59	1.0400	1.98	
Sunoco	30.49	0.6000	1.97	
Harris	49.63	0.9700	1.95	
Moody's	21.76	0.4250	1.95	
Robert Half International	27.25	0.5300	1.94	
Rockwell Automation	60.08	1.1600	1.93	
Omnicom Group	41.51	0.8000	1.93	
BB&T	34.82	0.6600	1.90	
Wyndham Worldwide	25.40	0.4800	1.89	
Dun & Bradstreet	75.80	1.4200	1.87	
Monsanto	57.52	1.0750	1.87	
Pall	36.87	0.6800	1.84	
Principal Financial Group	29.85	0.5500	1.84	
Cintas	26.66	0.4900	1.84	
KLA-Tencor	32.67	0.6000	1.84	
Jabil Circuit	15.25	0.2800	1.84	
L-3 Communications	89.88	1.6500	1.84	
Microsoft	28.88	0.5300	1.84	

Staff/921
Storm/6

Vulcan Materials	54.51	1.0000	1.83	
Occidental Petroleum	83.03	1.5200	1.83	
Washington Post	498.13	9.1000	1.83	
Sherwin-Williams	79.48	1.4500	1.82	
Total System Services	15.43	0.2800	1.81	
Mead Johnson Nutrition	51.25	0.9250	1.80	
Gap	23.83	0.4300	1.80	
MetLife	43.23	0.7800	1.80	
Murphy Oil	55.78	1.0000	1.79	
Kroger	22.16	0.3950	1.78	
Assurant	36.26	0.6400	1.77	
Tiffany	46.50	0.8200	1.76	
CSX	55.58	0.9800	1.76	
Walgreen	36.17	0.6325	1.75	
Johnson Controls	31.58	0.5500	1.74	
JPMorgan Chase	41.55	0.7100	1.71	
Freeport-McMoran C&G	70.24	1.2000	1.71	
Union Pacific	74.79	1.2600	1.68	
Xerox	10.10	0.1700	1.68	
C.H. Robinson Worldwide	60.68	1.0200	1.68	
Safeway	24.00	0.4000	1.67	
American Express	43.33	0.7200	1.66	
Abercrombie & Fitch	42.33	0.7000	1.65	
Staples	22.38	0.3700	1.65	
Whirlpool	105.24	1.7200	1.63	
Dr Pepper Snapple Group	36.78	0.6000	1.63	
Fortune Brands	49.42	0.8000	1.62	
Family Dollar Stores	39.98	0.6400	1.60	
Ameriprise Financial	46.18	0.7300	1.58	
Nordstrom	42.08	0.6600	1.57	
Parker-Hannifin	67.05	1.0400	1.55	
Starbucks	26.70	0.4100	1.54	
Fastenal	54.25	0.8200	1.51	
Goodrich	74.22	1.1200	1.51	
Rockwell Collins	63.77	0.9600	1.51	
NIKE	76.43	1.1400	1.49	
Airgas	63.29	0.9400	1.49	
Costco Wholesale	57.94	0.8450	1.46	
Coach	41.45	0.6000	1.45	
Western Union	16.79	0.2400	1.43	
Schwab (Charles)	17.64	0.2500	1.42	
Aon	42.40	0.6000	1.42	
Lowe's Cos.	27.10	0.3800	1.40	
CME Group	329.20	4.6000	1.40	

Staff/921
Storm/7

TJX	45.74	0.6300	1.38	
Unum Group	24.05	0.3300	1.37	
Ecolab	48.85	0.6600	1.35	
Allegheny Technologies	53.46	0.7200	1.35	
Apartment Invest & Mgmt	22.35	0.3000	1.34	
Patterson Companies	30.80	0.4100	1.33	
Coca-Cola Enterprises	27.07	0.3600	1.33	
CBS	15.09	0.2000	1.33	
Best Buy	44.43	0.5800	1.31	
Chesapeake Energy	23.28	0.3000	1.29	
Baker Hughes	46.70	0.6000	1.28	
AK Steel Holding	15.62	0.2000	1.28	
Ross Stores	54.08	0.6900	1.28	
Halliburton	28.34	0.3600	1.27	
Prudential Financial	63.16	0.8000	1.27	
Target	56.28	0.7100	1.26	
Schlumberger	66.84	0.8400	1.26	
Newell Rubbermaid	16.74	0.2100	1.25	
PerkinElmer	23.06	0.2800	1.21	
RadioShack	20.67	0.2500	1.21	
Expedia	23.18	0.2800	1.21	
Harley Davidson	33.38	0.4000	1.20	
Wynn Resorts	84.28	1.0000	1.19	
Sigma-Aldrich	56.52	0.6600	1.17	
Bank of New York Mellon	30.98	0.3600	1.16	
AmerisourceBergen	31.22	0.3600	1.15	
Torchmark	52.71	0.6000	1.14	
International Game Technology	21.09	0.2400	1.14	
Questar	46.58	0.5300	1.14	
XTO Energy	45.44	0.5000	1.10	
Corning	18.22	0.2000	1.10	
Stryker	56.75	0.6200	1.09	
Cliffs Natural Resources	56.79	0.6200	1.09	
D.R. Horton	13.84	0.1500	1.08	
Smith International	44.75	0.4800	1.07	
Flowserve	111.96	1.1900	1.06	
Carnival	38.88	0.4100	1.05	
Noble Energy	68.55	0.7200	1.05	
CVS/Caremark	35.75	0.3725	1.04	
News Corp.	14.48	0.1500	1.04	
Valero Energy	19.57	0.2000	1.02	
Tellabs	8.82	0.0900	1.02	
CONSOL Energy	39.30	0.4000	1.02	
Disney	35.76	0.3600	1.01	

Staff/921
Storm/8

Iron Mountain	25.03	0.2500	1.00	
Fluor	50.47	0.5000	0.99	
Alcoa	12.13	0.1200	0.99	
National Oilwell Varco	40.56	0.4000	0.99	
Goldman Sachs	141.97	1.4000	0.99	
Progressive	20.34	0.2000	0.98	
Cummins	71.76	0.7000	0.98	
U.S. Bancorp	26.68	0.2600	0.97	
Expeditors Intl Washington	41.30	0.4000	0.97	
Gannett	16.59	0.1600	0.96	
Broadcom	33.41	0.3200	0.96	
Devon Energy	67.87	0.6500	0.96	
Morgan Stanley	28.38	0.2600	0.92	
Wells Fargo	32.91	0.3000	0.91	
Estee Lauder	63.14	0.5700	0.90	
Tyson Foods	18.02	0.1600	0.89	
Macy's	23.90	0.2100	0.88	
Franklin Resources	109.49	0.9400	0.86	
Bard (C.R.)	84.02	0.7200	0.86	
PACCAR	44.54	0.3750	0.84	
Altera	24.18	0.2000	0.83	
Oracle	24.19	0.2000	0.83	
Hartford Financial Svc.Gp.	26.74	0.2200	0.82	
Lennar	19.46	0.1600	0.82	
FMC	64.07	0.5150	0.80	
Ball	51.52	0.4000	0.78	
CA	21.47	0.1600	0.75	
Massey Energy	35.28	0.2600	0.74	
Quest Diagnostics	54.89	0.4000	0.73	
McKesson	66.10	0.4800	0.73	
Loews	34.92	0.2500	0.72	
FIS	28.86	0.2000	0.69	
Newmont Mining	58.20	0.4000	0.69	
Peabody Energy	42.26	0.2900	0.69	
Visa	84.16	0.5750	0.68	
Hess	58.61	0.4000	0.68	
Roper Industries	60.65	0.4050	0.67	
Hewlett Packard	48.42	0.3200	0.66	
Anadarko Petroleum	55.84	0.3600	0.64	
Scripps Networks Interactive	46.95	0.3000	0.64	
Apache	96.66	0.6000	0.62	
Huntington Bancshares	6.48	0.0400	0.62	
EOG Resources	104.74	0.6300	0.60	
PNC Financial Services	68.61	0.4000	0.58	

Staff/921
Storm/9

DENTSPLY International	35.91	0.2050	0.57	
CF Industries Holdings	71.87	0.4000	0.56	
Helmerich & Payne	36.63	0.2000	0.55	
FedEx	88.11	0.4800	0.54	
Discover Financial Services	14.90	0.0800	0.54	
Equifax	32.82	0.1600	0.49	
Legg Mason	33.38	0.1600	0.48	
KeyCorp	8.58	0.0400	0.47	
Comerica	43.15	0.2000	0.46	
Regions Financial	8.67	0.0400	0.46	
Marriott Intl. (A)	35.60	0.1600	0.45	
Polo Ralph Lauren	89.03	0.4000	0.45	
Capital One Financial	44.78	0.2000	0.45	
Marshall & Ilsley	8.99	0.0400	0.44	
Weyerhaeuser	47.15	0.2000	0.42	
Starwood Hotels & Resorts	50.78	0.2000	0.39	
U.S. Steel	52.96	0.2000	0.38	
DeVry	60.61	0.2200	0.36	
Cabot Oil & Gas	33.13	0.1200	0.36	
Textron	22.64	0.0800	0.35	
El Paso	11.86	0.0400	0.34	
Range Resources	47.67	0.1600	0.34	
Allergan	62.32	0.2000	0.32	
Janus Capital Group	12.83	0.0400	0.31	
State Street	42.81	0.1200	0.28	
Fifth Third Bancorp	14.61	0.0400	0.27	
MasterCard	223.24	0.6000	0.27	
Host Hotels & Resorts	15.92	0.0400	0.25	
Bank of America	17.16	0.0400	0.23	
Danaher	84.22	0.1600	0.19	
Zions Bancorp	27.74	0.0400	0.14	
Southwest Airlines	12.86	0.0180	0.14	
Lincoln National	29.51	0.0400	0.14	
Aetna	29.61	0.0400	0.14	
Amphenol	44.99	0.0600	0.13	
SunTrust Banks	30.45	0.0400	0.13	
Pioneer Natural Resources	63.85	0.0800	0.13	
CIGNA	33.13	0.0400	0.12	
UnitedHealth Group	29.85	0.0300	0.10	
Precision Castparts	124.02	0.1200	0.10	
Statistics: S&P 500 Dividend Yields				
Maximum Value			10.44	
Minimum Value of Above, Non-Zero Dividend Yields			0.10	

Staff/921
Storm/10

Average Dividend Yield (%) of All S&P 500 Stocks			1.72	
Average Dividend Yield (%) of Above, Non-Zero Dividend Yields			2.33	
Standard Deviation of of All S&P 500 Stocks			1.78	
Standard Deviation of Above, Non-Zero Dividend Yields			1.69	
Number of S&P 500 Stocks in the Statistics			500	
Number Stocks with Non-Zero Dividend Yields			370	
Number Stocks with Zero Dividends			130	

Stocks in the S&P 500 Index That Have Zero Dividends.
Adobe Systems
Advanced Micro Devices
AES
Agilent Technologies
Akamai Technologies
Amazon
American Int'l. Group
American Tower
Amgen
Apollo Group
Apple
Autodesk
AutoNation
AutoZone
Bed Bath & Beyond
Berkshire Hathaway
Big Lots
Biogen Idec
BMC Software
Boston Scientific
Cameron International
CareFusion
CB Richard Ellis
Celgene
Cephalon
Cerner
Cisco Systems
Citigroup
Citrix Systems
Cognizant Technology
Computer Sciences
Compuware
Constellation Brands
Coventry Health Care
DaVita
Dean Foods
Dell
Denbury Resources
DirecTV Group
Discovery Communications
E*Trade Financial
Eastman Kodak
eBay
Electronic Arts
EMC
Express Scripts
First Horizon National
First Solar
Fiserv
FLIR Systems
FMC Technologies
Ford Motor
Forest Laboratories

Staff/921
Storm/11

GameStop
Genworth Financial
Genzyme
Gilead Sciences
Goodyear Tire & Rubber
Google
Harman Intl.
Hospira
Humana
InterContinental Exchange
Interpublic Group
Intuit
Intuitive Surgical
Jacobs Engineering Group
JDS Uniphase
Juniper Networks
King Pharmaceuticals
Kohl's
Laboratory Corp. of America
Leucadia National
Lexmark Int'l.
Life Technologies
LSI
McAfee
Medco Health Solutions
MEMC Electronic Materials
MetroPCS Communications
Micron Technology
Millipore
Monster Worldwide
Motorola
Mylan
Nabors
NASDAQ OMX Group
NetApp
New York Times Cl. A
Novell
Novellus Systems
NRG Energy
NVIDIA
Office Depot
O'Reilly Automotive
Owens-Illinois
Pactiv
Priceline
PulteGroup
QLogic
Quanta Services
Red Hat
Rowan
SAIC
Salesforce.com
SanDisk
Sears Holdings
SLM
Southwestern Energy
Sprint Nextel
St. Jude Medical
Stericycle
Symantec
Tenet Healthcare
Teradata
Teradyne
Tesoro
Thermo Fisher Scientific
Titanium Metals
Urban Outfitters
Varian Medical Systems
Verisign
Viacom (B)
Waters
Watson Pharmaceuticals
WellPoint
Western Digital
Whole Foods Market
Yahoo
Zimmer Holdings

Staff/921
Storm/12

- To the top of this page.
- To Nasdaq 100 stock dividends.
- To Dow Jones stock dividends.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 922

Exhibits in Support
Of Opening Testimony

June 4, 2010

Staff/922
Storm/1

Chapter 14

THE EQUITY PREMIUM IN RETROSPECT

RAJNISH MEHRA*

University of California, Santa Barbara, and NBER

EDWARD C. PRESCOTT*

University of Minnesota, and Federal Reserve Bank of Minneapolis

Contents

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Handbook of the Economics of Finance, Edited by G.M. Constantinides, M. Harris and R. Stulz

Abstract

This paper is a critical review of the literature on the "equity premium puzzle". The puzzle, as originally articulated more than fifteen years ago, underscored the inability of the standard paradigm of Economics and Finance to explain the magnitude of the risk premium, that is, the return earned by a risky asset in excess of the return to a relatively riskless asset such as a U.S. government bond. The paper summarizes the historical experience for the USA and other industrialized countries and details the intuition behind the discrepancy between model prediction and empirical data. Various research approaches that have been proposed to enhance the model's realism are detailed and, as such, the paper reviews the major directions of theoretical financial research over the past ten years. The author argues that the majority of the proposed resolutions fail along crucial dimensions and proposes a promising direction for future research.

Keywords

asset pricing, equity risk premium, CAPM, consumption CAPM, risk free rate puzzle

JEL classification: G10, G12

1. Introduction

More than two decades ago, we demonstrated that the equity premium (the return earned by a risky security in excess of that earned by a relatively risk-free T-bill), was an order of magnitude greater than could be rationalized in the context of the standard neoclassical paradigms of financial economics *as a premium for bearing risk*. We dubbed this historical regularity 'the equity premium puzzle'. [Mehra and Prescott (1985)]. Our challenge to the profession has spawned a plethora of research efforts to explain it away.

In this paper, we take a retrospective look at the puzzle, critically examine the data sources used to document the puzzle, attempt to clearly explain it and evaluate the various attempts to solve it. The paper is organized into four parts. Section 2 documents the historical equity premium in the United States and in selected countries with significant capital markets in terms of market value and comments on the data sources. Section 3 examines the question: "Is the equity premium due to a premium for bearing non-diversifiable risk?" Section 4 examines the related question: "Is the equity premium due to borrowing constraints, a liquidity premium or taxes?" Finally, Section 5 examines the equity premium expected to prevail in the future.

We conclude that research to date suggests that the answer to the first question is "no", unless one is willing to accept that individuals are implausibly risk averse. In answer to the second question McGrattan and Prescott (2001) found that, most likely, the high equity premium observed in the post-war period *was* indeed the result of a combination of the factors that included borrowing constraints and taxes.

2. The equity premium: history

2.1. Facts

Any discussion of the equity premium over time confronts the question of which average returns are more useful in summarizing historical information: arithmetic or geometric? It is well known that the arithmetic average return exceeds the geometric average return and that if the returns are log-normally distributed, the difference between the two is one-half the variance of the returns. Since the annual standard deviation of the equity premium is about 20%, this can result in a difference of about 2% between the two measures, which is non-trivial since the phenomena under consideration has an arithmetic mean of between 2 and 8%. In Mehra and Prescott (1985), we reported arithmetic averages, since the best available evidence indicated that stock returns were uncorrelated over time. When this is the case, the expected future value of a $1 investment is obtained by compounding the arithmetic average of the sample return, which is the correct statistic to report if one is interested in the *mean* value of the investment.[1] If, however, the objective is to obtain the *median*

[1] We present a simple proof in Appendix A.

future value of the investment, then the initial investment should be compounded at the geometric sample average. When returns are serially correlated, then the arithmetic average[2] can lead to misleading estimates and thus the geometric average may be the more appropriate statistic to use. In this paper, as in our 1985 paper, we report arithmetic averages. However, in instances where we cite the results of research when arithmetic averages are not available, we clearly indicate this.[3]

2.2. Data sources

A second crucial consideration in a discussion of the historical equity premium has to do with the reliability of early data sources. The data documenting the historical equity premium in the USA can be subdivided into three distinct sub-periods: 1802–1871, 1871–1926 and 1926–present. The quality of the data is very different for each subperiod. Data on stock prices for the nineteenth century is patchy, often necessarily introducing an element of arbitrariness to compensate for its incompleteness.

2.2.1. Subperiod 1802–1871

2.2.1.1. Equity return data. We find that the equity return data prior to 1871 is not particularly reliable. To the best of our knowledge, the stock return data used by all researchers for the period 1802–1871 is due to Schwert (1990), who gives an excellent account of the construction and composition of early stock market indexes. Schwert (1990) constructs a "spliced" index for the period 1802–1987; his index for the period 1802–1862 is based on the work of Smith and Cole (1935), who constructed a number of early stock indexes. For the period 1802–1820, their index was constructed from an equally weighted portfolio of seven bank stocks, while another index for 1815–1845 was composed of six bank stocks and one insurance stock. For the period 1834–1862 the index consisted of an equally weighted portfolio of (at most) 27 railroad stocks.[4] They used one price quote, per stock, per month, from local newspapers. The prices used were the average of the bid and ask prices, rather than transaction prices, and their computation of returns ignores dividends. For the period 1863–1871, Schwert uses data from Macaulay (1938), who constructed a value-weighted index using a portfolio of about 25 north-east and mid-Atlantic railroad stocks;[5] this index

[2] The point is well illustrated by the textbook example where an initial investment of $100 is worth $200 after one year and $100 after two years. The arithmetic average return is 25% whereas the geometric average return is 0%. The latter coincides with the true return.

[3] In this case an approximate estimate of the arithmetic average return can be obtained by adding one-half the variance of the returns to the geometric average.

[4] "They chose stocks in hindsight ... the sample selection bias caused by including only stocks that survived and were actively quoted for the whole period is obvious" [Schwert (1990)].

[5] "It is unclear what sources Macaulay used to collect individual stock prices but he included all railroads with actively traded stocks" (Ibid).

also excludes dividends. Needless to say, it is difficult to assess how well this data proxies the "market", since undoubtedly there were other industry sectors that were not reflected in the index.

2.2.1.2. Return on a risk-free security. Since there were no Treasury bills at the time, researchers have used the data set constructed by Siegel (1998) for this period, using highly rated securities with an adjustment for the default premium. It is interesting to observe, as mentioned earlier, that based on this data set the equity premium for the period 1802–1862 was *zero.* We conjecture that this may be due to the fact that since most financing in the first half of the nineteenth century was done through debt, the distinction between debt and equity securities was not very clear-cut.[6]

2.2.2. Sub-period 1871–1926

2.2.2.1. Equity return data. Shiller (1990) is the definitive source for the equity return data for this period. His data is based on the work of Cowles (1939), which covers the period 1871–1938. Cowles used a value-weighted portfolio for his index, which consisted of 12 stocks[7] in 1871 and ended with 351 in 1938. He included all stocks listed on the New York Stock Exchange, whose prices were reported in the *Commercial and Financial Chronicle.* From 1918 onward he used the Standard and Poor's (S&P) industrial portfolios. Cowles reported dividends, so that, unlike the earlier indexes for the period 1802–1871, a total return calculation was possible.

2.2.2.2. Return on a risk-free security. There is no definitive source for the short-term risk-free rate in the period before 1920, when Treasury certificates were first issued. In our 1985 study, we used short-term commercial paper as a proxy for a riskless short-term security prior to 1920 and Treasury certificates from 1920–1930. Our data prior to 1920, was taken from Homer (1963). Most researchers have either used our data set or Siegel's.

2.2.3. Sub-period 1926–present

2.2.3.1. Equity return data. This period is the "Golden Age" in regards to accurate financial data. The NYSE database at the Center for Research in Security Prices (CRSP) was initiated in 1926 and provides researchers with high quality equity return data.

[6] The first actively traded stock was floated in the USA in 1791 and by 1801 there were over 300 corporations, although less than 10 were actively traded [Siegel (1998)].

[7] It was only from February 16, 1885, that Dow Jones began reporting an index, initially composed of 12 stocks. The S&P index dates back to 1928, though for the period 1928–1957 it consisted of 90 stocks. The S&P 500 debuted in March 1957.

Table 1
U.S. equity premium using different data sets

Data set	% real return on a market index (mean)	% real return on a relatively riskless security (mean)	% equity premium (mean)
1802–1998 (Siegel)	7.0	2.9	4.1
1871–1999 (Shiller)	6.99	1.74	5.75
1889–2000 (Mehra–Prescott)	8.06	1.14	6.92
1926–2000 (Ibbotson)	8.8	0.4	8.4

The Ibbotson Associates Yearbooks [8] are also a very useful compendium of post–1926 financial data.

2.2.3.2. Return on a risk-free security. Since the advent of Treasury bills in 1931, short maturity bills have been an excellent proxy for a "real" risk-free security since the innovation in inflation is orthogonal to the path of real GNP growth. [9] Of course, with the advent of Treasury Inflation Protected Securities (TIPS) on January 29, 1997, the return on these securities *is* the real risk-free rate.

2.3. Estimates of the equity premium

Historical data provides us with a wealth of evidence documenting that for over a century, stock returns have been considerably higher than those for Treasury-bills. This is illustrated in Table 1, which reports the unconditional estimates [10] for the equity premium in the USA based on the various data sets used in the literature, going back to 1802. The average annual real return, (the inflation-adjusted return) on the U.S. stock market over the last 110 years has been about 8.06%. Over the same period, the return on a relatively riskless security was a paltry 1.14%. The difference between these two returns, the "equity premium", was 6.92%.

Furthermore, this pattern of excess returns to equity holdings is not unique to the USA but is observed in every country with a significant capital market. The USA, together with the UK, Japan, Germany and France, accounts for more than 85% of the capitalized global equity value.

[8] Ibbotson Associates, 2001, "Stocks, bonds, bills and inflation," 2000 Yearbook (Ibbotson Associates, Chicago).

[9] See Litterman (1980) who also found that that in post-war data the innovation in inflation had a standard deviation of one half of one percent.

[10] To obtain unconditional estimates we use the entire data set to form our estimate. The Mehra–Prescott data set covers the longest time period for which *both* consumption and stock return data is available. The former is necessary to test the implication of consumption-based asset-pricing models.

Table 2
Equity premium in different countries[a]

Country		% real return on a market index (mean)	% real return on a relatively riskless security (mean)	% equity premium (mean)
UK	1947–1999	5.7	1.1	4.6
Japan	1970–1999	4.7	1.4	3.3
Germany	1978–1997	9.8	3.2	6.6
France	1973–1998	9.0	2.7	6.3

[a] Source: UK from Siegel (1998), the rest are from Campbell (2001).

Table 3
Terminal value of $1 invested in stocks and bonds[a]

Investment period	Stocks		T-bills	
	Real	Nominal	Real	Nominal
1802–1997	$558,945	$7,470,000	$276	$3,679
1926–2000	$266.47	$2,586.52	$1.71	$16.56

[a] Source: Ibbotson (2001) and Siegel (1998).

The annual return on the British stock market was 5.7% over the post-war period, an impressive 4.6% premium over the average bond return of 1.1%. Similar statistical differentials are documented for France, Germany and Japan. Table 2 illustrates the equity premium in the post-war period for these countries.

The dramatic investment implications of this differential rate of return can be seen in Table 3, which maps the capital appreciation of $1 invested in different assets from 1802 to 1997 and from 1926 to 2000.

As Table 3 illustrates, $1 invested in a diversified stock index yields an ending wealth of $558,945 versus a value of $276, *in real terms,* for $1 invested in a portfolio of T-bills for the period 1802–1997. The corresponding values for the 75-year period, 1926–2000, are $266.47 and $1.71. We assume that all payments to the underlying asset, such as dividend payments to stock and interest payments to bonds are reinvested and that there are no taxes paid.

This long-term perspective underscores the remarkable wealth building potential of the equity premium. It should come as no surprise therefore, that the equity premium is of central importance in portfolio allocation decisions, estimates of the cost of capital and is front and center in the current debate about the advantages of investing Social Security funds in the stock market.

In Table 4 we report the premium for some interesting sub-periods: 1889–1933, when the USA was on a gold standard; 1934–2000, when it was off the gold standard;

Table 4
Equity premium in different sub-periods[a]

Time period	% real return on a market index (mean)	% real return on a relatively riskless security (mean)	% equity premium (mean)
1889–1933	7.01	3.09	3.92
1934–2000	8.76	−0.17	8.93
1946–2000	9.03	0.68	8.36

[a] Source: Mehra and Prescott (1985). Updated by the authors.

Table 5
Equity premium: 30-year moving averages[a]

Time period	% real return on a market index (mean)	% real return on a relatively riskless security (mean)	% equity premium (mean)
1900–1950	6.51	2.01	4.50
1951–2000	8.98	1.41	7.58

[a] Source: Mehra and Prescott (1985). Updated by the authors

and 1946–2000, the postwar period. Table 5 presents 30 year moving averages, similar to those reported by the U.S. meteorological service to document 'normal' temperature.

Although the premium has been increasing over time, this is largely due to the diminishing return on the riskless asset, rather than a dramatic increase in the return on equity, which has been relatively constant. The low premium in the nineteenth century is largely due to the fact that the equity premium for the period 1802–1861 was zero.[11] If we exclude this period, we find that difference in the premium in the second half of the nineteenth century relative to average values in the twentieth century is less striking.

We find a dramatic change in the equity premium in the post 1933 period – the premium rose from 3.92% to 8.93%, an increase of more than 125%. Since 1933 marked the end of the period when the USA was on the gold standard, this break can be seen as the change in the equity premium after the implementation of the new policy.

[11] See the earlier discussion on data.

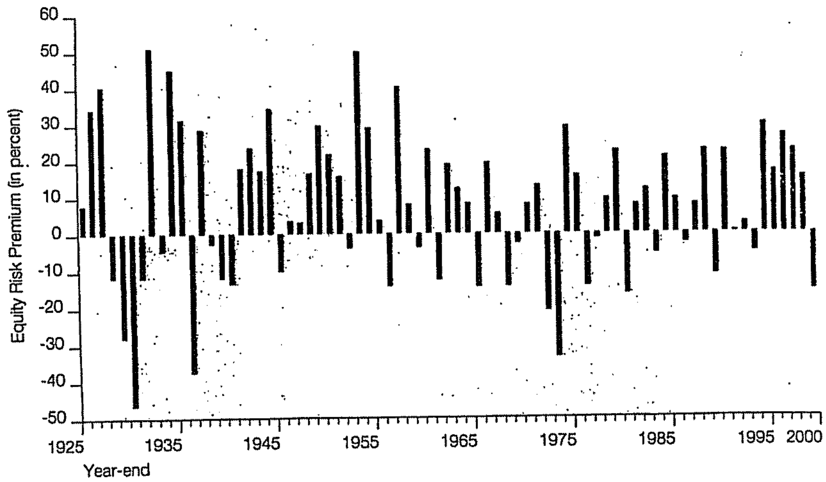

Fig. 1. Realized equity risk premium per year, 1926–2000. Source: Ibbotson (2001).

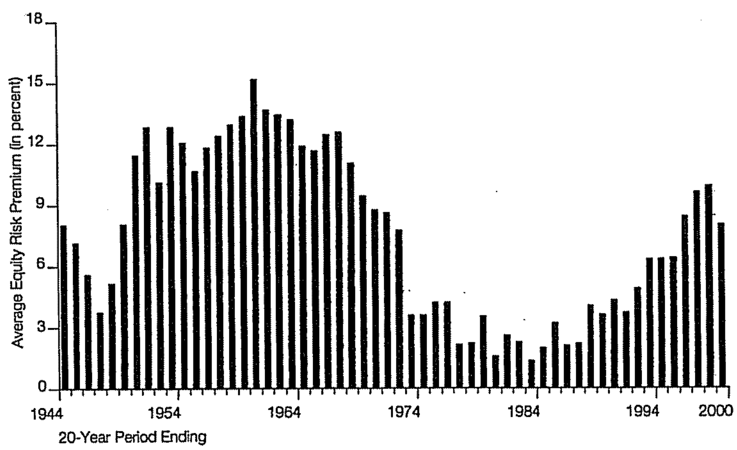

Fig. 2. Equity risk premium over 20-year periods, 1926–2000. Source: Ibbotson (2001).

2.4. Variation in the equity premium over time

The equity premium has varied considerably over time, as illustrated in Figures 1 and 2. Furthermore, the variation depends on the time horizon over which it is measured. There have even been periods when the equity premium has been negative.

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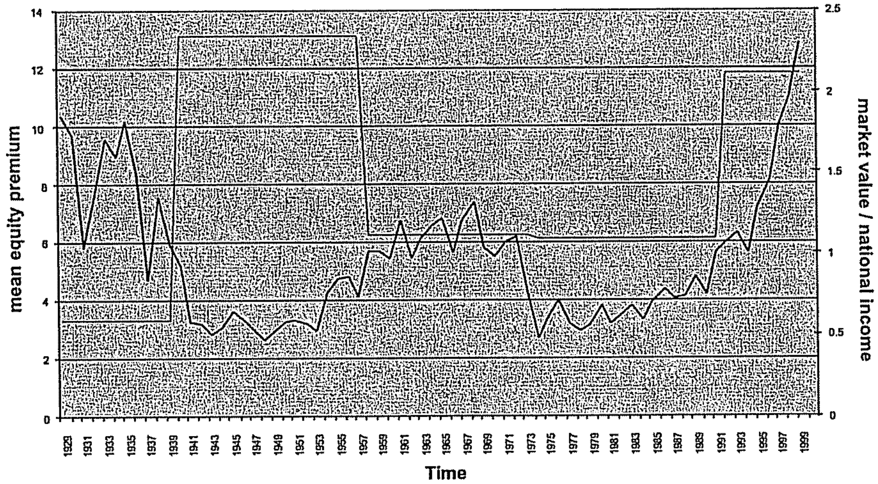

Fig. 3. Market value/national income and mean equity premium (averaged over time periods when MV/NI > 1 and MV/NI < 1).

The low frequency variation has been *counter-cyclical.* This is shown in Figure 3 where we have plotted stock market value as a share of national income[12] and the mean equity premium averaged over certain time periods. We have divided the time period from 1929 to 2000 into sub-periods, where the ratio market value of equity to national income was greater than 1 and where it was less than 1. Historically, as the figure illustrates, subsequent to periods when this ratio was high the realized equity premium was low. A similar result holds when stock valuations are low relative to national income. In this case the subsequent equity premium is high.

Since After Tax Corporate Profits as a share of National Income are fairly constant over time, this translates into the observation that the realized equity premium was low subsequent to periods when the Price/Earnings ratio is high and vice versa. This is the basis for the returns predictability literature in Finance [Campbell and Shiller (1988) and Fama and French (1988)].

In Figure 4 we have plotted stock market value as a share of national income and the *subsequent* three-year mean equity premium. This provides further conformation that historically, periods of relatively high market valuation have been followed by periods when the equity premium was relatively low.

[12] In Mehra (1998) it is argued that the variation in this ratio is difficult to rationalize in the standard neoclassical framework since over the same period after tax cash flows to equity as a share of national income are fairly constant. Here we do not address this issue and simply utilize the fact that this *ratio has varied considerably over time.*

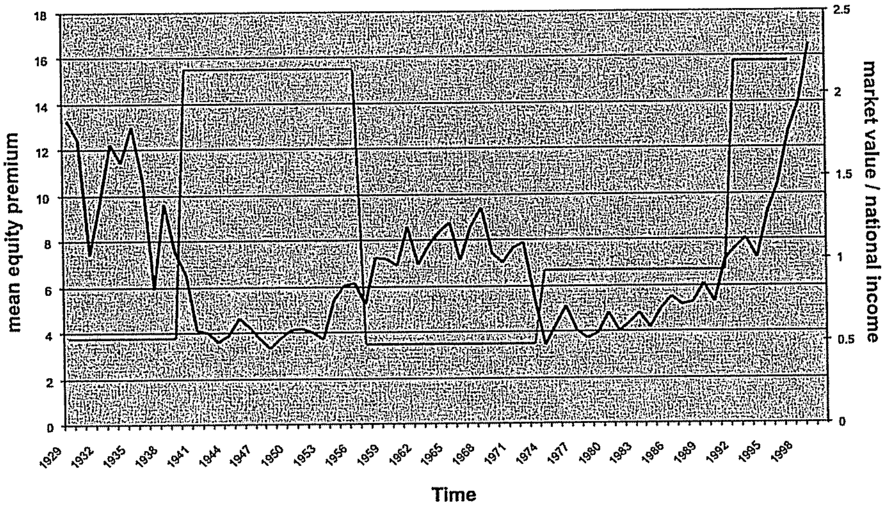

Fig. 4. Market value/national income and 3-year ahead equity premium (averaged over time periods when MV/NI > 1 and MV/NI < 1).

3. Is the equity premium due to a premium for bearing non-diversifiable risk?

In this section, we examine various models that attempt to explain the historical equity premium. We start with a model with standard (CRRA) preferences, then examine models incorporating alternative preference structures, idiosyncratic and uninsurable income risk, and models incorporating a disaster state and survivorship bias.

Why have stocks been such an attractive investment relative to bonds? Why has the rate of return on stocks been higher than on relatively risk-free assets? One intuitive answer is that since stocks are "riskier" than bonds, investors require a larger premium for bearing this additional risk; and indeed, the standard deviation of the returns to stocks (about 20% per annum historically) is larger than that of the returns to T-bills (about 4% per annum), so, obviously they are considerably more risky than bills! But are they?

Figures 5 and 6 illustrate the variability of the annual real rate of return on the S&P 500 index and a relatively risk-free security over the period 1889–2000. Of course, the index did not consist of 500 stocks for the entire period. To enhance and deepen our understanding of the risk–return trade-off in the pricing of financial assets, we take a detour into modern asset-pricing theory and look at why different assets yield different rates of return. The deus ex machina of this theory is that assets are priced such that, ex-ante, the loss in marginal utility incurred by sacrificing current consumption and buying an asset at a certain price is equal to the expected gain in marginal utility, contingent on the anticipated increase in consumption when the asset pays off in the future.

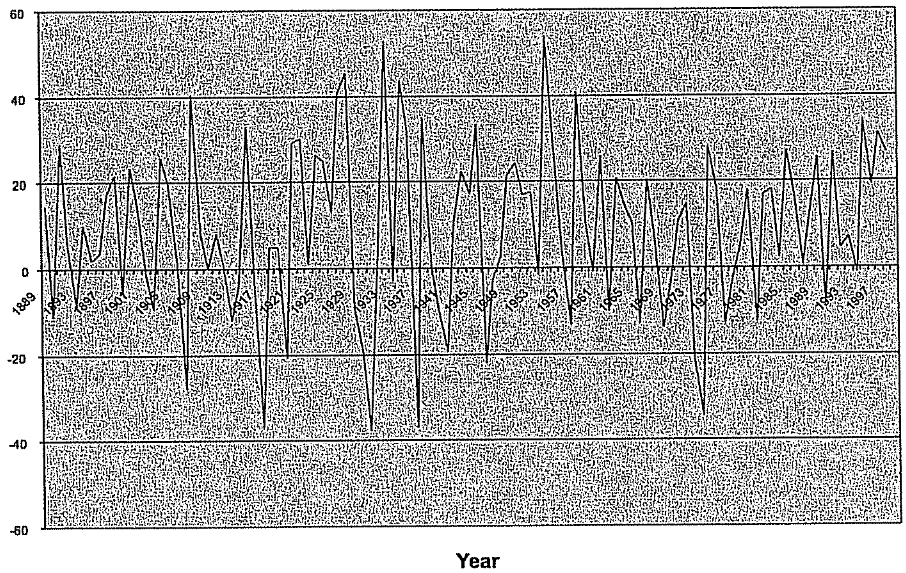

Fig. 5. Real annual return on S&P 500, 1889–2000 (%). Source: Mehra and Prescott (1985). Data updated by the authors.

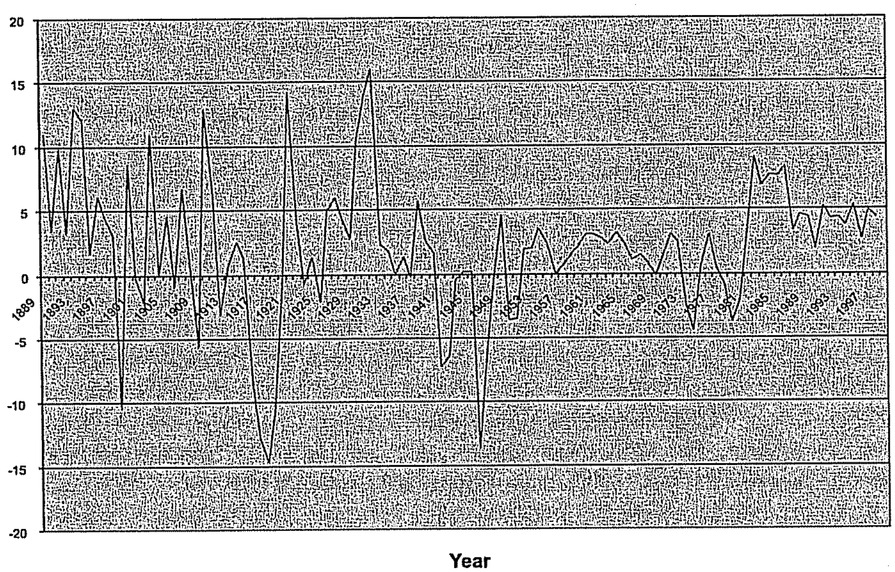

Fig. 6. Real annual return on a relatively riskless security, 1889–2000 (%). Source: Mehra and Prescott (1985). Data updated by the authors.

The operative emphasis here is the *incremental loss or gain* of utility of consumption and should be differentiated from incremental consumption. This is because the *same* amount of consumption may result in different degrees of well-being at different times. As a consequence, assets that pay off when times are good and consumption levels are high – when the marginal utility of consumption is low – are less desirable than those that pay off an equivalent amount when times are bad and additional consumption is more highly valued. Hence consumption in period t has a different price if times are good than if times are bad.

Let us illustrate this principle in the context of the standard, popular paradigm, the Capital Asset-Pricing Model (CAPM). The model postulates a linear relationship between an asset's 'beta', a measure of systematic risk, and its expected return. Thus, high-beta stocks yield a high expected rate of return. That is because in the CAPM, good times and bad times are captured by the return on the market. The performance of the market, as captured by a broad-based index, acts as a surrogate indicator for the relevant state of the economy. A high-beta security tends to pay off more when the market return is high – when times are good and consumption is plentiful; it provides less incremental utility than a security that pays off when consumption is low, is less valuable and consequently sells for less. Thus, higher beta assets that pay off in states of low marginal utility will sell for a lower price than similar assets that pay off in states of high marginal utility. Since rates of return are inversely proportional to asset prices, the lower beta assets will, on average, give a lower rate of return than the former.

Another perspective on asset pricing emphasizes that economic agents prefer to smooth patterns of consumption over time. Assets that pay off a larger amount at times when consumption is already high "destabilize" these patterns of consumption, whereas assets that pay off when consumption levels are low "smooth" out consumption. Naturally, the latter are more valuable and thus require a lower rate of return to induce investors to hold these assets. (Insurance policies are a classic example of assets that smooth consumption. Individuals willingly purchase and hold them, despite their very low rates of return).

To return to the original question: are stocks that much riskier than T-bills so as to justify a six percentage differential in their rates of return?

What came as a surprise to many economists and researchers in finance was the conclusion of a paper by Mehra and Prescott, written in 1979. Stocks and bonds pay off in approximately the same states of nature or economic scenarios and hence, as argued earlier, they should command approximately the same rate of return. In fact, using standard theory to estimate risk-adjusted returns, we found that stocks on average should command, at most, a one percent return premium over bills. Since, for as long as we had reliable data (about 100 years), the mean premium on stocks over bills was considerably and consistently higher, we realized that we had a puzzle on our hands. It took us six more years to convince a skeptical profession and for our paper *The equity premium: a puzzle* to be published. [Mehra and Prescott (1985)].

3.1. Standard preferences

The neoclassical growth model and its stochastic variants are a central construct in contemporary finance, public finance, and business-cycle theory. It has been used extensively by, among others, Abel et al. (1989), Auerbach and Kotlikoff (1987), Barro and Becker (1988), Brock (1979), Cox, Ingersoll and Ross (1985), Donaldson and Mehra (1984), Lucas (1978), Kydland and Prescott (1982) and Merton (1971). In fact, much of our economic intuition is derived from this model class. A key idea of this framework is that consumption today and consumption in some future period are treated as different goods. Relative prices of these different goods are equal to people's willingness to substitute between these goods and businesses' ability to transform these goods into each other.

The model has had some remarkable successes when confronted with empirical data, particularly in the stream of macroeconomic research referred to as Real Business-Cycle Theory, where researchers have found that it easily replicates the essential macroeconomic features of the business cycle. See, in particular, Kydland and Prescott (1982). Unfortunately, when confronted with financial market data on stock returns, tests of these models have led, without exception, to their rejection. Perhaps the most striking of these rejections is contained in our 1985 paper.

To illustrate this we employ a variation of Lucas' (1978) pure exchange model. Since per capita consumption has grown over time, we assume that the growth rate of the endowment follows a Markov process. This is in contrast to the assumption in Lucas' model that the endowment level follows a Markov process. Our assumption, which requires an extension of competitive equilibrium theory,[13] enables us to capture the non-stationarity in the consumption series associated with the large increase in per capita consumption that occurred over the last century.

We consider a frictionless economy that has a single representative "stand-in" household. This unit orders its preferences over random consumption paths by

$$\mathrm{E}_0\left\{\sum_{t=0}^{\infty}\beta^t U(c_t)\right\}, \quad 0<\beta<1, \tag{1}$$

where c_t is the per capita consumption and the parameter β is the subjective time discount factor, which describes how impatient households are to consume. If β is small, people are highly impatient, with a strong preference for consumption now versus consumption in the future. As modeled, these households live forever, which implicitly means that the utility of parents depends on the utility of their children. In the real world, this is true for some people and not for others. However, economies with both types of people – those who care about their children's utility and those who do not – have essentially the same implications for asset prices and returns.[14]

[13] This extension is developed in Mehra (1988).

[14] See Constantinides, Donaldson and Mehra (2002).

Thus, we use this simple abstraction to build quantitative economic intuition about what the returns on equity and debt should be. $E_0\{\cdot\}$ is the expectation operator conditional upon information available at time zero (which denotes the present time), and $U: R_+ \to R$ is the increasing, continuously differentiable concave utility function. We further restrict the utility function to be of the constant relative risk aversion (CRRA) class

$$U(c,\alpha) = \frac{c^{1-\alpha}}{1-\alpha}, \quad 0 < \alpha < \infty, \tag{2}$$

where the parameter α measures the curvature of the utility function. When $\alpha = 1$, the utility function is defined to be logarithmic, which is the limit of the above representation as α approaches 1. The feature that makes this the "preference function of choice" in much of the literature in Growth and Real Business Cycle Theory is that it is scale invariant. This means that a household is more likely to accept a gamble if both its wealth and the gamble amount are scaled by a positive factor. Hence, although the level of aggregate variables such as capital stock have increased over time, the resulting equilibrium return process is stationary. A second attractive feature is that it is one of only two preference functions that allows for aggregation and a "stand-in" representative agent formulation that is independent of the initial distribution of endowments. One disadvantage of this representation is that it links risk preferences with time preferences. With CRRA preferences, agents who like to smooth consumption across various states of nature also prefer to smooth consumption over time, that is, they dislike growth. Specifically, the coefficient of relative risk aversion is the reciprocal of the elasticity of intertemporal substitution. There is no fundamental economic reason why this must be so. We will revisit this issue in Section 3.3, where we examine preference structures that do not impose this restriction.[15]

We assume that there is one productive unit which produces output y_t in period t which is the period dividend. There is one equity share with price p_t that is competitively traded; it is a claim to the stochastic process $\{y_t\}$.

Consider the intertemporal choice problem of a typical investor at time t. He equates the loss in utility associated with buying one additional unit of equity to the discounted expected utility of the resulting additional consumption in the next period. To carry over one additional unit of equity p_t units of the consumption good must be sacrificed and the resulting loss in utility is $p_t U'(c_t)$. By selling this additional unit of equity, in the next period, $p_{t+1} + y_{t+1}$ additional units of the consumption good can be consumed and $\beta \mathrm{E}_t\{(p_{t+1} + y_{t+1})\, U'(c_{t+1})\}$ is the expected value of the incremental utility next period. At an optimum these quantities must be equal. Hence the fundamental relation that prices assets is $p_t U'(c_t) = \beta \mathrm{E}_t\{(p_{t+1} + y_{t+1})\, U'(c_{t+1})\}$. Versions of this expression can be found in Rubinstein (1976), Lucas (1978), Breeden

[15] Epstein and Zin (1991) and Weil (1989).

(1979) and Prescott and Mehra (1980), among others. Excellent textbook treatments can be found in Cochrane (2001), Danthine and Donaldson (2001), Duffie (2001) and LeRoy and Werner (2001).

We use it to price both stocks and riskless one period bonds. For equity we have

$$1 = \beta \mathrm{E}_t \left\{ \frac{U'(c_{t+1})}{U'(c_t)} R_{e,t+1} \right\}, \tag{3}$$

where

$$R_{e,t+1} = \frac{p_{t+1} + y_{t+1}}{p_t}, \tag{4}$$

and for the riskless one-period bonds the relevant expression is

$$1 = \beta \mathrm{E}_t \left\{ \frac{U'(c_{t+1})}{U'(c_t)} \right\} R_{f,t+1}. \tag{5}$$

Where the gross rate of return on the riskless asset is by definition

$$R_{f,t+1} = \frac{1}{q_t}, \tag{6}$$

with q_t being the price of the bond. Since $U(c)$ is assumed to be increasing, we can rewrite Equation (3) as

$$1 = \beta \mathrm{E}_t \left\{ M_{t+1} R_{e,t+1} \right\}, \tag{7}$$

where M_{t+1} is a strictly positive stochastic discount factor. This guarantees that the economy will be arbitrage free and the law of one-price holds. A little algebra shows that

$$\mathrm{E}_t \left(R_{e,t+1} \right) = R_{f,t+1} + \mathrm{Cov}_t \left\{ \frac{-U'(c_{t+1}), R_{e,t+1}}{\mathrm{E}_t(U'(c_{t+1}))} \right\}. \tag{8}$$

The equity premium $\mathrm{E}_t(R_{e,t+1}) - R_{f,t+1}$ can thus be easily computed. Expected asset returns equal the risk-free rate plus a premium for bearing risk, which depends on the covariance of the asset returns with the marginal utility of consumption. Assets that co-vary positively with consumption – that is, they payoff in states when consumption is high and marginal utility is low – command a high premium since these assets "destabilize" consumption.

The question we need to address is the following: is the magnitude of the covariance between the marginal utility of consumption large enough to justify the observed 6% equity premium in U.S. equity markets? If not, how much of this historic equity premium is a compensation for bearing non-diversifiable aggregate risk.

To address this issue, we present a variation on the framework used in our original paper on the equity premium. An advantage of our original approach was that we could easily test the sensitivity of our results to changes in distributional assumptions.[16] We found that our results were essentially unchanged for very different consumption processes, provided that the mean and variances of growth rates equaled the historically observed values and the coefficient of relative risk aversion was less than ten.[17] Using this insight on the robustness of the results to distributional assumptions from our earlier analysis we consider the case where the growth rate of consumption $x_{t+1} \equiv \frac{c_{t+1}}{c_t}$ is iid and lognormal. We do this to facilitate exposition and because this results in closed form solutions.[18]

As a consequence, the gross return on equity $R_{e,t}$ (defined above) is iid and lognormal. Substituting $U'(c_t) = c_t^{-\alpha}$ in the fundamental pricing relation and noting that in this exchange economy the equilibrium consumption process is $\{y_t\}$

$$p_t = \beta \mathrm{E}_t \left\{ (p_{t+1} + y_{t+1}) \frac{U'(c_{t+1})}{U'(c_t)} \right\}, \tag{9}$$

we get

$$p_t = \beta \mathrm{E}_t \left\{ (p_{t+1} + y_{t+1}) x_{t+1}^{-\alpha} \right\}. \tag{10}$$

As p_t is homogeneous of degree one in y_t we can represent it as

$$p_t = w y_t$$

and hence $R_{e,t+1}$ can be expressed as

$$R_{e,t+1} = \frac{(w+1)}{w} \cdot \frac{y_{t+1}}{y_t} = \frac{w+1}{w} \cdot x_{t+1}. \tag{11}$$

It is easily shown[19] that

$$w = \frac{\beta \mathrm{E}_t \{x_{t+1}^{1-\alpha}\}}{1 - \beta \mathrm{E}_t \{x_{t+1}^{1-\alpha}\}}. \tag{12}$$

[16] In contrast to our approach, which is in the applied general equilibrium tradition, there is another tradition of testing Euler equations (such as Equation 9) and rejecting them. Hansen and Singleton (1982) and Grossman and Shiller (1981) exemplify this approach.
[17] See Mehra and Prescott (1985, pp. 156–157). The original framework also allowed us to address the issue of leverage.
[18] The exposition below is based on Abel (1988). Our original analysis is presented in Appendix B.
[19] See Appendix A in Mehra (2003).

hence

$$\mathrm{E}_t\{R_{e,t+1}\} = \frac{\mathrm{E}_t\{x_{t+1}\}}{\beta \mathrm{E}_t\{x_{t+1}^{1-\alpha}\}}. \tag{13}$$

Analogously, the gross return on the riskless asset can be written as

$$R_{f,t+1} = \frac{1}{\beta}\frac{1}{\mathrm{E}_t\{x_{t+1}^{-\alpha}\}}. \tag{14}$$

Since we have assumed the growth rate of consumption and dividends to be log normally distributed,

$$\mathrm{E}_t\{R_{e,t+1}\} = \frac{\exp\left[\mu_x + \frac{1}{2}\sigma_x^2\right]}{\beta \exp\left[(1-\alpha)\,\mu_x + \frac{1}{2}(1-\alpha)^2\sigma_x^2\right]}, \tag{15}$$

and

$$\ln \mathrm{E}_t\{R_{e,t+1}\} = -\ln\beta + \alpha\mu_x - \tfrac{1}{2}\alpha^2\sigma_x^2 + \alpha\sigma_x^2, \tag{16}$$

where $\mu_x = \mathrm{E}(\ln x)$, $\sigma_x^2 = \mathrm{Var}(\ln x)$ and $\ln x$ is the *continuously compounded* growth rate of consumption. Similarly

$$R_f = \frac{1}{\beta \exp\left[-\alpha\mu_x + \frac{1}{2}\alpha^2\sigma_x^2\right]}, \tag{17}$$

and

$$\ln R_f = -\ln\beta + \alpha\mu_x - \tfrac{1}{2}\alpha^2\sigma_x^2 \tag{18}$$

$$\therefore \qquad \ln \mathrm{E}\{R_e\} - \ln R_f = \alpha\sigma_x^2. \tag{19}$$

From Equation (11) it also follows that

$$\ln \mathrm{E}\{R_e\} - \ln R_f = \alpha\sigma_{x,R_e}, \tag{20}$$

where

$$\sigma_{x,R_e} = \mathrm{Cov}(\ln x, \ln R_e). \tag{21}$$

The (log) equity premium in this model is the product of the coefficient of risk aversion and the covariance of the (continuously compounded) growth rate of consumption with the (continuously compounded) return on equity or the growth rate of dividends. From Equation 19, it is also the product of the coefficient of relative risk aversion and the variance of the growth rate of consumption. As we see below, this variance σ_x^2 is 0.00125, so unless the coefficient of risk aversion α is large, a high equity premium is impossible. The growth rate of consumption just does not vary enough!

In Mehra and Prescott (1985) we report the following sample statistics for the U.S. economy over the period 1889–1978:

Mean risk-free rate R_f	1.008
Mean return on equity $\mathrm{E}\{R_e\}$	1.0698
Mean growth rate of consumption $\mathrm{E}\{x\}$	1.018
Standard deviation of the growth rate of consumption $\sigma\{x\}$	0.036
Mean equity premium $\mathrm{E}\{R_e\} - R_f$	0.0618

In our calibration, we are guided by the tenet that model parameters should meet the criteria of cross-model verification. Not only must they be consistent with the observations under consideration but they should not be *grossly inconsistent* with other observations in growth theory, business-cycle theory, labor market behavior and so on. There is a wealth of evidence from various studies that the coefficient of risk aversion α is a small number, certainly less than 10. A number of these studies are documented in Mehra and Prescott (1985). We can then pose a question: if we set the risk aversion coefficient α to be 10 and β to be 0.99 what are the expected rates of return and the risk premium using the parameterization above?

Using the expressions derived earlier we have

$$\ln R_f = -\ln\beta + \alpha\mu_x - \tfrac{1}{2}\alpha^2\sigma_x^2 = 0.120,$$

or

$$R_f = 1.127,$$

that is, a risk-free rate of 12.7%! Since

$$\begin{aligned}\ln \mathrm{E}\{R_e\} &= \ln R_f + \alpha\sigma_x^2 \\ &= 0.132,\end{aligned}$$

we have

$$\mathrm{E}\{R_e\} = 1.141,$$

or a return on equity of 14.1%. This implies an equity risk premium of 1.4%, far lower than the 6.18% historically observed equity premium. In this calculation we have been very liberal in choosing the values for α and β. Most studies indicate a value for α that is close to 3. If we pick a lower value for β, the risk-free rate will be even higher and the premium lower. So the 1.4% value represents the maximum equity risk premium that can be obtained in this class of models given the constraints on α and β. Since the observed equity premium is over 6%, we have a puzzle on our hands that risk considerations alone cannot account for.

Philippe Weil (1989) has dubbed the high risk-free rate obtained above "the risk-free rate puzzle". The short-term real rate in the USA averages less than 1%, while the high value of α required to generate the observed equity premium results in an unacceptably high risk-free rate. The risk-free rate as shown in Equation (18) can be decomposed into three components:

$$\ln R_f = -\ln\beta + \alpha\mu_x - \tfrac{1}{2}\alpha^2\sigma_x^2.$$

The first term, $-\ln\beta$, is a time preference or impatience term. When $\beta < 1$ it reflects the fact that agents prefer early consumption to later consumption. Thus, in a world of perfect certainty and no growth in consumption, the unique interest rate in the economy will be $R_f = 1/\beta$.

The second term, $\alpha\mu_x$, arises because of growth in consumption. If consumption is likely to be higher in the future, agents with concave utility would like to borrow against future consumption in order to smooth their lifetime consumption. The higher the curvature of the utility function and the larger the growth rate of consumption, the greater the desire to smooth consumption. In equilibrium this will lead to a higher interest rate since agents in the aggregate cannot simultaneously increase their current consumption.

The third term, $\frac{1}{2}\alpha^2\sigma_x^2$ arises due to a demand for precautionary saving. In a world of uncertainty, agents would like to hedge against future unfavorable consumption realizations by building "buffer stocks" of the consumption good. Hence, in equilibrium, the interest rate must fall to counter this enhanced demand for savings.

Figure 7 plots $\ln R_f = -\ln\beta + \alpha\mu_x - \frac{1}{2}\alpha^2\sigma_x^2$ calibrated to the U.S. historical values with $\mu_x = 0.0175$ and $\sigma_x^2 = 0.00123$ for various values of β. It shows that the precautionary savings effect is negligible for reasonable values of α, $(1 < \alpha < 5)$.

For $\alpha = 3$ and $\beta = 0.99$, $R_f = 1.65$, which implies a risk-free rate of 6.5% – much higher than the historical mean rate of 0.8%. The economic intuition is straightforward – with consumption growing at 1.8% a year with a standard deviation of 3.6%, agents with isoelastic preferences have a sufficiently strong desire to borrow to smooth consumption that it takes a high interest rate to induce them not to do so.

The late Fischer Black[20] proposed that $\alpha = 55$ would solve the puzzle. Indeed it can be shown that the 1889–1978 U.S. experience reported above can be reconciled with $\alpha = 48$ and $\beta = 0.55$. To see this, observe that since

$$\sigma_x^2 = \ln\left[1 + \frac{\text{var}(x)}{[\text{E}(x)]^2}\right] = 0.00125$$

[20] Private communication 1981.

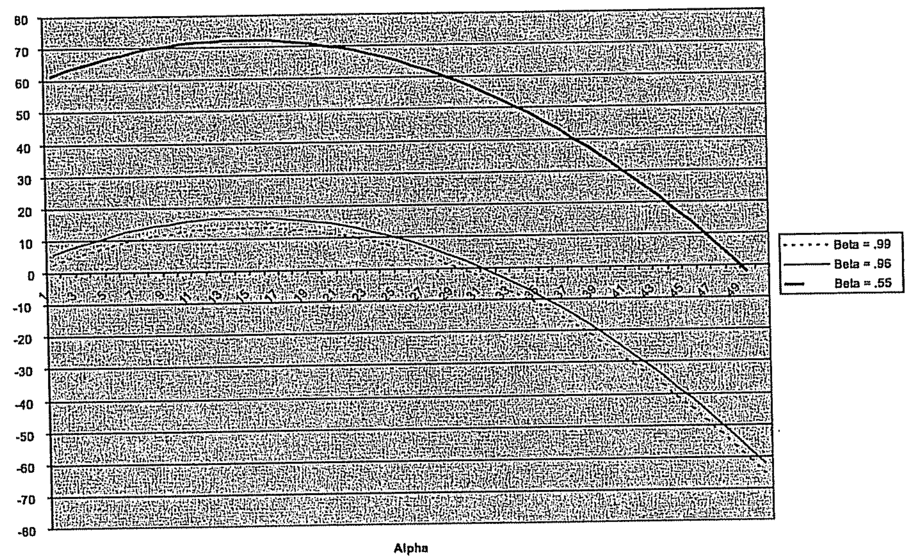

Fig. 7. Mean risk-free rate vs. alpha.

and

$$\mu_x = \ln \mathrm{E}(x) - \tfrac{1}{2}\sigma_x^2 = 0.0172,$$

this implies

$$\alpha = \frac{\ln \mathrm{E}(R) - \ln R_F}{\alpha_x^2} \\ = 47.6.$$

Since

$$\ln \beta = -\ln R_F + \alpha \mu_x - \tfrac{1}{2}\alpha^2 \sigma_x^2 \\ = -0.60,$$

this implies

$$\beta = 0.55.$$

Besides postulating an unacceptably high α, another problem is that this is a "knife edge" solution. No other set of parameters will work, and a *small change* in α will lead to an unacceptable risk-free rate as shown in Figure 7. An alternate approach is

Staff/922
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to experiment with negative time preferences; however there seems to be no empirical evidence that agents do have such preferences.[21]

Figure 7 shows that for extremely high α the precautionary savings term dominates and results in a "low" risk-free rate.[22] However, then a small change in the growth rate of consumption will have a large impact on interest rates. This is inconsistent with a cross-country comparison of real risk-free rates and their observed variability. For example, throughout the 1980s, South Korea had a much higher growth than the USA but real rates were not appreciably higher. Nor does the risk-free rate vary considerably over time, as would be expected if α was large. In Section 3 we show how alternative preference structures can help resolve the risk-free rate puzzle.

An alternative perspective on the puzzle is provided by Hansen and Jagannathan (1991). The fundamental pricing equation can be written as

$$E_t\left(R_{e,t+1}\right) = R_{f,t+1} - \mathrm{Cov}_t\left\{\frac{M_{t+1}, R_{e,t+1}}{\mathrm{E}_t\left(M_{t+1}\right)}\right\}. \tag{22}$$

This expression also holds unconditionally so that

$$\mathrm{E}\left(R_{e,t+1}\right) = \frac{R_{f,t+1} - \sigma\left(M_{t+1}\right)\sigma\left(R_{e,t+1}\right)\rho_{R,M}}{\mathrm{E}_t\left(M_{t+1}\right)}, \tag{23}$$

or

$$\frac{\mathrm{E}\left(R_{e,t+1}\right) - R_{f,t+1}}{\sigma\left(R_{e,t+1}\right)} = -\frac{\sigma\left(M_{t+1}\right)\rho_{R,M}}{\mathrm{E}_t\left(M_{t+1}\right)}, \tag{24}$$

and since

$$\begin{gathered} -1 \leqslant \rho_{R,M} \leqslant 1 \\ \left|\frac{\mathrm{E}\left(R_{e,t+1}\right) - R_{f,t+1}}{\sigma\left(R_{e,t+1}\right)}\right| \leqslant \frac{\sigma\left(M_{t+1}\right)}{\mathrm{E}\left(M_{t+1}\right)}. \end{gathered} \tag{25}$$

This inequality is referred to as the Hansen–Jagannathan lower bound on the pricing kernel.

For the U.S. economy, the Sharpe Ratio, $\mathrm{E}(R_{e,t+1}) - R_{f,t+1}/\sigma(R_{e,t+1})$, can be calculated to be 0.37. Since $\mathrm{E}_t(M_{t+1})$ is the expected price of a one-period risk-free bond, its value must be close to 1. In fact, for the parameterization discussed earlier, $\mathrm{E}_t(M_{t+1}) = 0.96$ when $\alpha = 2$. This implies that the lower bound on the standard deviation for the pricing kernel must be close to 0.3 if the Hansen–Jagannathan bound

[21] In a model with growth, equilibrium can exist with $\beta > 1$. See Mehra (1988) for the restrictions on the parameters α and β for equilibrium to exist.

[22] Kandel and Stambaugh (1991) have suggested this approach.

is to be satisfied. However, when this is calculated in the Mehra–Prescott framework, we obtain an estimate for $\sigma(M_{t+1}) = 0.002$, which is off by more than an order of magnitude.

We would like to emphasize that the equity premium puzzle is a *quantitative* puzzle; standard theory is consistent with our notion of risk that, on average, stocks should return more than bonds. The puzzle arises from the fact that the quantitative predictions of the theory are an order of magnitude different from what has been historically documented. The puzzle cannot be dismissed lightly, since much of our economic intuition is based on the very class of models that fall short so dramatically when confronted with financial data. It underscores the failure of paradigms central to financial and economic modeling to capture the characteristic that appears to make stocks comparatively so risky. Hence the viability of using this class of models for any quantitative assessment, say, for instance, to gauge the welfare implications of alternative stabilization policies, is thrown open to question.

For this reason, over the last 15 years or so, attempts to resolve the puzzle have become a major research impetus in Finance and Economics. Several generalizations of key features of the Mehra and Prescott (1985) model have been proposed to better reconcile observations with theory. These include alternative assumptions on preferences,[23] modified probability distributions to admit rare but disastrous events,[24] survival bias,[25] incomplete markets,[26] and market imperfections.[27] They also include attempts at modeling limited participation of consumers in the stock market,[28] problems of temporal aggregation[29] and behavioral explanations.[30] However, none have fully resolved the anomalies. We examine some of the research efforts to resolve the puzzle[31] below and in Section 4.

23 For example, Abel (1990), Bansal and Yaron (2000), Benartzi and Thaler (1995), Boldrin, Christiano and Fisher (2001), Campbell and Cochrane (1999), Constantinides (1990), Epstein and Zin (1991) and Ferson and Constantinides (1991).

24 See, Rietz (1988) and Mehra and Prescott (1988).

25 Brown, Goetzmann and Ross (1995).

26 For example, Bewley (1982), Brav, Constantinides and Geczy (2002), Constantinides and Duffie (1996), Heaton and Lucas (1997, 2000), Krebs (2000), Lucas (1994), Mankiw (1986), Mehra and Prescott (1985), Storesletten, Telmer and Yaron (2001) and Telmer (1993).

27 For example, Aiyagari and Gertler (1991), Alvarez and Jermann (2000), Bansal and Coleman (1996), Basak and Cuoco (1998), Constantinides, Donaldson and Mehra (2002), Danthine, Donaldson and Mehra (1992), Daniel and Marshall (1997), He and Modest (1995), Heaton and Lucas (1996) and Luttmer (1996), McGrattan and Prescott (2001) and Storesletten, Telmer and Yaron (2001).

28 Attanasio, Banks and Tanner (2002), Brav, Constantinides and Geczy (2002), Brav and Geczy (1995), Mankiw and Zeldes (1991) and Vissing-Jorgensen (2002).

29 Gabaix and Laibson (2001), Heaton (1995) and Lynch (1996).

30 See Barberis, Huang and Santos (2001) and Mehra and Sah (2002).

31 The reader is also referred to the excellent surveys by Narayana Kocherlakota (1996), John Cochrane (1997), Cochrane and Hansen (1992) and by John Campbell (1999, 2001).

3.2. *Estimating the equity risk premium versus estimating the risk aversion parameter*

Estimating or measuring the relative risk parameter using statistical tools is very different than estimating the equity risk premium. Mehra and Prescott (1985), as discussed above, use an extension of Lucas' (1978) asset-pricing model to estimate how much of the historical difference in yields on treasury bills and corporate equity is a premium for bearing aggregate risk. Crucial to their analysis is their use of micro observations to restrict the value of the risk aversion parameter. *They did not estimate either the risk aversion parameter or the discount rate parameters.* Mehra and Prescott (1985) reject extreme risk aversion based upon observations on individual behavior. These observations include the small size of premia for jobs with uncertain income and the limited amount of insurance against idiosyncratic income risk. Another observation is that people with limited access to capital markets make investments in human capital that result in very uneven consumption over time.

A sharp estimate for the magnitude of the risk aversion parameter comes from macroeconomics. The evidence is that the basic growth model, when restricted to be consistent with the growth facts, generates business cycle fluctuations if and only if this risk aversion parameter is near zero. (This corresponds to the log case in standard usage). The point is that the risk aversion parameter comes up in wide variety of observations at both the household and the aggregate level and is *not found to be large.*

For all values of the risk-aversion coefficient less than ten, which is an upper bound number for this parameter, Mehra and Prescott find that a premium for bearing aggregate risk accounts for little of the historic equity premium. This finding has stood the test of time.

Another tradition is to use consumption and stock market data to estimate the degree of relative risk aversion parameter and the discount factor parameter. This is what Grossman and Shiller report they did in their *American Economic Review Papers and Proceedings* article (1982, p. 226). Hansen and Singleton, in a paper in which they develop "a method for estimating nonlinear rational expectations models directly from stochastic Euler equations", illustrate their methods by estimating the risk aversion parameter and the discount factor using stock dividend consumption prices (1982, p. 1269).

What the work of Grossman and Shiller (ibid) and Hansen and Singleton (ibid) establish is that using consumption and stock market data and assuming frictionless capital markets is a bad way to estimate the risk aversion and discount factor parameters. It is analogous to estimating the force of gravity near the earth's surface by dropping a feather from the top of the Leaning Tower of Pisa, under the assumption that friction is zero.

A tradition related to statistical estimation is to statistically test whether the stochastic Euler equation arising from the stand-in household's intertemporal optimization holds. Both Grossman and Shiller (1981) and Hansen and Singleton (1982) reject this relation. The fact that this relation is inconsistent with time series data from the USA is no reason to conclude that the model economy used by Mehra and Prescott to estimate how much of the historical equity premium is a premium for bearing aggregate risk is not a good one for that purpose. Returning to the analogy from Physics, it would be silly to reject Newtonian mechanics as a useful tool for drawing scientific inference because the distance traveled by the feather did not satisfy $\frac{1}{2}gt^2$.

3.3. Alternative preference structures

3.3.1. Modifying the conventional time – and state – separable utility function

The analysis above shows that the isoelastic preferences used in Mehra and Prescott (1985) can only be made consistent with the observed equity premium if the coefficient of relative risk aversion is implausibly large. One restriction imposed by this class of preferences is that the coefficient of risk aversion is rigidly linked to the elasticity of intertemporal substitution. One is the reciprocal of the other. What this implies is that if an individual is averse to variation of consumption across different states *at a particular point of time* then he will be averse to *consumption variation over time.* There is no a priori reason that this must be so. Since, on average, consumption is growing over time, the agents in the Mehra and Prescott (1985) setup have little incentive to save. The demand for bonds is low and as a consequence the risk-free rate is counterfactually high. Epstein and Zin (1991) have presented a class of preferences that they term "Generalized Expected Utility" (GEU) which allows independent parameterization for the coefficient of risk aversion and the elasticity of intertemporal substitution. In this class of preferences utility is recursively defined by

$$U_t = \left\{(1-\beta)\, c_t^{\rho} + \beta \left\{\mathrm{E}_t\left(\tilde{U}_{t+1}^{\alpha}\right)\right\}^{\frac{\rho}{\alpha}}\right\}^{\frac{1}{\rho}}, \tag{26}$$

where $1-\alpha$ is the coefficient of relative risk aversion and $\sigma = \frac{1}{1-\rho}$ the elasticity of intertemporal substitution. The usual isoelastic preferences follow as a special case when $\rho = \alpha$. In the Epstein and Zin model, agents' wealth W evolves as $W_{t+1} = (W_t - c_t)(1 + R_{w,t+1})$ where $R_{w,t+1}$ is the return on *all* invested wealth and is potentially *unobservable.* To examine the asset-pricing implications of this modification we examine the pricing kernel[32]

$$k_{t+1} = \beta^{\frac{\alpha}{\rho}} \left(\frac{c_{t+1}}{c_t}\right)^{\frac{\alpha(\rho-1)}{\rho}} \left(1 + R_{w,t+1}\right)^{\frac{\alpha-\rho}{\rho}}. \tag{27}$$

Thus, the price p_t of an asset with payoff y_{t+1} at time $t+1$ is

$$p_t = \mathrm{E}_t\left(k_{t+1}\, y_{t+1}\right). \tag{28}$$

In this framework the asset is priced *both* by its covariance with the growth rate of consumption (the first term in Equation 27) *and* with the return on the wealth portfolio.

[32] Epstein and Zin (1991) use dynamic programming to calculate this. See their Equations 8–13. Although the final result is correct, there appear to be errors in the intermediate steps.

This captures the pricing features of both the standard consumption CAPM and the traditional static CAPM. To see this, note that when $\alpha = \rho$, we get the consumption CAPM and with logarithmic preferences $(\alpha/\rho = 0)$, the static CAPM.

Another feature of this class of models is that a high coefficient of risk aversion, $1 - \alpha$, does not necessarily imply that agents will want to smooth consumption over time. However, the main difficulty in testing this alternative preference structure stems from the fact that the counterparts of Equations (3) and (5) using GEU depend on variables that are *unobservable,* and this makes calibration tricky. One needs to make specific assumptions on the consumption process to obtain first-order conditions in terms of observables. Epstein and Zin (1991) use the "market portfolio" as a proxy for the wealth portfolio and claim that their framework offers a solution to the equity premium puzzle. We feel that this proxy overstates the correlation between asset returns and the wealth portfolio and hence their claim.

This modification has the *potential* to resolve the risk-free rate puzzle. We illustrate this below. Under the log-normality assumptions from Section 3.1, and using the market portfolio as a stand-in for the wealth portfolio we have

$$\ln R_f = -\ln\beta + \frac{\mu_x}{\sigma} - \frac{\alpha/\rho}{2\sigma^2}\sigma_x^2 + \frac{(\alpha/\rho) - 1}{2}\sigma_m^2. \tag{29}$$

Here σ_m^2 is the variance of the return on the "market portfolio" of all invested wealth. Since $1 - \alpha$ need not equal $1/\sigma$, we can have a large α without making σ small and hence obtain a reasonable risk-free rate if one is prepared to assume a large σ. The problem with this is that there is independent evidence that the elasticity of intertemporal substitution is *small* [Campbell (2001)], hence this generality is not very useful when the model is accurately calibrated.

3.3.2. *Habit formation*

A second approach to modifying preferences was initiated by Constantinides (1990) by incorporating habit formation. This formulation assumes that utility is affected not only by current consumption but also by past consumption. It captures a fundamental feature of human behavior that repeated exposure to a stimulus diminishes the response to it. The literature distinguishes between two types of habit, "internal" and "external" and two modeling perspectives, "difference" and "ratio". We illustrate these below. Internal habit formation captures the notion that utility is a decreasing function of *one's own* past consumption and marginal utility is an increasing function of one's own past consumption. Models with external habit emphasize that the operative benchmark is not one's own past consumption but the consumption relative to other agents in the economy.

Constantinides (1990) considers a model with internal habit where utility is defined over the *difference* between current consumption and lagged past consumption. Although the Constantinides (1990) model is in continuous time with a general lag structure, we can illustrate the intuition behind this class of models incorporating "habit" by considering preferences with a one period lag

$$U(c) = \mathrm{E}_t \sum_{s=0}^{\infty} \beta^s \frac{(c_{t+s} - \lambda c_{t+s-1})^{1-\alpha}}{1-\alpha}, \quad \lambda > 0. \tag{30}$$

If $\lambda = 1$ and the subsistence level is fixed, the period utility function specializes to the form

$$u(c) = \frac{(c-x)^{1-\alpha}}{1-\alpha},$$

where x is the fixed subsistence level.[33] The implied local coefficient of relative risk aversion is

$$-\frac{cu''}{u'} = \frac{\alpha}{1-x/c}. \tag{31}$$

If $x/c = 0.8$ then the effective risk aversion is 5α!

This preference ordering makes the agent extremely averse to consumption risk even when the risk aversion is small. For small changes in consumption, changes in marginal utility can be large. Thus, while this approach cannot resolve the equity premium puzzle without invoking extreme aversion to consumption risk, it can address the risk-free rate puzzle since the induced aversion to consumption risk increases the demand for bonds, thereby reducing the risk-free rate. Furthermore, if the growth rate of consumption is assumed to be iid, an implication of this model is that the risk-free rate will vary considerably (and counterfactually) over time. Constantinides (1990) gets around this problem since the growth rate in his model is not iid.[34]

An alternate approach to circumvent this problem has been expounded by Campbell and Cochrane (1999). The model incorporates the possibility of recession as a state variable so that risk aversion varies in a highly nonlinear manner.[35] The risk aversion of investors rises dramatically when the chances of a recession become larger and thus the model can generate a high equity premium. Since risk aversion increases precisely when consumption is low, it generates a precautionary demand for bonds that helps lower the risk-free rate. This model is consistent with both consumption and asset market data. However, it is an open question whether investors actually have the huge time varying counter-cyclical variations in risk aversion postulated in the model.

[33] See also the discussion in Weil (1989).

[34] In fact, a number of studies suggest that there is a small serial correlation in the growth rate.

[35] If we linearize the "surplus consumption ratio" in the Campbell–Cochrane (1999) model, we get the same variation in the risk-free rate as in the standard habit model. The nonlinear "surplus consumption ratio" is essential to reducing this variation.

Another modification of the Constantinides (1990) approach is to define utility of consumption relative to average per capita consumption. This is an external habit model where preferences are defined over the ratio of consumption to lagged[36] aggregate consumption. Abel (1990) terms his model "Catching up with the Joneses". The idea is that one's utility depends not on the absolute level of consumption, but on how one is doing relative to others. The effect is that, once again, an individual can become extremely sensitive and averse to consumption variation. Equity may have a negative rate of return and this can result in personal consumption falling relative to others. Equity thus becomes an undesirable asset relative to bonds. Since average per capita consumption is rising over time, the induced demand for bonds with this modification helps in mitigating the risk-free rate puzzle.

Abel (1990) defines utility as the *ratio* of consumption relative to average per capita consumption rather than the difference between the two. It can be shown that this is not a trivial modification.[37] While "difference" habit models can, in principle, generate a high equity premium, ratio models generate a premium that is similar to that obtained with standard preferences.

To illustrate, consider the framework in Abel (1990) specialized to the "catching up with the Joneses" case. At time t, the representative agent in the economy chooses the level of consumption c_t to maximize

$$U(c) = \mathrm{E}_t \sum_{t=0}^{\infty} \beta^t \frac{\left(c_t/C_{t-1}^{\gamma}\right)^{1-\alpha}}{1-\alpha}, \quad \alpha > 0, \tag{32}$$

where C_{t-1} is the lagged aggregate consumption. In equilibrium of course $C_t = c_t$, a fact we use in writing the counterparts of Equations (3) and (5) below.

$$1 = \beta \mathrm{E}_t \left\{ R_{e,t+1} x_t^{\gamma(\alpha-1)} x_{t+1}^{-\alpha} \right\}, \tag{33}$$

$$1 = \beta R_{f,t+1} \mathrm{E}_t \left\{ x_t^{\gamma(\alpha-1)} x_{t+1}^{-\alpha} \right\}, \tag{34}$$

where $x_{t+1} \equiv \frac{c_{t+1}}{c_t}$ is the growth rate of consumption. Under the assumptions made in Section 3.1 we can write

$$R_{f,t+1} = \frac{\mathrm{E}_t \left\{ x_{t+1}^{\gamma(\alpha-1)} \right\}}{\beta \mathrm{E}_t \left\{ x_{t+1}^{-\alpha} \right\}}, \tag{35}$$

and

$$\mathrm{E}_t \left\{ R_{e,t+1} \right\} = \mathrm{E}_t \left\{ x_{t+1}^{\gamma(\alpha-1)} \right\} \frac{\mathrm{E}_t \left\{ x_{t+1} \right\} + A \mathrm{E}_t \left\{ x_{t+1}^{1+\gamma(\alpha-1)} \right\}}{A}. \tag{36}$$

We see that in the expression $\ln R_f = -\ln\beta + \alpha\mu_x - \frac{1}{2}\alpha^2\sigma_x^2 - \gamma(1-\alpha)\mu_x$, the equity premium is $\ln \mathrm{E}\{R_e\} - \ln R_f = \alpha\sigma_{x,z}$, which is exactly the same as what was obtained

[36] Hence "Catching up with the Joneses" rather than "keeping up with the Joneses" [Abel (1990, footnote 1)].

[37] See Campbell (2001) for a detailed discussion.

earlier. Hence the equity premium is unchanged! However when $\gamma > 0$, a high α does not lead to the risk-free rate puzzle.

The statement, "External habit simply adds a term to the Euler Equation 60 which is known at time t, and this does not affect the premium" in Campbell (2001) appears to be inconsistent with the results in Table 1 Panel B in Abel (1990).

3.3.3. Resolution

Although the "set up" in Abel (1990) and Campbell (2001) is similar, Campbell's result is based on the assumption that asset returns and the growth rate of consumption are jointly log-normally distributed in *both* the "standard time additive" case *and* the "Joneses" case. In Abel (1990) the return distributions are endogenously determined and Campbell's assumption is *internally inconsistent* in the context of that model.

In Abel (1990), with "standard time additive" preferences, *if* consumption growth is log-normally distributed gross asset returns will also be lognormal, however, this is *not* the case with the "Joneses" preferences. In the latter case since $1 + R_{i,t+1} = x_t^{1-\alpha}(x_{t+1} + Ax_{t+1}^{\alpha})/A$, log-normality of x will *not* induce log-normality in $1 + R_{i,t+1}$.

Abel (1990) reports expressions for $\mathrm{E}(1 + R_{i,t+1})$ and $\mathrm{E}(1 + R_{f,t+1})$ in his Equations 17 and 18.

Let $\prod_{\text{Abel}} = \ln(\mathrm{E}(1 + R_{i,t+1})) - \ln(\mathrm{E}(1 + R_{f,t+1}))$. In the Abel model with $\theta = 0$ (the "standard time additive" case), *if* the growth rate of consumption is assumed to be lognormally distributed $\prod_{\text{Abel}}$ can be written as:

$$\prod_{\text{Abel}} = \mathrm{E}\left(\ln\left(1 + R_{i,t+1}\right)\right) + 0.5\,\mathrm{Var}\left(\ln\left(1 + R_{i,t+1}\right)\right) - \mathrm{E}\left(\ln\left(1 + R_{f,t+1}\right)\right) - 0.5\,\mathrm{Var}\left(\ln\left(1 + R_{f,t+1}\right)\right), \tag{37}$$

or

$$\prod_{\text{Abel}} = \prod_{\text{Campbell}} + 0.5\left[\mathrm{Var}\left(\ln\left(1 + R_{i,t+1}\right)\right) - \mathrm{Var}\left(\ln\left(1 + R_{f,t+1}\right)\right)\right], \tag{38}$$

or

$$\prod_{\text{Abel}} = \prod_{\text{Campbell}} + 0.5\,\mathrm{Var}(\ln(x)), \tag{39}$$

where $\prod_{\text{Campbell}} = \mathrm{E}(\ln(1 + R_{i,t+1})) - \mathrm{E}(\ln(1 + R_{f,t+1}))$, is the definition of the equity premium in Campbell (2001).

With "standard time additive" preferences and log-normally distributed returns, the analysis in both Abel and Campbell are equivalent. Indeed, a direct evaluation of $\prod_{\text{Abel}}$ from Equations 17 and 18 in Abel (1990) yields $\prod_{\text{Abel}} = \alpha\,\mathrm{Cov}(\ln x, \ln(1 + R_i))$.

This is identical to that obtained by adjusting Equation 62 in Campbell by adding $0.5\,\mathrm{Var}(\ln(x))$.

However, in Abel (1990) with "Joneses" preferences, if the growth rate of consumption is log-normally distributed, asset returns will *not be* lognormal, hence the analysis in Campbell (2001) after Equation 60 will *not* apply.

In Abel (1990), as preferences change, return distributions will change, hence if the counterpart of Equation 16 (in Campbell) represents the equity premium in the "standard time additive" framework, then Equation 62 will *not* be the relevant expression for the premium in the "Joneses" case. Counterparts of Equations 16 and 62 in Campbell (2001) will not *both* hold *simultaneously* in Abel (1990).

To summarize, models with habit formation and relative or subsistence consumption have had success in addressing the risk-free rate puzzle but only limited success with resolving the equity premium puzzle, since in these models effective risk aversion and prudence become implausibly large.

3.4. Idiosyncratic and uninsurable income risk

At a theoretical level, aggregate consumption is a meaningful economic construct if the market is complete, or effectively so.[38] Market completeness is implicitly incorporated into asset-pricing models in finance and neoclassical macroeconomics through the assumption of the existence of a representative household. In complete markets, heterogeneous households are able to equalize, state by state, their marginal rate of substitution. The equilibrium in a heterogeneous full-information economy is isomorphic in its pricing implications to the equilibrium in a representative-household, full-information economy, if households have von Neumann–Morgenstern preferences.

Bewley (1982), Mankiw (1986) and Mehra and Prescott (1985) suggest the potential of enriching the asset-pricing implications of the representative-household paradigm, by relaxing the assumption of complete markets.[39]

Current financial paradigms postulate that idiosyncratic income shocks must exhibit three properties in order to explain the returns on financial assets: uninsurability, persistence heteroscedasticity and counter cyclical conditional variance. In infinite horizon models, agents faced with uninsurable income shocks will dynamically self-insure, effectively smoothing consumption. Hence the difference in the equity premium in incomplete markets and complete markets is small.[40]

[38] This section draws on Constantinides (2002).

[39] There is an extensive literature on the hypothesis of complete consumption insurance. See, Altonji, Hayashi and Kotlikoff (1992), Attanasio and Davis (1997), Cochrane (1991) and Mace (1991).

[40] Lucas (1994) and Telmer (1993) calibrate economies in which consumers face uninsurable income risk and borrowing or short-selling constraints. They conclude that consumers come close to the complete-markets rule of complete risk sharing, although consumers are allowed to trade in just one security in a frictionless market. Aiyagari and Gertler (1991) and Heaton and Lucas (1996) add transaction costs

Constantinides and Duffie (1996), propose a model incorporating heterogeneity that captures the notion that consumers are subject to idiosyncratic income shocks that cannot be insured away. For instance, consumers face the risk of job loss, or other major personal disasters that cannot be hedged away or insured against.[41] Equities and related pro-cyclical investments exhibit the undesirable feature that they drop in value when the probability of job loss increases, as, for instance, in recessions. In economic downturns, consumers thus need an extra incentive to hold equities and other similar investment instruments; the equity premium can then be rationalized as the added inducement needed to make equities palatable to investors.

The model provides an explanation of the counter-cyclical behavior of the equity risk premium: the risk premium is highest in a recession since equities are a poor hedge against the potential loss of employment. It also provides an explanation of the unconditional equity premium puzzle: even though *per capita* consumption growth is poorly correlated with stocks returns, investors require a hefty premium to hold stocks over short-term bonds because stocks perform poorly in recessions, when an investor is more likely to be laid off.

Since the proposition demonstrates the existence of equilibrium in frictionless markets, it implies that the Euler equations of household (but not necessarily of *per capita*) consumption must hold. Furthermore, since the given price processes have embedded in them whatever predictability of returns of the dividend-price ratios and other instruments that the researcher cares to ascribe to them, the *equilibrium* price processes have this predictability built into them *by construction.*

Constantinides and Duffie (1996), point out that periods with frequent and large uninsurable idiosyncratic income shocks are associated with both dispersed cross-sectional distribution of the household consumption growth and low stock returns. Brav, Constantinides and Geczy (2002) provide empirical evidence of the impact of uninsurable idiosyncratic income risk on pricing. They estimate the relative risk aversion (RRA) coefficient and test the set of Euler equations of *household* consumption on the premium of the value-weighted and the equally weighted market portfolio return over the risk-free rate, and on the premium of value stocks over growth stocks.[42] They do not reject the Euler equations of *household* consumption with an economically plausible RRA coefficient of between two and four, although they reject the Euler equations of *per capita* consumption with any value of the RRA coefficient.

and/or borrowing costs and reach a similar negative conclusion, provided that the supply of bonds is not restricted to an unrealistically low level.

[41] Storesletten, Telmer and Yaron (2001) provide empirical evidence from the Panel Study on Income Dynamics (PSID) that idiosyncratic income shocks are persistent and have counter cyclical conditional variance. Storesletten, Telmer and Yaron (2000) corroborate this evidence by studying household consumption over the life cycle.

[42] In related studies, Jacobs (1999) studies the PSID database on food consumption; Cogley (1999) and Vissing-Jorgensen (2002) study the CEX database on broad measures of consumption; Jacobs and Wang (2001) study the CEX database by constructing synthetic cohorts; and Ait-Sahalia, Parker and Yogo (2001) measure the household consumption with the purchases of certain luxury goods.

Krebs (2000) extends the Constantinides and Duffie (1996) model by introducing rare idiosyncratic income shocks that drive consumption close to zero. In his model, the conditional variance and skewness of the idiosyncratic income shocks are nearly constant over time. He provides a theoretical justification of the difficulty of empirically assessing the contribution of these catastrophic shocks in the low-order cross-sectional moments.

3.5. Models incorporating a disaster state and survivorship bias

Rietz (1988) has proposed a solution to the puzzle that incorporates a very small probability of a very large drop in consumption. He finds that in such a scenario the risk-free rate is much lower than the return on an equity security. This model requires a 1-in-100 chance of a 25% decline in consumption to reconcile the equity premium with a risk aversion parameter of 10. Such a scenario has not been observed in the USA for the last years for which we have economic data. Nevertheless, one can evaluate the implications of the model. One implication is that the real interest rate and the probability of the occurrence of the extreme event move inversely. For example, the perceived probability of a recurrence of a depression was probably very high just after World War II and subsequently declined over time. If real interest rates rose significantly as the war years receded, that evidence would support the Rietz hypothesis. Similarly, if the low probability event precipitating the large decline in consumption were a nuclear war, the perceived probability of such an event has surely varied over the last 100 years. It must have been low before 1945, the first and only year the atom bomb was used. And it must have been higher before the Cuban Missile Crisis than after it. If real interest rates had moved as predicted, that would support Rietz's disaster scenario. But they did not.

Another attempt at resolving the puzzle proposed by Brown et al. (1995) focuses on survival bias.

The central thesis here is that the ex-post measured returns reflect the premium, in the USA, on a stock market that has successfully weathered the vicissitudes of fluctuating financial fortunes. Many other exchanges were unsuccessful and hence the ex-ante equity premium was low. Since it was not known a priori which exchanges would survive, for this explanation to work, stock and bond markets must be differentially impacted by a financial crisis. Governments have expropriated much of the real value of nominal debt by the mechanism of unanticipated inflation. Five historical instances come readily to mind: During the German hyperinflation, holders of bonds denominated in Reich marks lost virtually all value invested in those assets. During the Poincaré administration in France in the 1920s, bond-holders lost nearly 90% of the value invested in nominal debt. And in the 1980s, Mexican holders of dollar-denominated debt lost a sizable fraction of its value when the Mexican government, in a period of rapid inflation, converted the debt to pesos and limited the rate at which these funds could be withdrawn. Czarist bonds in Russia and Chinese debt holdings (subsequent to the fall of the Nationalists) suffered a similar fate under communist regimes.

The above examples demonstrate that in times of financial crisis, bonds are as likely to lose value as stocks. Although a survival bias may impact on the *levels* of both the return on equity and debt, there is no evidence to support the assertion that these crises impact *differentially* on the returns to stocks and bonds; hence the equity premium is not impacted. In every instance where trading equity has been suspended, due to political upheavals, etc., governments have either reneged on their debt obligations or expropriated much of the real value of nominal debt through the mechanism of unanticipated inflation.

The difficulty that, collectively, several model classes have had in explaining the equity premium as a compensation for bearing risk leads us to conclude that perhaps it is *not* a "risk premium" but rather due to other factors. We consider these in the next section.

4. Is the equity premium due to borrowing constraints, a liquidity premium or taxes?

4.1. Borrowing constraints

In models with borrowing constraints and transaction costs, the effect is to force investors to hold an inventory of bonds (precautionary demand) to smooth consumption. Hence in infinite horizon models with borrowing constraints, agents come close to equalizing their marginal rates of substitution with little effect on the equity premium[43] Some recent attempts to resolve the puzzle incorpor.ating both borrowing constraints *and* consumer heterogeneity appear promising. One approach, which departs from the representative agent model, has been proposed in Constantinides, Donaldson and Mehra (2002).

In order to systematically illustrate these ideas, the authors construct an overlapping-generations (OLG) exchange economy in which consumers live for three periods. In the first period, a period of human capital acquisition, the consumer receives a relatively low endowment income. In the second period, the consumer is employed and receives wage income subject to large uncertainty. In the third period, the consumer retires and consumes the assets accumulated in the second period.

The authors explore the implications of a borrowing constraint by deriving and contrasting the stationary equilibria in two versions of the economy. In the *borrowing-constrained* version, the young are prohibited from borrowing and from selling equity short. The *borrowing-unconstrained* economy differs from the borrowing-constrained one only in that the borrowing constraint and the short-sale constraint are absent.

[43] This is true unless the supply of bonds is unrealistically low. See Aiyagari and Gertler (1991).

An *unconstrained* representative agent's maximization problem is formulated as follows. An agent born in period t solves

$$\max_{\{z^e_{t,i}, z^b_{t,i}\}} \mathrm{E}\left(\sum_{i=0}^{2} \beta^i U\left(C_{t,i}\right)\right), \tag{40}$$

s.t.

$$c_{t,0} + q^e_t z^e_{t,1} + q^b_t z^b_{t,1} \leqslant w^0, \tag{41}$$

$$\begin{aligned} c_{t,1} + q^e_{t+1} z^e_{t,2} + q^b_{t+1} z^b_{t,2} &\leqslant \left(q^e_{t+1} + d_{t+1}\right) z^e_{t,1} + \left(q^b_{t+1} + b\right) z^b_{t,1} + w^1_{t+1} c_{t,2} \\ &\leqslant \left(q^e_{t+2} + d_{t+2}\right) z^e_{t,2} + \left(q^b_{t+2} + b\right) z^b_{t,2}, \end{aligned} \tag{42}$$

$c_{t,j}$ is the consumption in period $t+j$ $(j = 0, 1, 2)$ of a consumer born in period t. There are two types of securities in the model: *bonds* and *equity* with *ex-coupon* and *ex-dividend* prices q^b_t and q^e_t, respectively. Bonds are a claim to a coupon payment b every period, while the equity is a claim to the dividend stream $\{d_t\}$. The consumer born in period t receives deterministic wage income $w^0 > 0$ in period t, when young; stochastic wage income $w^1_{t+1} > 0$ in period $t+1$, when middle-aged; and zero wage income in period $t+2$, when old. The consumer purchases $z^e_{t,0}$ shares of stock and $z^b_{t,0}$ bonds when young. The consumer adjusts these holdings to $z^e_{t,1}$ and $z^b_{t,1}$, respectively, when middle-aged. The consumer liquidates his/her entire portfolio when old. Thus, $z^e_{t,2} = 0$ and $z^b_{t,2} = 0$.

When considering the borrowing constrained equilibrium the following additional constraints are imposed $z^e_{t,j} > 0$ and $z^b_{t,2} > 0$.

The model introduces two forms of market incompleteness. First, consumers of one generation are prohibited from trading claims against their future wage income with consumers of another generation.[44] Second, consumers of one generation are prohibited from trading bonds and equity with consumers of an unborn generation. As discussed earlier, absent a complete set of contingent claims, consumer heterogeneity in the form of *uninsurable, persistent* and *heteroscedastic* idiosyncratic income shocks, with *counter-cyclical* conditional variance, can potentially resolve empirical difficulties encountered by representative-consumer models.[45]

The novelty of the paper lies in incorporating a life-cycle feature to study asset pricing. The idea is appealingly simple. As discussed earlier, the attractiveness of equity as an asset depends on the correlation between consumption and equity income. If equity pays off in states of high marginal utility of consumption, it will command a higher price (and consequently a lower rate of return), than if its payoff is in states

[44] Being homogeneous within their generation, consumers have no incentive to trade claims with consumers of their own generation.

[45] See Mankiw (1986) and Constantinides and Duffie (1996).

where marginal utility is low. Since the marginal utility of consumption varies inversely with consumption, equity will command a high rate of return if it pays off in states when consumption is high, and vice versa.[46]

A key insight of their paper is that as the correlation of equity income with consumption *changes* over the life cycle of an individual, so does the attractiveness of equity as an asset. Consumption can be decomposed into the sum of wages and equity income. A young person looking forward at his life has uncertain future wage *and* equity income; furthermore, the correlation of equity income with consumption will not be particularly high, as long as stock and wage income are not highly correlated. This is empirically the case, as documented by Davis and Willen (2000). Equity will thus be a hedge against fluctuations in wages and a "desirable" asset to hold as far as the young are concerned.

The same asset (equity) has a very different characteristic for the middle-aged. Their wage uncertainty has largely been resolved. Their future retirement wage income is either zero or deterministic and the innovations (fluctuations) in their consumption occur from fluctuations in equity income. At this stage of the life cycle, equity income is highly correlated with consumption. Consumption is high when equity income is high, and equity is no longer a hedge against fluctuations in consumption; hence, for this group, it requires a higher rate of return.

The characteristics of equity as an asset therefore change, depending on who the predominant holder of the equity is. Life cycle considerations thus become crucial for asset pricing. If equity is a "desirable" asset for the marginal investor in the economy, then the observed equity premium will be low, relative to an economy where the marginal investor finds it unattractive to hold equity. The *deus ex machina* is the *stage* in the life cycle of the marginal investor.

The authors argue that the young, who should be holding equity in an economy without frictions and with complete contraction, are effectively shut out of this market because of borrowing constraints. The young are characterized by low wages; ideally they would like to smooth lifetime consumption by borrowing against future wage income (consuming a part of the loan and investing the rest in higher return equity). However, they are prevented from doing so because human capital alone does not collateralize major loans in modern economies for reasons of moral hazard and adverse selection.

In the presence of borrowing constraints, equity is thus exclusively priced by the middle-aged investors, since the young are effectively excluded from the equity markets and we observe a high equity premium. If the borrowing constraint is relaxed, the young will borrow to purchase equity, thereby raising the bond yield. The increase

[46] This is precisely the reason as explained earlier why high-beta stocks in the simple CAPM framework have a high rate of return. In that model, the return on the market is a proxy for consumption. High-beta stocks pay off when the market return is high, i.e., when marginal utility is low, hence their price is (relatively) low and their rate of return high.

in the bond yield induces the middle-aged to shift their portfolio holdings from equity to bonds. The increase in demand for equity by the young and the decrease in the demand for equity by the middle-aged work in opposite directions. On balance, the effect is to increase both the equity and the bond return while simultaneously shrinking the equity premium. Furthermore, the relaxation of the borrowing constraint reduces the net demand for bonds and the risk-free rate puzzle re-emerges.

4.2. *Liquidity premium*

Bansal and Coleman (1996) develop a monetary model that offers an explanation of the equity premium. In their model, some assets other than money play a key feature by facilitating transactions. This affects the rate of return they offer in equilibrium.

Considering the role of a variety of assets in facilitating transactions, they argue that, on the margin, the transaction service return of money relative to interest bearing checking accounts should be the interest rate paid on these accounts. They estimate this to be 6%, based on the rate offered on NOW accounts for the period they analyze. Since this is a substantial number, they suggest that other money-like assets may also implicitly include a transaction service component to their return. Insofar as T-bills and equity have a different service component built into their returns, this may offer an explanation for the observed equity premium. In fact, if this service component differential were about 5%, there would be no equity premium puzzle.

We argue that this approach can be challenged on three accounts. First, the majority of T-bills are held by institutions, that do not use them as compensatory balances for checking accounts and it is difficult to imagine their having a significant transaction service component. Second, the returns on NOW and other interest bearing accounts have varied over time. These returns have been higher post-1980 than in earlier periods. In fact, for most of the twentieth century, checking accounts were *not* interest bearing. However, contrary to the implications of this model, the equity premium has not diminished in the post-1980 period when presumably the implied transaction service component was the greatest. Third, this model implies that there should be a significant yield differential between T-bills and long term government bonds that presumably do not have a significant transaction service component. However, this has not been the case.

4.3. *Taxes and regulation*

McGrattan and Prescott (2000, 2001) take the position that factors other than a premium for bearing non-diversifiable risk account for the large difference in the return on corporate equity and the after-tax real interest rate in the 1960–2000 period. They find that changes in the tax and legal-regulatory systems in the USA that permitted retirement accounts and pension funds to hold corporate equity and reductions in marginal income tax rates account for the high return on corporate equity in this period.

Subsequent to the writing of our equity premium paper [Mehra and Prescott (1985)], real business-cycle theory was developed by Kydland and Prescott (1982). Real business-cycle theory uses the stochastic growth model augmented to include the labor–leisure decision. One finding of the real business-cycle literature is that the real after-tax interest rate varies in the range from 4 to 4.5%. Another finding is that the predicted after-tax return on corporate equity is essentially equal to this real interest rate. These results are closely related to and consistent with what Mehra and Prescott (1985) found in their "Equity Premium Puzzle" paper. The key difference is the empirical counterpart of the real interest rate. Mehra and Prescott (1985) use the highly liquid T-bill rate, corrected for expected inflation. Business-cycle theorists [see McGrattan and Prescott (2000, 2001), who incorporate the details of the tax system] use the intertemporal marginal rate of substitution for consumption to determine this interest rate.

Why was the average real return on T-bills significantly below the real interest rate as found in the business-cycle literature? Why was the average real return on corporate equity significantly above this real interest rate in the 1960–2000 period? The low realized real return on T-bills in this period probably has to do with the liquidity services that T-bills provide. The total T-bill real return, including liquidity services, could very well have been in the range from 4 to 4.5%.

A more interesting question is, why was the return on corporate equity so high in the 1960–2000 period? McGrattan and Prescott (2000) answer this question in the process of estimating the fundamental value of the stock market in 1962 and 2000. They chose these two points in time because, relative to GDP, after-tax corporate earnings, net corporate debt, and corporate tangible capital stock were approximately the same and the tax system had been stable for a number of years. Further, at neither point in time was there any fear of full or partial expropriation of capital. *What differed was that the value of the stock market relative to GDP in 2000 was nearly twice as large as in 1962.*

What changed between 1962 and 2000 were the tax and legal-regulatory systems. The marginal tax rate on corporate distributions was 43% in the 1955–1962 period and only 17% in the 1987–2000. This marginal tax rate on dividends does not have consequences for steady-state after-tax earnings or steady-state corporate capital, provided that tax revenues are returned lump-sum to households. This tax rate *does* however have consequences for the value of corporate equity.

The important changes in the legal-regulatory system, most of which occurred in the late 1970s and early 1980s, were that corporate equity was permitted to be held as pension fund reserves and that people could invest on a before-tax basis in individual retirement accounts that could include equity. The threat of a lawsuit is why debt assets and not equity with higher returns were held as pension fund reserves in 1962. At that time, little equity was held in defined contribution plans retirement accounts because the total assets in these accounts were then a small number. Thus, debt and not equity could and was held tax free in 1962. In 2000, both could be held tax free in defined benefit and defined contribution pension funds and in individual retirement accounts.

Not surprisingly, the assets held in untaxed retirement accounts were large in 2000, being approximately 1.3 GDP [McGrattan and Prescott (2000)].

McGrattan and Prescott (2000, 2001) in determining whether the stock market was overvalued or undervalued vis-a-vis standard growth theory exploit the fact that the value of a set of real assets is the sum of the values of the individual assets in the set. They develop a method for estimating the value of intangible corporate capital, something that is not reported on balance sheets and, like tangible capital, adds to the value of corporations. Their method uses only national account data and the equilibrium condition that after-tax returns are equated across assets. They also incorporate the most important features of the U.S. tax system into the model they use to determine the value of corporate equity, in particular, the fact that capital gains are only taxed upon realization.

The formula they develop for the fundamental value of corporate equities V is

$$V = (1-\tau_d)\, K_T' + (1-\tau_d)(1-\tau_c)\, K_I', \tag{43}$$

where τ_d is the tax rate on distributions; τ_c is the tax rate on corporate income; K_T' is the end-of-period tangible corporate capital stock; and K_I' is the end-of-period intangible corporate capital stock.

The reasons for the tax factors are as follows. Corporate earnings significantly exceed corporate investment. As a result, aggregate corporate distributions are large and positive. Historically, these distributions have been in the form of dividends. Therefore, the cost of a unit of tangible capital on the margin is only $1-\tau_d$ units of forgone consumption. In the case of intangible capital, the consumption cost of a unit of capital is even smaller because investments in intangible capital reduce corporate tax liabilities.[47]

The tricky part of the calculation is in constructing a measure of intangible capital. These investments reduce current accounting profits and they increase future economic profits. The formula for steady-state before tax accounting profits is

$$\pi = \frac{i}{1-\tau_c} K_T + iK_I - gK_I, \tag{44}$$

where g is the steady-state growth rate of the economy and the interest rate i the steady-state after-tax real interest rate. Note that gK_I is steady-state net investment in intangible capital, which reduces accounting profits because it is expensed. Note also, that all the variables in formula (44) are reported in the system of national accounts with the exception of i and K_I.

McGrattan and Prescott (2001) estimate i using national income data. Their estimate of i is the after-tax real return on capital in the noncorporate sector, which has

[47] In fact, formula (1) must be adjusted if economic depreciation and accounting depreciation are not equal and if there is an investment tax credit. See McGrattan and Prescott (2001).

as much capital as does the corporate sector. They find that the stock market was neither overvalued nor undervalued in 1962 and 2000. The primary reason for the low valuation in 1962 relative to GDP and high valuation in 2000 relative to GDP is that τ_d was much higher in 1962 than it was in 2000. The secondary reason is that the value of foreign subsidiaries of U.S. corporations grew in the period. An increase in the size of the corporate intangible capital stock was also a contributing factor.

McGrattan and Prescott (2001) find that in the economically and politically stable 1960–2000 period, the after-tax real return on holding corporate equity was as predicted by theory if the changes in the tax and regulatory system were *not* anticipated. These unanticipated changes led to a large unanticipated capital gain on holding corporate equity. Evidence of the importance of these changes is that the share of corporate equity held in retirement accounts and as pension fund reserves increased from essentially zero in 1962 to slightly over 50% in 2000. This is important because it means that half of corporate dividends are now subject to zero taxation.

In periods of economic uncertainty, such as those that prevailed in the 1930–1955 period with the Great Depression, World War II, and the fear of another great depression, the survival of the capitalistic system was in doubt. In such times, low equity prices and high real returns on holding equity are not surprising. This is the Brown, Goetzmann and Ross (1995) explanation of the equity premium. By 1960, the fears of another great depression and of an abandonment of the capitalistic system in the USA had vanished, and clearly other factors gave rise to the high return on equity in the 1960–2000 period.

5. An equity premium in the future?

There is a group of academicians and professionals who claim that at present there is no equity premium, and by implication, no equity premium puzzle. To address these claims we need to differentiate between two different interpretations of the term "equity premium". One is the *ex-post* or realized equity premium. This is the actual, *historically observed* difference between the return on the market, as captured by a stock index, and the risk free rate, as proxied by the return on government bills. This is what we addressed in Mehra and Prescott (1985). However, there is a related concept – the *ex-ante* equity premium. This is a forward-looking measure of the premium, that is, the equity premium that is *expected* to prevail in the future or the conditional equity premium given the current state of the economy. To elaborate, after a bull market, when stock valuations are high relative to fundamentals, the ex-ante equity premium is likely to be low. However, it is precisely in these times, when the market has risen sharply, that the ex-post, or the realized premium is high. Conversely, after a major downward correction, the ex-ante (expected) premium is likely to be high while the realized premium will be low. This should not come as a surprise since returns to stock have been documented to be mean-reverting.

Dimson, Marsh and Staunton (2000), Siegel (1998) and Fama and French (2002) document that equity returns over the past 50 years have been higher than their expected values. Fama and French argue that since the average realized return over this period exceeds the one-year ahead conditional forecast (based on the price dividend ratio) by an average of 3.11 to 4.88% per year, the expected equity premium should have declined by this amount. The key implication here is that the expected equity premium is small.

If investors have overestimated the equity premium over the second half of this century, Constantinides (2002) argues that "we now have a bigger puzzle on our hands". Why have investors systematically biased their estimates over such a long horizon? He, however, finds no statistical support for the Fama and French claim.[48]

Which of these interpretations of the equity premium is relevant for an investment advisor? Clearly this depends on the planning horizon. The equity premium that we documented in our 1985 paper is for very long investment horizons. It has little to do with what the premium is going to be over the next couple of years. The ex-post equity premium is the realization of a stochastic process over a certain period and as shown earlier (see Figures 1, 2 and 3) it has varied considerably and counter-cyclically over time.

Market watchers and other professionals who are interested in short-term investment planning will wish to project the conditional equity premium over their planning horizon. This is by no means a simple task. Even if the conditional equity premium given current market conditions is small, and there appears to be general consensus that it is, this in itself does not imply that it was obvious either that the historical premium was too high or that the equity premium has diminished.

The data used to document the equity premium over the past 100 years is as good an economic data set as we have and this is a long series when it comes to economic data. Before we dismiss the premium, not only do we need to understand the observed phenomena but we also need a plausible explanation why the future is likely to be any different from the past. In the absence of this, and based on what we currently know, we can make the following claim: over the long horizon the equity premium is likely to be similar to what it has been in the past and the returns to investment in equity will continue to substantially dominate that in T-bills for investors with a long planning horizon.

Appendix A

Suppose the distribution of returns period by period is independently and identically distributed. Then as the number of periods tends to infinity, the future value of the

[48] "Notwithstanding the possibility that regime shifts may well have occurred during this period and that behavior deviations from rationality may have been at work, the simple present-value model matches the gross features of the equity return and the price–dividend ratio without having to resort to regime shifts or deviations from rationality" [Constantinides (2002)].

investment, computed at the arithmetic average of returns tends to the expected value of the investment with probability 1.

To see this, let $V_T = \prod_{t=1}^{T}(1+r_t)$, where r_t is the asset return in period t and V_T is the terminal value of one dollar at time T.

Then

$$\mathrm{E}(V_T) = \mathrm{E}\left[\prod_{i=1}^{T}(1+r_t)\right].$$

Since the r_t's are assumed to be uncorrelated, we have

$$\mathrm{E}(V_T) = \prod_{i=1}^{T}\mathrm{E}(1+r_t).$$

or

$$\mathrm{E}(V_T) = \prod_{i=1}^{T}(1+\mathrm{E}(r_t)).$$

Let the arithmetic average, $\mathrm{AA} = \frac{1}{T}\sum_{t=t}^{T} r_t$. Then, by the strong law of large numbers [Billingsley (1995, Theorem 22.1)]

$$\mathrm{E}(V_T) \to \prod_{i=1}^{T}(1+\mathrm{AA}) \quad \text{as} \quad T \to \infty,$$

or

$$\mathrm{E}(V_T) \to (1+\mathrm{AA})^T,$$

as the number of periods T becomes large.

If asset returns, r_t, are identically and independently log normally distributed, then, as the number of periods tends to infinity, the future value of an investment compounded at the continuously compounded geometric average rate tends to the median value of the investment.

Let $V_T = \prod_{t=1}^{T}(1+r_t)$, where r_t is the asset return in period t and V_T is the terminal value of one dollar at time T.

The Geometric Average is defined by:

$$\mathrm{GA} = \left[\prod_{t=1}^{T}(1+r_t)\right]^{1/T} - 1,$$

hence $V_T = (1+\mathrm{GA})^T$ and $\ln(1+\mathrm{GA}) = \frac{1}{T}\sum \ln(1+r_t)$.

Let the continuously compounded geometric rate of return = μ_{rc}. Then by definition

$$\ln(1 + \mathrm{GA}) = \mu_{rc},$$

or

$$1 + \mathrm{GA} = \exp[\mu_{rc}],$$

and

$$(1 + \mathrm{GA})^T = \exp[T\mu_{rc}].$$

By the properties of the lognormal distribution, the median value of V_T = exp[E (ln V_T)] and by the strong law of large numbers $\mathrm{E}(\ln V_T) = \sum \mathrm{E}\ln(1 + r_t) \rightarrow T\mu_{re}$ as $T \rightarrow \infty$ [Billingsley (1995, Theorem 22.1)].

Hence the median value of $V_T = \exp[T\mu_{rc} = (1 + \mathrm{GA})^T$ as claimed above.

Appendix B. The original analysis of the equity premium puzzle

In this Appendix we present our original analysis of the equity premium puzzle. Needless to say, it draws heavily from Mehra and Prescott (1985).

B.1. The economy, asset prices and returns

We employ a variation of Lucas' (1978) pure exchange model. Since per capita consumption has grown over time, we assume that the growth rate of the endowment follows a Markov process. This is in contrast to the assumption in Lucas' model that the endowment level follows a Markov process. Our assumption, which requires an extension of competitive equilibrium theory, enables us to capture the non-stationarity in the consumption series associated with the large increase in per capita consumption that occurred in the 1889–1978 period.

The economy we consider was judiciously selected so that the joint process governing the growth rates in aggregate per capita consumption and asset prices would be stationary and easily determined. The economy has a single representative "stand-in" household. This unit orders its preferences over random consumption paths by

$$E_0\left\{\sum_{t=0}^{\infty}\beta^t U(c_t)\right\}, \quad 0 < \beta < 1, \tag{B.1}$$

where c_t is per capita consumption, β is the subjective time discount factor, E{·} is the expectation operator conditional upon information available at time zero (which denotes the present time) and U: $R_+ \rightarrow R$ is the increasing concave utility function.

To insure that the equilibrium return process is stationary, we further restrict the utility function to be of the constant relative risk aversion (CRRA) class

$$U(c,\alpha) = \frac{c^{1-\alpha}}{1-\alpha}, \quad 0 < \alpha < \infty. \tag{B.2}$$

The parameter α measures the curvature of the utility function. When α is equal to one, the utility function is defined to be the logarithmic function, which is the limit of the above function as α approaches one.

We assume there is one productive unit which produces output y_t in period t which is the period dividend. There is one equity share with price p_t that is competitively traded; it is a claim to the stochastic process $\{y_t\}$.

The growth rate in y_t is subject to a Markov chain; that is,

$$y_{t+1} = x_{t+1}\, y_t, \tag{B.3}$$

where $x_{t+1} \in \{\lambda_1, \ldots, \lambda_n\}$ is the growth rate, and

$$\Pr\{x_{t+1} = \lambda_1;\ x_t = \lambda_j\} = \phi_{ij}. \tag{B.4}$$

It is also assumed that the Markov chain is ergodic. The λ_i are all positive and $y_0 > 0$. The random variable y_t is observed at the beginning of the period, at which time dividend payments are made. All securities are traded ex-dividend. We also assume that the matrix A with elements $a_{ij} \equiv \beta\phi_{ij}\lambda_j^{1-\alpha}$ for $i,j = 1, \ldots, n$ is stable; that is, $\lim A^m$ as $m \to \infty$ is zero. In Mehra (1988) it is shown that this is necessary and sufficient for expected utility to exist if the stand-in household consumes y_t every period. The paper also defines and establishes the existence of a Debreu (1954) competitive equilibrium with a price system having a dot product representation under this condition.

Next we formulate expressions for the equilibrium time t price of the equity share and the risk-free bill. We follow the convention of pricing securities ex-dividend or ex-interest payments at time t, in terms of the time t consumption good. For any security with process $\{d_s\}$ on payments, its price in period t is

$$P_t = \mathrm{E}_t\left\{\sum_{s=t+1}^{\infty} \beta^{s-t}\frac{U'(y_s)\, d_s}{U'(y_t)}\right\}, \tag{B.5}$$

as the equilibrium consumption is the process $\{y_s\}$ and the equilibrium price system has a dot product representation.

The dividend payment process for the equity share in this economy is $\{y_s\}$. Consequently, using the fact that $U'(c) = c^{-\alpha}$,

$$\begin{aligned} P_t^e &= P^e(x_t, y_t) \\ &= \mathrm{E}\left\{\sum_{s=t+1}^{\infty} \beta^{s-t}\frac{y_t^{\alpha}}{y_s^{\alpha}} y_s \mid x_t, y_t\right\}. \end{aligned} \tag{B.6}$$

Variables x_t and y_t are sufficient relative to the entire history of shocks up to, and including, time t for predicting the subsequent evolution of the economy. They thus constitute legitimate state variables for the model. Since $y_s = y_t x_{t+1} \cdots x_s$, the price of the equity security is homogeneous of degree one in y_t which is the current endowment of the consumption good. As the equilibrium values of the economies being studied are time invariant functions of the state (x_t, y_t), the subscript t can be dropped. This is accomplished by redefining the state to be the pair (c, i), if $y_t = c$ and $x_t = \lambda_i$. With this convention, the price of the equity share from Equation (B.6) satisfies

$$p^e(c,i) = \beta \sum_{j=1}^{n} \phi_{ij} \left(\lambda_j c\right)^{-\alpha} \left[p^e\left(\lambda_j c, j\right) + \lambda_j c\right] c^{\alpha}. \tag{B.7}$$

Using the result that $p^e(c,i)$ is homogeneous of degree one in c, we represent this function as

$$p^e(c,i) = w_i c, \tag{B.8}$$

where w_i is a constant. Making this substitution in Equation (B.7) and dividing by c yields

$$w_i = \beta \sum_{j=1}^{n} \phi_{ij} \lambda_j^{(1-\alpha)} \left(w_j + 1\right) \quad \text{for} \quad i = 1, \ldots, n. \tag{B.9}$$

This is a system of n linear equations in n unknowns. The assumption that guaranteed existence of equilibrium guarantees the existence of a unique positive solution to this system.

The period return if the current state is (c, i) and next period state $(\lambda_j c, j)$ is

$$\begin{aligned} r_{ij}^e &= \frac{p^e\left(\lambda_j c, j\right) + \lambda_j c - p^e(c,i)}{p^e(c,i)} \\ &= \frac{\lambda_j \left(w_j + 1\right)}{w_i} - 1, \end{aligned} \tag{B.10}$$

The equity's expected period return if the current state is i is

$$R_i^e = \sum_{j=1}^{n} \phi_{ij} r_{ij}^e. \tag{B.11}$$

Capital letters are used to denote expected return. With the subscript i, it is the expected return conditional upon the current state being (c, i). Without this subscript it is the expected return with respect to the stationary distribution. The superscript indicates the type of security.

The other security considered is the one-period real bill or riskless asset, which pays one unit of the consumption good next period with certainty. From Equation (B.6),

$$\begin{aligned} p_i^f &= p^f(c,i) \\ &= \beta \sum_{j=1}^{n} \phi_{ij} \frac{U'(\lambda_j c)}{U'(c)} \\ &= \beta \sum \phi_{ij} \lambda_j^{-\alpha}. \end{aligned} \tag{B.12}$$

The certain return on this riskless security is

$$R_i^f = \frac{1}{p_i^f - 1}, \tag{B.13}$$

when the current state is (c, i).

As mentioned earlier, the statistics that are probably most robust to the modeling specification are the means over time. Let $\pi \in R^n$ be the vector of stationary probabilities on i. This exists because the chain on i has been assumed to be ergodic. The vector π is the solution to the system of equations

$$\pi = \phi^T \pi,$$

with

$$\sum_{i=1}^{n} \pi_i = 1 \quad \text{and} \quad \phi^T = \{\phi_{ji}\}.$$

The expected returns on the equity and the risk-free security are, respectively,

$$R^e = \sum_{i=1}^{n} \pi_i R_i^e \quad \text{and} \quad R^f = \sum_{i=1}^{n} \pi_i R_i^f. \tag{B.14}$$

Time sample averages will converge in probability to these values given the ergodicity of the Markov chain. The risk premium for equity is $R^e - R^f$, a parameter that is used in the test.

The parameters defining preferences are α and β while the parameters defining technology are the elements of $[\phi_{ij}]$ and $[\lambda_i]$. Our approach is to assume two states for the Markov chain and to restrict the process as follows:

$$\lambda_1 = 1 + \mu + \delta, \quad \lambda_2 = 1 + \mu - \delta,$$

$$\phi_1 1 = \phi_2 2 = \phi, \quad \phi_1 2 = \phi_2 1 = (1 - \phi).$$

The parameters μ, ϕ, and δ now define the technology. We require $\delta > 0$ and $0 < \phi < 1$. This particular parameterization was selected because it permitted us to independently

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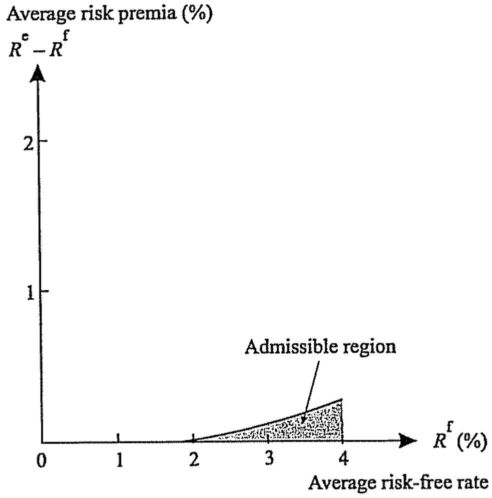

Fig. 8. Set of admissible average equity risk premia and real returns.

vary the average growth rate of output by changing μ, the variability of consumption by altering δ, and the serial correlation of growth rates by adjusting ϕ.

The parameters were selected so that the average growth rate of per capita consumption, the standard deviation of the growth rate of per capita consumption and the first-order serial correlation of this growth rate, all with respect to the model's stationary distribution, matched the sample values for the U.S. economy between 1889–1978. The sample values for the U.S. economy were 0.018, 0.036 and –0.14, respectively. The resulting parameter's values were $\mu = 0.018$, $\delta = 0.036$ and $\phi = 0.43$. Given these values, the nature of the test is to search for parameters α and β for which the model's averaged risk-free rate and equity risk premium match those observed for the U.S. economy over this ninety-year period.

The parameter α, which measures peoples' willingness to substitute consumption between successive yearly time periods is an important one in many fields of economics. As mentioned in the text there is a wealth of evidence from various studies that the coefficient of risk aversion α is a small number, certainly less than 10. A number of these studies are documented in Mehra and Prescott (1985). This is an important restriction, for with large α virtually any pair of average equity and risk-free returns can be obtained by making small changes in the process on consumption.

Given the estimated process on consumption, Figure 8 depicts the set of values of the average risk-free rate and equity risk premium which are both consistent with the model and result in average real risk-free rates between zero and four percent. These are values that can be obtained by varying preference parameters α between zero and ten and β between zero and one. The observed real return of 0.80% and equity premium of 6% is clearly inconsistent with the predictions of the model. The largest premium obtainable with the model is 0.35%, which is not close to the observed value.

An advantage of our approach is that we can easily test the sensitivity of our results to such distributional assumptions. With α less than ten, we found that our results were essentially unchanged for very different consumption processes, provided that the mean and variances of growth rates equaled the historically observed values. We use this fact in motivating the discussion in the text.

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CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 923

Exhibits in Support
Of Opening Testimony

June 4, 2010

PGE RISK FACTORS

Included below are two extracts from the Company's SEC Form 10-K filing for the fiscal year ending December 31, 2009. First is Item 1A Risk Factors, followed by a partial extract from Item 7, the Company's MD&A of Financial Condition and Results of Operations.

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that could have a significant impact on PGE's business, financial condition, results of operations or cash flows, or that may cause the Company's actual results to vary from the forward-looking statements contained in this Annual Report on Form 10-K, include, but are not limited to, those set forth below.

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that the OPUC authorizes PGE to charge for its retail services are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. The OPUC has the authority to disallow recovery of any costs that it considers excessive or imprudently incurred. Furthermore, the regulatory process does not provide assurance that PGE will be able to achieve the earnings level authorized. Although the OPUC is required to establish rates that are fair, just and reasonable, it has significant discretion in determining the application of this standard.

In PGE's 2009 General Rate Case, the Company's initial proposal included an overall rate increase of 8.9%, compared to a 7.3% overall increase approved by the OPUC. The Company attempts to manage costs at levels consistent with the reduced rate increase. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the reduced rate increase could adversely affect the Company's operations or results of operations. On February 16, 2010, PGE filed with the OPUC a general rate case with a 2011 test year (2011 General Rate Case). This 2011 General Rate Case seeks to more closely align customer prices with the Company's cost structure. There can be no assurance that the OPUC will approve the rate increase sought by PGE in this case. For additional information regarding the 2011 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operation."

PGE utilizes a PCAM by which the Company can adjust future prices to reflect a portion of the difference between each year's forecasted and actual NVPC. Use of the approved cost sharing methodology requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, application of the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydro availability, and volatile wholesale energy prices. In 2009, PGE's actual NVPC exceeded the baseline NVPC included in prices by $22 million. As this amount was below the threshold for recovery under the PCAM, PGE absorbed these increased costs.

The current economic downturn has reduced the demand for electricity and has impaired the financial soundness of many customers, which has adversely affected PGE's results of operations and could continue to do so.

The economic slow-down has resulted in a rise in Oregon's average unemployment rate to 11.4% for 2009 from 6.4% for 2008 and 5.2% for 2007, compared to the national average unemployment rate of 9.3% for 2009. Oregon's seasonally-adjusted

PGE RISK FACTORS

unemployment rate increased to 10.8% in December 2009 compared to 9% in December 2008. The slowing of the Oregon and national economies has resulted in reduced demand for electricity and could result in a continued reduction in such demand. This reduced demand has adversely affected the Company's results of operations and cash flow and could continue to do so. As a result of the economic slow down, PGE experienced, among other unfavorable trends, the following in 2009:

- A decrease of 9% in energy deliveries to industrial customers from 2008; and
- The sale of electricity, originally intended to meet forecasted retail load requirements, into a depressed wholesale market.

In addition, the Company's uncollectible customer accounts increased in 2009 compared to 2008. If customers are not successful in generating sufficient revenue or are unable to secure financing, they may not be able to pay, or may delay payment of, amounts owed to the Company. The inability of customers to pay the Company could adversely affect the Company's results of operations and cash flow.

Furthermore, as a result of the current economic downturn affecting the economies of the state of Oregon, the United States and other parts of the world, the Company's vendors and service providers could experience serious cash flow problems. As a result, PGE's vendors and service providers may be unable to perform under existing contracts or may significantly increase their prices or reduce their output or performance on future contracts.

The construction of new generating facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in prices, reduced plant efficiency, or higher operating costs.

Long-term increases in both the number of customers and demand for energy will require continued expansion and reinforcement of PGE's generation, transmission, and distribution systems. Construction of new generating facilities, or modifications to existing facilities, could be affected by various factors, including unanticipated delays and cost increases, which could result in the disallowance of certain costs in the rate determination process. In addition, the failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Access to capital markets is important to PGE's ability to operate and to complete its ongoing capital projects, including Biglow Canyon Phase III, the smart meter project, and ongoing upgrades and replacements of transmission, distribution and generation infrastructure. In their normal course of business, credit rating agencies re-examine PGE's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase the interest rates and fees on PGE's revolving credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

PGE RISK FACTORS

In addition, if Moody's Investor Service (Moody's) and/or Standard and Poor's Ratings Services (S&P) reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

Current capital and credit market conditions may adversely affect the Company's access to capital, cost of capital, and ability to execute its business plan as currently scheduled.

Access to capital and credit markets is important to PGE's ability to operate. The Company faces significant capital requirements in 2010 and for the next few years and expects to issue debt and equity securities in order to fund certain major projects. In addition, because of contractual commitments and regulatory requirements, the Company has limited ability to delay or terminate these projects, which include Biglow Canyon Phase III and the smart meter project in 2010. For additional information concerning PGE's capital requirements, see "Capital Requirements" in the Liquidity and Capital Resources section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its business plan as currently scheduled.

Adverse market performance could result in reductions in the fair market value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained depreciation of the fair value of the plans' assets could result in significant increases in funding requirements, adversely affecting PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under the Company's defined benefit pension plan. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the pension plan. Additionally, changes in interest rates affect the Company's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding. During 2008, the value of the pension plan assets declined substantially, contributing to the pension plan's underfunded status of $120 million as of December 31, 2008. During 2009, the value of the pension plan assets appreciated and changes in certain actuarial assumptions resulted in an improvement in the underfunded status of the pension plan to $85 million as of December 31, 2009. As a result, the Company expects to make no contribution to the pension plan in 2010 and a $19 million contribution in 2011, pursuant to the requirements of the federal Pension Protection Act.

Performance of the capital markets also affects the value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans and a Supplemental Executive Retirement Plan. As changes in the value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans. In 2008, PGE recorded a loss on the fair value of these assets of $17

PGE RISK FACTORS

million, which reduced net income by $12 million for the year ended December 31, 2008, while in 2009, PGE recorded a gain of $9 million, which increased net income by $5 million for the year ended December 31, 2009.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see the "Contractual Obligations and Commercial Commitments" table in the Liquidity and Capital Resources section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Pension and Other Postretirement Plans" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements.

Market prices for power and natural gas are subject to forces that are often not predictable and which can result in price volatility, and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, ultimately affecting the Company's liquidity and results of operations.

PGE purchases power and natural gas in the open market or pursuant to short-term, long-term or variable-priced contracts as part of its normal business operations. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in these markets can affect the availability, price and demand for power and natural gas.

Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the market value of derivative instruments and cash requirements to purchase power and natural gas. Although the Company's PCAM can be expected to partially mitigate adverse financial effects related to market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

If power and natural gas prices decline relative to the terms of PGE's existing purchased power and natural gas agreements, PGE may be required to provide increased margin deposits in accordance with these purchased power and natural gas agreements which could adversely affect the Company's liquidity. In the latter half of 2008 and into 2009, as a result of depressed wholesale power and natural gas prices, PGE was required to provide increased levels of margin deposits for its existing purchased power and natural gas agreements.

Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. The Company may not be able to fully recover these increased costs through ratemaking.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company's results of operations, financial condition or cash flows.

From time to time in the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims and other matters, which could result in adverse

PGE RISK FACTORS

judgments, settlements, fines, penalties, injunctions, or other relief. These actions are subject to many uncertainties and management cannot predict the outcome of individual matters with assurance. The final resolution of some of the matters in which PGE is involved could require the Company to make additional expenditures, in excess of established accruals, over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position or results of operations.

There are certain pending legal and regulatory proceedings, such as those related to PGE's recovery of its investment in Trojan, the proceedings related to refunds on wholesale market transactions in the Pacific Northwest and the investigation and any resulting remediation efforts related to the Portland Harbor site, that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements and Item 3.—"Legal Proceedings."

Legislative or regulatory efforts to reduce greenhouse gas emissions could lead to increased capital and operating costs and have an adverse impact on the Company's operations or results of operations.

PGE expects that future federal, and possibly state, legislation or regulations may result in the imposition of limitations on greenhouse gas emissions from the Company's fossil fuel-fired electric generating facilities. Legislation has been introduced in the U.S. Congress that would require greenhouse gas emission reductions from such generating facilities and other sectors of the economy. No such legislation has yet been enacted, although the House of Representatives passed climate legislation in June 2009. Compliance with any greenhouse gas emission reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and/or offsets, fuel switching, and/or retirement of high-emitting generation facilities and replacement with lower emitting generation facilities.

The cost to comply with expected greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to the timing of the implementation of emissions reduction rules, required levels of emissions reductions, requirements with respect to the allocation of emissions allowances, the maturation, regulation and commercialization of carbon capture and sequestration technology, and PGE's compliance alternatives. Accordingly, the Company cannot estimate the effect of any such legislation on its results of operations, financial condition or cash flows; the cost to comply with such requirements, however, could be material. The Company would likely seek to recover such costs through the ratemaking process. However, there can be no assurance that such recovery would be granted.

Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, full recovery is not assured. Inability to fully recover such costs in future rates could have a negative impact on the Company's results of operations. Extended maintenance and

PGE RISK FACTORS

repair outages at Colstrip Unit 4 and Boardman resulted in incremental replacement power costs of $16 million in 2009.

Under certain circumstances, one or more of the banks participating in PGE's credit facilities could decline to fund an advance requested by the Company or could withdraw from participation in the credit facilities.

PGE has revolving credit facilities with various banks for an aggregate amount available to the Company for general corporate purposes of $600 million. These credit facilities supplement operating cash flow and provide a primary source of liquidity. The credit facilities may also be used as backup for commercial paper borrowings. The Company is required to make certain representations to the banks each time it requests an advance under one of the credit facilities.

These credit facilities are commitments on the part of the banks to make loans and, in certain cases, to issue letters of credit. However, in the event of the occurrence of certain events that could result in a material adverse change in the business, financial condition or results of operations of PGE, the Company may not be able to make certain representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facilities.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for an advance, which could cause the representation to be untrue at the time made and constitute an event of default. Such a circumstance could result in a loss of the banks' commitments under the credit facilities and, in certain circumstances, an acceleration of repayment of any outstanding advance.

Weather conditions that reduce stream flows, or unfavorable wind conditions, could adversely affect generation expected from PGE's hydro and wind resources and increase the Company's cost of generation or purchased power required to meet this energy gap.

PGE derives a portion of its power supply from its hydroelectric facilities and from hydroelectric facilities owned by certain public utility districts in the state of Washington and the City of Portland, with whom the Company has long-term power purchase contracts. Regional rainfall and snow pack levels affect stream flows and the resulting amount of generation available from these facilities. Shortfalls in low-cost hydro production would require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market, which could have an adverse effect on operating results.

PGE also derives a portion of its power supply from wind resources, output from which is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's other generating resources or purchased power from the wholesale market, both of which would have an adverse effect on operating results.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future rates could have a negative impact on the Company's results of operations.

PGE RISK FACTORS

The effects of weather on electricity usage can adversely affect operating results.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's financial and operating results. Temperatures outside the normal range can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing energy sales and revenues. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company's transmission and distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Measures required to comply with state and federal regulations related to emissions from thermal electric generating plants could result in increased capital expenditures and changes to PGE's operations that could increase operating costs, reduce generating capacity and adversely affect the Company's results of operations.

In June 2009, the OEQC adopted a rule as part of a separate regulatory process related to haze, mercury, and the Company's air permits that would require the installation of emissions controls at Boardman in three phases. The OEQC's rule has been submitted to the EPA for approval as part of the SIP. The Company expects the EPA to issue a decision on the SIP in 2010. For additional information, see "Environmental Matters" in Item 1.—"Business."

Although the full impact of required state and federal remediation measures is not yet determinable, they could have an adverse effect on future operations, operating costs, and generating capacity at both Boardman and Colstrip. The Company would seek to recover through the ratemaking process any costs of additional emission control equipment or emission reduction measures that may be required. However, there can be no assurance that such recovery would be granted.

In addition, PGE could be subject to litigation brought by environmental groups and other private parties alleging violations of state or federal law and seeking the imposition of penalties, damages, injunctive relief, and the closure of plants. For additional information, see Sierra Club et al. v. Portland General Electric Company in Item 3.—"Legal Proceedings."

Failure of PGE's wholesale suppliers to perform their contractual obligations could adversely affect the Company's ability to deliver electricity and increase the Company's costs.

PGE relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with such contracts in a timely manner could disrupt PGE's ability to deliver electricity and require the Company to incur additional expenses to meet the needs of its customers. In addition, as these contracts expire, PGE could be unable to continue to purchase natural gas, coal or electricity on terms and conditions equivalent to those of existing agreements. Cost and availability of natural gas and coal can also impact the cost and output of the Company's thermal generating plants.

PGE RISK FACTORS

Capital expenditures and changes in operations required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

A portion of PGE's total energy requirement is comprised of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, and Willamette rivers. Operation of these projects is subject to extensive regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the amount of hydro generation available to meet the Company's energy requirements. The Company would likely seek recovery of any such expenditures through the ratemaking process; however, there can be no assurance that such recovery would be granted.

Storms and other natural disasters could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

The Company has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

To the extent reasonably possible, PGE utilizes insurance to cost effectively mitigate the risk of physical loss or damage to the Company's property, excluding transmission and distribution property, resulting from natural disasters, subject to certain coverage terms and conditions. The Company would likely seek recovery of large storm-related losses to transmission and distribution property through the ratemaking process; however, there can be no assurance that any recovery would be granted. If such recovery is not granted, these increased costs could have an adverse effect on PGE's results of operations.

PGE's business is subject to extensive regulation that affects the Company's operations and costs.

PGE is subject to regulation by the FERC and the OPUC, and by federal, state and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and affects many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's business. However, changes in these regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

PGE has an aging workforce with a significant number of employees approaching retirement age.

PGE RISK FACTORS

The Company anticipates higher averages of retirement rates over the next ten years and will likely need to replace a significant number of employees in key positions. PGE's ability to successfully implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company would face greater challenges in providing quality service to its customers and meeting regulatory requirements, both of which could affect operating results.

Conditions that may be imposed in connection with the renewal of hydroelectric licenses could require large capital expenditures.

PGE is currently involved in renewing the federal license for its hydroelectric projects on the Clackamas River. The FERC, under the Federal Power Act, may impose conditions with respect to environmental, operating and other matters in connection with the renewal of PGE's license. The Company cannot predict with certainty the requirements that might be imposed during the relicensing process, the economic impact of those requirements, whether a new license will ultimately be issued or whether PGE will be willing to meet the relicensing requirements to continue operating its Clackamas hydroelectric projects. The Company would likely seek recovery of any additional costs related to such licensing requirements through the ratemaking process.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Information Regarding Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements relate to expectations, beliefs, plans, objectives for future operations, assumptions, business prospects, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events, liquidity or performance, and other matters. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs, projections and forecasts are expressed in good faith and are believed by PGE to have a reasonable basis, including, but not limited to, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. There can be no assurance that PGE's expectations, beliefs or projections and forecasts will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;

PGE RISK FACTORS

- the continuing effects of the economic downturn in the state of Oregon, the United States and other parts of the world, including reductions in demand for electricity, sale of excess energy during periods of low wholesale market prices, impaired financial soundness of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues, including, but not limited to, the proceedings related to the Trojan Investment Recovery, the Pacific Northwest Refund proceeding, the Portland Harbor investigation, and other matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K;
- operational factors affecting PGE's power generation facilities, including forced outages, hydro conditions, wind conditions, and disruption of fuel supply, which may result in repair costs as well as higher costs for replacement power;
- unanticipated delays and cost increases in connection with the construction or modification of generating facilities and other capital projects, which could result in the disallowance of certain costs pursuant to the rate determination process;
- capital market conditions, including interest rate volatility and reductions in demand for investment-grade bonds or commercial paper, as well as changes in PGE's credit ratings, which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction costs, and the repayments of maturing debt;
- declines in the market prices of assets held by defined benefit pension plans and other benefit plans and decreases in the discount rate associated with plan liabilities that may result in increased funding requirements for such plans;
- wholesale prices for natural gas, coal, oil and other fuels and their impact on the availability and price of wholesale power in the western United States;
- declines in wholesale power and natural gas prices or reductions in PGE's credit rating below investment grade, which would require the Company to post additional collateral, in the form of either letters of credit or cash, to counterparties pursuant to existing power and natural gas purchase agreements;
- changes in residential, commercial, and industrial growth and demographic patterns in PGE's service territory;
- future laws, regulations, and proceedings that could increase the Company's costs or affect the operations of the Company's thermal generating plants by imposing requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;
- unseasonable or extreme weather and other natural phenomena, which, in addition to affecting customer demand for power, could significantly affect PGE's ability and cost to procure adequate supplies of fuel or power to serve its customers, and could increase the costs to maintain the Company's generating facilities and transmission and distribution system;
- the effectiveness of PGE's risk management policies concerning the creditworthiness of its customers and counterparties;
- the effects of Oregon law related to utility rate treatment of income taxes, which may result in earnings volatility and adversely affect PGE's results of operations;
- the outcome of efforts to relicense the Company's Clackamas River hydroelectric projects, as required by the FERC;

PGE RISK FACTORS

- changes in, and compliance with, laws and policies concerning endangered species or protection of the environment;
- the effects of climate change, including effects on energy costs and consumption, as well as effects on the Company's operations and expenses;
- new federal, state, and local laws that could have adverse effects on operating results;
- employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;
- general political, economic, and financial market conditions;
- natural disasters and similar risks, such as earthquake, flood, drought, lightning, wind, and fire;
- acts of war or terrorism; and
- financial or regulatory accounting principles or policies imposed by governing bodies.

CASE: UE 215
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 924

Exhibits in Support
Of Opening Testimony

June 4, 2010

May 25, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated May 12, 2010
Question No. 391

Request:

Risks faced by PGE are discussed in Exhibits PGE/1100 Hager – Valach/26-30 and PGE/1200 Zepp/11 – 19, including the statement that "…PGE is more risky than the sample I use to determine the benchmark cost of equity estimates" at Exhibit PGE/1200 Zepp/1 lines 12 - 13. Please discuss any risk in each of the 31 comparable (to PGE) companies (other than PGE, itself) that either does not exist for PGE or exists to a lesser degree for PGE. The discussion should include, but not be limited to each of the following, for each comparable company individually in comparison with PGE:

a. **Reliance, as a percent of total system load, on owned generation facilities using nuclear fuels;**
b. **Reliance, as a percent of total system load, on owned generation facilities fueled by coal;**
c. **Reliance, as a percent of total system load, on owned generation facilities fueled by fossil fuels other than coal;**
d. **Projected growth, on a percentage basis, in numbers of total customers;**
e. **Projected growth, on a percentage basis, in residential customers;**
f. **Projected growth, on a percentage basis, in commercial customers;**
g. **Projected growth, on a percentage basis, in industrial customers;**
h. **Percentage reduction in and the annual amounts of electricity delivered to industrial customers: 2009 versus 2007;**
i. **Quantitative degree to which additions to owned electricity generation capacities are incorporated into rates on an annual, "streamlined," single issue rate case basis versus PGE's Renewable Resources Automatic Adjustment Clause (Schedule 122);**
j. **Percent of residential customers across all jurisdictional service areas currently covered by one or more decoupling mechanisms; and**

k. Capital expenditure programs, expressed both in dollar terms and as a percentage of existing rate base, relative to the same metrics and in the same timeframe, for PGE.

Response:

Dr. Zepp clearly states the risks he considered in forming his opinion that PGE requires a risk premium of 20 basis points above the cost of equity for his benchmark sample. Those risks include the ones discussed by Mr. Hager and Mr. Valach in PGE Exhibit 1100, risks previously determined by the Oregon Commission, and the risks summarized in PGE Exhibit 1200, pages 7-8. Dr. Zepp fully explains the risks he considered in PGE Exhibit 1200, pages 11-19.

a. In this case, Dr. Zepp did not do a literature search or conduct a study of the impact on risk of having generation facilities using nuclear fuels. It would require a special study to examine whether generation facilities using nuclear fuels increase or decreases risk and, thus the question is beyond the scope of Dr. Zepp's analysis.

b. In this case, Dr. Zepp did not do a literature search or conduct a study of the impact on risk of having generation facilities using coal. It would require a special study to examine whether generation facilities using coal increases or decreases risk and thus the question is beyond the scope of Dr. Zepp's analysis.

c. In this case, Dr. Zepp did not do a literature search or conduct a study of the impact on risk of having generation facilities using fossil fuels other than coal. It would require a special study to examine whether generation facilities using fossil fuels other than coal increase or decreases risk and thus the question is beyond the scope of Dr. Zepp's analysis.

d. In this case, Dr. Zepp did not conduct a study of projected growth in the number of total customers for the electric utilities in his benchmark sample. It would require a special study to gather that information and thus it is beyond the scope of his analysis.

e. In this case, Dr. Zepp did not conduct a study of projected growth in the number of residential customers for the electric utilities in his benchmark sample. It would require a special study to gather that information and thus it is beyond the scope of his analysis.

f. In this case, Dr. Zepp did not conduct a study of projected growth in the number of commercial customers for the electric utilities in his benchmark sample. It would require a special study to gather that information and thus it is beyond the scope of his analysis.

g. In this case, Dr. Zepp did not conduct a study of projected growth in the number of industrial customers for the electric utilities in his benchmark sample. It would require a special study to gather that information and thus it is beyond the scope of his analysis.

h. Dr. Zepp is not aware of whether the deliveries of power to the industrial customers served by the various utilities in his sample increased or decreased between 2007 and 2009. A response to this question would require a new special study and thus is beyond the scope of Dr. Zepp's testimony.

i. Dr. Zepp did not conduct a study of the quantitative degree to which additions to owned electricity generation capacities are incorporated into rates on an annual, "streamlined," single issue rate case basis versus PGE's Renewable Resources and thus this question is beyond the scope of his analysis. A response to this question would require a new special study and thus is beyond the scope of Dr. Zepp's testimony.

j. Dr. Zepp did not collect data on the percentage of residential customers covered by decoupling mechanisms and thus this question is beyond the scope of his analysis. A response to this question would require a new special study and thus is beyond the scope of Dr. Zepp's testimony.

k. Dr. Zepp did not collect data related to the capital expenditure programs of the utilities in his benchmark sample. As discussed in PGE Exhibit 1200, page 15, Dr. Zepp focused on PGE's past and forecasted capital expenditure programs to determine if PGE has higher or lower risk today compared to the past. A response to this question would require a new special study and thus is beyond the scope of his testimony.

CASE: UE 215
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Jorge Ordonez. I am employed by the Oregon Public Utility Commission (OPUC) as the Senior Financial Economist in the Economic and Policy Analysis Section. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualifications Statement is found in Exhibit Staff/1001, Ordonez /1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the cost of long-term debt and the marginal cost study for Portland General Electric Company ("PGE" or "Company").

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I have prepared Staff Exhibit/1001 consisting of one page, Staff Exhibit/1002 consisting of eight pages and Staff Exhibit/1003 consisting of three pages.

SUMMARY RECOMMENDATION

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. For this testimony, the recommended cost of debt is 6.075%. However, Staff intends to update PGE's cost of long-term debt based on the actual coupon rate and issuance net proceeds of the First Mortgage Bonds (FMBs) that PGE anticipates issuing on July 15, 2010. Accordingly, Staff may present an updated recommendation in its rebuttal testimony.

With one exception, which I discuss later in this testimony, I recommend that the Commission conclude that PGE's marginal cost study is reasonable. However, this position should not be seen as setting a precedent for future rate cases, in which Staff may review specific parts of the study and may propose changes based on contemporaneous facts, methodologies and trends. Additionally, as noted by the Commission in Order No. 98-374 of Docket No. UM 827, calculating the marginal cost is as much an art as it is a science.[1]

EMBEDDED COST OF LONG-TERM DEBT

Q. WHAT IS LONG-TERM DEBT?

A. The Commission has historically defined long-term debt as debt with a maturity of more than one year.

Q. WHAT IS PGE'S PROPOSED COST OF LONG-TERM DEBT?

A. In Exhibit PGE/1101 Hager-Valach/1, PGE proposes an embedded cost of long-term debt of 6.077% as of December 31, 2011.

Q. HOW DID PGE ARRIVE AT THE 6.077% FIGURE?

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[1] Page 12 of Order No. 98-374 of Docket No. UM 827: "We will not require a single marginal cost approach for all utilities. Calculating marginal costs is a much of an art as it is a science. Allowing utilities to address the issue of calculating marginal costs in different ways has led to significant and productive new approaches to efficient pricing and costing of electrical service. We do not believe that mandating a single approach will advance the art of marginal cost analysis, and it could significantly impede progress. Furthermore, utilities should be allowed to choose approaches that best fit the particular circumstances of their systems and nature of their customers. We do not believe that we are capable of identifying a single approach that will satisfy the needs of every utility and its respective customers."

A. PGE calculated the cost of long-term debt based on each debt series' coupon rate[2] and issuance net proceeds[3] to produce a yield to maturity.[4] In the event that a bond was issued to refinance a higher-cost bond, the pre-tax premium and any unamortized cost associated with the refinancing were subtracted from the gross proceeds of the issued bonds. The embedded cost or yield to maturity for each debt series was then multiplied by the face amount weight[5] of each debt issue relative to the total face amount of issued debt. The sum of the embedded cost multiplied by the face amount weight for all debt issuances represents the embedded cost of debt.

In addition to all existing long-term securities, PGE included the following three *pro forma* series of securities that the Company anticipates issuing in 2010: the 5.1% coupon of $97.8 million Pollution Control Revenue Bonds[6] (PCRBs), the 5% coupon of $23.6 million PCRBs[7] and the 4% coupon of $58.6 million FMBs.[8]

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[2] *See* Exhibit PGE/1101 Hager-Valach/1, column H.

[3] *See* Exhibit PGE/1101 Hager-Valach/1, column L.

[4] *See* Exhibit PGE/1101 Hager-Valach/1, column M.

[5] *See* Exhibit PGE/1101 Hager-Valach/1, column Q.

[6] *See* Exhibit PGE/1101 Hager-Valach/1, row 18.

[7] *See* Exhibit PGE/1101 Hager-Valach/1, row 19.

[8] *See* Exhibit PGE/1101 Hager-Valach/1, row 20.

PGE estimated the coupon rates of PCRBs based on a new issue pricing analysis provided by Wells Fargo Securities specifically addressing PGE's prospective remarketing of these securities.[9]

PGE estimated the 4% coupon of $58.6 million FMBs by adjusting an indicated yield provided by an investment bank to reflect the issuance of a seven-year maturity.[10]

Q. DOES STAFF HAVE ANY COMMENT ABOUT PGE'S CALCULATION OF ITS COST OF LONG-TERM DEBT?

A. Yes. Staff would like to point out that the Commission has traditionally used the date when rates become effective as the triggering date for determining long-term debt[11] (in this case, December 31, 2010[12]). However, PGE calculated its cost of long-term debt as of December 31, 2011.[13]

Q. IS THERE ANY MATERIAL DIFFERENCE IN CALCULATING PGE'S COST OF LONG-TERM DEBT AS OF DECEMBER 31, 2011 INSTEAD OF DECEMBER 31, 2010?

A. Not in this rate case, because PGE does not plan to issue long-term debt in the period between January 1 and December 31, 2011.

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9 *See* PGE's response to Staff Data Request OPUC 96 in Exhibit Staff/1002, Ordonez/1.

10 *See* PGE's confidential response to Staff Data Request OPUC 92.

11 *See* Order No. 01-787, in Docket No. UE 116, page 16, "Date for Determining Cost of Long-Term Debt."

12 In its initial filing, PGE requests that tariff changes be effective January 1, 2011.

13 *See* the header of Exhibit PGE/1101 Hager-Valach/1.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PGE'S EMBEDDED COST OF LONG-TERM DEBT?

A. I recommend an embedded cost of long-term debt of 6.071%,[14] based on PGE's responses to Staff Data Requests 294 and 295.[15]

Q. WHAT ADJUSTMENTS DID PGE MAKE TO ITS INITIAL FILING IN RESPONDING TO STAFF DATA REQUESTS 294 AND 295?

A. PGE adjusted its cost of long-term debt upward from the original application to reflect an additional discount from the face value at issuance of its $300 million FMBs issued on April 13, 2009. PGE inadvertently omitted the additional discount from PGE's customary report of securities issued filed with the Commission on August 27, 2009, but amended this report on March 11, 2010.[16] PGE also adjusted its cost of long-term debt downward to reflect actual coupon rates and expenses incurred in issuing two PCRB series of securities on March 11, 2010 as updated in PGE's responses to Staff Data Requests 294 and 295.

Q. DOES STAFF INTEND TO UPDATE THE COST OF LONG-TERM DEBT?

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[14] *See* Exhibit Staff/1002, Ordonez/6.

[15] *See* Exhibit Staff/1002, Ordonez/2-7.

[16] *See* Exhibit Staff/1002, Ordonez/8.

A. Yes. For Staff's surrebuttal testimony, I intend to update PGE's cost of long-term debt based on the actual coupon rate and issuance net proceeds of the $58.6 million FMBs that PGE anticipates issuing on July 15, 2010.[17]

PGE MARGINAL COST STUDY

Q. DID PGE PROVIDE A MARGINAL COST STUDY AS SUPPORT FOR THE COMPANY'S RATE SPREAD AND RATE DESIGN?

A. Yes. PGE provided cost studies in support of the allocation of the revenue requirement for each schedule or rate class covering the functions of production, transmission, ancillary services, distribution, metering, billing and other consumer costs.[18]

Q. DO YOU HAVE ANY COMMENTS ON PGE'S COSTS OF SPECIFIC FUNCTIONS?

A. Yes. I would like to comment on the cost approaches that support the allocation of production costs.

Q. HOW DID PGE ESTIMATE THE MARGINAL COST OF PRODUCTION?[19]

A. PGE used a long-run incremental cost methodology that takes into account the costs of marginal demand and marginal energy. This methodology is consistent with the one proposed by the Company in Docket No. UM-1415.[20]

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[17] In the likely event that some actual expense information is unavailable for inclusion in testimony, I will estimate values for any unavailable expenses based on recent debt issuance experience, noting where I have done so.

[18] *See* Exhibit PGE/1504 Kuns-Cody/1.

[19] Production costs are also referred to as generation costs.

Q. PLEASE CONTINUE YOUR EXPLANATION, FOCUSING FIRST ON PGE'S MARGINAL DEMAND COSTS.

A. PGE estimated the marginal *capacity* cost as the fixed cost, including O&M, of the Simple Cycle Combustion Turbine (SCCT).[21]

PGE then added the fixed gas transport cost plus 12% of reserve requirements, arriving at a cost of $191.18/kW-yr.[22]

Q. **DO YOU AGREE WITH PGE'S ESTIMATED MARGINAL DEMAND COSTS?**

A. I accept the estimated gas transport cost and 12% reserve additions, but I believe PGE's fixed SCCT costs are overstated in the context of identifying the marginal costs of demand.

Q. **PLEASE EXPLAIN WHY THE GENERATION DEMAND COSTS MAY BE OVERSTATED.**

A. The available SCCTs have different front-end capital costs that vary directly with each respective technology's fuel efficiency. The technology projected in PGE's Integrated Resource Plan (IRP), and which is the basis of PGE's marginal capacity cost estimate, is more fuel-efficient than other available SCCT technologies. For example, PacifiCorp uses a technology with projected

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[20] As a result of Docket No. UE 197 (PGE's most recently concluded general rate case), the Commission opened Docket No. UM 1415 to address issues of cost allocation, rate spread and rate design, leading to the filing of revised tariff sheets by PGE in its next general rate proceeding.

[21] *See* Exhibit PGE/1500 Kuns-Cody/9, lines 3-4.

[22] *See* Exhibit PGE/1504 Kuns-Cody/6.

long-run marginal fixed costs of only $79.88/kW-yr.[23] It is Staff's position that SCCT fixed costs *beyond* the minimum required to achieve a given level of peak *demand* should be classified as "energy" rather than "demand" costs. In that spirit, substituting the PacifiCorp figure for the $134.36/kW used by PGE yields a final generation demand cost estimate of $130.17/kW-yr. Dr. George Compton of the OPUC Staff uses this latter figure in formulating his rate spread recommendations in Exhibit Staff/1100.

Q. PLEASE CONTINUE YOUR EXPLANATION, NOW FOCUSING ON PGE'S MARGINAL ENERGY COST.

A. PGE's estimated marginal energy cost is a combination of new gas and wind renewable resources. This results in an attribution of 58% of the marginal energy cost to the energy cost of a CCCT (excluding the fixed cost of the SCCT) and 42% to the energy cost of a generic wind farm.[24, 25]

Q. PLEASE EXPLAIN HOW PGE ESTIMATED THE ENERGY COSTS FOR THE GAS RESOURCES.

A. PGE arrived at the annual energy cost for gas resources by summing the fuel, variable O&M, CO_2 compliance and other fixed costs from 2011 through 2030, and expressing those costs in 2011 values.[26]

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23 *See* Docket 217 Exhibit PP&L 1607, tab 2.3.

24 *See* confidential work paper file: "HourlyMCenergy-GRC11_CONF."

25 *See* PGE's response to Staff Data Request 320 in Exhibit Staff/1003, Ordonez/1.

26 *See* confidential work paper file: "LRMC_GRC11_CONF."

Q. PLEASE EXPLAIN HOW PGE ESTIMATED THE ENERGY COSTS FOR THE WIND RENEWABLE RESOURCES.

A. PGE estimated the cost for the wind renewable resources at $93.62/MWh in real levelized 2011 dollars. Additionally, PGE removed the wheeling portion of the estimated costs because it is including two transmission line projects, resulting in an $85.69/MWh cost of wind renewable resources.[27, 28]

Q. DID STAFF ADDRESS ISSUES RELATED TO PGE'S GENERATION COSTS IN PGE'S MOST RECENTLY CONCLUDED GENERAL RATE CASE?

A. Yes. In Docket UE 197, Staff recommended that PGE rely less on wholesale market prices in its production cost estimates.[29] Additionally, Staff indicated that it seems reasonable to use potential new electrical generating plants as the basis for capacity and energy costs instead of relying exclusively on wholesale market energy prices.[30]

Q. HAS PGE ADOPTED STAFF'S RECOMMENDATION OF UE 197 IN THIS DOCKET?

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[27] *See* Exhibit PGE/1500 Kuns-Cody/11, line 1-2.

[28] *See* PGE's responses to Staff Data Requests 322 and 324 in Exhibit Staff/1003, Ordonez/2-3.

[29] *See* Exhibit Staff/600 Storm/3 in Docket UE 197

[30] *See* Exhibit Staff/600 Storm/6-7 in Docket UE 197

A. Yes. As described above, in the current proceeding, PGE is proposing a long-run generation methodology for estimating the Company's marginal capacity cost and marginal energy cost.[31]

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT THE COMPANY'S MARGINAL COST STUDY?

A. With the exception noted above, yes. I find PGE's marginal cost study reasonable.

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[31] *See* Exhibit PGE/1500 Kuns-Cody/8, lines 12-18.

CASE: UE 215
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Financial Economist, Economic and Policy Analysis Section
ADDRESS	550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2115
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008 Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007 Fulbright Scholar, MBA, concentration in finance Willamette University, Oregon, 2005 Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002 BS, Mechanical Engineering, energy and thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist in the Economic Research and Financial Analysis Division, evaluating utilities' financial applications, cost of capital and marginal cost studies.

CASE: UE 215
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

June 4, 2010

March 8, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated February 22, 2010
Question No. 096

Request:

Regarding PGE Exhibit / 1101, Hager – Valach / 1, lines 18 and 19, column (h), coupon rates of 5.10% and 5.00% for "Clstrp 98A Fixed" and "Brdmn 98A Fixed," respectively, please explain the underlying assumptions made by PGE to arrive at these coupon rates.

Response:

The coupon rate estimates of 5.1% and 5.0% were based on a new issue pricing analysis performed by Wells Fargo Securities specifically addressing PGE's prospective remarketing of these two issues. That analysis was provided as a file titled "Market Update Pricing 01.08.2010 - Wells Fargo.pdf" in the confidential work papers accompanying PGE Exhibit 1100.

As stated in PGE's testimony in PGE Exhibit 1100, the estimates related to planned bond issuances will be updated as new information becomes available; an updated cost of long-term debt analysis will be provided for this proceeding as well.

April 21, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated April 6, 2010
Question No. 294

Request:

Has the Company issued any of the securities listed in Exhibit / 1101, Hager – Valach / 1, lines 18-20, as of the time of receiving this set of data requests?

Response:

Yes. On March 11, 2010, PGE completed the remarketing of two series of Pollution Control Bonds totaling $121.4 million (lines 18 and 19 of PGE Exhibit 1101). PGE filed the customary Report of Securities for these remarketings with the OPUC on April 19, 2010, in docket UF 4158.

April 21, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated April 6, 2010
Question No. 295

Request:

If the answer of the preceding data request is "yes" please:

a. **Update the cost of long-term debt provided in Exhibit / 1101, Hager – Valach / 1.**
b. **Provide the customary report of security issuances with Public Utility Commission of Oregon.**
c. **Provide the expense breakdown, which should include, but not be limited to, items such as premium or discount, underwriting discount, trustee fees, legal fees, SEC filing fees, auditor/accountant fees, printing and engraving expenses, rating agencies' expenses, cost of credit enhancements, cost of letter of credit (for tax exempt securities), etc.**

Response:

a. Please see Attachment 295-A for PGE's updated cost of long-term debt estimate for the 2011 test year. This attachment updates PGE Exhibit 1101 to incorporate the actual remarketing expenses, issuance dates, and coupon rates for the two series of Pollution Control Bonds (PCBs) on lines 18 and 19 of the exhibit, as well as the actual issuance expenses for the 3.460% Series on line 17. These updates from estimates to actuals result in a reduction of approximately 0.008% (6.077% - 6.069%) to PGE's overall effective long-term debt cost, relative to that presented in PGE Exhibit 1101.

Also included in this update is a correction to the reported issuance expense for the 6.100% Series bond on line 15. As stated in PGE's response to OPUC Data Request No. 021, the original Report of Securities filed on August 27, 2009 and PGE Exhibit

1101 did not reflect the fact that this Series was issued at a $222,000 discount to par. In this update, the discount was added to the "DD&E Issue Costs" (Column J), which increases the "Embedded Cost" (Column M) of this Series by approximately 1 basis point (0.01%), relative to that presented in PGE Exhibit 1101. PGE filed a revised Report of Securities with the OPUC in docket UF 4257 on March 10, 2010.

The updates discussed above result in a reduction of approximately 0.006% (6.077% - 6.071%) to PGE's overall effective cost of long-term debt, relative to that presented in PGE Exhibit 1101.

b. The Report of Securities for the remarketing of the PCBs referenced in part "a" of this response was filed with the OPUC in docket UF 4158 on April 19, 2010 and is also provided as Attachment 295-B.

   Attachment 295-B is confidential and subject to Protective Order No. 10-056.

c. A breakdown of the issuance expenses is included in the Report of Securities discussed in part "b" of this response and provided as Attachment 295-B.

UE 215
Attachment 295-A

PGE Updated Cost of Long-term Debt
2011 Test Year

Cost of Long-Term Debt
December 31, 2011
Updated April 16, 2010

(A)	Ledger (B)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)	Call Premium & Unamort. DD&E of Refunded Issue (K)	F/N	Net Proceeds (L) [I - J - K]	Embedded Cost (M)	Net to Gross Rate (N) [L/I]	Face Amount Outstanding (O)	Net Outstanding (P) [N * O]	Face Amount Weight (Q) [O / Total]	Weighted Rate (R) [Q * M]
1	G11501	Series MTN	9.310% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	1.105%	0.104%
2	G21195	PCB	Trojan 90A Fixed	1-Jul-98	1-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	1	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.531%	0.029%
3	G11514	FMB	5.6675% Series	28-Oct-02	25-Oct-12	10	5.245%	$100,000,000	$11,305,461	$0		$88,694,539	6.823%	88.695%	$100,000,000	$88,694,539	5.526%	0.377%
4	G11516	Series VI MTN	5.625% Series	4-Aug-03	1-Aug-13	10	5.398%	$50,000,000	$408,842	$1,946,809	2	$47,644,349	6.032%	95.289%	$50,000,000	$47,644,349	2.763%	0.167%
5	G11517	Series VI MTN	6.750% Series	4-Aug-03	1-Aug-23	20	6.523%	$50,000,000	$521,342	$1,946,809	2	$47,531,849	6.985%	95.064%	$50,000,000	$47,531,849	2.763%	0.193%
6	G11518	Series VI MTN	6.875% Series	4-Aug-03	1-Aug-33	30	6.648%	$50,000,000	$521,342	$1,946,809	2	$47,531,849	7.046%	95.064%	$50,000,000	$47,531,849	2.763%	0.195%
7	G11521	FMB	6.310% Series	26-May-06	1-May-36	30	6.310%	$175,000,000	$1,270,865	$6,199,472	3	$167,529,663	6.640%	95.731%	$175,000,000	$167,529,663	9.671%	0.642%
8	G11519	FMB	6.260% Series	26-May-06	1-May-31	25	6.260%	$100,000,000	$723,857	$4,132,982	3	$95,143,161	6.662%	95.143%	$100,000,000	$95,143,161	5.526%	0.368%
9	G11522	FMB	5.800% Series	16-May-07	1-Jun-39	32	5.800%	$170,000,000	$1,447,420	$50,969	4	$168,501,611	5.861%	99.119%	$170,000,000	$168,501,611	9.394%	0.551%
10	G11523	FMB	5.810% Series	19-Sep-07	1-Oct-37	30	5.810%	$130,000,000	$1,627,092	$0		$128,372,908	5.899%	98.748%	$130,000,000	$128,372,908	7.184%	0.424%
11	G11524	FMB	5.800% Series	12-Dec-07	1-Mar-18	10	5.800%	$75,000,000	$637,500	$0		$74,362,500	5.912%	99.150%	$75,000,000	$74,362,500	4.145%	0.245%
12	G11525	FMB	4.450% Series	15-Apr-08	1-Apr-13	5	4.450%	$50,000,000	$915,100	$1,990,993	5	$47,093,907	5.806%	94.188%	$50,000,000	$47,093,907	2.763%	0.160%
13	G11526	FMB	6.500% Series	15-Jan-09	15-Jan-14	5	6.500%	$63,000,000	$412,020	$0		$62,587,980	6.656%	99.346%	$63,000,000	$62,587,980	3.481%	0.232%
14	G11526	FMB	6.800% Series	15-Jan-09	15-Jan-16	7	6.800%	$67,000,000	$438,180	$0		$66,561,820	6.919%	99.346%	$67,000,000	$66,561,820	3.702%	0.256%
15	G11527	FMB	6.100% Series	13-Apr-09	15-Apr-19	10	6.100%	$300,000,000	$2,608,223	$0	6	$297,391,777	6.218%	99.131%	$300,000,000	$297,391,777	16.578%	1.031%
16	G11528	FMB	5.430% Series	3-Nov-09	3-May-40	30.5	5.430%	$150,000,000	$1,034,283	$0		$148,965,717	5.477%	99.310%	$150,000,000	$148,965,717	8.289%	0.454%
17	G11529	FMB	3.460% Series	15-Jan-10	15-Jan-15	5	3.460%	$70,000,000	$473,458	$0	7	$69,526,542	3.609%	99.324%	$70,000,000	$69,526,542	3.868%	0.140%
18	G211851	PCB	Clstrp 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$97,800,000	$688,885	$1,521,911	8	$95,589,204	5.168%	97.739%	$97,800,000	$95,589,204	5.405%	0.279%
19	G211861	PCB	Brdmn 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$23,600,000	$166,234	$912,065	8	$22,521,701	5.346%	95.431%	$23,600,000	$22,521,701	1.304%	0.070%
20	N/A	FMB	4.000% Series	15-Jul-10	15-Jul-17	7	4.000%	$58,600,000	$439,500	$0		$58,160,500	4.124%	99.250%	$58,600,000	$58,160,500	3.238%	0.134%
			Annual expense from loss on reacquired debt							$391,732		($391,732)						
			Totals					$1,809,600,000	$25,919,952	$21,225,531		$1,762,454,517			$1,809,600,000	$1,762,846,249	100.00%	6.050%
			Cost of LT Debt (Includes annual expense from loss on reacquired debt)															6.071%

	Losses on Reacquired Debt	Issue Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense
Y61181	13.50% FMB Due 10/1/12	19-Oct-82	25-Apr-88	$75,000,000	$8,989,952	$374,581
G21184	5.450% Colstrip 98B Fixed PCB due 04/30/33	1-May-03	1-May-09	$21,000,000	$411,622	$17,151
						$391,732

Footnote

1 On 7/1/98, the Trojan variable rates were fixed, although not extended.

2 $5.8 million in call premia resulting from acquisition of 9.46% and 7.75% issues was allocated evenly among August 2003 issues (see UE 180, PGE Exhibit 1400, page 3).

3 There was a $12 million call premium on the 8.125% redeemed issue. A portion was disallowed in UE 180. The remainder is rolled into the new debt and will be paid over the period of the May 2006 issuances.

4 $5.1 million Trojan 1990B PCBs redeemed early in June 2007. Unamortized loss of $50,969 was added to the 5.80% series $170MM issued in May 2007 used to redeem the PCBs.

5 In February 2008, PGE repurchased the 5.279% issue due 04/01/2013. The issue was subsequentally reissued on 04/15/2008 at 4.45% for a period of 5 years (due on original maturity date of 04/01/2013).

6 "DD&E Issue Costs" (column J) was updated to reflect $222,000 discount to par at issuance.

7 "DD&E Issue Costs" (column J) was updated to reflect actual issuance expenses.

8 PCB Issues put-back to PGE in May 2009. PGE re-marketed in March 2010 (due on original maturity date of 05/01/2033). "Coupon" (column H) and "DD&E Issue Costs" (column J) were updated to reflect actuals.

UE 215
Attachment 295-B

Confidential and Subject to Protective Order No. 10-056

Report of Securities filed in docket UF 4158 for
$121.4 million PCB remarketing

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

RECEIVED
2010 MAR 11 A 10:23
P.U.C.

March 10, 2010

Via E-Filing and US Mail

Oregon Public Utility Commission
550 Capitol Street NE, Ste. 215
Salem, OR 97308-2148

RE: **UF-4257 - PGE Finance Application**

Attention: ***Commission Filing Center***

In accordance with Condition No. 4 of Commission Order No. 09-089, dated March 16, 2009, enclosed is the following:

1) *Revised* report of securities and disposition of net proceeds for $300 million First Mortgage Bonds (6.10% Series) due April 15, 2019.

PGE inadvertently excluded the issuance discount in its original filing on August 27, 2009. This document correctly reflects the net proceeds for the $300 million of debt issued in April 2009.

This document is confidential and subject to treatment prescribed under OAR 860-011-0080 (Confidential Information). This item is provided on yellow paper and placed in a separately sealed envelope bearing the legend "CONFIDENTIAL." Additionally, please do not release this information to anyone outside the Public Utility Commission Staff and please store this information in a locked file cabinet. Electronics for the attachment have been provided and should not be placed on the OPUC Website. If you are unable to honor this request, please notify us immediately.

If you have any questions, please feel free to contact me at (503) 464-7580 or Kim Gilman at (503) 464-7802.

Sincerely,

Patrick G. Hager

Patrick G. Hager
Manager, Regulatory Affairs

Encls

cc: Steve Storm, OPUC (w/ enclosure)
Jorge Ordonez, OPUC
Jim Warberg
Cheryl Chevis

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CASE: UE 215
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

Exhibits in Support
Of Opening Testimony

June 4, 2010

May 05, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated April 26, 2010
Question No. 320

Request:

Regarding Exhibit /1500, Kuns - Cody/10, lines 7-12, please provide a detailed explanation of how PGE estimated the attribution of 58% and 42% of energy costs of a CCCT and generic wind farm respectively. If the information requested was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in either portable document format (PDF) files or Excel workbook (with cell references and formulae intact) files.

Response:

PGE relied on the analysis presented in Table 13-1 Energy Action Plan (page 320) of its 2009 Integrated Resource Plan (IRP.) From this table, the witnesses used the 2020 average energy values for both a Combined Cycle Combustion Turbine and the Renewable Resource Actions necessary to achieve compliance with RPS standards. The table below summarizes the attribution of the 58% and 42%:

Resource	aMW	Percent of Total
CCCT	406	58%
RPS to 2015	122	18%
RPS to 2020	168	24%
Totals	696	100%

Attachment 320-A contains a .pdf copy of PGE's 2009 IRP.

May 05, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated April 26, 2010
Question No. 322

Request:

Regarding Exhibit /1500, Kuns - Cody/10, lines 19-21, please provide a detailed explanation of the methods by which PGE estimated the generic wind farm fully allocated cost of $93.62/MWh. If the information requested was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in either portable document format (PDF) files or Excel workbook (with cell references and formulae intact) files.

Response:

PGE relied upon the information and analysis in its 2009 IRP to determine the fully allocated 2011 real levelized cost of $93.62/MWh for a generic wind farm. Page 118 of the draft IRP mentions the $93.62 figure. This document is provided as Attachment 322-A.

The assumptions contained in support of this figure include the following:

- A 31% capacity factor.
- Capital costs reflective of Phase II of Biglow Canyon.
- Integration costs of $11.83/MWh (2009$) escalated at inflation.
- Production Tax Credits at current levels and BETC that total to approximately $21/MWh real levelized in 2009 dollars.

The specific analysis is provided as OPUC Confidential Attachment 321. Please reference worksheet titled 'Wind Plant'.

May 05, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to OPUC Data Request
Dated April 26, 2010
Question No. 324

Request:

Regarding Exhibit /1500, Kuns - Cody/11, line 1 to 2, please provide in electronic spreadsheet format with cell references and formulae intact the calculation of the wheeling costs that were subtracted from the $93.62 to arrive to the $85.69/MWh energy cost of wind. If the information requested was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in either portable document format (PDF) files or Excel workbook (with cell references and formulae intact) files.

Response:

The requested information is provided in PGE Response to OPUC Data Request No. 321, Attachment A. In order to derive the $85.69 figure, PGE removed the wheeling cost assumptions contained in worksheet Wind Plant, column L.

CASE: UE 215
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

June 4, 2010

INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist, employed three-quarter time by the Economic Research & Financial Analysis Division (ERFA) of the Public Utility Commission of Oregon (OPUC or Commission). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I represent the OPUC staff (Staff) in this docket regarding the subjects of rate spread and rate design.[1]

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Whether based upon input from the participants in UM 1415[2] or on its own initiative, Portland General Electric (PGE or Company) has adopted measures regarding rate spread and rate design that Staff can largely or fully endorse as improving upon the status quo. Having said that, there are some modifications and refinements to PGE's rate spread and rate design proposals that are appropriate. The purpose of this testimony is to present and explain those modifications and refinements.

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[1] "Rate spread" refers to the assignment of respective portions of the overall utility revenue requirement to the various customer schedules. "Rate design" refers to the individual tariff pricing components which combine to recover the customer schedules' assigned revenue targets.
[2] UM 1415 was the generic rate spread/rate design investigative docket established by the Commission in its order following the last PGE general rate case, Docket No. UE 197. *See* Order No. 09-020.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Topic 1 – Residential Rate Design Recommendations Pertaining to Schedules 7 (Basic Rates) and 102 (Regional Power Act Exchange Credit)

Topic 2 – Recommendations for Easing the Transition from Schedule 83 to Schedule 85 and for Smoothing the Impact of the Proposed Rate Increase Across the Levels of Consumption

Topic 3 – The Empirical Basis for and Composition of an Optional Refined Time-of-Use (TOU) Rate Design for Schedules 85 and 89

Topic 4 – The Empirical and Policy Bases for Some Minor Alterations to PGE's Rate Spread Proposal.

Q. DID YOU PREPARE EXHIBITS FOR THIS CASE?

A. Yes, they are listed as follows:

1101 – Witness Qualification Statement

1102 – Staff's Residential Rates Alternatives to PGE's Proposed Schedules 7 and 102

1103 – Staff's Alternatives to PGE's Proposed Schedule 85 Basic and Facilities Capacity Rates

1104 – Staff's Optional Refined Alternatives to PGE's Proposed Schedules 85 and 89 Energy Time of Use Rates

1105 – Staff's Alternative to PGE's Rate Spread Proposal

Q. PLEASE SUMMARIZE THE PRINCIPAL POINTS OF THIS TESTIMONY.

A. Topic 1: Residential Rate Design

- In order to simplify the residential rate, I propose that a two-block rate design be substituted for the Company-proposed three-block design. The inclining-block pricing structure would be retained.

- To preserve the benefits of the Regional Power Act Exchange Credit for basic consumption, I propose to limit the credit to the first 1000 kWhs of monthly residential consumption rather than applying it to all consumption, no matter how great. This change also has the benefit of stabilizing the aggregate credit since the variation in usage when limited to 1000 kWhs per customer is less that the variation in total overall usage.

Topic 2: Background – The current Large Nonresidential Schedule 83 applies to customers whose maximum monthly demand ranges from 30 kWs to 1000 kWs. The Company is proposing to place into a new Schedule 85 customers whose demands are above 200 kWs (and, as before, below 1000 kWs). Staff endorses this proposal.

- To reduce the chances of hardship from an undesired, mandatory shift from Schedule 83 to Schedule 85, I propose that a customer must cross the maximum demand threshold of the former schedule on six occasions, as opposed to only once, before the customer is shifted to Schedule 85.
- To mitigate the rate shock of moving from a Basic Charge as low as $30 per month to one as high as $400 per month, I propose Basic Charges in the $200 to $250 range. The other benefit of this action is some leveling of the billing increase percentage across the load levels.

Topic 3: Background – Schedule 89 currently, and Schedule 85 as proposed by PGE, have TOU rates with a sixteen hour peak and an eight hour off-peak (Monday through Saturday, with all of Sunday designated as off-peak).

- To capture in rates the substantial disparity in energy costs between the eight hour “super peak” and the remaining eight hours within the PGE-designated sixteen hour “peak,” I propose a seasonally differentiated three-period TOU rates as a customer option.

Topic 4: Rate Spread

- Staff proposes changes to PGE's cost study to better reflect demand-related generation costs. I also propose reducing the apparent inter-schedule cross-subsidization. This was done by relaxing the limitation that PGE had placed on major schedule rate increases. These changes have the principal effect of reducing the revenue requirement allocation to Residential Schedule 7 while increasing the allocation to Large Nonresidential Schedule 83.

TOPIC 1: RESIDENTIAL RATE DESIGN

Q. PLEASE DESCRIBE THE ENERGY PORTION OF THE PGE RESIDENTIAL SCHEDULE 7 RATE DESIGN THAT IS NOW IN EFFECT.

A. It is a two-block inverted rate, with the tail block commencing at 250 kWhs. The price differential between the first and second block is 1.7 cents/kWh.

Q. WHAT IS PGE PROPOSING IN THIS CASE?

A. Three inverted blocks, with the first one ending at 500 kWhs and the third beginning at 1000 kWhs.

Q. DOES STAFF REGARD THE NEW RATE PROPOSAL BY PGE TO BE SUPERIOR TO THE EXISTING DESIGN?

A. We do. Our focus, particularly, has been to have a strong price signal in effect above 1000 kWhs. That can only be achieved in a revenue-neutral manner by having lower rates below the 1000 kWh level.

Q. WHY DO YOU FOCUS ON A BREAK POINT OF 1000 KWHS?

A. Loads above that level are very likely to include central air conditioning and electric space heating—the primary sources of the residential class's contributions to the summer and winter system peaks.

Q. COULD THAT PRICE SIGNAL OBJECTIVE BE ACHIEVED BY A SIMPLER RATE DESIGN THAN WHAT IS BEING PROPOSED BY PGE IN THIS CASE?

A. Yes. Staff proposes retaining a two-block inverted rate design, but having the tail block commence at 1000 kWhs rather than at 250 kWhs. That constitutes Staff's recommendation on this subject.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH CONTRASTS YOUR RATE DESIGN PROPOSAL WITH PGE'S?

A. Yes. It is Staff/1102 Compton/1. The contrasting rates are in the block of shaded cells. Staff's proposed rates are designed to recover the same total revenues as would be collected by the Company's rates.

Q. ALONG WITH GREATER RATE SIMPLICITY, WHAT OTHER RATE-MAKING OBJECTIVES WOULD BE ACHIEVED BY STAFF'S RECOMMENDATION?

A. As shown in the upper portion of the exhibit, by contrasting Staff's and PGE's proposed monthly billings for consumption below 800 kWhs, the Company would be able, under the Staff proposal, to recover from small-usage customers more of the fixed costs that PGE regards as "customer costs" but that are not included in the ten-dollar monthly basic, or customer, charge.

Q. ANOTHER RATEMAKING OBJECTIVE IS TO HAVE ALL THE CUSTOMERS WITHIN A SCHEDULE EXPERIENCE APPROXIMATELY THE SAME

PERCENTAGE BILLING INCREASE. IN THAT LIGHT, ARE YOU DISTURBED BY THE GREATER PERCENTAGE INCREASES FOR SMALLER-USE CUSTOMERS THAT RESULT FROM THE STAFF PROPOSAL?

A. I agree that you have stated a commonly accepted ratemaking objective. But I'm sure we would also agree that in a given context objectives may be in conflict with each other. This is one of those occasions. But several things should be borne in mind here. First, the average residential monthly usage is 900 kWhs.[3] My exhibit shows the average-use customer to be benefitted by Staff's proposal. Second, Schedule 7's Staff-versus-PGE percentages may be disparate, but the disparity is placed into perspective by the right hand column of Staff's exhibit, which shows the differences between the two proposals in dollars rather than percentages.

Q. WHAT WAS THE BASIS OF THE 250 KWH BLOCKING BREAK-POINT IN THE CURRENT PGE RESIDENTIAL SCHEDULE?

A. I don't know the details, but it had something to do with the way the power sale portion of the Regional Power Act Exchange Credit was treated in the past.

Q. DOES THAT TREATMENT NOW PREVAIL?

A. No. There no longer is a power sale to PGE by BPA relating to the Regional Power Act credit. Further, the current Schedule 102 applies the credit to all residential consumption.

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[3] *See* PGE/1500 Kuns-Cody/20, line 14.

Q. AS A POLICY MATTER, DOES STAFF ENDORSE THAT TREATMENT OF THE CREDIT?

A. No. We find merit in limiting the credit to something in the neighborhood of average residential use—in this case 1000 kWhs per month. The viewpoint is that the residential portion of the regional "endowment" should apply to customers and to their average level of consumption rather than to residential consumption per se, regardless of its magnitude. Another consideration follows from the fact that PGE receives from BPA a fixed amount of dollars each year relating to the Regional Act Credit. The flow of the credit to customers as regards the tariff figure will be more stable if the credit is provided through the first 1000 kWhs of monthly usage.

Q. IN REVIEWING THE SUMMER PERIOD'S BILLINGS IN THIS EXHIBIT, AREN'T YOU CONCERNED ABOUT WHAT MAY BE AN INORDINATELY LARGE INCREASE FOR CUSTOMERS WHOSE MONTHLY USE GREATLY EXCEEDS THE SCHEDULE 7 AVERAGE?

A. From Staff's exhibit, I see that to reach an appreciable dollar difference between Staff's and the Company's monthly billing outcome requires consumption on the order of 4000 kWh's. That magnitude entails something well beyond ordinary household usage—unless you're talking about a very large or very inefficient house. Examples of "unordinary" use would be the heating of swimming pools or the charging of electric vehicles. Here the Schedule 7 optional TOU might very well come into play as a "safety valve." The summer on-peak period under the existing time-of-day rate is limited to the hours 3 p.m. to 8 p.m., which are the heaviest air conditioning hours. If the cause of a customer's high usage is something besides air conditioning—e.g., if it is for heating a swimming pool—then much of the customer's usage can readily be shifted to, or limited to, the mid-peak or even the off-peak period, where the rates are much lower. Even if the heavy use is attributable to air conditioning, the burden can be mitigated by minimizing use in the 3-to-8 p.m. period.

TOPIC 2: THE TRANSITION FROM SCHEDULE 83 TO SCHEDULE 85

Q. YOU STATED EARLIER THAT STAFF ENDORSES PGE'S PROPOSAL TO CREATE A NEW LARGE NONRESIDENTIAL CUSTOMER SCHEDULE BY SPLITTING OFF FROM THE CURRENT SCHEDULE (No. 83) THE CUSTOMERS WHOSE PEAK MONTHLY DEMANDS EXCEED 200 KWS. EXPLAIN THAT ENDORSEMENT.

A. The present PGE Schedule 83's range of thirty-to-1000 kWs is huge by any reckoning. Accordingly, it is difficult to claim that there exists a sufficient homogeneity of cost causation to warrant applying the same prices over the entire course of that range. Separating large from small customers enables prices to be constructed that better capture the scale economies and other cost differences that normally attend service to the larger customers. The range as chosen by PGE for Schedule 85 (i.e., of 200 kWs to 1000 kWs) is the same as what defines PacifiCorp's Schedule 30.

Q. ARE THERE ADVANTAGES TO CUSTOMERS IN THE NEW SCHEDULE 85 FROM BEING IN THEIR OWN SCHEDULE RATHER THAN REMAINING ON SCHEDULE 83?

A. Yes. PGE's cost-of-service study suggests that revenues currently collected from the customers who will occupy the new Schedule 85 are only 3.7% below costs while the revenues for the customers who remain on Schedule 83 are 11.7% below costs. (*See* PGE Exhibit/ 1503 Kuns-Cody/10.) That disparity will be expected to translate to a lower general rate increase for the Schedule 85 customer than would be experienced by the average Schedule 83 customer. I would note that there should also be system efficiency benefits from—as proposed by PGE—putting a larger share of the system's loads onto TOU rates for energy and demand.[4]

Q. YOU'VE LABELED THIS TOPIC "THE TRANSITION FROM SCHEDULE 83 TO SCHEDULE 85." MIGHT THAT TRANSITION BE DIFFICULT FOR PGE'S CUSTOMERS?

A. Yes. The transition may be "difficult" for a customer who's on the border between the two schedules. Refer to PGE Exhibit/1502 Kuns-Cody/12 and 13. What is seen is that the proposed percentage increases for customers whose demands are at the 200 kW level are substantially greater than what are being

[4] Regarding demand, the proposed Schedule 85 bills on the basis of on-peak demand (i.e., demand measured during the defined sixteen-hour week-daily peak period), whereas Schedule 83 bills on the basis of the highest demand reading regardless of when it occurred.

proposed for the larger customers within the schedule.[5] Adding to this “sticker shock” item for the borderline secondary voltage customer would be a Basic Charge of $400 per month on Schedule 85 versus $30[6] per month on Schedule 83.

Q. IS THERE A “QUICK AND EASY” MEANS FOR MITIGATING THE CIRCUMSTANCES WHERE A CUSTOMER DOES NOT WANT TO BE PLACED ON THE SCHEDULE 85 TARIFF (I.E., LARGELY DUE TO THE LATTER’S HIGH BASIC CHARGE)?

A. Yes. I propose that customers be afforded six occasions in a twelve month period of crossing the 200 kW threshold, rather than one, before the customer is moved from Schedule 83 to Schedule 85.[7] This staff proposal is consistent with PacifiCorp’s practice.[8] (Clarification: If a customer whose loads are known to exceed the 200 kW threshold *desires* to go onto Schedule 85 [e.g., due to its lower off-peak energy prices], that customer shouldn’t have to be billed for six months of above-threshold loads to make that change.)

Q. IS THERE A WAY TO REDUCE THE STICKER SHOCK TO WHICH YOU REFERRED EARLIER WHILE, AT THE SAME TIME, SMOOTHING OUT THE DISPARATE INCREASES BETWEEN THE LOWER-KW AND THE HIGHER-KW CUSTOMERS?

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[5] Example: A 50 percent load factor, secondary Schedule 85 customer with 200 kWs of demand would see an 8.1 percent increase over current Schedule 83 billings while a customer whose demand was 900 kWs would see only a 2.8 percent increase.

[6] No, I haven’t left off a zero.

[7] Since there is only one demand reading (i.e., the maximum value reached) per month for Schedule 83, a customer could go into a seventh month of above-200-kW demand before being forced onto Schedule 85.

[8] *See* Pacific Power & Light Company Oregon, Schedule 30.

A. Yes. The solution is to lower the Schedule 85 Basic Charge while elevating the Facilities Capacity Charge for that schedule.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE ADJUSTMENTS TO SCHEDULE 85 THAT YOU JUST DESCRIBED?

A. Yes. Staff/1103 Compton/1 and /2, which apply respectively to Secondary and to Primary, Three-Phase service on Schedule 85.[9] The shaded cells convey the prices that are at issue. The table on the bottom confirms the revenue neutrality of the Staff proposals as compared to the PGE proposals. The large table in the exhibit shows the billing impacts in going from the current Schedule 83 to a proposed Schedule 85.

Q. WHY IS YOUR PROPOSED TRADE-OFF TAKING PLACE BETWEEN THE BASIC CHARGE AND THE FACILITIES CAPACITY CHARGE?

A. I propose this trade-off because the two charges are designed to recover functionally related cost categories (i.e., the last segments of the distribution system, including the customer interface). This point is manifest in comparing PGE's proposed Schedules 83 and 85 Basic and Facilities Capacity Charges for Secondary voltage customers.[10] Schedule 83 has a very low monthly Basic Charge ($30) and relatively high Facilities Capacity charges ($3/kW for the first 30 kWs, and $2.50/kW thereafter); Schedule 85 has the very high Basic Charge ($400) and a significantly lower Facilities Capacity charges ($2.04/kW).[11]

[9] As stated earlier, the figures are suggestive in the sense that all the rates shown will be subject to adjustments based upon the final revenue requirement outcome of this docket.
[10] *See* PGE Exhibit/ 1501 Kuns-Cody/29 and /35.
[11] Note that PGE's proposed straight Demand (i.e., as opposed to Facilities Capacity demand) Charge is actually greater for Schedule 85 than for Schedule 83.

Q. REFERRING TO PGE EXHIBIT/1503 KUNS-CODY/7, I NOTE THAT THE COST-OF-SERVICE ALLOCATION TO "BASIC CHARGE SECONDARY" IS $403.62 PER MONTH. WHY DOES STAFF IN THIS INSTANCE NOT SUPPORT A PRICE ($400 PER MONTH) THAT IS REMARKABLY CLOSE TO THE COST-OF-SERVICE ESTIMATE?

A. Here again we have a conflict among worthy goals and objectives. Taking precedence here is a goal of compatibility among schedules, along with the customer sensitivity benefits of reducing rate shock. I assume that such a goal was in mind when the Company set its proposed Basic Charge at $30 per month for Schedule 83 even though the cost-of-service estimate is $127.05 per month. (*See* PGE Exhibit/1503 Kuns-Cody/7.[12]) On a percentage basis, $255 is closer to $403, than $30 is to $127—but here again we're being required to make a judgment call. And after all, large Secondary customers who will be entering Schedule 85 are now paying a Basic Charge of only $25 per month—which has heretofore been regarded as "just and reasonable." So whether the move, as recommended by Staff, is "only" to something on the order of $250 per month (a thousand percent increase!), there will be major progress towards the cost-of-service level. I would also note that in comparing the Percent Differences, except for the lowest load-factor customers, there is very little that separates the PGE and Staff proposals for Schedule 85.

[12] In this latter instance the sought for compatibility is with General Service Schedule 32, where the proposed Three-Phase Basic Charge is $16 per month. (*See* PGE Exhibit/1503 Kuns-Cody/4.)

TOPIC 3: AN OPTIONAL, REFINED TIME OF USE (TOU) RATE DESIGN FOR SCHEDULES 85 AND 89

Q. FOR SOME TIME NOW SCHEDULE 89 HAS HAD MANDATORY TOU RATES WITH A SIGNIFICANT PRICE GAP BETWEEN THE ON-PEAK AND OFF-PEAK ENERGY RATES. PGE HAS ALSO REQUESTED THAT SCHEDULE 85 HAVE MANDATORY TOU RATES WITH A COMPARABLE ON-PEAK/OFF-PEAK GAP.[13] WHAT DO YOU HAVE IN MIND WHEN YOU SAY "REFINED" TOU RATES?

A. As our intuition would suggest, PGE does not experience a true peak period of sixteen hour duration. At best, the peak period is closer to eight hours.[14] A complicating factor, admittedly, is the fact that the eight-hour peak is different in the summer from what it is in the winter—but in either season it would be highly unusual for the experienced peak to fall outside its respective season's eight-hour interval designation.[15] In those more extreme-temperature seasons, there is enough of a disparity between the true on-peak energy costs and the rest of the PGE "on-peak" period's costs to justify breaking that Company's "on-peak" period into what I'll designate as "peak" and "shoulder" time intervals.

Q. DO YOU HAVE AN EXHIBIT WHICH PROVIDES EMPIRICAL SUPPORT FOR THE CLAIM YOU JUST MADE?

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[13] Schedule 83, whence the Schedule 85 customers came, has not had, nor is it proposed to have, TOU energy rates.

[14] Clarification: By definition, a particular day's peak will not last eight hours. An "eight-hour peak period" means that, during a particular month, no day's peak will be expected to lie outside the designated eight hour interval.

[15] Note that the reference was explicitly to winter and summer, per se. The fall and spring months may experience peaks that defy a particular eight-hour interval designation. That "defiance" is moot because it would be most unusual for those latter seasons' peaks to stress the system's capacity.

A. Yes, Exhibit Staff/1104 Compton/1. It was prepared from data supplied by PGE. Note (from the bottom table) the 10 mills/kWh summertime gap between the peak and shoulder costs, and the seven mills/kWh gap in the non-summer.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DISPLAYS THE REFINED TOU RATES TO WHICH YOU HAVE ALLUDED?

A. Yes, Exhibit Staff/1104 Compton/2. PGE’s off-peak prices are preserved, and, in a revenue-neutral manner, the summer and non-summer peak and shoulder price gaps have been constructed to equate to those shown in the table at the bottom of Exhibit Staff/1104 Compton/1.

Q. I NOTICE THAT YOUR SUMMER AND NON-SUMMER ENERGY PRICES “CENTER” ON THE SAME, YEAR-ROUND PGE PEAK PRICES—DESPITE THE FACT THAT, DISREGARDING THE OFF-PEAK COSTS, THE SUMMER/NON-SUMMER COST DIFFERENTIAL IS GREATER THAN THE PEAK/SHOULDER DIFFERENTIAL FOR ANY SEASON. WHY HAVE YOU NOT CAPTURED THE INTER-SEASONAL COST GAPS ALONG WITH THE COST GAPS BETWEEN THE PEAKS AND SHOULDERS WITHIN THE SEASONS?

A. To avoid criticisms for placing an extra burden upon customers with preponderantly summertime loads, and in response to some parties’ having been opposed to seasonal rates in prior rate cases, Staff chose the policy option for this case to make its TOU proposal revenue neutral *vis-á-vis* the seasons.

Q. I HAVE ANOTHER QUESTION ON THIS SAME SUBJECT. IT IS CLEAR THAT WHAT YOU ARE FOCUSING UPON IS THE GAP BETWEEN PEAK AND SHOULDER COSTS. BUT IN LOOKING BACK AT EXHIBIT STAFF/1104 COMPTON/1, I NOTE THAT FOR THE MONTH OF DECEMBER YOUR PEAK/SHOULDER GAP IS GREATER THAN YOUR SUMMER SEASON AVERAGE. YET DECEMBER IS INCLUDED WITH THE SEASON (I.E., NON-SUMMER) THAT IS ASSIGNED THE LOWER PRICE SPREAD BETWEEN THE PEAK AND SHOULDER TARIFF VALUES. DOES THAT TROUBLE YOU?

A. No. According to some notions of a perfect world there would be hour-by-hour real-time pricing, with nothing so unsophisticated as TOU prices—which are so "yesterday." A major step to that ideal would, perhaps, be TOU rates that vary by the month. But Staff's objective in this case is really quite modest. It is merely to obtain rudimentary recognition in rates that electricity costs tend to be higher during the eight-hour peak periods than during the eight-hour shoulder periods of a given season. Recognizing some merit to rates simplicity, particularly when tariffs are to be modified, Staff would be content with a rate structure involving just two seasons, rather than three or four. And obviously December belongs with the "Non-Summer" season insofar as its split eight-hour, morning-and-evening, peak is quite different from the summer-time's afternoon, eight-hour peak.

Q. WAS STAFF SENSITIVE TO LARGE CUSTOMER CONCERNS THAT THE BASIS FOR PROPOSING THE REFINED TOU ENERGY RATES BE "OPTIONAL"?

A. Yes. And they are revenue neutral in the sense that if all customers signed up for the TOU options and their load patterns were unchanged, then PGE would earn exactly the same revenues as they project to earn with their own prices.

Q. BUT IT SHOULD GO WITHOUT SAYING THAT NOT ALL CUSTOMERS WILL SO SIGN UP, AND EVEN IF THEY DID, THEY WOULD NOT GENERATE THE SAME REVENUES AS PGE SHOWS AS BEING TARGETED…ERGO THE "REVENUE EROSION" ISSUE. WOULD YOU PLEASE ELABORATE UPON WHAT THAT ISSUE CONSTITUTES?

A. There are two types of revenue erosion. The more troublesome is where no consumption behavior is altered, but where a number of customers can self-select a price schedule that reduces their billings in a significant way. In this case the subject customers will be those who happen to already take relatively more power in the eight-hour shoulder period of what PGE has designated as the sixteen-hour "on-peak" period. Those customers, in their self interest, would choose the Staff's refined TOU option, thereby leaving the relatively heavy on-peak users to pay the standard PGE "on-peak" rate—which is lower than the refined TOU on-peak rate and which therefore would be incapable of offsetting the revenue loss from the self-selected customers' having taken advantage of the lower, refined TOU shoulder rate.[16]

The other type of revenue erosion is where customers actually shift their consumption behavior from the peak to the shoulder period. In this case the reduced revenues will be offset in the short run by reduced net-variable-power-costs to the utility as it is either able to sell into the more lucrative on-peak spot market the surpluses created by the load shift or is not forced to purchase as much of the relatively expensive on-peak spot-market power.[17] In the longer run, expensive heavy-load-hour market transactions are reduced due to the shifted loads and/or the utility is spared having to add as much of its own new and expensive generation capacity. Because of the short- and long-run cost savings as offsets to this latter form of revenue erosion, utilities tend to look upon such with relative equanimity.

Q. WHY AS A POLICY MATTER HAS STAFF CHOSEN THE OPTIONALITY ROUTE INSOFAR AS IT MIGHT ENTAIL AN UNDESIRABLE LOSS OF REVENUES FOR PGE?

A. It is our sense that the first form of revenue erosion may be exaggerated in its perceived magnitude. Consider the definition of the refined summer peak period—noon to eight p.m., with shoulders before and after that interval. In reviewing the summer shoulder-versus-peak MWh loadings from my exhibit, it

[16] The self-selected customers can argue, persuasively, that they have a lower cost of service compared to the customers whose usage is more heavily in the eight-hour true peak period, and that, accordingly, they deserve the lower billings.

[17] Whether or not the short-term energy cost savings will fully offset the loss in revenues will depend on the market conditions at the time of the load shift from the peak to the shoulder period.

is seen that they are comparable, with the maximum amount by which the peak load exceeded the shoulder load being about ten percent. In only one case—the largest customers within Schedule 89[18]--is the overall shoulder load larger than the peak load. Besides those few customers noted, how many of the Schedules 85 and 89 customers *already*, i.e., without load shifting, would be using more of their electricity in the shoulder periods that in the noon-to-eight-p.m. peak period? I would expect very few, if any. For both large industrial customers and large commercial customers it would seem that noon-to-4 p.m. would be the period of a typical summer day with the heaviest loads.[19]

Now consider the non-summer period, where the peak period is split between four hours in the morning (6 a.m. to 10 a.m.) and four hours in the evening (4 p.m. to 8 p.m.). Here our analysis must be a little more subtle. Turning again to my exhibit, it is seen that, indeed, the norm is for customers to use more electricity in the shoulder period (mostly between 10 a.m. and 4 p.m.) than in those combined peak periods. But there will only be a problem of adverse (to the utility) self-selection if some customers happened to *already* use *disproportionately* more of the shoulder-period power than did other customers. If all the customers have roughly the same proportion of peak and shoulder usage, no customer would be advantaged by accepting the refined TOU option—because that customer's bill would end up being roughly the same as

[18] That group, Schedule 89 Transmission, accounts for less than eight percent of the targeted combined loads of Schedules 85 and 89.
[19] The Schedule 89 customers, at least, already have 15-minute-interval load recording meters.

with the standard PGE tariff.[20] I will admit that a reasonable case might be made that manufacturers would be favored over retail commercial enterprises because the latter would be more likely to have operating hours that extend further into the evening winter refined peak period (although manufacturers may have the offsetting disadvantage of hours that extend further into the morning peak period).

In summary, I would conclude that insofar as Schedule 85 and 89 customers find the refined TOU tariffs attractive, and therefore opt for them, it will be because they believe it will be worthwhile to adjust their consumption behavior in conformance with the price signal and not because they already use an appreciably greater share of shoulder versus peak power than do most of the others within their schedule.

TOPIC 4: COST OF SERVICE AND THE SPREAD OF THE RATES

Q. UNDERLYING PGE'S RATE DESIGN AND SPREAD-OF-RATES PROPOSALS IS AN ELABORATE, MULTI-DIMENSIONAL COST-OF-SERVICE STUDY. IS STAFF GENERALLY ACCEPTING OF THAT STUDY?

A. Yes. However, there is one key element of the PGE study to which we take exception.

Q. WHAT IS IT?

[20] That is because the customer's usage mix would approximate the usage mix that created the revenue-neutral refined TOU price structure.

A. As noted by staff witness Jorge Ordonez, PGE based its generation capacity costs upon the specific simple-cycle combustion turbine gas peaking plant called for in its integrated resource plan (IRP). As a result, PGE's generation marginal demand costs that are more than twice, for example, the amount employed by PacifiCorp in its recently filed general rate case application.[21] The biggest difference between the two cost estimates owes to the fact that PGE's plant is somewhat more fuel efficient than that noted in the PacifiCorp plant. But fuel efficiency is not a capacity or demand parameter. It is Staff's long-held position that capital costs undertaken in the interest of fuel cost savings should be classified as "energy costs" rather than "demand costs." Making that classification change brings down the PGE capacity cost estimate appreciably.[22]

Q. HAVE YOU PREPARED AN EXHIBIT WHICH SHOWS THE COST-OF-SERVICE CONSEQUENCES OF MAKING THAT ADJUSTMENT TO GENERATION DEMAND COSTS?

A. Yes, Exhibit Staff/1105 Compton/1. Comparing the Staff-revised cost-of-service results (Column K in the exhibit) with the Company's cost-of-service results (Column D), it is seen that the demand estimate change shifts about $7 million away from the cost of service of the residential class (Schedule 7). While about $5 million of that amount falls to the large-customer Schedules 85

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[21] *See* PGE Exhibit/ 1504 Kuns-Cody/6 and PacifiCorp C. Craig Paice Exhibit PPL/1607 Tab 4. Generation Capacity

[22] Because PGE incorporates natural gas delivery capacity costs in its marginal electric generation demand cost estimate, its final figure is still well above PacifiCorp's. Because of the residential class's lower load factor as compared to that of the industrial schedules, having greater generation demand costs translates to a larger overall generation cost allocation to the residential class.

and 89, their percentage rate increases called for by the revised cost-of-service study (Column L) remain well below the system average.

Q. NOW LET'S TURN TO THE RATE SPREAD PROPOSALS. FROM THE PGE CONSTRAINTS LISTED ON YOUR EXHIBIT, I NOTE THAT THE COMPANY CALLS FOR LIMITING THE RATE INCREASES AMONG THE "CORE" CUSTOMER SCHEDULES TO 1.25 TIMES THE SYSTEM AVERAGE AND NO GREATER THAN TWICE THE OVERALL AVERAGE FOR THE OTHER SCHEDULES. COMPARING COLUMNS E AND G, I OBSERVE THAT IN ONLY TWO INSTANCES (SCHEDULES 7 AND 32) DOES THE COMPANY'S RECOMMENDED INCREASE MATCH WHAT DIRECTLY ISSUES FROM THE COST OF SERVICE METHODOLOGY. IS PGE'S APPROACH REASONABLE?

A. Yes, it is generally reasonable, but we can do better.

Q. WHAT DO YOU HAVE IN MIND?

A. Note from the CIO (i.e., Customer Impact Offset) Revenues in the PGE Methodology group (Column F) that the inter-schedule cross-subsidies amount to almost $14 million. It has been Staff's intent—joined in a general fashion by the other parties—to try to minimize the level of subsidies.[23] Such would be accomplished in this case by eliminating the "1.25-times" constraint that PGE applied to the core customer schedules, and then applying its "2.00-times" constraint to all the schedules, including the core customer schedules. Utilizing Staff's cost of service results (Columns K and L) as the base, the

[23] It is recognized that cost-of-service studies represent neither empirical nor conceptual precision.

recommended approach is to "allow" the schedules for which a larger-than-average percentage increase is called for to be charged with that increase (subject to the 2.00-times constraint), and then to add about two percent to the schedules whose called-for percentage increase is well beneath the system average. This approach produces the net revenue spread displayed in Column J. Note that the described two percent "adder" does not interfere with the latter schedules' percentage increases remaining significantly below the system average (as revealed in Column I).

Q. THE EXHIBIT WE HAVE BEEN REVIEWING DOES NOT REPRESENT THE LAST WORD ON THIS SUBJECT. THE ALLOCATIONS WILL HAVE TO BE RECONSTITUTED IN ORDER TO REFLECT THE COMMISSION-DETERMINED OVERALL REVENUE REQUIREMENT. THE VARIOUS STIPULATED TO OR RULED UPON COST REDUCTIONS MAY HAVE DIFFERENT IMPACTS AMONG THE CUSTOMER SCHEDULES. HOW MIGHT THE STAFF'S RATE SPREAD RECOMMENDATIONS BE ALTERED IN ORDER TO DEAL WITH THOSE CONTINGENCIES?

A. Only one guideline should be modified. As the overall percentage increase comes down, the "2.00-times" constraint can be relaxed—upwards (i.e., while still allowing an increase that is beneath the 14.85% maximum shown in Column I). The objective, and outcome, would be to reduce all the increases shown in Column I. Continuing to keep all the called-for above-average-percentage increases at their full cost of service levels (recognizing the relaxed "2.00-times" constraint), should enable the "subsidizing" schedules (i.e., Nos.

15, 85, 89, 91, and 92) to have even lower percentage increases than are shown in Column I.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1101

Witness Qualification Statement

June 4, 2010

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist (3/4), Economic Research & Financial Analysis Division (ERFA)

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), the AVISTA General Rate Case (UG 181), the 2008 PGE General Rate Case (UE 197), the 2009 PacifiCorp General Rate Case (UE210), and the 2009 Idaho Power Rate Cases (UE213 & 214).

CASE: UE 215
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1102

Staff's Residential Rates Alternatives to PGE's Proposed Schedules 7 and 102

June 4, 2010

Residential Rate Design -- OPUC Staff Proposal

Tariff Schedule 7, Single-Phase Residential Service

The Schedule 7 Paradigm: Eliminate the middle (i.e., 500-1000 kWhs) block, keep PGE's tail-block price.

Effect of Proposed Rate Change on Monthly Bills -- Staff and PGE Proposals

	kWh's	Monthly Bill: Current Tariff	Staff-Proposed Tariff	Percent Difference	PGE-Proposed Tariff	Percent Difference	Staff-Proposed Minus PGE-Proposed
	50	$ 14.11	$ 15.06	6.7%	$ 14.75	4.5%	$0.32
	100	$ 18.22	$ 20.13	10.4%	$ 19.49	7.0%	$0.64
	200	$ 26.45	$ 30.25	14.4%	$ 28.98	9.6%	$1.27
	250	$ 30.56	$ 35.32	15.6%	$ 33.73	10.4%	$1.59
	300	$ 35.56	$ 40.38	13.6%	$ 38.48	8.2%	$1.91
	400	$ 45.57	$ 50.51	10.8%	$ 47.97	5.3%	$2.54
	500	$ 55.58	$ 60.64	9.1%	$ 57.46	3.4%	$3.18
	600	$ 65.59	$ 70.76	7.9%	$ 68.70	4.7%	$2.07
	700	$ 75.59	$ 80.89	7.0%	$ 79.93	5.7%	$0.96
	800	$ 85.60	$ 91.02	6.3%	$ 91.17	6.5%	-$0.15
	900	$ 95.61	$ 101.14	5.8%	$ 102.40	7.1%	-$1.26
	1000	$ 105.62	$ 111.27	5.4%	$ 113.64	7.6%	-$2.37
Fall-Winter Average	1010	$ 106.62	$ 112.47	5.5%	$ 114.83	7.7%	-$2.37
	1100	$ 115.63	$ 123.26	6.6%	$ 125.63	8.6%	-$2.37
	1200	$ 125.63	$ 135.25	7.7%	$ 137.62	9.5%	-$2.37
	1300	$ 135.64	$ 147.25	8.6%	$ 149.61	10.3%	-$2.37
	1400	$ 145.65	$ 159.24	9.3%	$ 161.60	11.0%	-$2.37
	1500	$ 155.66	$ 171.23	10.0%	$ 173.60	11.5%	-$2.37
	1750	$ 180.68	$ 201.21	11.4%	$ 203.58	12.7%	-$2.37
	2000	$ 205.70	$ 231.19	12.4%	$ 233.56	13.5%	-$2.37
	2500	$ 255.74	$ 291.15	13.8%	$ 293.52	14.8%	-$2.37
	3000	$ 305.78	$ 351.11	14.8%	$ 353.48	15.6%	-$2.37
	4000	$ 405.86	$ 471.03	16.1%	$ 473.40	16.6%	-$2.37
	5000	$ 505.94	$ 590.95	16.8%	$ 593.32	17.3%	-$2.37
	7500	$ 756.14	$ 890.75	17.8%	$ 893.12	18.1%	-$2.37
	10000	$ 1,006.34	$ 1,190.55	18.3%	$ 1,192.92	18.5%	-$2.37

NOTE: Values shown reflect Schedule 7 prices, per se. PGE Exhibit/1502 Kuns-Cody/5 incorporates supplemental schedules.

Rate Design

	Current	Staff Proposed	PGE Proposed	
Basic Charge	$ 10	$ 10	$ 10	
kWh Unit Charge				
kWh's ≤ 250	$ 0.08223	$ 0.10127	$0.09492	kWhs ≤ 500
250 < kWh's ≤ 1000	$ 0.10008	$ 0.10127	$0.11235	500<kWhs≤1000
kWh's>1000	$ 0.10008	$ 0.11992	$ 0.11992	kWhs>1000

Billing Determinants

	Quantity	Revenues	Revenues	Quantity	
Customer Months	8,682,768	$ 86,827,680	$ 86,827,680	8,682,768	Customer Months
kWhs ≤ 1000	6,115,756	$619,342,610	$369,026,654	3,887,765	kWhs ≤ 500
kWhs>1000	1,507,871	$180,823,890	$250,314,789	2,227,991	500<kWhs≤1000
		$886,994,180	$180,823,890	1,507,871	kWhs>1000
			$ 886,993,013		

Residential Rate Design -- OPUC Staff Proposal

Tariff Schedules 7 and 102, Single-Phase Residential Service

The Schedule 102 Paradigm: Limit the Schedule 102 benefit to 1000 kWhs.

Effect of Proposed Rate Change on Monthly Bills -- Staff and PGE Proposals

		Monthly Bill					
	kWh's	Current Tariff	Staff-Proposed Tariff	Percent Difference	PGE-Proposed Tariff	Percent Difference	Staff-Proposed Minus PGE-Proposed
	50	$ 13.80	$ 14.67	6.3%	$ 14.43	4.6%	$0.24
	100	$ 17.60	$ 19.35	9.9%	$ 18.87	7.2%	$0.48
	200	$ 25.20	$ 28.70	13.9%	$ 27.73	10.1%	$0.96
	250	$ 29.00	$ 33.37	15.1%	$ 32.17	10.9%	$1.20
	300	$ 33.69	$ 38.04	12.9%	$ 36.60	8.7%	$1.44
	400	$ 43.07	$ 47.39	10.0%	$ 45.47	5.6%	$1.92
	500	$ 52.45	$ 56.74	8.2%	$ 54.34	3.6%	$2.40
	600	$ 61.84	$ 66.09	6.9%	$ 64.95	5.0%	$1.14
	700	$ 71.22	$ 75.44	5.9%	$ 75.56	6.1%	-$0.12
	800	$ 80.60	$ 84.78	5.2%	$ 86.17	6.9%	-$1.38
	900	$ 89.98	$ 94.13	4.6%	$ 96.78	7.5%	-$2.64
	1000	$ 99.37	$ 103.48	4.1%	$ 107.39	8.1%	-$3.91
Fall-Winter Average	1010	$ 100.31	$ 104.68	4.4%	$ 108.52	8.2%	-$3.84
	1100	$ 108.75	$ 115.47	6.2%	$ 118.75	9.2%	-$3.28
	1200	$ 118.13	$ 127.46	7.9%	$ 130.12	10.1%	-$2.66
	1300	$ 127.52	$ 139.46	9.4%	$ 141.49	11.0%	-$2.03
	1400	$ 136.90	$ 151.45	10.6%	$ 152.85	11.7%	-$1.41
	1500	$ 146.28	$ 163.44	11.7%	$ 164.22	12.3%	-$0.78
	1750	$ 169.74	$ 193.42	14.0%	$ 192.64	13.5%	$0.78
	2000	$ 193.20	$ 223.40	15.6%	$ 221.06	14.4%	$2.35
	2500	$ 240.11	$ 283.36	18.0%	$ 277.89	15.7%	$5.47
	3000	$ 287.03	$ 343.32	19.6%	$ 334.73	16.6%	$8.60
	4000	$ 380.86	$ 463.24	21.6%	$ 448.40	17.7%	$14.85
	5000	$ 474.69	$ 583.16	22.9%	$ 562.07	18.4%	$21.10
	7500	$ 709.26	$ 882.96	24.5%	$ 846.24	19.3%	$36.72
	10000	$ 943.84	$ 1,182.76	25.3%	$ 1,130.42	19.8%	$52.35

NOTE: Values shown reflect Schedules 7 and 102 prices, per se. PGE Exhibit/1502 Kuns-Cody/5 incorporates other schedules.

Rate Design

	Current	Staff Proposed		PGE Proposed		
Basic Charge	$ 10	$ 10		$ 10		
kWh Unit Charge		Sched. 7	Sched. 102	Sched. 7	Current Sched. 102	
kWh's ≤ 250	$ 0.08223	$ 0.10127	-$ 0.00779	$0.09492	-$ 0.00625	kWhs ≤ 500
250 < kWh's ≤ 1000	$ 0.10008	$ 0.10127	-$ 0.00779	$0.11235	-$ 0.00625	500<kWhs≤1000
kWh's>1000	$ 0.10008	$ 0.11992	$ 0.00000	$ 0.11992	-$ 0.00625	kWhs>1000

Billing Determinants

	Quantity	Revenues	Revenues	Quantity	
Customer Months	8,682,768	$ 86,827,680	$ 86,827,680	8,682,768	Customer Months
kWhs ≤ 1000	6,115,756	$571,700,871	$344,728,123	3,887,765	kWhs ≤ 500
kWhs>1000	1,507,871	$180,823,890	$236,389,845	2,227,991	500<kWhs≤1000
		$839,352,441	$171,399,697	1,507,871	kWhs>1000
			$ 839,345,344		

CASE: UE 215
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Staff's Alternatives to PGE's Proposed Schedule 85 Basic and Facilities Capacity Rates

June 4, 2010

Schedule 85 Rate Design -- OPUC Staff Proposal

Secondary, Three-phase service.

Paradigm: Reduce Basic Charge and Increase Facilities Capacity Charge in a Revenue-Neutral Manner

Effect of Proposed Rate Change on Monthly Bills -- PGE and Staff Proposals

Loads			Monthly Bill				
Load Factor	Demand kW	Energy kWh	Current Prices	Proposed PGE Prices	Percent Difference	Proposed Staff Prices	Percent Difference
30%	200	43,800	$3,888.84	$4,299.73	10.6%	$4,244.93	9.2%
30%	300	65,700	$5,830.81	$6,249.60	7.2%	$6,242.40	7.1%
30%	500	109,500	$9,714.75	$10,149.33	4.5%	$10,237.33	5.4%
30%	700	153,300	$13,598.69	$14,049.07	3.3%	$14,232.27	4.7%
30%	800	175,200	$15,540.66	$15,998.93	2.9%	$16,229.73	4.4%
30%	900	197,100	$17,482.63	$17,948.80	2.7%	$18,227.20	4.3%
30%	1,000	219,000	$19,424.60	$19,898.67	2.4%	$20,224.67	4.1%
50%	200	73,000	$5,781.00	$6,198.54	7.2%	$6,143.74	6.3%
50%	300	109,500	$8,669.05	$9,097.81	4.9%	$9,090.61	4.9%
50%	500	182,500	$14,445.15	$14,896.36	3.1%	$14,984.36	3.7%
50%	700	255,500	$20,221.25	$20,694.90	2.3%	$20,878.10	3.2%
50%	800	292,000	$23,109.30	$23,594.17	2.1%	$23,824.97	3.1%
50%	900	328,500	$25,997.35	$26,493.44	1.9%	$26,771.84	3.0%
50%	1,000	365,000	$28,885.40	$29,392.71	1.8%	$29,718.71	2.9%
70%	200	102,200	$7,673.16	$8,097.35	5.5%	$8,042.55	4.8%
70%	300	153,300	$11,507.29	$11,946.03	3.8%	$11,938.83	3.8%
70%	500	255,500	$19,175.55	$19,643.38	2.4%	$19,731.38	2.9%
70%	700	357,700	$26,843.81	$27,340.73	1.9%	$27,523.93	2.5%
70%	800	408,800	$30,677.94	$31,189.40	1.7%	$31,420.20	2.4%
70%	900	459,900	$34,512.07	$35,038.08	1.5%	$35,316.48	2.3%
70%	1,000	511,000	$38,346.20	$38,886.75	1.4%	$39,212.75	2.3%
90%	200	131,400	$9,565.32	$9,996.16	4.5%	$9,941.36	3.9%
90%	300	197,100	$14,345.53	$14,794.24	3.1%	$14,787.04	3.1%
90%	500	328,500	$23,905.95	$24,390.40	2.0%	$24,478.40	2.4%
90%	700	459,900	$33,466.37	$33,986.56	1.6%	$34,169.76	2.1%
90%	800	525,600	$38,246.58	$38,784.64	1.4%	$39,015.44	2.0%
90%	900	591,300	$43,026.79	$43,582.72	1.3%	$43,861.12	1.9%
90%	1,000	657,000	$47,807.00	$48,380.80	1.2%	$48,706.80	1.9%

NOTES: 1. Bill Comparison assumes 63% on-peak, 37% off-peak energy consumption; Facilities Capacity = 119% of Demand

2. Values shown reflect Schedule 85 prices, per se, not the supplemental schedules incorporated in

3. Schedule 85 is billed on the basis of on-peak demand whereas Schedule 83 bills on the basis of simple demand. Accordingly, the above comparisons with the PGE-proposed Schedule 83 assume that the Schedule 83 simple demands for each customer are the same as its Schedule-85 billed on-peak demands. Greater simple off-peak demands would translate to larger bills under the Schedule 83 rates than what are shown.

Rate Designs

Charge	Current (Sched. 83)	PGE 85 Proposed	Staff 85 Proposed
Basic ($/Month)	25.00	400.00	250.00
Demand ($/kW)	2.67	2.83	2.83
Facilities Capacity ≤ 30 ($/kW)	1.48	2.04	2.44
Facilities Capacity > 30 ($/kW)	2.15	2.04	2.44
On-Peak Energy ($/kWh)	0.06480	0.06939	0.06939
Off-Peak Energy ($/kWh)	0.06480	0.05760	0.05760

Billing Determinants

	Quantity	PGE Sched. 85 Revenues	Staff Sched. 85 Revenues
Customer-Months	22,524	$ 9,009,600	$ 5,631,000
Annual kWs faccap	8,360,016	$ 17,054,433	$ 20,433,033
Basic and Facilities Capacity Charges Total		$ 26,064,033	$ 26,064,033

Schedule 85 Rate Design -- OPUC Staff Proposal

Primary, Three-phase service.

Paradigm: Reduce Basic Charge and Increase Facilities Capacity Charge in a Revenue-Neutral Manner

Effect of Proposed Rate Change on Monthly Bills -- PGE and Staff Proposals

Loads			Monthly Bill				
Load Factor	Demand kW	Energy kWh	Current Prices	Proposed PGE Prices	Percent Difference	Proposed Staff Prices	Percent Difference
30%	200	43,800	$3,698.25	$4,128.91	11.6%	$4,046.79	9.4%
30%	300	65,700	$5,507.38	$6,013.36	9.2%	$5,970.18	8.4%
30%	500	109,500	$9,125.63	$9,782.26	7.2%	$9,816.96	7.6%
30%	700	153,300	$12,743.88	$13,551.17	6.3%	$13,663.75	7.2%
30%	800	175,200	$14,553.00	$15,435.62	6.1%	$15,587.14	7.1%
30%	900	197,100	$16,362.13	$17,320.07	5.9%	$17,510.53	7.0%
30%	1,000	219,000	$18,171.25	$19,204.53	5.7%	$19,433.93	6.9%
50%	200	73,000	$5,524.71	$5,967.56	8.0%	$5,885.44	6.5%
50%	300	109,500	$8,247.07	$8,771.34	6.4%	$8,728.16	5.8%
50%	500	182,500	$13,691.78	$14,378.91	5.0%	$14,413.61	5.3%
50%	700	255,500	$19,136.49	$19,986.47	4.4%	$20,099.05	5.0%
50%	800	292,000	$21,858.84	$22,790.25	4.3%	$22,941.77	5.0%
50%	900	328,500	$24,581.20	$25,594.03	4.1%	$25,784.49	4.9%
50%	1,000	365,000	$27,303.55	$28,397.81	4.0%	$28,627.21	4.8%
70%	200	102,200	$7,351.17	$7,806.22	6.2%	$7,724.10	5.1%
70%	300	153,300	$10,986.76	$11,529.33	4.9%	$11,486.15	4.5%
70%	500	255,500	$18,257.93	$18,975.55	3.9%	$19,010.25	4.1%
70%	700	357,700	$25,529.10	$26,421.77	3.5%	$26,534.35	3.9%
70%	800	408,800	$29,164.68	$30,144.88	3.4%	$30,296.40	3.9%
70%	900	459,900	$32,800.27	$33,867.99	3.3%	$34,058.45	3.8%
70%	1,000	511,000	$36,435.85	$37,591.09	3.2%	$37,820.49	3.8%
90%	200	131,400	$9,177.63	$9,644.88	5.1%	$9,562.76	4.2%
90%	300	197,100	$13,726.45	$14,287.31	4.1%	$14,244.13	3.8%
90%	500	328,500	$22,824.08	$23,572.19	3.3%	$23,606.89	3.4%
90%	700	459,900	$31,921.71	$32,857.07	2.9%	$32,969.65	3.3%
90%	800	525,600	$36,470.52	$37,499.50	2.8%	$37,651.02	3.2%
90%	900	591,300	$41,019.34	$42,141.94	2.7%	$42,332.40	3.2%
90%	1,000	657,000	$45,568.15	$46,784.38	2.7%	$47,013.78	3.2%

NOTES: 1. Bill Comparison assumes 63% on-peak, 37% off-peak energy consumption; Facilities Capacity = 118% of Demand
2. Values shown reflect Schedule 85 prices, per se, not the supplemental schedules incorporated in PGE Exhibit/1502 Kuns-Cody/12,13.
3. Schedule 85 is billed on the basis of on-peak demand whereas Schedule 83 bills on the basis of simple demand. Accordingly, the above comparisons with the PGE-proposed Schedule 83 assume that the Schedule 83 simple demands for each customer are the same as its Schedule-85 billed on-peak demands. Greater simple off-peak demands would translate to larger bills under the Schedule 83 rates than what are shown.

Rate Designs

Charge	Current (Sched. 83)	PGE 85 Proposed	Staff 85 Proposed
Basic ($/Month)	80.00	360.00	200.00
Demand ($/kW)	2.67	2.73	2.73
Facilities Capacity ($/kW)	1.46	1.97	2.30
On-Peak Energy ($/kWh)	0.06255	0.06733	0.06733
Off-Peak Energy ($/kWh)	0.06255	0.05554	0.05554

Schedule 85 Billing Determinants

	Quantity	PGE Revenues	Staff Revenues
Customer-Months	1560	$ 561,600	$ 312,000
Annual Fac Cap kWs	758,117	$ 1,493,490	$ 1,743,090
Basic and Demand Total		$ 2,055,090	$ 2,055,090

CASE: UE 215
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1104

Staff's Optional Refined Alternatives to PGE's Proposed Schedules 85 and 89 Energy Time-of-Use Rates

June 4, 2010

Peak, Shoulder, and Offpeak PGE Energy Cost Differentials

Rates Intervals Definitions	
Sunday, year-round: Offpeak	
Summer	
Peak:	Noon to 8 pm
Shoulder:	6 am to noon and 8 pm to 10 pm
Offpeak:	10 pm to 6 am
Non-Summer	
Peak:	6 am to 10 am and 4 pm to 8 pm
Shoulder:	10 am to 4 pm and 8 pm to 10 pm
Offpeak:	10 pm to 6 am

Average of Long-term Energy Marginal Costs/Prices (Mills/kWh)

	Rates Interval			
Month	**Offpeak**	**Peak**	**Shoulder**	**Grand Total**
Jan	76.3	95.9	84.8	84.2
Feb	78.6	91.8	84.3	84.0
Mar	74.1	85.6	82.9	80.0
Apr	59.0	70.5	67.8	64.8
May	43.8	67.3	62.0	55.5
Jun	30.6	60.0	50.4	44.8
Jul	62.0	104.9	90.1	81.8
Aug	69.5	101.6	91.1	85.1
Sep	67.6	92.7	88.0	80.7
Oct	75.6	89.3	86.1	82.3
Nov	77.8	90.7	87.7	84.4
Dec	86.5	109.4	96.2	96.0
Simple Average	66.8	88.3	81.0	77.0

Simple Averages (Mills/kWh)

	Offpeak	Peak	Shoulder	Grand Total
Summer	66.4	99.7	89.7	82.5
Non-Summer	66.9	84.5	78.0	75.1

Averages Abstracted (Mills/kWh)

	Offpeak	Peak	Shoulder
Summer	66	100	90
Non-Summer	66	85	78

Data Source: "Price" Tab from File "MCenergy-2011_GRC11.xlsx" of PGE 1500 Worksheets.

2

Staff's Refined TOU Energy Rates *Option* for Schedules 85 and 89

Staff Option Pricing Rules: Offpeak price same as PGE's; Summer Peak Price is 1 cent above Shoulder Price; Non-Summer Peak Price is 0.7 cents above the Shoulder Price.
Condition: No disparity between Staff and PGE regarding expected* seasonal revenue collections.

Energy Charge: Schedule 85 Secondary

	PGE Proposal, Summer			PGE Proposal, Non-Summer			Staff Proposed Option, Summer			Staff Proposed Option, Non-Summer		
	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)
Offpeak	240,065	5.360	$ 12,867	702,013	5.360	$ 37,628	240,065	5.360	$ 12,867	702,013	5.360	$ 37,628
Shoulder							217,906	6.021	$ 13,120	664,020	6.196	$ 41,143
Peak	452,547	6.539	$ 29,592	1,303,080	6.539	$ 85,208	234,641	7.021	$ 16,474	639,060	6.896	$ 44,070
Totals	692,612		$ 42,460	2,005,093		$ 122,836	692,612		$ 42,462	2,005,093		$ 122,840

Energy Charge: Schedule 85 Primary

	PGE Proposal, Summer			PGE Proposal, Non-Summer			Staff Proposed Option, Summer			Staff Proposed Option, Non-Summer		
	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)
Offpeak	25,847	5.168	$ 1,336	73,256	5.168	$ 3,786	25,847	5.168	$ 1,336	73,256	5.168	$ 3,786
Shoulder							22,344	5.832	$ 1,303	63,161	5.995	$ 3,787
Peak	46,115	6.347	$ 2,927	126,908	6.347	$ 8,055	23,771	6.832	$ 1,624	63,747	6.695	$ 4,268
Totals	71,962		$ 4,263	200,164		$ 11,841	71,962		$ 4,263	200,164		$ 11,840

Energy Charge: Schedule 89 Secondary

	PGE Proposal, Summer			PGE Proposal, Non-Summer			Staff Proposed Option, Summer			Staff Proposed Option, Non-Summer		
	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)
Offpeak	66,144	5.145	$ 3,403	172,366	5.145	$ 8,868	66,144	5.145	$ 3,403	172,366	5.145	$ 8,868
Shoulder							54,854	5.801	$ 3,182	149,480	5.979	$ 8,937
Peak	115,103	6.324	$ 7,279	294,378	6.324	$ 18,616	60,249	6.801	$ 4,098	144,898	6.679	$ 9,678
Totals	181,247		$ 10,682	466,744		$ 27,485	181,247		$ 10,683	466,744		$ 27,483

Energy Charge: Schedule 89 Primary

	PGE Proposal, Summer			PGE Proposal, Non-Summer			Staff Proposed Option, Summer			Staff Proposed Option, Non-Summer		
	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)
Offpeak	285,767	4.957	$ 14,165	807,777	4.957	$ 40,042	285,767	4.957	$ 14,165	807,777	4.957	$ 40,042
Shoulder							197,005	5.627	$ 11,085	570,739	5.789	$ 33,040
Peak	401,265	6.136	$ 24,622	1,132,478	6.136	$ 69,489	204,260	6.627	$ 13,536	561,739	6.489	$ 36,451
Totals	687,032		$ 38,787	1,940,255		$ 109,530	687,032		$ 38,787	1,940,255		$ 109,533

Energy Charge: Schedule 89 Transmission

	PGE Proposal, Summer			PGE Proposal, Non-Summer			Staff Proposed Option, Summer			Staff Proposed Option, Non-Summer		
	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)	MWhs	Price ¢/kWh	Revenues (x1000)
Offpeak	59,128	4.875	$ 2,882	167,904	4.875	$ 8,185	59,128	4.875	$ 2,882	167,904	4.875	$ 8,185
Shoulder							34,805	5.562	$ 1,936	102,477	5.701	$ 5,842
Peak	68,494	6.054	$ 4,147	206,660	6.054	$ 12,511	33,689	6.562	$ 2,211	104,183	6.401	$ 6,669
Totals	127,622		$ 7,029	374,564		$ 20,697	127,622		$ 7,029	374,564		$ 20,696

* Revenue neutrality assumes no altered behavior due to the refined TOU pricing option.

Staff/1104
Compton/2

CASE: UE 215
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1105

Staff's Alternative to PGE's Rates Spread Proposal

June 4, 2010

Staff's Alternative to PGE's Rates Spread Proposal

PORTLAND GENERAL ELECTRIC (UE 215)

A	B	C	D	E	F	G	H	I	J	K	L	M
			PGE METHODOLOGY					PGE COST-OF-SERVICE METHODOLOGY WITH SUBSTITUTION OF LOWER GENERATION DEMAND COSTS				
			Cost-of-Service Allocation			PGE Proposed Spread		Staff Proposed Spread		Cost-of-Service Allocation		
Grouping	Cycle MWH	Revenues at 2010 Prices ($000)	2011 Costs ($000)	Percent Change	CIO Revenues	Net Change	Net Revenues	Net Change	Net Revenues	2011 Costs ($000)	Percent Change	CIO Revenues
Schedule 7	7,623,626	$814,982	$886,977	8.83%	$0	8.83%	$ 886,977	7.95%	$ 879,751	$879,751	7.95%	$0
Schedule 15	24,166	$4,515	$4,548	0.73%	$57	2.00%	$ 4,605	2.80%	$ 4,642	$4,575	1.33%	$67
Schedule 32	1,466,414	$147,875	$160,044	8.23%	$0	8.23%	$ 160,044	8.18%	$ 159,974	$159,974	8.18%	$0
Schedule 38	38,502	$4,046	$5,532	36.73%	($885)	14.85%	$ 4,647	14.85%	$ 4,647	$5,552	37.23%	-$905
Schedule 47	22,186	$2,630	$4,865	84.96%	($1,844)	14.85%	$ 3,021	14.85%	$ 3,021	$4,794	82.27%	-$1,773
Schedule 49	69,403	$5,811	$13,316	129.14%	($6,593)	15.68%	$ 6,723	14.85%	$ 6,674	$13,109	125.57%	-$6,435
Schedule 83	2,422,868	$195,372	$218,153	11.66%	($4,652)	9.28%	$ 213,501	11.87%	$ 218,556	$218,556	11.87%	$0
Schedule 85	2,954,888	$229,215	$237,588	3.65%	$4,816	5.75%	$ 242,404	6.28%	$ 243,600	$240,101	4.75%	$3,499
Schedule 89	3,793,152	$263,312	$261,728	-0.60%	$7,510	2.25%	$ 269,239	2.58%	$ 270,097	$266,218	1.10%	$3,879
Schedule 91	108,918	$18,124	$18,323	1.10%	$160	1.98%	$ 18,483	3.25%	$ 18,713	$18,444	1.77%	$269
Schedule 92	4,740	$392	$378	-3.44%	$21	1.97%	$ 399	0.00%	$ 392	$386	-1.57%	$6
Schedule 93	573	$94	$121	28.54%	($13)	14.85%	$ 108	14.85%	$ 108	$123	29.96%	-$14
COS Cycle Totals	18,529,435											
Sch 485 Energy	12,667				$21		$21		$21			$21
Sch 76/489 Energy	700,724				$1,387		$1,387		$1,387			$1,387
TOTALS	19,242,826	$1,686,369	$1,811,574	7.42%	($14)		$ 1,811,560	7.42%	$ 1,811,582	$1,811,582	7.42%	($1)

PGE Constraints

Cap on Rate Change	1.25	(core schedules)
Cap on Rate Change	2.00	(irrigation, sch 38, 93)
Cap on CIO (mills/kWh)	(95.00)	(irrigation)

Staff Proposal

Duplicate PGE's Proposed Net Revenues/CIO except as follows:

- Multiple-to-Average Cap on Rate Increase: 2.00 Times (all schedules) — NOTE: This constraint over-rides the 95 mill benefit limitation for irrigation as proposed by PGE.
- Floor on Rate Decrease: 0%
- CIO Subsidy Rate: 1.46%
- Justification for Cost-of-Service Change: A cheaper, less fuel-efficient SCCT (i.e., reflecting true demand costs) capacity cost estimate from PacifiCorp is substituted for PGE's figure.
- Major Impact of Cost-of-Service Change: The change elevates the cost of service of Schedules 85-93, reduces the cost-of-service to Schedule 7, and leaves the other schedules' costs-of-service relatively unaffected.

References: PGE Exhibit/1503 Kuns-Cody/10, PGE Exhibit/1504 Kuns-cody/6, PGE Work Papers Ratespread11GRC.

Staff/1105
Compton/1

CASE: UE 215
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

June 4, 2010

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Irina Phillips. I am an Economist employed by the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. My qualifications appear in Exhibit 1201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony assesses Portland General Electric's (PGE or Company) Load Forecast for this proceeding's 2011 test year.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

OVERVIEW OF PGE MODEL

Q. WHY IS THE ACCURACY OF A LOAD FORECAST IMPORTANT?

A. The load forecast is important because it affects nearly all facets of a general rate review. Load levels affect revenue forecasts, power costs and rate base. Therefore it is important to have an accurate load forecast to use as the basis for establishing just and reasonable rates.

Q. WHAT IS PGE'S 2011 TEST YEAR FORECAST?

A. PGE forecasts on a cycle-month (billing) basis 19,243 million kilowatt-hours (kWh) delivered to end-use customers for test year 2011. This number includes deliveries to direct access customers (schedules 483 and 489). This forecast is 0.1% above the 2009 level of weather-adjusted actual energy delivered and 4.8% below the 20,214 million kWh weather-adjusted level included in the UE197 settlement (for test year 2009).

Q. WHAT ARE THE MAJOR DIFFERENCES BETWEEN THE 2011 FORECAST AND 2009 ACTUALS?

A. The forecast takes into account a very modest price-elasticity effect on demand (PGE anticipates higher electricity prices in 2011 compared to prices in effect in the 2009 base period), savings from energy efficiency (EE) programs and the impacts of Advanced Meter Infrastructure (AMI) programs.

Q. WHAT IS THE ESTIMATED QUANTITATIVE IMPACT OF THE PRICE-ELASTICITY EFFECT?

A. The price-elasticity effect is approximately 98.5 million kWh and reduces the basic 2011 forecast by approximately 0.5%. PGE assumed an overall rate increase of 12% in establishing this adjustment. PGE uses price-elasticity estimates of negative 0.08 and negative 0.03 for residential and non-residential demand, respectively, with non-residential demand being more price inelastic. These elasticity values are very inelastic meaning that PGE does not view usage in the short run as being very responsive to changes in price.

Q. WHAT IS THE ESTIMATED MAGNITUDE OF THE EE SAVINGS?

A. PGE and the Energy Trust of Oregon (ETO) estimate 174.1 million kWh incremental savings from these programs in 2011.[1] This serves to reduce the load forecast by 0.9%.

Q. WHAT BENEFITS OF THE AMI PROGRAM DOES PGE INCLUDE IN THE 2011 TEST YEAR FORECAST?

A. PGE expects that AMI will better identify previously unaccounted-for energy (and reduce losses caused by energy theft) by accelerating the disconnect process and reducing written-off power deliveries. PGE estimates that "Remote Disconnect" will decrease energy delivery and "Lost Revenue Protection" will increase it. The combined effect is an 8.1 million kWh reduction in forecasted load.

Q. WHAT IS THE PGE LOAD FORECAST MODEL?

A. The forecast model specification remains the same as the one used in previous general rate case filings. The forecast model is described in PGE Short-Term Energy and Load Forecast Presentation (Staff Exhibit 1202). PGE re-estimated coefficients to reflect structural or behavioral changes in the economy over time.

Q. WHAT ASSUMPTIONS WITH RESPECT TO WEATHER DID PGE USE IN THE FORECAST?

A. Since Docket No. UE 180, PGE has been using 15-year moving averages to represent forward-looking weather conditions.[2]

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[1] *See,* in Docket No. UE 215, Exhibits PGE/1400 Nguyen/4 and PGE/1405 Nguyen/1.
[2] *See*, in Docket No. UE 180, Exhibit PGE/1200 Nguyen/8 and, in Docket No. UE 197, Exhibit PGE/1100 Nguyen/5.

STAFF CONCERNS

Q. DID STAFF REVIEW THE PGE LOAD FORECAST?

A. Yes. Staff issued data requests Nos. 189-199 and reviewed the PGE modeling, inputs, and assumptions.

Q. WHAT CONCERNS DID YOUR REVIEW RAISE WITH RESPECT TO PGE'S 2011 TEST YEAR FORECAST?

A. I generally concur with PGE's forecast: the methodology used is consistent and reasonable. There are, however, several concerns raised during the course of my review.

Q. WHAT IS THE FIRST CONCERN?

A. There is significant fluctuation in the level of energy for Primary Voltage and Transmission Voltage Services between 2009 actuals and the 2011 forecast. Energy for Primary Voltage Service increased during recessionary 2009, is forecasted to increase by 7.9% in 2010 and to decline in 2011. Energy for Transmission Voltage Service dropped 29.6% in 2009, and is forecasted to drop an additional 8.1% in 2010 and then increase by 6.5% in 2011.[3] These calculations are based on values in Exhibit PGE/1401 Nguyen/1. Power costs and other factors have not been updated to reflect this adjustment as I am anticipating further sales adjustments as additional information and company positions become available.

Q. WHAT IS THE SECOND CONCERN?

[3] These rates are year-over-year changes.

A. I believe the 2010 expectation and the 2011 test year forecast for single-family and multiple-family building permits are overly optimistic (132.3% and 184.1% growth for single and multiple family permits in 2010).[4] PGE's response to Staff data request 195 explained that the company used long-term trends to derive the values for 2010 and 2011 but I believe these forecasts do not reflect the current low levels of activity in the residential construction industry. As noted, these assumptions appear to be overly optimistic. I recommend PGE forecast for building permits be revised to 2008 level. The impact of this would be to reduce both outside plant forecast as well as kWh sales.

Q. WHAT IS THE THIRD CONCERN?

A. I find the forecasts of residential use per occupied account inconsistent. The fluctuations in weather-adjusted single-family heat and mobile home non-heat between 2009 and 2011 seem anomalous. While I do not have a recommended adjustment at this time, staff is continuing to consider this concern and possible adjustments.

Q. WHAT IS THE FOURTH CONCERN?

A. There is some inconsistency in PGE's 2011 test year forecast of industrial deliveries. It seems unusual that PGE expects 11.3% growth in the High Tech sector in 2010 and an almost 2% decline in the following (2011 test) year.[5] There is also an atypical fluctuation in the Paper and Allied Industry

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[4] *See,* in Docket No. UE 215, Exhibit PGE/1406 Nguyen/1.
[5] *See,* in Docket No. UE215, Exhibit PGE/1409 Nguyen/1.

demand pattern. I do not have a specific adjustment at this time as I expect further information and clarification by the company on this issue.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION REGARDING PGE'S LOAD FORECAST AS PRESENTED IN THE COMPANY'S UE 215 APPLICATION?

A. I will continue to analyze the issue as well as await PGE's forecast update which PGE has indicated will be available by no later than July 15, 2010. My final set of recommendations will be based on the review of that forecast.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 215
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

WITNESS QUALIFICATION STATEMENT

June 4, 2010

NAME:	**Irina Phillips**
EMPLOYER:	**Oregon Public Utility Commission**
TITLE:	**Economist**
ADDRESS:	**550 CAPITOL ST. NE, SUITE 215** **Salem, OR 97308**
EDUCATION:	**Master of Science, Economics** **Oregon State University, Corvallis, OR** **Bachelor of Science, Economics and Management** **St. Petersburg State University of Economics and Finance, St. Petersburg, Russia**
EXPERIENCE:	**Provided testimony or comments in a variety of OPUC dockets, including UM 1431, UE 213, and UG 186. Assisted in Staff review of Integrated Resource Plans (LC48 and LC50).** **Between 2005 and 2009, worked as an Adjunct Instructor for Linn-Benton Community College, Albany, OR and Western Oregon University, Monmouth, OR** **Between 1996 and 1999, worked as a Financial Analyst for Gillette International LLC, Russian Office, St. Petersburg, Russia** **Between 1991 and 1994, worked as a Senior and Chief Accountant for Korex, Fiton and Tandem companies, St. Petersburg, Russia**

CASE: UE 215
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

June 4, 2010

PGE
SHORT-TERM
ENERGY AND LOAD
FORECAST
PRESENTATION

December 8, 2009

CLASSIFICATION OF CUSTOMERS FOR REPORTING PURPOSES

Voltage levels / ERC (Energy Revenue Class) as used in the Revenue Reports and NAICS Groups

Residential: Residential customers (**ERC1** for rate schedules 7, 9 and 15)
Secondary: Secondary voltage customers (**ERC3** - called General Service or Commercial)
May be referring to only schedules 32 (0-30 KW), 83 (31-1,000 KW) and 89 (> 1,000 KW)
Secondary voltage customers, or it may include Miscellaneous and Lighting Schedules.
ERC3 includes all schedules. Prior to 2003 secondary voltage was Schedule 32.
120 volts to 480 volts.
Primary: Primary voltage customers schedules (**ERC5** - called Industrial and sometimes Small Industrial)
Prior to 2003 primary voltage was Schedule 83 but now 83 (31-1,000 KW) and 89 (> 1,000 KW).
11,000 volts to 12,470 volts
Transmission: Transmission voltage customers (**ERC4** - called Industrial and sometimes Large Industrial)
Prior to 2003 transmission voltage was Schedules 89/99 but now 83 (31-1,000 KW)
and 89 (> 1,000 KW). 56.81 kV to 120.87 kV – normally called 57 kV
Lighting: Street and Highway lighting (91), traffic signals (92), recreational field lighting (93), and
Communication Devices (94) – (**ERC6** – called Lighting. (Sometimes part of Commercial)).

NAICS (North American Industry Classification System) – replacing SIC

Commercial: NAICS Code - commercial customers (NAICS 01-29 & 42-99).
Manufacturing: NAICS Code - manufacturing customers (NAICS 30-33), sometimes called Industrial.

ERC3 + ERC6 = Commercial but some use ERC3 = Commercial. ERC4 + ERC5 = Industrial.
RATE Commercial + Industrial = Secondary + Primary + Transmission = NAICS Commercial + Manufacturing

There is no standard definition for rate schedule Commercial. Sometimes it will be just Secondary voltage customers and sometimes it will include Miscellaneous and Lighting schedules. The same holds true for NAICS Commercial, sometimes will include Miscellaneous and Lighting schedules and sometimes it will not.

Also confusing is that the Rate schedule sectors are called Commercial and Industrial while the NAICS sectors can also be called Commercial and Industrial. Many times it is difficult to determine which the writer or speaker is referring to.

Net System: Net System Energy (called **Total System in the revenue reports as it is the total of the CIS Banner system, but Control area can be called Total System as it is the total transmission system**, so Net System is used in this report to reduce confusion). Net System is [Control area net of borderline].
Net System = COS + NCOS. |||| (Boarder line = (PUD, self generating and BPA adjustment)
COS: Cost of Service customers. Those customers on standard tariff rates.
NCOS: Non Cost of Service customers. For current year only.
NCOS = VPO + ESS.
VPO: Variable Price Option. On daily or monthly option.
ESS: (Direct Access) With Energy Service Supplier.
PGE: COS + VPO

OPT-OUT

2006 definition: For future years, those customers who have opted out. ie: told PGE "do not plan to serve my load next year", therefore exclude me from or "opt me out of" schedule 125B". Schedule 125B has been discontinued.
2008 definition: Those customers who have chosen a non-cost-of-service rate schedule.
<u>There are 2 options for a customer to opt-out of a cost-of-service rate:</u>
1. Chosen a 3 or 5 year commitment: Schedules 483 or 489. They can either be served by an ESS or served on a PGE variable price (daily or monthly) option. The System Total (net system) Revenue Report will show both a 483 for being with an ESS and another 483 for being on a VPO schedule. VPO schedules show up on the PGE Revenue Report.
2. Chosen a 1 year commitment to be served by an ESS. Schedules 532, 583 or 589

Depending on the context, "opt-out" may refer to only those customers with the 3 or 5 year commitment. Or it may refer to only those customers that have chosen to be served by an ESS. Or it may refer to all those on a non-cost-of-service rate schedule.

ENERGY FORECASTS:

Budget Forecast: the forecast used for the 2009 Budget (SDEC08E).

Rolling Forecast: Concatenation of most current forecast for each month. Forecast SDEC08E from January to February. Forecast SMAR09E from March to May. Forecast SJUN09E from June to the August. Forecast SSEP09E from September to present month.

History: The term "history" refers to "actual or weather-adjusted results" for a given historical time period. Actual energy is what is reported on the Revenue Reports. Weather-adjusted is the actual energy adjusted for the effects of weather.

ENERGY AND LOADS REPORTED AND ESTIMATED

(some use energy and loads interchangeable, but for this report energy is at the meter and load is at the bus bar)

There are 3 reported cycle energy at the meter from the Revenue Report (energy in kWh or MWh (000) or M-kWh (000,000)).

A. **Net System Energy:** Titled System Total - Energy billed to all PGE customers within our service area including PGE standard tariff, VPO and ESS kWh. Energy is reported in kWh but for other reports is converted to MWh. This is the basis for this monthly report.
B. **PGE Energy:** Energy billed to PGE standard tariff and VPO customers. (Excludes ESS energy) (Comparable to Merchant).
C. **ESS Energy or Direct Access Energy:** Energy billed to ESS customers.

There are 3 reported calendar loads at the Bus Bar (load in Avg MW / MWa – peak in MW).

D. **Control Area Load:** Load to serve all customers within our service area (PGE, ESS, border line (PUD and other)).
E. **Merchant Load:** Load needed to serve PGE energy customers (PGE standard tariff and VPO customers).
From the EGR+D (Energy Generated, Received + Delivered) report - energy is in MWh. See # 1 below.
F. **Net System Load.** Load to serve all PGE customers (total PGE and ESS). This is an estimated number derived either by subtracting (netting out) Boarder line (PUD, self generating and BPA adjustment) loads from Control area loads, or by adding estimated ESS loads to the energy purchased/generated to serve PGE standard tariff and VPO loads. From the Peak Load Summary report - load is reported in average megawatts (Avg MW or MWa), peak in megawatts (MW). See # 2.

Descriptions.

Prior to ESSs the "Total or Net System Load" from Risk Management and the "Net System Load" from Transmission Services (they call control area load total system load) were basically the same concept arrived at by different calculations. Prior to January 2005 the terms "Total System Load" and "Net System Load" were used interchangeable. We are striving to use "Net System" and not use "Total System" to reduce confusion.
Prior to ESSs, the two were normally within an Avg. MW of each other. Transmission Services from a top down approach and Risk Management from a bottom up approach. As Transmission Services and Risk Management are governed by FERC it has become difficult for them to determine the causes when there are differences in their reported results.

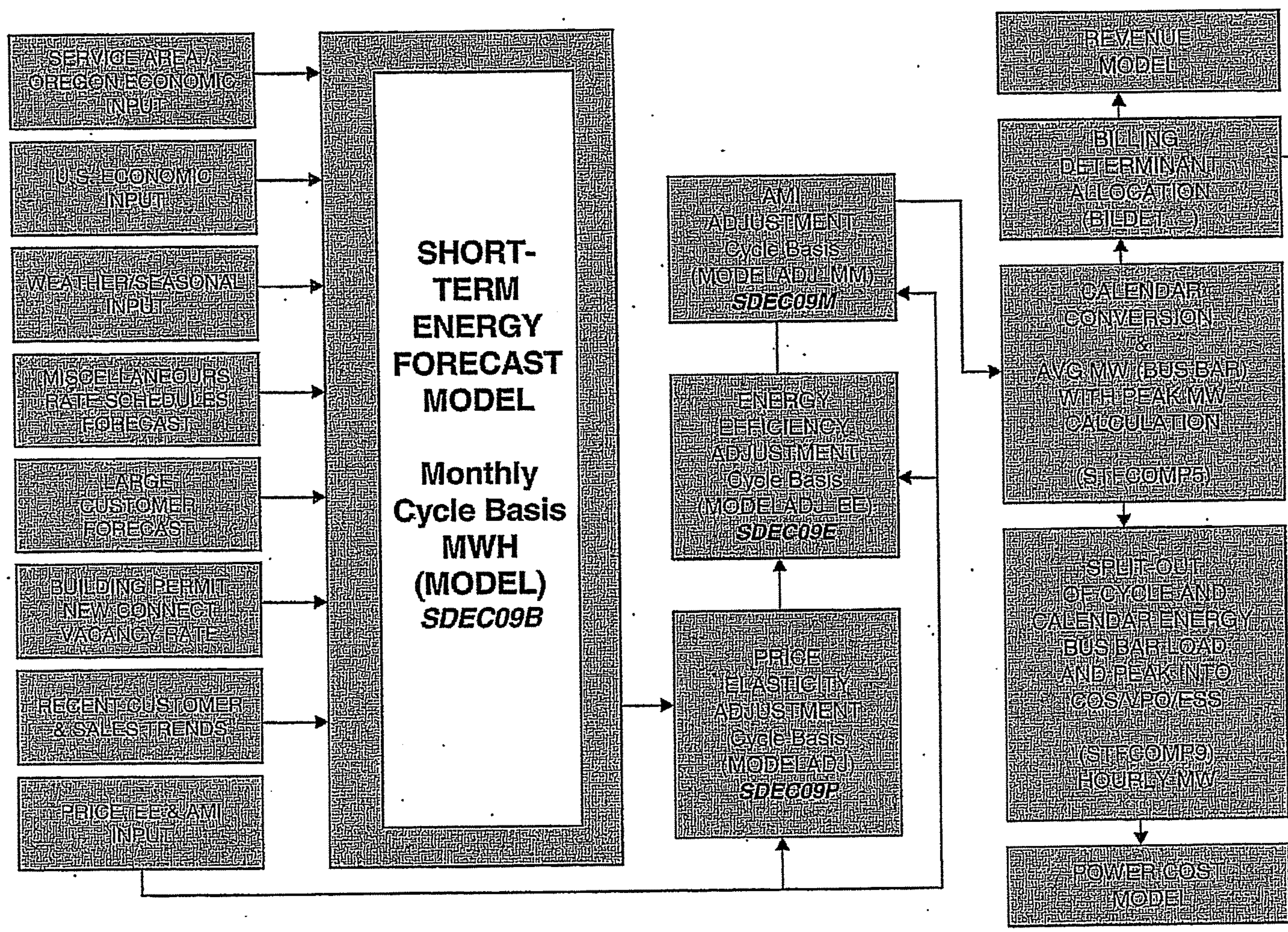
1. **Merchant Load:** MWh or Avg. MW calendar load at the bus bar purchased or generated to serve PGE energy customers. This does not include ESS load. This is energy purchased or generated by PGE to serve standard tariff and VPO loads. This load is calculated used a system called PSAS but has moved to PSAS-M. Reported in the EGR+D (Energy Generated, Received + Delivered) report produced by Risk Management.

2. **Net System Load:** Avg. MW or MWa on a calendar basis at the bus bar used to serve all PGE customers, ESS included. This is the Control Area net of (less) Boarder Line (PUD, self generation and BPA adjustments) load. This load includes ESS load. This load is calculated using a system called PSAS-T from transmission services. Net System loads are reported in the Peak Load and Summary Report. Hourly MW by Transmission Services. The actual report for Avg MW and peak using the hourly loads is by the Energy Forecast group of BDS.

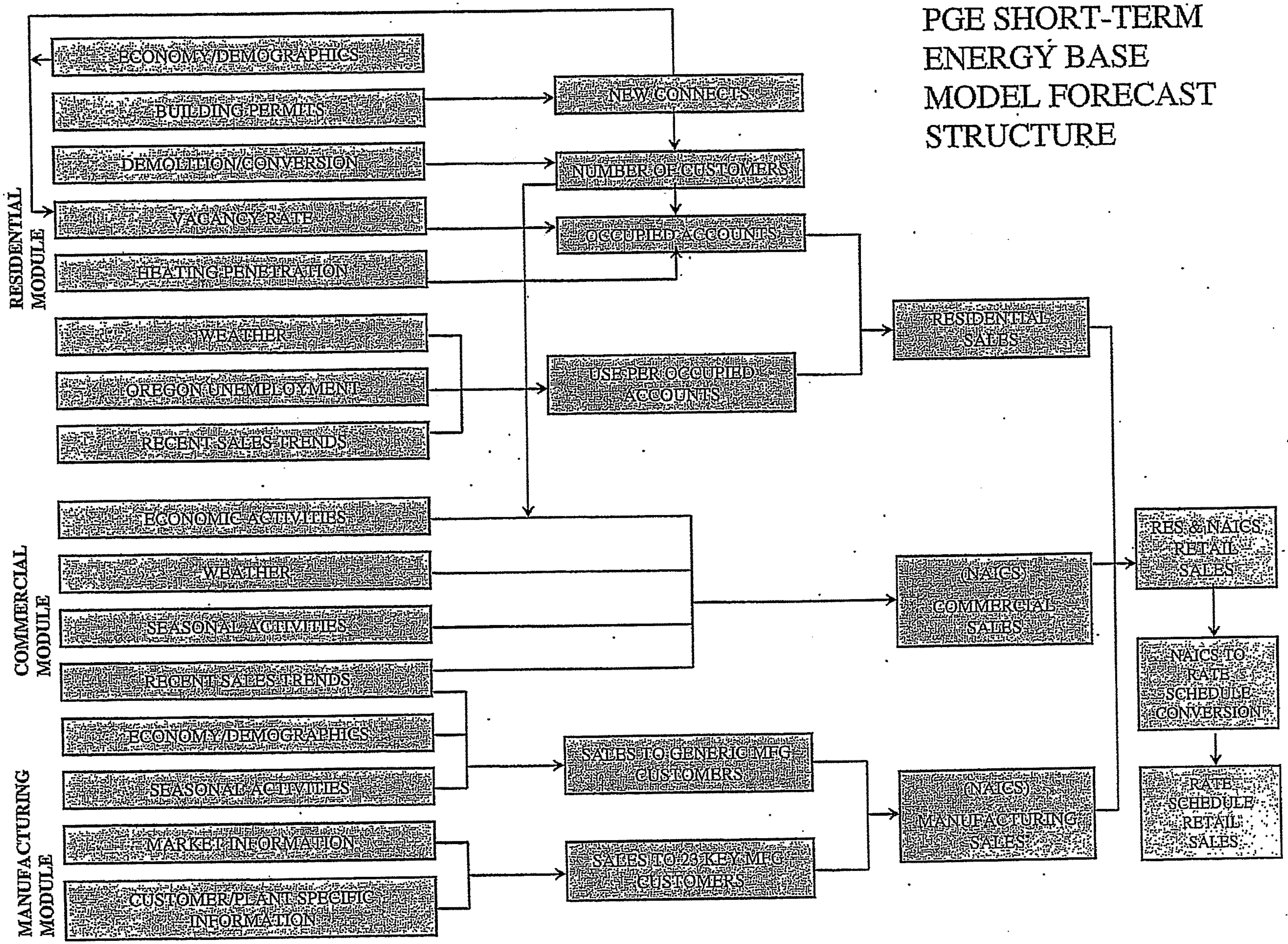
In theory: Net System Load = Merchant Load + ESS Load = Control Area Load – Boarder Line Load.

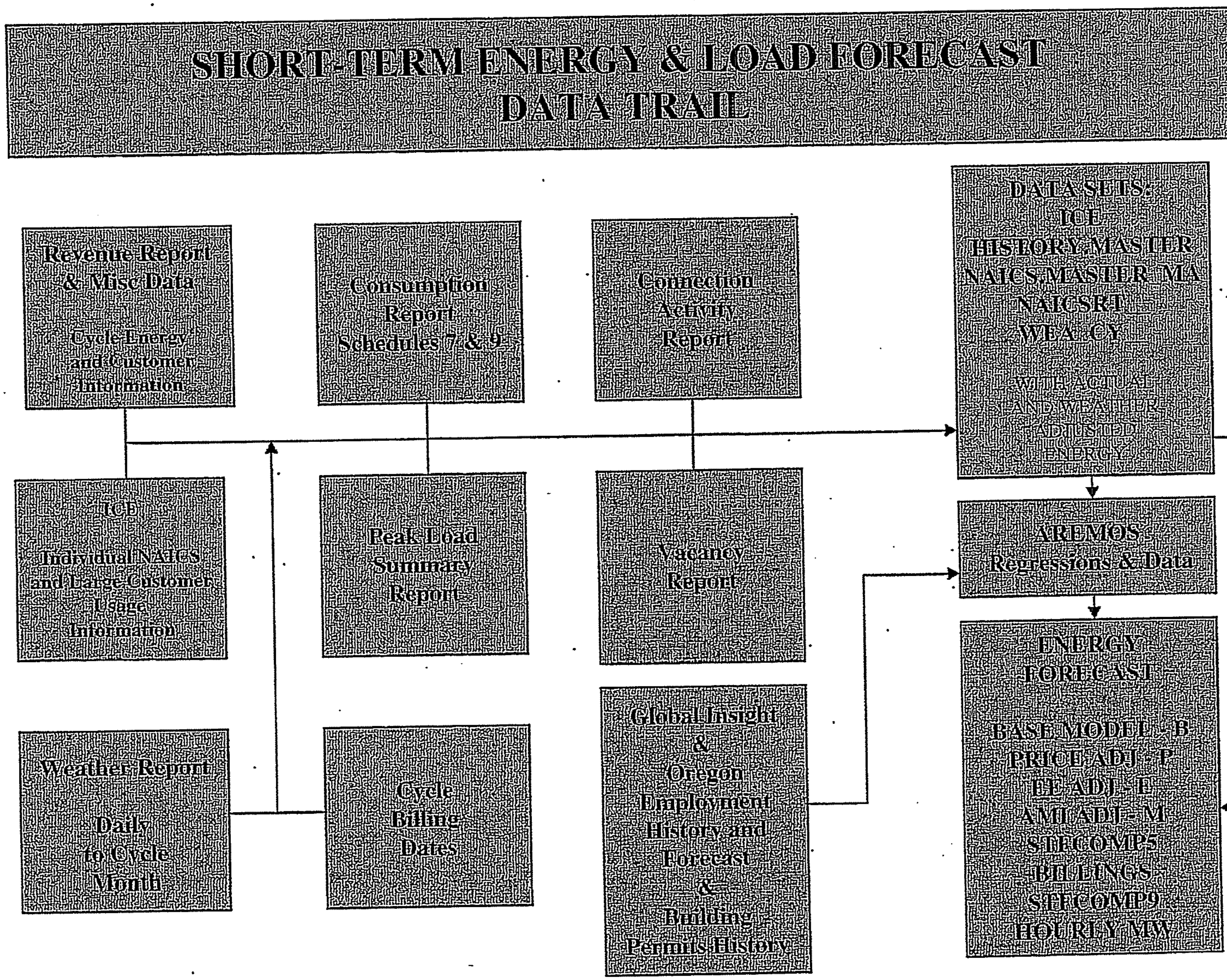
2

PGE SHORT-TERM RETAIL ENERGY & LOAD FORECAST PROCESS



PGE SHORT-TERM ENERGY BASE MODEL FORECAST STRUCTURE




SHORT-TERM ENERGY & LOAD FORECAST
DATA TRAIL
Revenue Report & Misc Data
Cycle Energy and Customer Information
Consumption Report Schedules 7 & 9
Connection Activity Report
DATA SETS:
ICE
HISTORY.MASTER
NAICS.MASTER_MA
NAICSRT
WEA_CY
WITH ACTUAL AND WEATHER ADJUSTED ENERGY
ICE
Individual NAICS and Large Customer Usage Information
Peak Load Summary Report
Vacancy Report
AREMOS
Regressions & Data
Weather Report
Daily to Cycle Month
Cycle Billing Dates
Global Insight & Oregon Employment History and Forecast & Building Permits History
ENERGY FORECAST
BASE MODEL - B
PRICE ADJ - P
EE ADJ - E
AMI ADJ - M
STFCOMP5
BILLINGS
STFCOMP9
HOURLY MW

CERTIFICATE OF SERVICE

UE 215

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 4th day of June, 2010.

Lois Meerdink

Lois Meerdink
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-8959

UE 215
Service List (Parties)

JOSEPH MACDONALD	15273 SE LA BONITA WAY OAKGROVE OR 97267
HEATHER RODE	21465 NW COFFEY LANE HILSBORO OR 97124 heatherrode@gmail.com
BOEHM KURTZ & LOWRY	
KURT J BOEHM ATTORNEY	36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
CITIZENS' UTILITY BOARD OF OREGON	
GORDON FEIGHNER **(C)** ENERGY ANALYST	610 SW BROADWAY, SUITE 308 PORTLAND OR 97205 gordon@oregoncub.org
ROBERT JENKS **(C)** EXECUTIVE DIRECTOR	610 SW BROADWAY STE 308 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN **(C)** LEGAL COUNSEL/STAFF ATTY	610 SW BROADWAY - STE 308 PORTLAND OR 97205 catriona@oregoncub.org
RAYMOND MYERS **(C)** ATTORNEY	610 SW BROADWAY - STE 308 PORTLAND OR 97205 ray@oregoncub.org
KEVIN ELLIOTT PARKS **(C)** STAFF ATTORNEY	610 SW BROADWAY STE 308 PORTLAND OR 97205 kevin@oregoncub.org
CITY OF PORTLAND - CITY ATTORNEY'S OFFICE	
BENJAMIN WALTERS **(C)** CHIEF DEPUTY CITY ATTORNEY	1221 SW 4TH AVE - RM 430 PORTLAND OR 97204 ben.walters@portlandoregon.gov
CITY OF PORTLAND - PLANNING & SUSTAINABILITY	
DAVID TOOZE SENIOR ENERGY SPECIALIST	1900 SW 4TH STE 7100 PORTLAND OR 97201 david.tooze@portlandoregon.gov
DAVISON VAN CLEVE PC	
S BRADLEY VAN CLEVE **(C)**	333 SW TAYLOR - STE 400 PORTLAND OR 97204 mail@dvclaw.com

DEPARTMENT OF JUSTICE	
STEPHANIE S ANDRUS **(C)** ASSISTANT ATTORNEY GENERAL	REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
ENERGY STRATEGIES LLC	
KEVIN HIGGINS **(C)** PRINCIPLE	215 STATE ST - STE 200 SALT LAKE UT 84111-2322 khiggins@energystrat.com
FRED MEYER STORES/KROGER	
NONA SOLTERO CORPORATE LAW DEPT #23C	3800 SE 22ND AVE PORTLAND OR 97202 nona.soltero@fredmeyer.com
IBEW LOCAL 125	
MARCY PUTMAN POLITICAL AFFAIRS & REPRESENTATIVE	17200 NE SACRAMENTO STREET PORTLAND OR 97230 marcy@ibew125.com
NORTHWEST ECONOMIC RESEARCH INC	
LON L PETERS **(C)**	607 SE MANCHESTER PLACE PORTLAND OR 97202 lon@nw-econ.com
PACIFIC POWER & LIGHT	
JORDAN A WHITE SENIOR COUNSEL	1407 W. NORTH TEMPLE, STE 320 SALT LAKE CITY UT 84116 jordan.white@pacificorp.com
PACIFICORP, DBA PACIFIC POWER	
OREGON DOCKETS	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PORTLAND GENERAL ELECTRIC	
RANDALL DAHLGREN	121 SW SALMON ST - 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
DOUGLAS C TINGEY **(C)**	121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com
PUBLIC UTILITY COMMISSION	
JUDY JOHNSON **(C)**	PO BOX 2148 SALEM OR 97308-2148 judy.johnson@state.or.us

RFI CONSULTING INC	
RANDALL J FALKENBERG **(C)**	PMB 362 8343 ROSWELL RD SANDY SPRINGS GA 30350 consultrfi@aol.com
RICHARDSON & O'LEARY	
GREGORY M. ADAMS	PO BOX 7218 BOISE ID 83702 greg@richardsonandoleary.com
RICHARDSON & O'LEARY PLLC	
PETER J RICHARDSON **(C)**	PO BOX 7218 BOISE ID 83707 peter@richardsonandoleary.com
SEMPRA ENERGY SOLUTIONS LLC	
GREG BASS	401 WEST A STREET SUITE 500 SAN DIEGO CA 92101 gbass@semprasolutions.com
THE INTERNATIONAL DARK SKY ASSOCIATION	
JAMES BENYA	3491 CASCADE TERRRACE WEST LINN OR 97068 jbenya@benyalighting.com
LEO SMITH	1060 MAPLETON AVE SUFFIELD CT 06078