HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

November 2, 2006

Filing Center
Public Utility Commission of Oregon
550 Capitol Street, NE
Salem, Oregon 97301

Re: Docket No. UE 180/UE 184/UE 181

Dear Filing Center:

Enclosed for filing please find Staff Exhibit 1900, which concerns issues raised by the City of Portland, City of Gresham and the League of Oregon Cities ("the Cities"), and Staff Exhibits 1901 through 1923, which concern cost of capital issues. I filed a motion requesting admission of these exhibits earlier today. I am serving electronic copies of these exhibits on all parties and hard copies on Portland General Electric Company ("PGE"), the Industrial Customers of Northwest Utilities and the Citizens' Utility Board. These are the only parties in this proceeding, other than staff, that have filed testimony regarding PGE's cost of capital. I am also serving a hard copy of Staff Exhibit 1900 on counsel for the Cities.

Thank you for your attention.

Very truly yours,

Stephanie S. Andrus
Assistant Attorney General

Enc.
c. Service list (w/out enclosures, except as noted above)

1162 Court Street NE, Salem, OR 97301-4096 Telephone: (503) 378-6322 Fax: (503) 378-5300 TTY: (503) 378-5938

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CITY OF
PORTLAND, OREGON
OFFICE OF CITY ATTORNEY

Linda Meng, City Attorney
1221 S.W. 4th Avenue, Suite 430
Portland, Oregon 97204
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RECEIVED
OCT 19 2006
Department of Justice
General Counsel-Salem

October 18, 2006

VIKIE BAILEY-GOGGINS
PUBLIC UTILITY COMMISSION
550 CAPITOL ST NE STE 215
SALEM, OR 97308-2148

STEPHANIE ANDRUS
PUC STAFF COUNSEL
DEPARTMENT OF JUSTICE
1162 COURT ST NE
SALEM, OR 97301-4096

RE:	Docket No.	Staff Request No.	Response Due By
	UE 180	DR 1 (Revised)	October 18, 2006

On October 11, 2006, Commission Staff issued a revised Data Request No. 1, seeking responses from the City of Portland to the following requests for information:

1. **Regarding COP/100, Jubb/5 – Jubb/10, in which Mr. Jubb states that converting PGE to an LLC prior to the stock distribution to Enron creditors would have had "significant benefits" for ratepayers and then specifies that those benefits "would have arisen from the increases in depreciation or amortization available annually for federal and state income tax reporting purposes on the "step up" in PGE's assets "tax basis" over their "book basis" in the amount of the gain realized and recognized by Enron on the distribution of PGE LLC to its creditors trust[,]" please respond to the following requests:**
   a) **Please provide any cases relied on by Mr. Jubb in forming his opinion that ratepayers would have realized significant benefits from the LLC conversion that address the ratemaking treatment of existing accumulated deferred federal income tax following an LLC conversion. Is Mr. Jubb aware of any other cases that address the ratemaking treatment of existing accumulated deferred federal income tax following an LLC conversion? If yes, please identify them.**
   b) **Please provide any cases relied on by Mr. Jubb in forming his opinion that ratepayers would have realized significant benefits from the LLC conversion that address the ratemaking treatment of the increased level of depreciation due to an LLC conversion. Is Mr. Jubb aware of any other cases that address the ratemaking treatment of the increased level of depreciation due to an LLC conversion? If yes, please identify them.**
   c) **Please provide any cases relied on by Mr. Jubb in forming his opinion that ratepayers would have realized significant benefits from the LLC conversion that address the return on a restated rate base due to an LLC conversion. Is Mr. Jubb aware of any other cases that address the return on a restated rate base due to an LLC conversion? If yes, please identify them.**

d) **Please provide any cases relied on by Mr. Jubb in forming his opinion that ratepayers would have realized significant benefits from the LLC conversion that address the calculation of income tax expense for ratemaking purposes following an LLC conversion. Is Mr. Jubb aware of any other cases that address the calculation of income tax expense for ratemaking purposes following an LLC conversion? If yes, please identify them.**

City of Portland Response:

The City of Portland objects to these requests on the following grounds:

- The City of Portland objects to these requests the grounds that they are overly broad, unduly burdensome, and seek information not reasonably calculated to lead to the discovery of admissible evidence.

- The City of Portland objects to these requests as improper, as neither the Oregon Rules of Civil Procedure nor the Oregon Public Utility Commission's administrative rules provide for this discovery.

- The City of Portland objects to these requests as improper, as they seek information that is outside the bounds of the testimony filed as COP/100, Jubb/5 – Jubb/10.

- The City of Portland objects to these requests on the grounds that they call for the City to provide legal conclusions as to what may constitute "cases that address the ratemaking treatment" as to the various questions posed.

- The City of Portland objects to these requests on the grounds that they seek the production of attorney work product/trial preparation material, which is protected from discovery under ORCP 36B(3), without having made the commensurate showing that Staff has substantial need of the materials, and is unable without undue hardship to obtain these materials;[1]

- The City of Portland objects to these requests on the grounds that they seek the production of materials that may be subject to the lawyer-client privilege.

Subject to and without waiving such objections, the City of Portland's witness, David R. Jubb, to whom this request is directed, responds as follows:

The request uses terms that are subject to several possible interpretations, without providing any related explanation or definitions. For example, the reference to "cases" in each of the

[1] It seems that Staff is embarking on a path akin to "mutually assured destruction," wherein each party will be faced with the proposition of seeking "cases" relied upon by others, in anticipation of facing requests for their legal positions.

requests suggests that the request seeks testimony on the results of legal research, and then application of any identified caselaw in the development of an opinion.

The Commission's prior treatment of acquisition costs generally seems to disfavor allowing acquisition premiums to be reflected in regulated utility rates. In approving the acquisition of PacifiCorp by Midamerican Energy Holdings Company from Scottish Power, the parties agreed that any acquisition premium paid by MEHC for PacifiCorp would be excluded from PacifiCorp's utility accounts. This condition was a carry-over of the condition approved in the original acquisition of PacifiCorp by Scottish Power plc. The same concern was addressed in the recent approval of the issuance of stock by Portland General Elec. Co., where the Commission identified one of the benefits of the proposed transaction as having no acquisition premium. The rationale for this treatment seems to be that writing up the regulated rate base would encourage sales of utilities, funded by corresponding rate increases.

In this regard, generally accepted accounting principals, (GAPP), may address accounting for purchase acquisition costs differently from regulatory accounting. Specifically SOP 90-7 did not apply to PGE because it did not seek protection under the corporate bankruptcy. Additionally, FAS 141 did not apply to the distribution of PGE to Enron's creditors because the distribution of PGE was not a business combination. Finally "push down" or "new basis accounting" would not apply to PGE because its shares were not acquired by Enron creditors in a single free market transaction.

Accounting is not generally created by a body of case law but by authoritative pronouncements by standard setters and regulators such as the AICPA, APB, ASB, EITF, FASB, and SEC. For instance PGE is most significantly affected by FAS 71 "Accounting for Certain Types of Regulation." This standard makes accounting for a regulated utility vary from a non regulated business enterprise. FAS 101 "Regulated Enterprises- Accounting for Discontinuation of Application of FASB Statement 71" would apply if PGE or some segment thereof were to become non-regulated.

Generally, the specialized industry sources of GAAP for PGE are FAS 71, 90, 92, 98, 101, 143, 144 and FTB 87-2 and EITF 92-7, 92-12, 93-4, 97-4. Mr. Jubb would acknowledge that he is not an expert in these particular areas.

However, accounting for taxes and deferred income taxes are simply governed consistent with FAS 109. Mr. Jubb is an expert in this area, as described in COP/100/Jubb/2. There are no exemptions or special provisions for income tax accounting for regulated enterprises. When a specialized industry GAAP such as FAS 71 creates an asset or liability related to a future rate increase or decrease (e.g. wind storm damage cost) the difference between general GAAP treatment (deduction) and specialized GAAP (capitalize) is simply treated as a temporary difference within the meaning of FAS 109.

As described in Staff/COP DR 01(a), the benefit concerning the treatment of the existing accumulated deferred federal income tax following an LLC conversion flows from the general rules of AICPA Practice Bulletin (PB) 14 that establishes that when an entity restructures itself as a limited liability company the basis of all assets and liabilities from its predecessor entity are carried forward. Also if the new entity is not a taxable one, any deferred tax assets or liabilities existing previously are to be written off at the time the change in tax status becomes effective; with the elimination of any debit or credit balance being affected by a charge or credit to current period tax expense. For PGE a tax liability (credit) would be eliminated (i.e., with a debit to the account) and that period's provision for income tax expense would receive a credit.

As described in Staff/COP DR 01(b), the benefit concerning the ratemaking effect of increased tax depreciation caused by the LLC conversion is demonstrated below. The form for this calculation is based upon the Excel spreadsheets developed by Commission staff for utility reporting of income taxes in the AR 499 administrative rulemaking. The Commission's worksheet was used as the basic form in this calculation. A copy of the spreadsheet is included with this response.

It is clear that if the actual taxes paid on the federal tax returns filed are reduced by increased tax depreciation (lines 1, 2 and 3 of the summary sheet) then the amount refunded to ratepayers (line 13) is increased by the amount exactly. For FAS 109 purposes, the increased tax depreciation is not a temporary difference but a permanent one, so it would flow through to ratepayers.

Line No.		Federal and State Taxes Paid and Properly Attributed
1	$ 18,710	Federal Income Taxes: from page 2, line 29
2	$ 3,782	State Income Taxes: from page 3, line 22 --OR-- page 4, line 34
3	$ 22,492	Total Taxes Paid and Properly Attributed: sum of lines 1 and 2

Question "c" is difficult to answer because its apparent underlying premise is false. Historical cost is the foundation of GAAP and traditionally GAAP has not permitted a business entity to simply adopt a new basis of accounting. Rather, consistency in treatment is the watchword. PB 14 establishes that when an entity restructures itself as a limited liability company the basis of all assets and liabilities from its predecessor entity are carried forward. FAS 71 does not allow a restatement of the rate base for any specialized utility GAAP treatment. Therefore, there is no restated GAAP (or regulatory) rate base due to the LLC conversion.

Question "d" is again difficult to answer because its apparent underlying premise is false. There are no special rules for the calculation of income tax expense under FAS 109 for a regulated utility. The normal FAS 109 rules apply including deferred tax accounting. In the regulated utility. The normal FAS 109 rules apply including deferred tax accounting. In the example below, calculation of income taxes is set at 40%. As above, the form for this calculation is based upon the Excel spreadsheets developed by Commission staff for utility reporting of income taxes in the AR 499 administrative rulemaking. The Commission's worksheet was used as the basic form in this calculation.

Federal and State Taxes Collected	
$ 360,000	Gross revenue (2)(l) / (2)(q)(A)(ii) - from rate case
$ 55,000	Pre-tax income (2)(g) / (2)(q)(A)(ii) - from general rate case
15.3%	Net to gross revenues (2)(q)(A)(ii) - line 5 divided by line 4
$ 22,000	State & Federal Income Taxes (including deferred) (2)(q)(A)(iii) - from general rate case
40.0%	Effective tax rate (2)(q)(A)(iii) – line 7 divided by line 5

Attachment

c. Patrick G. Hager, PGE Rates & Regulatory Affairs
PGE.OPUC.Filings@pgn.com

Tax Report pursuant to ORS 757.268 (Senate Bill 408)

SUMMARY: Federal & State Income Taxes Paid and Properly Attributed to Regulated Operations of the Utility and Taxes Collected

Line No.		
		Federal and State Taxes Paid and Properly Attributed
1	$ 18,710	Federal Income Taxes: from page 2, line 29
2	$ 3,782	State Income Taxes: from page 3, line 22 --OR-- page 4, line 34
3	**$ 22,492**	**Total Taxes Paid and Properly Attributed: sum of lines 1 and 2**
		Federal and State Taxes Collected
4	$ 360,000	Gross revenue (2)(l) / (2)(q)(A)(ii) - from rate case
5	$ 55,000	Pre-tax income (2)(g) / (2)(q)(A)(ii) - from general rate case
6	15.3%	Net to gross revenues (2)(q)(A)(ii) - line 5 divided by line 4
7	$ 22,000	State & Federal Income Taxes (including deferred) (2)(q)(A)(iii) - from general rate case
8	40.0%	Effective tax rate (2)(q)(A)(iii) - line 7 divided by line 5
9	$ 365,000	Revenue collected (2)(l) / (2)(q)(A)(i)
10	15.3%	Net to gross ratio (2)(q)(A)(ii) - from line 6
11	40.0%	Effective tax rate (2)(q)(A)(iii) - from line 8
12	**$ 22,306**	**(4)(e): Federal and State taxes authorized to be collected in rates - Product of lines 9, 10 and 11**
13	**$ 186**	**(4)(f): Difference between Taxes Paid and Taxes Collected - Line 3 minus line 12**

SUMMARY: Local Income Taxes Paid and Properly Attributed to Regulated Operations of the Utility and Taxes Collected

Line No.		
14	$ 1,249	Local Income Taxes Paid and Property Attributed: from page 5, line 16
15	$ 1,250	(2)(e)/(4)(k): Local Income Taxes Collected
16	**$ (1)**	**(4)(l): Difference between Taxes Paid and Taxes Collected - Line 14 minus line 15**

Federal Income Taxes Paid and Properly Attributed to Regulated Operations of the Utility

Line No.		
1	$ 37,000	Federal Income Taxes Paid by taxpayer
2	$ 3,000	+ Current Tax benefit (at statutory rates) of tax depreciation on public utility property
3	$ 80	+ Federal investment tax credits related to public utility property
4	$ 100	+ Tax benefits from charitable contributions and IRC Section 45 renewable electricity production tax credits of federal taxpayer (except Oregon regulated operations)
5	$ 40,180	Sum of lines 1 through 4

Line No.		Oregon Regulated Operations	Federal Taxpayer	Ratio
6	Total Gross Plant	$ 82,000	$ 185,000	44.3%
7	Total Wages & Salaries	$ 35,000	$ 60,000	58.3%
8	Total Sales and Other Receipts	$ 70,000	$ 145,000	48.3%

9	50.3%	Average of ratios on lines 6 through 8
10	20,215	**3(a) result: Line 5 multiplied by line 9**
11	$ 22,000	Proforma Federal stand-alone tax liability of Oregon regulated operations
12	$ (2,150)	Imputed negative tax of all losses in federal taxpayer group, after adjusting for lines 2 and 3

Line No.		Oregon Regulated Operations	System Regulated Operations	Ratio
13	Total Gross Plant	$ 82,000	$ 96,000	85.4%
14	Total Wages & Salaries	$ 35,000	$ 40,000	87.5%
15	Total Sales and Other Receipts	$ 70,000	$ 85,000	82.4%

16	85.1%	Average of ratios on lines 13 through 15
17	$ (1,829)	Line 12 multiplied by line 16
18	$ 20,171	**3(b) result: Sum of lines 11 and 17**
19	$ 20,215	**4(c): Greater of lines 10 and 18**
20	$ 22,000	**4(b) ORS 757.268(12)(a) cap: Line 11**
21	$ 40,080	**4(a) ORS 757.268(12)(b) cap: Sum of lines 1, 2, and 3.**
22	$ 20,215	Lowest of lines 19, 20 and 21
23	$ 50	+ Tax savings from charitable contributions of Oregon regulated operations.
24	$ 20	+ Tax credits associated with Oregon regulated operations for which expenditures not included in rates.
25	$ 100	+ Deferred taxes related to Oregon regulated operations, excluding deferred taxes related to depreciation of public utility property
26	$ 375	+ Deferred taxes related to depreciation of public utility property for Oregon regulated operations (including normalized excess deferred taxes).
27	$ (2,000)	- Current Tax benefit related to tax depreciation of public utility property for Oregon regulated operations.
28	$ (50)	- Tax benefits from federal investment tax credits recognized in rates.
29	**$ 18,710**	**4(d): Sum of lines 22 through 27**

State Income Taxes Paid and Properly Attributed to Regulated Operations of the Utility
For utility with OREGON ONLY state income taxes in rates

Line No.		
1	$ 5,000	Oregon State Income Taxes Paid by unitary group
2	$ 500	+ Current Tax benefit (at state statutory rate) of tax depreciation on public utility property
3	$ 29	+ State tax benefits from charitable contributions, and conservation and renewable production tax credits of unitary group (except Oregon regulated operations)
4	$ 5,529	Sum of lines 1 through 3

Line No.		Oregon Regulated Operations	State Unitary Taxpayer*	Ratio
5	Total Gross Plant	$ 82,000	$ 105,000	78.1%
6	Total Wages & Salaries	$ 35,000	$ 50,000	70.0%
7	Total Sales and Other Receipts	$ 70,000	$ 94,000	74.5%

* adjusted to reflect amounts allocated to Oregon regulated operations

Line No.		
8	74.2%	Average of ratios on lines 5 through 7
9	$ 4,102	**3(c) result: Line 4 multiplied by line 8**
10	$ 4,300	Proforma Oregon State stand-alone tax liability of Oregon regulated operations
11	$ (125)	Imputed negative tax of all losses in Oregon unitary group, after adjusting for line 2
12	$ 4,175	**3(d) result: Sum of lines 10 and 11**
13	$ 4,175	**4(c): Greater of lines 9 and 12**
14	$ 4,300	**4(b) ORS 757.268(12)(a) cap: Line 10**
15	$ 5,500	**4(a) ORS 757.268(12)(b) cap: Sum of lines 1 and 2**
16	$ 4,175	Lowest of lines 13, 14 and 15
17	$ 5	+ Tax savings from charitable contributions of Oregon regulated operations
18	$ 2	+ Tax credits associated with Oregon regulated operations for which expenditures not included in rates.
19	$ 10	+ Deferred taxes related to Oregon regulated operations, excluding deferred taxes related to depreciation of public utility property.
20	$ 40	+ Deferred taxes related to depreciation of public utility property for Oregon regulated operations.
21	$ (450)	- Current Tax benefit related to tax depreciation of public utility property for Oregon regulated operations.
22	**$ 3,782**	**4(d): Sum of lines 16 through 21**

State Income Taxes Paid and Properly Attributed to Regulated Operations of the Utility
For utility with NON-OREGON state income taxes in rates

Line No.		
1	75.8%	Adjustment for state tax rate
2	$ 6,000	Oregon State Income Taxes Paid by unitary group
3	$ 4,545	Adjusted Taxes Paid by unitary group: Line 1 multiplied by line 2
4	$ 500	+ Current Tax benefit (at state statutory rate) of tax depreciation on public utility property
5	$ 29	+ Tax benefits from charitable contributions, and conservation and renewable production tax credits of unitary group (except Oregon regulated operations)
6	$ 5,074	Sum of lines 3 through 5

	Oregon income tax rate from GRC	Oregon statutory tax rate	Ratio
Adjustment for state tax rate	5.00%	6.60%	75.8%

Line No.		Oregon Regulated Operations	State Unitary Taxpayer*	Ratio
7	Total Gross Plant	$ 82,000	$ 105,000	78.1%
8	Total Wages & Salaries	$ 35,000	$ 50,000	70.0%
9	Total Sales and Other Receipts	$ 70,000	$ 94,000	74.5%

* adjusted to reflect amounts allocated to Oregon regulated operations

Line No.		
10	74.2%	Average of ratios on lines 7 through 9
11	$ 3,765	**3(c) result: Line 6 multiplied by line 10**

<u>Alternative Calculation (One-time election with October 2006 tax report filing)</u>

Line No.		
12	$ 9,500	Sum of state taxes paid in all jurisdictions (line 11 amount), using the formula on lines 1-11, with 100% on line 1, for each state.**

Line No.		Oregon Regulated Operations	System Regulated Operations	Ratio
13	Total Gross Plant	$ 82,000	$ 200,000	41.0%
14	Total Wages & Salaries	$ 35,000	$ 90,000	38.9%
15	Total Sales and Other Receipts	$ 70,000	$ 175,000	40.0%

Line No.		
16	40.0%	Average of ratios on lines 13 through 15
17	$ 3,796	**Alternative 3(c) result: Line 12 multiplied by line 16**
18	$ 3,765	Either line 11 or 17 (per one-time election)
19	$ 10,000	Total Proforma state stand-alone tax liability of System Regulated Operations**
20	$ (1,000)	Imputed negative tax of all losses in unitary groups in all states, after adjusting for line 4**
21	$ 9,000	Sum of lines 19 and 20
22	40.0%	Average of ratios on lines 13 through 15
23	$ 3,597	**3(d) result: Line 21 multiplied by line 22**
24	$ 3,765	**4(c) result: Greater of lines 18 and 23**

Line No.		Taxable income of OR regulated oper.	Taxable income of System regulated	Ratio
25	Ratio: taxable income	$ 67,000	$ 160,000	41.9%

Line No.		
25	41.9%	Ratio: taxable income
26	$ 4,188	**4(b) ORS 757.268(12)(a) cap: Line 19 multiplied by line 25**
27	$ 12,500	**4(a) ORS 757.268(12)(b) cap: Sum of lines 2 and 4 for all states****
28	$ 3,765	Lowest of lines 24, 26 and 27.
29	$ 5	+ Tax savings from charitable contributions of Oregon regulated operations
30	$ 2	+ Tax credits associated with Oregon regulated operations for which expenditures not included in rates.
31	$ 10	+ Deferred taxes related to Oregon regulated operations, excluding deferred taxes related to depreciation of public utility property
32	$ 40	+ Deferred taxes related to depreciation of public utility property for Oregon regulated operations.
33	$ (450)	- Current Tax benefit related to tax depreciation of public utility property for Oregon regulated operations.
34	**$ 3,372**	**4(d): Sum of lines 28 through 33**

** show calculation separately for each state

Tax Year: 2005

Local Income Taxes Paid and Properly Attributed to Regulated Operations of the Utility
Calculate separately for each local taxing authority

Line No.		
1	$ 1,400	Local Income Taxes Paid by taxpayer
2	$ 100	+ Current Tax benefit of tax depreciation on public utility property
3	$ 4	+ Tax benefits of charitable contributions of taxpayer (except Oregon regulated operations)
4	$ 1,504	Sum of lines 1 through 3

Line No.		Oregon Regulated Operations	Taxpayer	Ratio
5	Gross income in local taxing authority	$ 235,000	$ 270,000	87.0%

6	87.0%	Ratio on line 5
7	$ 1,309	**3(e)/4(i) result: Line 4 multiplied by line 6**
8	$ 1,260	**4(h) ORS 757.268(12)(a) cap: Proforma local stand-alone tax liability of regulated operations**
9	$ 1,500	**4(g) ORS 757.268(12)(b) cap: Sum of lines 1 and 2**
10	$ 1,260	Lowest of lines 7, 8 and 9
11	$ 3	+ Local tax effect of tax savings from charitable contributions of Oregon regulated operations.
12	$ 1	+ Local tax effect of tax credits associated with Oregon regulated operations for which expenditures not included in rates.
13	$ 10	+ Local tax effect of deferred taxes related to Oregon regulated operations, excluding deferred taxes related to depreciation of public utility property.
14	$ 15	+ Local tax effect of deferred taxes related to depreciation of public utility property for Oregon regulated operations.
15	$ (40)	- Local tax effect of Current Tax benefit related to tax depreciation of public utility property for Oregon regulated operations.
16	**$ 1,249**	**4(j): Sum of lines 10 through 15**

April 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated March 30, 2006
Question No. 130

Request:

What is the current, secondary market yield on debt that is outstanding by the Company? Provide a matrix that provides support for each maturity of debt outstanding as well as for each type of debt (e.g. unsecured MTN vs. FMBs).

Response:

Please see Attachment 130-A, which is the most current available *Mergent Bond Record*, for the yield to maturity of PGE bonds.

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UE 180
Attachment 130-A

Mergent Bond Record

January 2006

CUSIP	ISSUE	MOODY'S® RATING	INTEREST DATES	CURRENT CALL PRICE	CALL DATE	SINK FUND PROV	CURRENT PRICE		YIELD TO MAT.	2006 HIGH	2006 LOW	AMT. OUTST. MIL. $	ISSUED	ISSUED PRICE
708160BP	Penney J C Inc nt 7.6 04/01/07	Ba1	A&O 01	N.C.		No	102.88	bid	5.30	104.00	102.88	425	04/09/97	100.00
708160BH	nt 7.375 08/15/08	Ba1	F&A 15	N.C.		No	105.50	bid	5.14	105.50	104.75	200	08/14/96	99.96
708160BY	nt 9 08/01/12	Ba1	F&A 01	N.C.		No	118.25	bid	5.71	118.25	114.75	230.203	12/10/02	0.00
708160BW	nt rule 144a 9 08/01/12	Ba1r	F&A 01	N.C.		No	118.25	bid	5.71	118.25	114.75	810.731	07/26/02	100.00
710198HE	Peoples Bk Bridgeport Conn sub nt 9.875 11/15/10	Baa1	M&N 15	N.C.		No	121.21	bid	4.98	121.34	118.66	79.7	11/13/00	99.26
713291AL	Pepco Hldgs Inc nt fltg rt 5.035 06/01/10	Baa2	M,J,S&D 01	100.00	NoChange	No	98.67	bid	5.37	99.88	98.56	250	06/07/05	100.00
71343PAA	PepsiAmericas Inc nt 4.875 01/15/15	Baa1	J&J 15	—		No	97.80	bid	5.18	98.69	96.34	300	01/05/05	99.72
71343PAB	nt 5 05/15/17	Baa1	M&N 15	—		No	98.13	bid	5.21	99.15	96.77	250	05/11/05	99.18
71343PAC	nt 5.5 05/15/35	Baa1	M&N 15	—		No	98.01	bid	5.62	100.32	95.87	250	05/11/05	99.42
713440AZ	PepsiCo Cap Res Inc gtd deb zero cpn 0 04/01/10	Aa3	—	100.00	fr 04/01/06	No	80.63	bid	—	79.57	78.31	23	03/31/82	0.00
714046AD	[1] [2] Perkinelmer Inc sr sub nt 8.875 01/15/13	Ba1	J&J 15	104.44	fr 01/15/08	No	111.00	bid	6.93	111.88	109.00	0.03	05/08/03	0.00
716016AB	[1] [2] PETCO Animal Supplies Inc sr sub nt 10.75 11/01/11	B1	M&N 01	105.38	fr 11/01/06	No	108.50	bid	8.94	110.25	108.50	111.1	05/14/02	0.00
716442AJ	Petro CDA sr nt 5.95 05/15/35	Baa2	M&N 15	—		No	118.17	bid	4.89	119.08	113.92	600	05/11/05	98.77
71644EAG	sr nt 5.95 05/15/35	Baa2	M&N 15	—		No	101.95	bid	5.83	102.31	96.81	600	05/11/05	98.77
715911AE	Petro Stopping Ctrs L P / Petro Finl Corp sr secd nt rule 144a 9 02/15/12	B3	F&A 15	104.50	fr 02/15/08	No	101.00	bid	8.79	101.00	97.75	25	07/13/05	100.00
71645WAG	[1] [20] Petrobras Intl Fin Co global nt 9.125 07/02/13	Baa2	J&J 02	N.C.		No	117.38	bid	6.26	116.75	105.10	750	06/27/03	99.20
71645WAJ	Petrobras Intl Fin Co global nt 7.75 09/15/14	Baa2	M&S 15	N.C.		No	108.97	bid	6.43	114.48	104.41	600	09/08/04	98.64
71645WAH	[1] [20] Petrobras Intl Fin Co global nt 8.375 12/10/18	Baa2	J&D 10	N.C.		No	113.13	bid	6.91	111.95	109.00	750	12/03/02	98.95
71645WAF	Petrobras Intl Fin Co global nt step-up 9 04/01/08	Baa2	A&O 01	N.C.		No	113.13	bid	2.93	116.00	112.88	400	03/24/03	98.65
716548AF	Petroleo Brasiliero S A nt rule 144a 10 10/17/06	Baa2	A&O 17	N.C.		No	104.13	bid	5.07	108.00	104.13	250	10/15/96	99.78
716589AA	Petroleum Expt Ltd sr secd nt rule 144a 4.623 06/15/10	Aaa	J&D 15	—		No	101.19	bid	4.33	101.63	100.18	400	07/14/05	100.00
716589AB	sr secd nt rule 144a 4.633 06/15/10	Aaa	J&D 15	—		No	101.23	bid	4.33	101.67	100.22	250	07/14/05	100.00
716589AC	sr secd nt rule 144a 5.265 06/15/11	Baa1	J&D 15	—		No	104.76	bid	4.29	105.32	103.41	903.6	07/14/05	100.00
716708AF	Petroliam Nasional Berhad bd rule 144a 7.625 10/15/26	A1	A&O 15	N.C.		No	124.50	bid	5.74	124.23	119.04	500	10/10/96	98.65
716708AE	nt rule 144a 7.125 10/18/06	A1	A&O 18	N.C.		No	101.66	bid	4.98	102.41	101.62	800	10/10/96	99.80
716708AC	rule 144a bd 7.75 08/15/15	A1	F&A 15	N.C.		No	119.81	bid	5.18	120.43	117.10	625	08/10/95	99.27
71674PAB	[1] [2] PetroQuest Energy Inc / PetroQuest Energy LLC sr nt 10.375 05/15/12	Caa1	M&N 15	105.19	fr 05/15/09	No	105.00	bid	9.36	106.25	104.50	150	08/24/05	0.00
71676QAA	Petrozuata Finance Inc bd ser a rule 144a 7.63 04/01/09	Ba3	A&O 01	—		Yes	0.00		—	0.00	0.00	232.057	06/17/97	100.00
71676QAC	bd ser b rule 144a 8.22 04/01/17	Ba3	A&O 01	—		Yes	26.00	bid	22.31	26.00	26.00	625	06/17/97	100.00
71676QAE	bd ser c rule 144a 8.37 10/01/22	Ba3	A&O 01	—		No	0.00		—	0.00	0.00	75	06/17/97	100.00
6933EYAA	[2] Pgn Eurofinance 2003 Ltd gtd nt rule 144a 7.5 02/24/14	B1	F&A 24	N.C.		No	126.53	bid	3.74	127.04	124.23	125	02/13/04	98.00
71711WAB	Pharma Svcs Inter Hldgs Corp sr disc nt 0 04/01/14	Caa1	A&O 01	105.75	fr 04/01/09	No	74.00	bid	—	75.00	71.50	219	04/05/05	56.94
717265AJ	Phelps Dodge Corp deb 7.125 11/01/27	Baa2	M&N 01	—		No	108.63	bid	6.45	113.08	105.03	150	10/31/97	99.52
717265AK	sr nt 8.75 06/01/11	Baa2	J&D 01	—		No	115.66	bid	5.43	117.52	113.09	348.6	05/24/01	99.83
717265AL	sr nt 9.5 06/01/31	Baa2	J&D 01	—		No	134.67	bid	6.93	143.17	131.07	275	05/24/01	99.75
717265AM	sr nt 6.125 03/15/34	Baa2	M&S 15	—		No	97.29	bid	6.31	102.09	94.19	150	03/01/04	99.87
693320AE	PHH Corp nt 6.03/01/08	Baa3	M&S 01	—		No	101.25	bid	5.38	101.86	99.85	400	02/13/03	99.59
693320AF	nt 7.125 03/01/13	Baa3	M&S 01	—		No	105.25	bid	6.23	107.06	103.02	600	02/13/03	99.33
71742QAM	[2] Phibro Animal Health Corp / Philipp Bros Neth III B V debt unit 13 12/01/07	B2	J&D 01	105.00	fr 06/01/06	No	100.34	bid	12.80	100.38	100.34	127.491	02/04/05	0.00
718252AJ	Philippine Long Distance Tel Co nt 10.625 05/15/07	Ba2	M&N 15	N.C.		No	109.50	bid	5.11	109.50	109.50	100	08/12/02	0.00
718252AK	nt 11.375 05/15/12	Ba2	M&N 15	N.C.		No	123.00	bid	6.98	123.75	118.50	250	08/12/02	0.00
718507BH	Phillips Pete Co deb 6.65 07/15/18	A1	J&J 15			No	112.80	bid	5.29	115.25	110.71	300	06/30/98	99.69
718507AZ	deb 7.125 03/15/28	A1	M&S 15	102.70	fr 03/15/08	No	108.69	bid	6.45	108.75	104.23	300	03/17/98	98.27
718507BK	deb 7 03/30/29	A1	M&S 30	—		No	119.68	bid	5.60	120.92	115.53	200	03/26/99	99.29
718507BJ	nt 6.375 03/30/09	A1	M&S 30	—		No	104.36	bid	4.92	105.82	104.05	300	03/26/99	99.93
718507BQ	Phillips Pete Co nt 8.75 05/25/10	A1	M&N 25	—		No	115.18	bid	4.92	116.77	114.75	1350	05/18/00	99.54
718507AR	Phillips Pete Co nt 9.375 02/15/11	A1	F&A 15	N.C.		No	119.42	bid	5.08	121.50	118.86	350	02/13/91	99.77
718507BL	Phillips Pete Co sec nt 7.87 10/18/21	A1	A&O 18	N.C.		No	101.17	bid	7.75	101.52	99.32	28.74	10/13/99	100.00
718592AB	Phillips Van Heusen Corp deb 7.75 11/15/23	Ba3	M&N 15	N.C.		No	104.00	bid	7.38	107.25	101.50	100	11/04/93	99.42
718592AJ	sr nt 7.25 02/15/11	B1	F&A 15	103.63	fr 02/15/08	No	101.63	bid	6.88	102.50	99.00	150	07/07/04	0.00
718592AG	sr nt 8.125 05/01/13	B1	M&N 01	104.06	fr 05/01/08	No	105.50	bid	7.18	106.75	102.50	150	11/07/03	0.00
71902QAC	Phoenix Color Corp sr sub nt 10.375 02/01/09	Caa1	F&A 01	101.73	fr 02/01/06	No	96.00	bid	11.91	92.50	91.00	105	05/05/99	0.00
71902EAA	Phoenix Cos Inc sr nt 6.675 02/16/08	Baa3	F,M,A&N 16	N.C.		No	101.16	bid	6.09	104.84	100.79	153.687	11/10/05	101.00
71912NAA	Phoenix Pk Fdg Ltd bd rule 144a 7.267 04/01/13	A3	J,A,J&O 01	—		Yes	99.88	bid	7.29	100.36	98.31	77.546	05/14/98	100.00
720830AB	[1] [120] Pierre Foods Inc sr sub nt 9.875 07/15/12	B3	J&J 15	104.94	fr 07/15/08	No	104.00	bid	9.08	104.00	100.50	125	02/07/05	0.00
721467AC	[1] [2] Pilgrims Pride Corp sr nt 9.625 09/15/11	Ba2	M&S 15	104.81	fr 09/15/06	No	106.25	bid	8.27	108.00	105.63	300	08/06/01	100.00
721467AD	Pilgrims Pride Corp sr sub nt 9.25 11/15/13	Ba3	M&N 15	104.63	fr 11/15/08	No	107.00	bid	8.08	111.00	107.00	100	03/10/04	0.00
723686AA	Pioneer Hi Bred Intl Inc sr nt 5.75 01/15/09	A2	J&J 15	—		No	101.79	bid	5.11	102.48	101.32	200	01/12/99	99.85
724479AG	Pitney Bowes Inc nt 5 03/15/15	Aa3	M&S 15	—		No	98.51	bid	5.20	100.16	97.51	400	03/17/05	99.23
72650RAJ	[1] [2] Plains All Amern Pipeline LP/PPA Fin sr nt 5.25 06/15/15	Baa3	J&D 15	—		No	106.67	bid	4.40	106.95	105.27	150	10/11/05	0.00
727610AD	Plastipak Hldgs Inc sr nt rule 144a 8.5 12/15/15	B2	J&D 15	104.25	fr 12/15/10	No	101.75	bid	8.25	101.50	100.75	250	12/02/05	100.00
72813PAH	[2] Playtex Prods Inc sr sub nt 9.375 06/01/11	Caa1	J&D 01	104.69	fr 06/01/06	No	105.50	bid	8.13	105.75	102.75	350	07/19/01	0.00
72925PAB	[1] [124] Plum Creek Timberlands L P nt 5.875 11/15/15	Baa3	M&N 15	—		No	102.18	bid	5.59	110.35	100.05	300	11/08/05	99.73
693476AU	PNC Fdg Corp nt 4.2 03/10/08	A2	M&S 10	N.C.		No	98.70	bid	4.83	99.11	98.16	350	03/03/05	99.95
693476AV	nt 4.5 03/10/10	A2	M&S 10	N.C.		No	98.02	bid	5.02	99.25	97.39	350	03/03/05	99.77
693476@A	[1] [181] PNC Fdg Corp sr nt 5.125 12/14/10	A2	J&D 14	N.C.		No	100.13	bid	5.09	100.26	99.70	400	12/07/05	99.95
730448AP	Pogo Producing Co sr sub nt ser b 8.25 04/15/11	Ba3	A&O 15	104.13	fr 04/15/06	No	104.50	bid	7.24	105.25	104.00	200	05/02/01	0.00
730448AR	sr sub nt 6.625 03/15/15	Ba3	M&S 15	103.31	fr 03/15/10	No	98.75	bid	6.80	99.50	97.00	300	09/30/05	0.00
730448AS	sr sub nt rule 144a 6.875 10/01/17	Ba3	A&O 01	103.44	fr 10/01/10	No	97.50	bid	7.18	101.50	97.00	500	09/21/05	100.00
730450AD	Pohang Iron & Stl Ltd nt 7.125 11/01/06	A2	M&N 01	N.C.		No	101.74	bid	4.96	102.49	101.68	300	10/29/96	99.89
730481AE	[1] [2] Poindexter J B Inc sr nt 8.75 03/15/14	B1	M&S 15	104.38	fr 03/15/09	No	84.00	bid	11.63	92.00	84.00	200	04/12/05	0.00
731753AB	Polymer Hldgs LLC / Polymer Hldgs Cap Corp sr disc nt 0 07/15/14	Caa2	J&J 15	106.00	fr 01/15/09	No	73.00	bid	—	72.75	71.50	150	09/01/05	61.28
73179UAF	[1] [2] Polypore Inc eur$ sr sub nt 8.75 05/15/12	Caa2	M&N 15	104.38	fr 05/15/08	No	111.79	bid	6.51	112.24	111.23	150	11/03/04	0.00
73179UAC	sr sub nt 8.75 05/15/12	Caa2	M&N 15	104.38	fr 05/15/08	No	88.13	bid	11.29	90.25	87.00	225	11/03/04	0.00
73179VAC	Polypore Intl Inc sr disc nt 0 10/01/12	Ca	A&O 01	105.25	fr 10/01/08	No	56.00	bid	—	56.00	51.75	300	06/13/05	64.45
732827AB	Pope & Talbot Inc deb 8.375 06/01/13	B3	J&D 01	N.C.		No	68.00	bid	15.11	93.00	73.75	75	05/25/93	99.28
732827AD	sr nt 8.375 06/01/13	B3	J&D 01	N.C.		No	68.00	bid	15.11	93.00	73.75	60	09/04/02	0.00
736508BG	Portland Gen Elec Co 1st mtg bd rule 144a 8.125 02/01/10	Baa1	F&A 01	—		No	102.95	bid	7.29	103.38	102.03	150	10/03/02	100.00
736508BC	nt 7.875 03/15/10	Baa2	M&S 15	N.C.		No	110.82	bid	5.02	111.28	109.79	150	03/08/00	99.16
737415AH	Post Apartment Homes LP nt 5.45 06/01/12	Baa3	J&D 01	—		No	98.83	bid	5.67	99.38	97.38	100	05/25/05	99.93
73755LAA	Potash Corp Sask Inc nt 7.125 06/15/07	Baa1	J&D 15	N.C.		No	102.99	bid	4.97	103.93	102.88	400	06/11/97	99.33
73755LAB	nt 7.75 05/31/11	Baa1	M&N 30	—		No	111.80	bid	5.25	113.13	110.84	600	05/16/01	99.34
73755LAC	nt 4.875 03/01/13	Baa1	M&S 01	—		No	96.82	bid	5.41	98.97	95.80	250	02/27/03	99.44
737662BP	Potomac Edison Co 1st mtg bd 5.35 11/15/14	Baa2	M&N 15	—		No	100.48	bid	5.28	100.68	97.56	175	08/31/05	0.00
737662BR	1st mtg bd 5.125 08/15/15	Baa2	F&A 15	—		No	98.60	bid	5.31	106.06	104.21	145	10/25/05	0.00
737662BM	nt 5 11/01/06	Baa3	M&N 01	—		No	99.35	bid	5.81	99.58	99.14	100	11/01/01	99.74
737679CZ	Potomac Elec Pwr Co sr secd nt 5.4 06/01/35	A3	J&D 01	—		No	96.61	bid	5.61	98.27	94.65	175	05/24/05	99.65
69352JAG	PPL Energy Supply LLC reset put secs (reps) 5.7 10/15/35	Baa2	A&O 15	N.C.		No	100.25	bid	5.68	100.97	97.71	300	10/20/05	99.98
693522AA	PQ Corp sr sub nt rule 144a 7.5 02/15/13	B3	F&A 15	103.75	fr 02/15/09	No	93.50	bid	8.69	97.25	91.38	275	02/03/05	100.00
899191@A	[1] [20] Preem Hldgs A B eur$ sr secd nt rule 144a 10.625 03/31/11	B2	Mar 31	105.31	fr 03/31/06	No	104.36	bid	9.58	104.57	104.36	305	04/03/01	100.00
74044PAA	Pregis Corp sr sub nt rule 144a 12.375 10/15/13	Caa1	A&O 15	106.19	fr 10/15/09	No	98.50	bid	12.66	99.00	98.00	150	10/06/05	98.15

Notes: Moody's® ratings are subject to change. Because of the possible time lapse between Moody's® assignment or change of a rating and your use of this monthly publication, we suggest you verify the current rating of any security or issuer in which you are interested. For standard abbreviations and symbols, see page 6.

September 26, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 19, 2006
Question No. 530

Request:

Referring to UE 180 – UE 181 – UE 184 / PGE /2000, Hager-Valach/8, lines 10-12, is PGE aware of any currently outstanding debt issuances that were lower-cost due to Enron's ownership of PGE? If yes, please identify the issuances and provide analysis and work papers demonstrating that the issuance is lower cost.

Response:

PGE's objects to this request on the basis that it is vague. The time period is unclear. Notwithstanding this objection, PGE responds as follows:

An analysis of the PGE's currently held long-term debt issues versus Standard and Poor's and Moody's market rates is contained in Exhibit 2014, which demonstrates that PGE's issuances were close, if not below, the "BBB/Baa" rated issuances and at times lower than the "A/Aa" rated issuances.

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September 26, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 19, 2006
Question No. 534

Request:

Referring to UE 180 – UE 181 – UE 184 / PGE /2000, Hager-Valach/9, lines 14-15, is it PGE's belief that only currently outstanding debt should be considered to determine whether "PGE's incremental cost of debt on a portfolio basis" is higher than the market?

Response:

PGE objects to this request on the basis that is it vague. It is not clear to PGE what "only currently outstanding debt" is. Notwithstanding this objection, PGE responds as follows:

No. PGE Exhibit 2000, page 9, lines 11-15 explains the portfolio basis analysis.

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 622

Request:

Please provide indicative quotes from three different investment banks for issuances of $50 million, $100 million, and $150 million in 5, 7, 10, 15, 20 and 30-year maturities for senior-secured and senior-unsecured bonds, as of the present time. Please include spreads above Treasuries as well as all expenses. Please also include copies of actual correspondence from the investment banks regarding this request. If indicative quotes are not available, please provide whatever information the company has available to provide current market pricing for the assumed issuances listed above.

Response:

Attachments 622-A, 622-B, and 622-C are the "indicative quotes" from three different investment banks. PGE received these worksheets via e-mail. These quotes are estimates only and were made by third parties at a specific point in time without the benefit of information they would normally garner when actually marketing PGE securities. Actual rates for a real transaction could vary from the estimates. They also do not reflect all issuance costs related to the transaction, which vary depending on the type of transaction, including the size.

Attachments 622-A, 622-B, and 622-C are confidential and subject to Protective Order No. 06-111.

UE 180
Attachment 622-A

Confidential and Subject to Protective Order No. 06-111

Provided Electronically (CD) Only
Summary Terms

Exhibit 1904
Page 2of4

UE 180
Attachment 622-B

Confidential and Subject to Protective Order No. 06-111

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JP Morgan Presentation

Exhibit 1904
Page 3 of 4

UE 180
Attachment 622-C

Confidential and Subject to Protective Order No. 06-111

Provided Electronically (CD) Only
New Issue Annalysis

Exhibit 1904
Page 4 of 4

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 623

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/57, lines 12-17, does PGE believe its risk positioning model contains all relevant explanatory variables? Please explain.

Response:

No. The testimony states "all models are misspecified to some degree." However, PGE believes that its model provides a sufficient number of explanatory variables for the hypothesis.

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October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 624

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/57, lines 18-19, what is the premise for your models? Please provide any theoretical backing PGE relies upon to justify the premise of its models.

Response:

See PGE Exhibit 2000, page 53, lines 15-21.

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 625

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/57, lines 8-9, please provide a detailed discussion that explains how PGE's regression includes the effects of the tax cut on required returns. Does PGE's regression attempt to control for or isolate this impact? If no, please explain why this is unnecessary.

Response:

PGE did not claim that the regression includes the effects of the tax cut on required returns. Rather, PGE stated that "[w]e agree with Staff that the tax cut *might have affected* required returns and this effect, if any, would already be included in our regression." [emphasis added]

The 2003 tax cut would be included in the Risk Positioning regression in the same way the previous tax cuts were included. The tax cut effects, if any, would be incorporated into the estimated coefficients.

See Staff/1000/Morgan/27 lines 6-22. The citation discusses the aggregate level of dividend payouts and not the individual investor's required risk premium. PGE does not become any less risky as a result of the 2003 tax cut. The passage states that the impact of the 2003 tax cut will impact the *price* of the stock and not the *required return.*

Additionally, in Staff/1003/177, a Lehman Brothers report states that "[w]e believe that the enacted dividend tax reduction is now fully incorporated into utility valuations." Again, this statement refers to the *price* of the stock—not the risk premium.

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 626

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/61, line 16. Please provide all evidence PGE relied upon to conclude that there is no logical grouping for the data.

Response:

PGE used common sense and determined that logically one would group the data either by jurisdiction or by month since these were the two primary characteristics of our model. However, neither grouping seemed appropriate.

1. Cross Sectional Analysis:
The data which are monthly Treasury bond rates, the specific utility's cost of debt, and the authorized ROE decided. Given the fact that the data are monthly, it is logical to consider cross-sectional information by month. However, we do not have a sufficient number of data points in any given month to consider. We could have grouped the cross-sectional data by year, but we believe that this would be inappropriate since we would not capture changes in interest rate during the year.

2. Time Series Analysis
An appropriate grouping could be by jurisdiction as noted in our testimony in PGE/2000/Hager-Valach/61 lines 20-21, but we don't have sufficient data by jurisdiction for a robust estimation.

Please refer to Attachment 626-A for an analysis of the number of cases per jurisdiction across the data set. The entire data set is included for review.

UE 180
Attachment 626-A

Frequency of Decisions by Jurisdiction

Exhibit 1908
Page 2 of 7

Number of Non-Stipulated Cases Per Jurisdiction and by State

Number of Cases		
State	Name	Total
WI	Madison Gas & Electric	17
	Wisconsin Electric Power	16
	Wisconsin Power & Light	13
	Wisconsin Public Service	19
	Northern States Power	6
WI Total		71
NY	Central Hudson Gas & Elec	8
	Consolidated Edison	3
	Long Island Lighting	4
	New York State Electric & Gas	7
	Niagara Mohawk Power	6
	Orange & Rockland Utilities	3
	Rochester Gas & Electric	11
NY Total		42
CA	Pacific Gas & Electric	8
	San Diego Gas & Electric	6
	Sierra Pacific Power	3
	Southern California Edison	9
CA Total		26
TX	CapRockEnergy	1
	Central Power & Light	1
	Dallas Power & Light	1
	El Paso Electric	3
	Gulf States Utilities	2
	Houston Lighting & Power	3
	Texas Electric Service	1
	Texas Utilities Electric	1
	Texas Utilities Power	2
	Texas-New Mexico Power	3
	West Texas Utilities	3
TX Total		21
IA	IES Utilities	1
	Interstate Power	5
	Iowa Electric Light & Power	4
	Iowa Power	5
	Iowa Public Service	2
	Iowa Southern Utilities	2
	Iowa-Illinois Gas & Electric	1
	MidAmericanEnergy	1
IA Total		21
PA	Duquesne Light	2
	Metropolitan Edison	2
	Pennsylvania Electric	1
	Pennsylvania Power	3
	Pennsylvania Power & Light	3
	Philadelphia Electric	4
	West Penn Power	3
	Western Pennsylvania Power	2

PA Total		20
SC	Carolina Power & Light	5
	Duke Power	5
	South Carolina Electric & Gas	10
SC Total		20
MA	Boston Edison	4
	Cambridge Electric Light Co	1
	Commonwealth Electric	2
	Eastern Edison	1
	Fitchburg Gas & Electric	1
	Massachusetts Electric	3
	Western Massachusetts El	7
MA Total		19
OH	Cleveland Electric Illuminati	4
	Columbus & Southern Ohio Elec	1
	Dayton Power & Light	1
	Monongahela Power	1
	Monongehela Power	1
	Ohio Edison	4
	Ohio Power	1
	Toledo Edison	4
	Cincinnati Gas&Electric	2
OH Total		19
MN	Interstate Power	2
	Minnesota Power & Light	2
	Otter Tail Power	2
	Northern States Power	11
MN Total		17
HI	Hawaiian Electric	11
	Maui Electric	5
HI Total		16
IL	Central Illinois Public Serv	2
	Commonwealth Edison	4
	Illinois Power	6
	Iowa-Illinois Gas & Electric	2
	MidAmerican Energy	2
	Union Electric	2
IL Total		18
VA	Appalachian Power	4
	Potomac Edison	3
	Virginia Power	8
VA Total		15
MD	Baltimore Gas & Electric	6
	Delmarva Power & Light	2
	Potomac Edison	3
	Potomac Electric Power	3
MD Total		14
WA	Avista	2
	PacifiCorp	3
	Puget Sound Power & Light	5
	Washington Water Power	4
WA Total		14

CT	Connecticut Light & Power	8
	United Illuminating	3
	United Illuninating	1
	UnitedIlluminating	1
CT Total		13
FL	Florida Power & Light	4
	Florida Power Corporation	3
	Gulf Power	2
	Tampa Electric	3
FL Total		12
ID	Avista	2
	Idaho Power	2
	Utah Power & Light	2
	Washington Water Power	5
ID Total		11
KS	AquilaNetworks-WPK	1
	Kansas City Power & Light	3
	Kansas Gas & Electric	4
	West Plains Energy	2
	Westar Energy	1
KS Total		11
KY	Kentucky Power	2
	Kentucky Utilities	1
	Louisville Gas & Electric	5
	Union Light Heat & Power	3
KY Total		11
IN	Indiana Michigan Power	1
	Indianapolis Power & Light	1
	Northern Indiana Public Servi	1
	PSI Energy	5
	Public Service Indiana	1
	Southern Indiana Gas & Electr	1
IN Total		10
MI	Consumers Energy	1
	Consumers Power	3
	Detroit Edison	4
	Indiana Michigan Power	1
	Upper Peninsula Power	1
MI Total		10
NC	Carolina Power & Light	3
	Duke Power	5
	North Carolina Power	2
NC Total		10
AZ	Arizona Public Service	5
	Citizens Utilities	2
	Tucson Electric Power	1
	Tuscon Electric Power	1
AZ Total		9
MT	Montana Power	6
	Montana-Dakota Utilities	1
	PacifiCorp	2
MT Total		9

NV	Nevada Power	4
	Sierra Pacific Power	5
NV Total		9
LA	Central Louisiana Electric	1
	Gulf States Utilities	2
	Louisiana Power & Light	3
	New Orleans Public Service	1
	Southwestern Electric Power	1
LA Total		8
WY	PacifiCorp	7
	Utah Power & Light	2
WY Total		9
NJ	Atlantic City Electric	2
	Jersey Central Power & Light	3
	Public Service Electric & Gas	2
NJ Total		7
OK	Oklahoma Gas & Electric	5
	Public Service Oklahoma	2
OK Total		7
OR	Idaho Power	2
	PacifiCorp	4
	Portland General Electric	2
OR Total		8
DC	Potomac Electric Power	6
DC Total		6
ME	Bangor Hydro	3
	Central Maine Power	3
ME Total		6
UT	PacifiCorp	3
	Utah Power & Light	2
UT Total		5
WV	Appalachian Power	2
	Monongahela Power	2
	Potomac Edison	1
	Virginia Power	1
WV Total		6
DE	Delmarva Power & Light	5
DE Total		5
MO	Empire District Electric	2
	Kansas City Power & Light	1
	Union Electric	2
MO Total		5
AR	Arkansas Power & Light	1
	Entergy	1
	Southwestern Electric Power	2
AR Total		4
MS	Mississippi Power	3
	Missouri Public Service	1
MS Total		4
GA	Georgia Power	3
GA Total		3
ND	Montana-Dakota Utilities	2

ND	Nantahala Power and Light	1
ND Total		3
NM	Public Service of New Mexico	2
	Southwestern Electric Power	1
NM Total		3
RI	Naragansett Electric	3
RI Total		3
VT	Central Vermont Pub Svc	1
	Green Mountain Power	2
VT Total		3
CO	Public Service Colorado	1
CO Total		1
NH	PublicServiceNewHampshire	1
NH Total		1
Grand Total		565

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 628

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/61, line 20, please provide all evidence PGE relied upon to conclude that there is no logical grouping for the data.

Response:

Please refer to PGE's response to OPUC Data Request No. 626.

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Staff Exhibit 1909
Page 1 of 1

ue 180/181/184

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 630

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/58, lines 7-8, did PGE rely on a strong theoretical background for its conclusion of lagged Treasury rates in its regression? If yes, please provide the background materials relied upon. If no, why not?

Response:

The reference is taken out of context. PGE's comment regarding a "strong theoretical background" was in reference to the addition of another variable to the regression. The discussion considered the possibility of omitted variables. For a discussion of the lag determination, see PGE Exhibit 2000, pages 62-63.

As discussed in PGE Exhibit 2000, page 53, we postulated that authorized ROE decisions by regulatory commissions are influenced by interest rates. We also postulated that the information that Commissioners actually have before them could be very recent or several months old. Thus, we tested for the effect of lagged "information," expecting that the most recent interest rate information available would be about a month old when the decision was finally released. We also thought that if the commission could only use information that was filed, then there might be a lag longer than one month. We then tested to determine the appropriate lags and found that 1-month and 8-month lags were best. Subsequent, more refined statistical testing determined that the most appropriate lag was 7-months. The difference between these three lags was very small as were the estimates.

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October 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Revised Data Request
Dated October 6, 2006
Question No. 638

Request: ***(October 6, 2006)***

Referring to PGE/2100 Zepp/15, please provide a listing of all assumptions investors might reasonably consider as they price electric utility stocks with a DCF model. Please indicate how the assumptions directly relate to the end DCF results. Include adjustment factors, if available.

Revised: ***(October 11, 2006)***

Referring to PGE/2100 Zepp/15, please identify the assumptions that Mr. Morgan did not consider that Dr. Zepp believes investors might reasonably consider as they price electric utility stocks with a DCF model. Please describe how each of these additional factors would be incorporated into a DCF analysis and provide the expected impact on the DCF results related to each assumption.

Response:

PGE objects to this request on the basis that it is vague, ambiguous, and unduly burdensome. Notwithstanding this objection, PGE responds as follows:

According to Kolbe, Read and Hall (*The Cost of Capital Estimating the Rate of Return for Public Utilities,* MIT Press 1986, pages 53-65), other assumptions could include that (a) market prices are equivalent to the present value of cash flows investors expect, (b) the discount rate is the cost of equity, (c) investors expect the cost of equity to remain constant in the future periods, (d) cash flows relevant for the calculation are dividends, (e) investors do not expect any variation in the growth of dividends, (f) variation in inflation will not occur, (g) planned sale price is also dependent upon future dividend growth, and (h) dividends are expected to grow at a constant rate for an indefinite future period.

In addition, Myron Gordon, who formally derived the DCF model in *The Cost of Capital to a Public Utility* (MSU Public Utility Studies 1974), set forth many more assumptions when he derived the DCF model.

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October 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 639

Request:

Referring to Dr. Zepp's response to Staff Data Request 606, please list all assumption Dr. Zepp thinks should be used in his DCF analyses.

Response:

Please see PGE Response to OPUC Data Request No. 638.

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Staff Exhibit 1912
ue 180/181/184 Page 1 of 1

October 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Revised Data Request
Dated October 6, 2006
Question No. 640

Request: *(October 6, 2006)*

Referring to PGE/2100 Zepp/18, please update Dr. Zepp's DCF models (Exhibits 2105 and 2106) using Value Line's updated forecast of accounting ROEs for the electric utility industry of 11.5 percent. Additionally, please update the analysis to include all assumptions Dr. Zepp feels are reasonable, without regard for Staff's input assumptions.

Revised: *(October 11, 2006)*

Referring to PGE/2100 Zepp/18, please update Dr. Zepp's DCF models (Exhibits 2105 and 2106) using Value Line's updated forecast of accounting ROEs for the electric utility industry of 11.5 percent. Additionally, based on the response to Staff Data Request 638, please update the analysis to include the impact of the assumptions Dr. Zepp feels are reasonable, without regard for Staff's input assumptions.

Response:

Dr. Zepp relied on Mr. Morgan's exhibits to prepare his rebuttal testimony.

Dr. Zepp's testimony shows the ROE that would have been produced by Mr. Morgan at the time Mr. Morgan prepared his testimony if Mr. Morgan had recognized all of Value Line's assumptions and forecasts. As stated in Dr. Zepp's testimony, Mr. Morgan's exhibits showed Value Line forecast a 12.5% ROE at the time Mr. Morgan prepared his testimony, but Mr. Morgan ignored that Value Line estimate. Had Mr. Morgan relied upon all of the Value Line estimates provided in his exhibits, Mr. Morgan's cost of equity estimate would have been higher.

It is inappropriate to change one of the inputs to the rebuttal analysis Dr. Zepp prepared without examining all of the other changes that have occurred since Mr. Morgan prepared his testimony. Please note that Dr. Zepp provided his exhibits electronically, and Staff is able to determine how the internal rate of return changes if just one assumption is changed.

October 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 643

Request:

Referring to PGE/2100 Zepp/18, does the Value Line ROE forecast exclude the impact of the "s x v" factor?

Response:

Yes. The "s x v" growth will impact book value per share and thus earnings in future years, but not the contemporaneous period.

October 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 644

Request:

Referring to Exhibit 2104, please provide a listing of past growth rates for the water utility sample Dr. Zepp used.

Response:

For the most recent ten-year period, the average of past growth in book value per share (BVPS), earnings per share (EPS), and common stock prices is 8.3%. Please see Attachment 644-A.

UE 180
Attachment 644-A

Exhibit 1915
Page 2 of 3

		Average Annual Changes 1996 to 2005			
		Price	BVPS	EPS	Average
1	American States Water	9.0%	4.3%	7.3%	6.9%
2	Aqua America	26.4%	10.0%	9.4%	15.2%
3	California Water Service	10.3%	3.2%	4.1%	5.9%
4	Connecticut Water Service	8.4%	4.5%	3.1%	5.3%
5	Middlesex Water	7.8%	4.2%	2.1%	4.7%
6	SJW Corporation	17.7%	6.8%	10.1%	11.5%
	Sample Average	13.3%	5.5%	6.0%	8.3%

October 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Revised Data Request
Dated October 6, 2006
Question No. 647

Request: ***(October 6, 2006)***

What is the sample of comparable companies Dr. Zepp thinks would reasonably approximate the riskiness of PGE's rate-regulated operations?

Revised: ***(October 11, 2006)***

Referring to the statement at PGE/2100 Zepp/12 (Taking into account that PGE is more risky than companies in Mr. Morgan's sample…") what is the sample of comparable companies Dr. Zepp thinks would reasonably approximate the riskiness of PGE's rate-regulated operations? Please explain.

Response:

Dr. Zepp did not make that determination; he relied upon Mr. Morgan's sample to prepare his rebuttal.

October 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 648

Request:

Since 2000, has Dr. Zepp used a multi-stage DCF model or other cost of capital model for any cost of equity analysis? Please provide copies of all testimony authored by Dr. Zepp, including electronic workpapers with formulae intact, since 2000. If Dr. Zepp has completed other ROE analyses for electric utility companies, please identify the selection criteria used, if not explicitly stated in testimony.

Response:

PGE objects to this request on the basis that it is unduly burdensome. Dr. Zepp has testified in dozens of rate cases since 2000. Dr. Zepp typically only has a hard copy of previously filed testimony. Dr. Zepp estimates it would take two to three days to locate and copy all of the documents requested. In addition, Dr. Zepp upgraded to a new computer in the last couple of years and did not archive or transfer all of his electronic files. Notwithstanding this objection, PGE responds as follows:

With respect to electric utility cost of equity estimates, Dr. Zepp prepared rebuttal testimony in a recent Arizona Public Service case. Attachments 648-A and 648-B are Dr. Zepp's electronic work papers and testimony, respectively, from that case. Attachment 648-C is Dr. Zepp's testimony in the Municipal Power & Light case.

With respect to water utility rate cases, Dr. Zepp has testified in numerous water cases. Attachment 648-D is testimony and workpapers from an Arizona water utility rate case and Attachment 648-E is testimony and workpapers from a California water utility rate case.

UE 180
Attachment 648-A

Dr. Zepp's Workpapers from recent Arizona Public Service Case

Exhibit 1917
Page 2 of 268

Arizona Public Service
Growth in Earnings and Dividends and Indicated Costs of Equity
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B] Growth Estimate	[C] Dividends Yield	[D] Indicated Cost of Equity
1				
2	Dividends per Share growth from 1997 to 2007	2.2%	4.5%	6.7%
3	Dividends per Share growth from 2004 to 2007	3.3%	4.5%	7.8%
4	Earnings per Share growth from 1997 to 2007	4.3%	4.5%	8.8%
5	Earnings per Share growth from 2004 to 2007	5.2%	4.5%	9.7%

6 Source: Mr. Reiker's electronic work papares and Value Line.

Arizona Public Service
Intrinsic Growth and Indicated Costs of Equity
Mr. Reiker's Sample of Electric Utilities

Line No.	[A] Company	[B] Retention Growth 1998 to 2007 br	[C] Stock Financing Growth vs	[D] Intrinsic Growth 1998 to 2007 br + vs	Dividend Yield	Indicated Cost of Equity
1	Mr. Reiker's Estimate for his complete sample	4.6%	1.4%	5.9%	4.5%	10.4%
		Retention Growth 2007 br	Stock Financing Growth vs	Intrinsic Growth 2007 br + vs		
2	Forward-looking Estimate	4.8%	1.4%	6.2%	4.5%	10.7%

3 Source: Mr. Reiker's work electronic papers.

03/25/2004

Arizona Public Service
Revised Calculation of Expected Annual Growth in Dividends and Indicated Costs of Equity
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B] Growth rate	[C] Dvidend Yield	[D] Indicated Equity Cost
	Blended (1997-2007) estimates of growth			
1	DPS Growth	2.2%		
2	EPS Growth	4.3%		
3	Intrinsic Growth	5.9%		
4	Average	4.2%	4.5%	8.7%
	Forward-looking Estimates of Growth			
5	DPS Growth	3.3%		
6	EPS Growth	5.2%		
7	Intrinsic Growth	6.2%		
8	Average	5.7% n/	4.5%	10.2%

Note
9 n/ Average of forward-looking estimates of EPS growth and Intrinsic growth.

########

Arizona Public Service
Update of Calculation of Current Market Risk Premium
Based on DCF Analysis of the *Value Line* Industrial Composite
Dated March 19,2004.

BR growth	B 0.680	R 0.170	BR 11.6%	
VS growth	S 0.017	V 0.709	VS 1.2%	
Intrinsic Growth				12.77%
Dividend Yield				1.60%
Expected market return				14.37%
Long Term Treasury Yield				5.25%
Current market risk premium				9.12%

Source: *Value Line Selection & Opinion,* March 19, 2004.

########

Arizona Public Service
Revised Cost of Equity Estimates for Arizona Public Service
Correct Errors and Inconsistencies in Mr. Reiker's Constant Growth DCF Analysis and Revise CAPM
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B]		[C]		[D]		[E]
	Constant Growth DCF			D_1/P_0	+	g	=	k
1	Constant Growth DCF Estimate			4.5%	+	4.2%	=	8.7%
2	Multi-Stage DCF Estimate						=	10.6%
3	**Average of DCF Estimates**							**9.6%**
4								
5	**CAPM Method**	Rf	+	β	x	(Rp)	=	k
6	Historical Market Risk Premium	5.25%	+	0.67	x	7.00%	=	9.9%
7	Current Market Risk Premium	5.25%	+	0.67	x	9.12%	=	11.4%
8	**Average of CAPM Estimates**							**10.6%**
9								
10						**Average**		**10.1%**
11								
12						**Include Financing Costs**		**10.6%**
13								

14 Source: Mr. Reiker's electronic work papers, Ibbotson Associates 2003 SBBI Yearbook, and Schedule CEO-4RB.

15 Note: CAPM revised to base estimates of Rf and MRP on current long-term Treasury rate. Current MRP is derived in Schedule CEO-4RB.

03/25/2004

Calculation of current market risk premium

Line No.							
	Long-Term Treasury		Beta of Market		Current MRP		
18	5.25%	+					
19			Expected Div. Yield		Expected Growth		COE Est.
20	Val Ln Indust Cmp		1.60%	+	BR+VS	=	15.0%
21							
22							
23							
24							

Fedral Reserve Feb. 2004 Long Treasury 5.25%

Exhibit 1917
Page 7 of 268

Arizona Public Service
Revised Cost of Equity Estimates for Arizona Public Service
Based on an Average of Forward-Looking Estimates of DCF Growth and Revised CAPM
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B]		[C]		[D]		[E]
	Constant Growth DCF			D_1/P_0	+	g	=	k
1	Constant Growth DCF Estimate			4.5%	+	5.7%	=	10.2%
2	Multi-Stage DCF Estimate						=	10.6%
3	**Average of DCF Estimates**							**10.4%**
4								
5	**CAPM Method**	Rf	+	β	x	(Rp)	=	k
6	Historical Market Risk Premium	5.25%	+	0.67	x	7.00%	=	9.9%
7	Current Market Risk Premium	5.25%	+	0.67	x	9.12%	=	11.4%
8	**Average of CAPM Estimates**							**10.6%**
9								
10						**Average**		**10.5%**
11								
						Include Financing Costs		**11.0%**

12
13 Source: Mr. Reiker's electronic work papers, Ibbotson Associates 2003 SBBI Yearbook, and Schedule CEO-4RB.
14 Note: CAPM revised to base estimates of Rf and MRP on current long-term Treasury rate. Current MRP is derived in Schedule CEO-4RB.

03/25/2004

Line	Calculation of current market risk premium						
15							
16							
17	Long-Term Treasury		Beta of Market		Current MRP		
18	5.25%	+	1.00	x	9.75%	=	15.0%
19			Expected Div. Yield		Expected Growth		COE Est.
20	Val Ln Indust Cmp		1.60%	+	BR+VS	=	15.0%

Line	Treasury Yields: 10/09/2003 (10/9/03 WSJ)	
21		
22		
23	5-YR	3.18%
24	7-YR	3.72%
	10-YR	4.30%
	AVG:	5.25%

Exhibit 1917
Page 8 of 268

Arizona Public Service
Risk Premiums Computed as Difference Between
Authorized ROEs and Baa Corporate Bond Rates[a]
During the Period 1983-2003

Regression Output:

Constant ("A_0")		0.065
Std Err of Y Est		0.008
R Squared		0.619
No. of Observations		545
Degrees of Freedom		543
Slope ("A_1")	-0.399	
Std Err of Coef.	0.013	
t-statistic	-29.7	

Equity Cost Estimate		Predicted Risk Premium		Baa Rate[b]	
11.0%	=	3.6%	+	7.4%	Forecast
10.3%	=	4.0%	+	6.3%	Current

Formula: Risk Premium = A_0 + (A_1 x Baa Corporate Rate)[c]

Sources and Notes:

_a/ Source of Data: Oregon PUC Response to NW Natural Data request in UG 132 updated with data in Phillip Cross, "Rate of Return: Still an Issue at PUCs," *Public Utilities Fortnightly*, December 1998 and 2000 plus decisions reported by Regulatory Research Associates.

_b/ Blue Chip Financial consensus forecast for Second Quarter 2005 as of March 1, 2004 and current Baa rate as reported by the Federal Reserve.

_c/ 8-month lag between order date and Baa yield adopted based on the results of an Oregon PUC Staff study.

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Arizona Public Service
Comparison of Betas and Common Equity Ratios
To Examine If Mr. Reiker's Leverage Argument Holds for All
Utilities in His Sample of Electric Utilities

		Beta	Common Equity Ratio	Inconsistent Companies
1	Alliant Energy	0.70	45.9%	1
2	Ameren	0.65	49.3%	
3	Avista	0.75	42.3%	
4	Cent. Vermont P.S.	0.45	58.9%	
5	CH Energy Group	0.70	63.7%	2
6	Cleco Corporation	0.90	36.6%	
7	Con. Edison	0.55	50.0%	
8	DPL Inc.	0.80	33.8%	
9	DTE Energy Co.	0.60	37.6%	3
10	Empire District	0.60	45.1%	
11	Energy East Corp.	0.70	40.3%	
12	Entergy Corp.	0.65	51.3%	
13	FirstEnergy	0.70	39.3%	
14	FPL Group, Inc.	0.60	50.2%	
15	Green Mtn. Power	0.60	49.1%	
16	Hawaiian Electric	0.55	45.9%	
17	IDACORP, Inc.	0.75	50.1%	4
18	MGE Energy Inc.	0.55	57.3%	
19	NiSource Inc.	0.65	46.9%	
20	Northeast Utilities	0.65	34.1%	5
21	NSTAR	0.65	37.7%	6
22	P.S. Enterprise Gp.	0.75	27.6%	
23	Pinnacle West	0.70	50.6%	7
24	PNM Resources	0.70	50.3%	8
25	Progress Energy	0.85	41.6%	
26	Puget Energy, Inc.	0.65	39.5%	9
27	SCANA Corp.	0.60	43.5%	10
28	Sempra Energy	0.80	39.3%	
29	Southern Co.	0.65	48.7%	
30	TECO Energy,Inc.	0.75	29.1%	
31	Westar Energy	0.60	27.9%	11
32	Wisconsin Energy	0.60	38.7%	12
33	WPS Resources	0.70	52.4%	13
	mean	0.67	44.1%	

Source : Mr. Reiker's electronic work papers.

03/25/2004

mean	mean	median	median	
1	0	1	0	1
0	0	1	0	
1	1	1	0	
0	0	1	0	
1	0	1	0	2
1	1	1	0	
0	0	1	0	
1	1	1	0	
0	1	1	0	3
0	0	1	0	
1	1	1	0	
0	0	1	0	
1	1	1	0	
0	0	1	0	
0	0	1	0	
0	0	1	0	
1	0	1	0	4
0	0	1	0	
0	0	1	0	
0	1	1	0	5
0	1	1	0	6
1	1	1	0	
1	0	1	0	7
1	0	1	0	8
1	1	1	0	
0	1	1	0	9
0	1	1	0	10
1	1	1	0	
0	0	1	0	
1	1	1	0	
0	1	1	0	11
0	1	1	0	12
1	0	1	0	13

Arizona Public Service

Authorized and Earned Returns on Equity for
Mr. Reiker's Sample Utilities

		Earned ROE	Authorized ROE
1	Alliant Energy	6.20%	11.54%
2	Ameren	12.30%	11.14%
3	Avista	6.60%	10.96%
4	Cent. Vermont P.S.	9.10%	11.00%
5	CH Energy Group	9.00%	10.30%
6	Cleco Corporation	nm	12.25%
7	Con. Edison	8.50%	10.80%
8	DPL Inc.	15.30%	nr
9	DTE Energy Co.	10.10%	13.50%
10	Empire District	8.40%	nr
11	Energy East Corp.	8.80%	11.15%
12	Entergy Corp.	10.80%	11.19%
13	FirstEnergy	3.00%	12.20%
14	FPL Group, Inc.	13.40%	nr
15	Green Mtn. Power	11.10%	10.50%
16	Hawaiian Electric	10.20%	11.22%
17	IDACORP, Inc.	5.40%	nr
18	MGE Energy Inc.	11.80%	11.06%
19	NiSource Inc.	12.20%	11.97%
20	Northeast Utilities	5.50%	10.43%
21	NSTAR	14.90%	11.63%
22	P.S. Enterprise Gp.	22.10%	9.88%
23	Pinnacle West	6.20%	11.25%
24	PNM Resources	5.20%	10.25%
25	Progress Energy	11.30%	12.75%
26	Puget Energy, Inc.	8.40%	11.00%
27	SCANA Corp.	12.60%	11.93%
28	Sempra Energy	20.70%	10.90%
29	Southern Co.	16.50%	12.87%
30	TECO Energy,Inc.	nm	11.25%
31	Westar Energy	2.80%	11.02%
32	Wisconsin Energy	10.90%	12.20%
33	WPS Resources	10.20%	11.70%
		10.3%	11.4%

Notes: nm/ no meaningful value
nr/ not reported.
Source: CA Turner Utiltiy Reports, March 2004.

03/25/2004

Arizona Public Service

Revised Schedule 7: Mr. Hill's DCF Equity Cost Estimate Based on Mr. Reiker's Estimates of VS Growth

		Dividend	Growth Rate			DCF Cost of
	Company	Yield[a/]	BR[b/]	VS[c/]	BR+VS	Equity Capital
CV	Central Vermont P.S.	3.96%	4.75%	0.06%	4.81%	8.77%
EAS	Energy East	4.62%	4.50%	0.07%	4.57%	9.19%
FE	FirstEnergy	4.40%	4.50%	0.34%	4.84%	9.24%
SO	Southern Company	4.74%	5.00%	5.45%	10.45%	15.19%
AEE	Ameren	5.76%	3.00%	1.66%	4.66%	10.42%
CNL	Cleco	5.34%	4.75%	0.66%	5.41%	10.75%
DPL	DPL, Inc.	5.05%	5.75%	0.00% [b/]	5.75%	10.80%
EDE	Empire District	5.90%	3.50%	2.99%	6.49%	12.39%
ETR	Entergy Corp	3.35%	6.00%	0.23%	6.23%	9.58%
GXP	Great Plains	5.23%	4.25%	0.31% [b/]	4.56%	9.79%
HE	Hawaiian Electric	5.49%	3.00%	0.86%	3.86%	9.35%
PNW	Pinnacle West	4.86%	4.50%	0.24%	4.74%	9.60%
	Average	4.89%	4.46%	1.07%	5.53%	10.42%
	Equity cost with Financing Costs					10.92%

Sources of data:
a/ Mr. Hill Schedule 6.
b/ Mr. Hill Schedule 5 page 1 of 2.
c/ Mr. Reiker's estimates of VS growth from Staff work paper tab CoDATA except for the two indicated.

03/25/2004

Company	Ticker		1997	2004	'06-'08	'97-'07		'04-'07
1 Alliant Energy	LNT	DPS	2	1	1.2	cut	cut	6.3%
2 Ameren	AEE	DPS	2.54	2.54	2.62	0.3%	0.5	1.0%
3 Avista	AVA	DPS	1.24	0.48	0.6	cut	cut	7.7%
4 Cent. Vermont P.S.	CV	DPS	0.88	0.92	1.04	1.7%	1.0	4.2%
5 CH Energy Group	CHG	DPS	2.14	2.16	2.2	0.3%	0.5	0.6%
6 Cleco Corporation	CNL	DPS	0.79	0.9	0.9	1.3%	2.5	0.0%
7 Con. Edison	ED	DPS	2.1	2.26	2.32	1.0%	1.0	0.9%
8 DPL Inc.	DPL	DPS	0.91	0.94	0.98	0.7%	1.5	1.4%
9 DTE Energy Co.	DTE	DPS	2.06	2.06	2.1	0.2%	0.0	0.6%
10 Empire District	EDE	DPS	1.28	1.28	1.28	0.0%	0.0	0.0%
11 Energy East Corp.	EAS	DPS	0.7	1.04	1.16	5.2%	5.5	3.7%
12 Entergy Corp.	ETR	DPS	1.8	1.82	2.06	1.4%	cut	4.2%
13 FirstEnergy	FE	DPS	1.5	1.5	1.7	1.3%	0.0	4.3%
14 FPL Group, Inc.	FPL	DPS	1.92	2.48	2.72	3.5%	4.0	3.1%
15 Green Mtn. Power	GMP	DPS	1.61	0.8	0.92	cut	cut	4.8%
16 Hawaiian Electric	HE	DPS	2.44	2.48	2.48	0.2%	0.5	0.0%
17 IDACORP, Inc.	IDA	DPS	1.86	1	1	cut	cut	0.0%
18 MGE Energy Inc.	MGEE	DPS	1.29	1.36	1.38	0.7%	1.0	0.5%
19 NiSource Inc.	NI	DPS	0.92	0.92	1	0.8%	4.0	2.8%
20 Northeast Utilities	NU	DPS	0.25	0.62	0.78	12.1%	cut	8.0%
21 NSTAR	NST	DPS	1.88	2.21	2.33	2.2%	2.0	1.8%
23 P.S. Enterprise Gp.	PEG	DPS	2.16	2.2	2.32	0.7%	0.0	1.8%
24 Pinnacle West	PNW	DPS	1.13	1.83	2.13	6.5%	8.5	5.2%
25 PNM Resources	PNM	DPS	0.63	0.95	1.07	5.4%	20.0	4.0%
26 Progress Energy	PGN	DPS	1.9	2.32	2.5	2.8%	3.0	2.5%
27 Puget Energy, Inc.	PSD	DPS	1.84	1	1.12	cut	cut	3.8%
28 SCANA Corp.	SCG	DPS	1.51	1.46	1.7	1.2%	cut	5.2%
29 Sempra Energy	SRE	DPS	1.56	1	1	cut	cut	0.0%
30 Southern Co.	SO	DPS	1.3	1.42	1.58	2.0%	1.5	3.6%
31 TECO Energy,Inc.	TE	DPS	1.17	0.76	1	cut	cut	9.6%
32 Westar Energy	WR	DPS	2.1	0.76	0.92	cut	cut	6.6%
33 Wisconsin Energy	WEC	DPS	1.54	0.8	1	cut	cut	7.7%
34 WPS Resources	WPS	DPS	1.92	2.2	2.32	1.9%	2.0	1.8%
						2.22%		3.26%
							2.8	

				2004 Update		revised	Joel	Reiker	
1 Alliant Energy	LNT	EPS	1.9	1.65	1.9	0.0%	0.0%	4.8%	1.9
2 Ameren	AEE	EPS	2.44	3	3.3	3.1%	3.1%	3.2%	3.3
3 Avista	AVA	EPS		1.15	1.5 u	9.3%	-4.4% x	9.3%	1.25
4 Cent. Vermont P.S.	CV	EPS	1.32	1.55	1.85	3.4%	3.4%	6.1%	1.85
5 CH Energy Group	CHG	EPS	2.97	2.7	3	0.1%	0.1%	3.6%	3
6 Cleco Corporation	CNL	EPS	1.09	1.4	1.5	3.2%	3.2%	2.3%	1.5
7 Con. Edison	ED	EPS	2.95	3	3.2	0.8%	0.8%	2.2%	3.2
8 DPL Inc.	DPL	EPS	1.2	1.3	1.45 d	1.9%	4.4%	3.7%	1.85
9 DTE Energy Co.	DTE	EPS	2.88	3.45	4.25	4.0%	4.0%	7.2%	4.25
10 Empire District	EDE	EPS	1.29	1.35	1.5 d	1.5%	3.1%	3.6%	1.75
11 Energy East Corp.	EAS	EPS	1.29	1.7	2	4.5%	4.5%	5.6%	2
12 Entergy Corp.	ETR	EPS	2.25	4.2	4.5	7.2%	7.2%	2.3%	4.5
13 FirstEnergy	FE	EPS	1.94	2.65	3	4.5%	4.5%	4.2%	3
14 FPL Group, Inc.	FPL	EPS	3.57	5.1	5.7	4.8%	4.8%	3.8%	5.7
15 Green Mtn. Power	GMP	EPS	1.57	1.95	2.15	3.2%	3.2%	3.3%	2.15
16 Hawaiian Electric	HE	EPS	2.76	3.2	3.5 u	2.4%	0.8%	3.0%	3
17 IDACORP, Inc.	IDA	EPS		1.8	1.9	1.8%	-4.3% x	1.8%	1.5
18 MGE Energy Inc.	MGEE	EPS	1.4	2	2.25	4.9%	4.9%	4.0%	2.25
19 NiSource Inc.	NI	EPS	1.54	1.7	1.85	1.9%	1.9%	2.9%	1.85
20 Northeast Utilities	NU	EPS		1.3	2	15.4%	x	15.4%	2
21 NSTAR	NST	EPS	2.71	3.5	4	4.0%	4.0%	4.6%	4
23 P.S. Enterprise Gp.	PEG	EPS	2.41	3.7	4 d	5.2%	6.4%	2.6%	4.5
24 Pinnacle West	PNW	EPS	2.76	3	3.4 u	2.1%	1.8%	4.3%	3.3
25 PNM Resources	PNM	EPS	1.88	2	2.15	1.4%	1.4%	2.4%	2.15
26 Progress Energy	PGN	EPS	2.66	3.65	3.95 d	4.0%	4.5%	2.7%	4.15
27 Puget Energy, Inc.	PSD	EPS	1.28	1.75	2	4.6%	4.6%	4.6%	2
28 SCANA Corp.	SCG	EPS	1.9	2.6	3	4.7%	4.7%	4.9%	3
29 Sempra Energy	SRE	EPS	2.2	2.7	3.25	4.0%	4.0%	6.4%	3.25
30 Southern Co.	SO	EPS	1.58	1.95	2.3 d	3.8%	4.0%	5.7%	2.35
31 TECO Energy,Inc.	TE	EPS	1.61	1	2	2.2%	2.2%	26.0%	2
32 Westar Energy	WR	EPS		1.65	2	6.6%	x	6.6%	2
33 Wisconsin Energy	WEC	EPS	0.54	2.3	2.75	17.7%	17.7%	6.1%	2.75
34 WPS Resources	WPS	EPS	2.13	2.9	3.15	4.0%	4.0%	2.8%	3.15
						4.30%	3.37%	5.21%	

He just uses the VL calculation of retained to CE

check on Alliant	0.0069406	0.018267		0.017008264	check	0.03132		
						Future	Past	
	1998	1999	2000	2001	2002	'06-'08	'98-'02	

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1 Alliant Energy	LNT	BR	NMF	0.7%	1.9%	1.6%	NMF	3.0%	1.40%
2 Ameren	AEE	BR	1.2%	1.2%	3.4%	3.6%	0.2%	2.5%	1.92%
3 Avista	AVA	BR	2.9%	NMF	8.0%	4.8%	1.2%	3.5%	4.23%
4 Cent. Vermont P.S.	CV	BR	NMF	2.5%	1.5%	0.5%	3.9%	4.5%	2.10%
5 CH Energy Group	CHG	BR	2.7%	2.5%	3.1%	3.1%	NMF	3.0%	2.85%
6 Cleco Corporation	CNL	BR	3.8%	4.2%	6.5%	6.5%	5.6%	5.0%	5.32%
7 Con. Edison	ED	BR	3.6%	4.1%	2.2%	3.8%	4.0%	2.5%	3.54%
8 DPL Inc.	DPL	BR	3.3%	4.2%	8.9%	13.7%	NMF	9.0%	7.53%
9 DTE Energy Co.	DTE	BR	3.9%	4.7%	4.3%	0.1%	6.4%	5.5%	3.88%
10 Empire District	EDE	BR	1.8%	NMF	0.5%	NMF	NMF	3.0%	1.15%
11 Energy East Corp.	EAS	BR	5.5%	8.8%	8.0%	7.1%	2.9%	4.0%	6.46%
12 Entergy Corp.	ETR	BR	2.1%	3.7%	5.8%	5.7%	7.1%	5.0%	4.88%
13 FirstEnergy	FE	BR	2.3%	5.0%	5.7%	4.3%	4.3%	4.5%	4.32%
14 FPL Group, Inc.	FPL	BR	6.2%	6.6%	6.3%	7.0%	4.6%	5.5%	6.14%
15 Green Mtn. Power	GMP	BR	NMF	NMF	NMF	7.7%	8.7%	6.0%	8.20%
16 Hawaiian Electric	HE	BR	1.8%	1.5%	1.7%	4.4%	4.3%	3.5%	2.74%
17 IDACORP, Inc.	IDA	BR	2.6%	2.9%	7.5%	6.3%	NMF	2.0%	4.83%
18 MGE Energy Inc.	MGEE	BR	0.7%	1.5%	2.9%	2.3%	2.7%	4.5%	2.02%
19 NiSource Inc.	NI	BR	6.7%	2.6%	1.7%	NMF	3.9%	4.0%	3.73%
20 Northeast Utilities	NU	BR	NMF	NMF	NMF	5.6%	3.2%	6.0%	4.40%
21 NSTAR	NST	BR	3.9%	2.4%	4.8%	5.0%	5.2%	5.5%	4.26%
23 P.S. Enterprise Gp.	PEG	BR	2.8%	5.3%	7.5%	7.8%	8.3%	8.0%	6.34%
24 Pinnacle West	PNW	BR	6.4%	7.1%	6.8%	7.3%	2.9%	3.5%	6.10%
25 PNM Resources	PNM	BR	8.4%	5.2%	6.5%	12.3%	3.1%	3.5%	7.10%
26 Progress Energy	PGN	BR	4.0%	2.5%	NMF	4.3%	5.0%	4.5%	3.95%
27 Puget Energy, Inc.	PSD	BR	0.1%	1.0%	3.6%	NMF	1.3%	4.5%	1.50%
28 SCANA Corp.	SCG	BR	3.4%	–	4.8%	4.6%	5.5%	5.0%	4.58%
29 Sempra Energy	SRE	BR	NMF	0.9%	7.4%	11.9%	13.1%	9.5%	8.33%
30 Southern Co.	SO	BR	2.7%	3.6%	4.1%	2.5%	4.1%	5.0%	3.40%
31 TECO Energy,Inc.	TE	BR	2.6%	2.3%	5.5%	6.1%	3.2%	7.0%	3.94%
32 Westar Energy	WR	BR	NMF	NMF	NMF	NMF	NMF	6.0%	
33 Wisconsin Energy	WEC	BR	0.6%	1.9%	NMF	6.0%	8.3%	6.5%	4.20%
34 WPS Resources	WPS	BR	NMF	1.2%	1.9%	2.7%	3.1%	2.5%	2.23%
							4.67%	4.77%	4.30%
								Future	Past
							2002	'06-'08	'98-'02

			D-02	D-03	10/9/03	CAP STRUC
1 Alliant Energy	LNT	BV	19.89	20.15	20.09	#REF!
2 Ameren	AEE	BV	24.93	26.35	26.03	#REF!
3 Avista	AVA	BV	14.84	15.15	15.08	#REF!
4 Cent. Vermont P.S.	CV	BV	16.83	17.1	17.04	#REF!
5 CH Energy Group	CHG	BV	30.31	29.3	29.53	#REF!
6 Cleco Corporation	CNL	BV	11.77	10.4	10.71	#REF!
7 Con. Edison	ED	BV	27.68	28.9	28.62	#REF!
8 DPL Inc.	DPL	BV	6.38	6.85	6.74	#REF!
9 DTE Energy Co.	DTE	BV	27.26	28.35	28.10	#REF!
10 Empire District	EDE	BV	14.59	14.95	14.87	#REF!
11 Energy East Corp.	EAS	BV	16.97	17.7	17.53	#REF!
12 Entergy Corp.	ETR	BV	35.24	38.25	37.57	#REF!
13 FirstEnergy	FE	BV	23.92	24.8	24.60	#REF!
14 FPL Group, Inc.	FPL	BV	34.96	38.25	37.50	#REF!
15 Green Mtn. Power	GMP	BV	18.51	19.65	19.39	#REF!
16 Hawaiian Electric	HE	BV	28.43	29.7	29.41	#REF!
17 IDACORP, Inc.	IDA	BV	23.01	22.6	22.69	#REF!
18 MGE Energy Inc.	MGEE	BV	13.1	15.35	14.84	#REF!
19 NiSource Inc.	NI	BV	16.78	18.05	17.76	#REF!
20 Northeast Utilities	NU	BV	17.33	17.65	17.58	#REF!
21 NSTAR	NST	BV	24.5	25.8	25.50	#REF!
23 P.S. Enterprise Gp.	PEG	BV	17.7	19.5	19.09	#REF!
24 Pinnacle West	PNW	BV	29.44	30.4	30.18	#REF!
25 PNM Resources	PNM	BV	24.9	25.95	25.71	#REF!
26 Progress Energy	PGN	BV	28.73	30.5	30.10	#REF!
27 Puget Energy, Inc.	PSD	BV	16.27	16.7	16.60	#REF!
28 SCANA Corp.	SCG	BV	19.64	21.1	20.77	#REF!
29 Sempra Energy	SRE	BV	13.79	15.45	15.07	#REF!
30 Southern Co.	SO	BV	12.15	12.9	12.73	#REF!
31 TECO Energy,Inc.	TE	BV	14.86	12.8	13.27	#REF!
32 Westar Energy	WR	BV	13.68	14.6	14.39	#REF!
33 Wisconsin Energy	WEC	BV	18.44	20.15	19.76	#REF!
34 WPS Resources	WPS	BV	24.45	27.45	26.77	#REF!

			1997	1998	1999	2000	2001	2002
1 Alliant Energy	LNT	common eq	607.4867	1606.3	2155.6	2037.5	1918.3	1836.2
2 Ameren	AEE	common eq	3018.84	3056.1	3089.7	3196.7	3348.8	3842
3 Avista	AVA	common eq	748.7448	488	393.5	724.2	720.1	712.8
4 Cent. Vermont P.S.	CV	common eq	187.0596	179.2	184	190.7	183.5	197.6
5 CH Energy Group	CHG	common eq	477.1008	472.2	420.9	480.7	496.3	486.9

6 Cleco Corporation	CNL	common eq	389.9924	424.7	438.7	464.9	492	562.5
7 Con. Edison	ED	common eq	5929.638	6025.6	5412	5472.4	5666.3	5921.1
8 DPL Inc.	DPL	common eq	1286.406	1383.7	1451.6	892.4	821.1	829.9
9 DTE Energy Co.	DTE	common eq	3562.205	3698	3909	4015	4589	4565
10 Empire District	EDE	common eq	219.1468	229.8	234.2	240.2	268.3	329.3
11 Energy East Corp.	EAS	common eq	1803.867	1713.5	1404	1716.5	1781.2	2460.6
12 Entergy Corp.	ETR	common eq	6694.223	7445.5	7119.4	7003.7	7456	7838.2
13 FirstEnergy	FE	common eq	4159.895	4449.2	4563.9	4653.1	7398.6	7120
14 FPL Group, Inc.	FPL	common eq	4845.503	5126	5370	5593	6015	6390
15 Green Mtn. Power	GMP	common eq	114.504	106.8	100.6	92	101.3	91.7
16 Hawaiian Electric	HE	common eq	814.726	827	847.6	839.1	877.2	1046.3
17 IDACORP, Inc.	IDA	common eq	711.9573	730.4	753	820.8	871	874.8
18 MGE Energy Inc.	MGEE	common eq	180.9	182.3	185.7	200.3	216.3	227.4
19 NiSource Inc.	NI	common eq	1264.233	1149.7	1353.5	3415.2	3469.4	4174.9
20 Northeast Utilities	NU	common eq	2127.141	2047.4	2083.3	2218.6	2117.6	2210.5
21 NSTAR	NST	common eq	1065.499	1050.6986	1523.5	1376.4	1262.6	1299.3
23 P.S. Enterprise Gp.	PEG	common eq	5212.141	5098	3996	3996	4137	3987
24 Pinnacle West	PNW	common eq	2027.437	2163.4	2205.7	2382.7	2499.3	2686.2
25 PNM Resources	PNM	common eq	804.4902	861.6	887.1	924.6	885	974
26 Progress Energy	PGN	common eq	2819.464	2949.3	3412.6	5424.2	6003.5	6677
27 Puget Energy, Inc.	PSD	common eq	1358.034	1352.7	1379.1	1426.6	1362.7	1523.8
28 SCANA Corp.	SCG	common eq	1787.951	1746	2099	2032	2194	2177
29 Sempra Energy	SRE	common eq	1570.367	2913	2986	2494	2692	2825
30 Southern Co.	SO	common eq	9644.8	9797	9204	10690	7984	8710
31 TECO Energy,Inc.	TE	common eq	1445.136	1507.8	1417.8	1506.9	1971.6	2611.7
32 Westar Energy	WR	common eq	2013.974	1937.9	1875.4	1906.6	1820.1	956.7
33 Wisconsin Energy	WEC	common eq	1863.484	1903.1	2007.7	2016.8	2056.1	2139.4
34 WPS Resources	WPS	common eq	478	517.2	536.3	542.8	715.9	782.8

			1998	1999	2000	2001	2002
1 Alliant Energy	LNT	funds from common st	33.8	36.5	1.1	288.6	200.7
2 Ameren	AEE	funds from common st	0	0	0	33.4	658
3 Avista	AVA	funds from common st	0	0	2.6	8.3	7
4 Cent. Vermont P.S.	CV	funds from common st	0.5	0.1	0.5	0.6	0.4
5 CH Energy Group	CHG	funds from common st	0	0	0	0	0
6 Cleco Corporation	CNL	funds from common st	0.1	0.2	0	0	44.3
7 Con. Edison	ED	funds from common st	0	0	0	0	25.1
8 DPL Inc.	DPL	funds from common st	19.7	0	526.4	289	0
9 DTE Energy Co.	DTE	funds from common st	0	0	0	0	445
10 Empire District	EDE	funds from common st	5.1	6.4	3.9	41	56.5
11 Energy East Corp.	EAS	funds from common st	0	0	0	7.2	17.8
12 Entergy Corp.	ETR	funds from common st	19.3	15.3	41.9	64.3	130.1
13 FirstEnergy	FE	funds from common st	204.2	0	0	96.7	0
14 FPL Group, Inc.	FPL	funds from common st	0	0	0	0	378
15 Green Mtn. Power	GMP	funds from common st	1.6	1.1	1.3	1.7	1
16 Hawaiian Electric	HE	funds from common st	58.2	3.4	14.1	0	32.5
17 IDACORP, Inc.	IDA	funds from common st	0	0	0	4	15.8
18 MGE Energy Inc.	MGEE	funds from common st	0	1.7	9	10.9	13.6
19 NiSource Inc.	NI	funds from common st	10.4	324.9	2042.1	15.1	734.9
20 Northeast Utilities	NU	funds from common st	2.7	5.3	4.3	1.8	7.5
21 NSTAR	NST	funds from common stock		0	0	0	0
23 P.S. Enterprise Gp.	PEG	funds from common st	525	0	0	0	996
24 Pinnacle West	PNW	funds from common st	0	0	0	0	199.2
25 PNM Resources	PNM	funds from common st	0	0	0	0	0
26 Progress Energy	PGN	funds from common st	0	0	0	488.3	687
27 Puget Energy, Inc.	PSD	funds from common st	0	1.1	0	200	120.2
28 SCANA Corp.	SCG	funds from common st	0	0	0	0	149
29 Sempra Energy	SRE	funds from common st	34	3	12	41	13
30 Southern Co.	SO	funds from common st	869	274	910	425	1766
31 TECO Energy,Inc.	TE	funds from common st	6.7	0.3	218.3	348.4	1008.2
32 Westar Energy	WR	funds from common st	17.3	43.2	60	26.6	20.9
33 Wisconsin Energy	WEC	funds from common st	10.3	272.8	89.3	51.6	234.6
34 WPS Resources	WPS	funds from common st	0	9	0	96.4	28.3

			1998	1999	2000	2001	2002	s
1 Alliant Energy	LNT	s	5.6%	2.3%	0.1%	14.2%	10.5%	6.5%
2 Ameren	AEE	s	0.0%	0.0%	0.0%	1.0%	19.6%	4.1%
3 Avista	AVA	s	0.0%	0.0%	0.7%	1.1%	1.0%	0.6%
4 Cent. Vermont P.S.	CV	s	0.3%	0.1%	0.3%	0.3%	0.2%	0.2%
5 CH Energy Group	CHG	s	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6 Cleco Corporation	CNL	s	0.0%	0.0%	0.0%	0.0%	9.0%	1.8%
7 Con. Edison	ED	s	0.0%	0.0%	0.0%	0.0%	0.4%	0.1%
8 DPL Inc.	DPL	s	1.5%	0.0%	36.3%	32.4%	0.0%	14.0%
9 DTE Energy Co.	DTE	s	0.0%	0.0%	0.0%	0.0%	9.7%	1.9%
10 Empire District	EDE	s	2.3%	2.8%	1.7%	17.1%	21.1%	9.0%
11 Energy East Corp.	EAS	s	0.0%	0.0%	0.0%	0.4%	1.0%	0.3%
12 Entergy Corp.	ETR	s	0.3%	0.2%	0.6%	0.9%	1.7%	0.7%
13 FirstEnergy	FE	s	4.9%	0.0%	0.0%	2.1%	0.0%	1.4%
14 FPL Group, Inc.	FPL	s	0.0%	0.0%	0.0%	0.0%	6.3%	1.3%
15 Green Mtn. Power	GMP	s	1.4%	1.0%	1.3%	1.8%	1.0%	1.3%

16 Hawaiian Electric	HE	s	7.1%	0.4%	1.7%	0.0%	3.7%	2.6%
17 IDACORP, Inc.	IDA	s	0.0%	0.0%	0.0%	0.5%	1.8%	0.5%
18 MGE Energy Inc.	MGEE	s	0.0%	0.9%	4.8%	5.4%	6.3%	3.5%
19 NiSource Inc.	NI	s	0.8%	28.3%	150.9%	0.4%	21.2%	40.3%
20 Northeast Utilities	NU	s	0.1%	0.3%	0.2%	0.1%	0.4%	0.2%
21 NSTAR	NST	s		0.0%	0.0%	0.0%	0.0%	0.0%
23 P.S. Enterprise Gp.	PEG	s	10.1%	0.0%	0.0%	0.0%	24.1%	6.8%
24 Pinnacle West	PNW	s	0.0%	0.0%	0.0%	0.0%	8.0%	1.6%
25 PNM Resources	PNM	s	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
26 Progress Energy	PGN	s	0.0%	0.0%	0.0%	9.0%	11.4%	4.1%
27 Puget Energy, Inc.	PSD	s	0.0%	0.1%	0.0%	14.0%	8.8%	4.6%
28 SCANA Corp.	SCG	s	0.0%	0.0%	0.0%	0.0%	6.8%	1.4%
29 Sempra Energy	SRE	s	2.2%	0.1%	0.4%	1.6%	0.5%	1.0%
30 Southern Co.	SO	s	9.0%	2.8%	9.9%	4.0%	22.1%	9.6%
31 TECO Energy, Inc.	TE	s	0.5%	0.0%	15.4%	23.1%	51.1%	18.0%
32 Westar Energy	WR	s	0.9%	2.2%	3.2%	1.4%	1.1%	1.8%
33 Wisconsin Energy	WEC	s	0.6%	14.3%	4.4%	2.6%	11.4%	6.7%
34 WPS Resources	WPS	s	0.0%	1.7%	0.0%	17.8%	4.0%	4.7%
								4.6%

GDP	
1929	103.6
1930	91.2
1931	76.5
1932	58.7
1933	56.4
1934	66.0
1935	73.3
1936	83.8
1937	91.9
1938	86.1
1939	92.2
1940	101.4
1941	126.7
1942	161.9
1943	198.6
1944	219.8
1945	223.1
1946	222.3
1947	244.2
1948	269.2
1949	267.3
1950	293.8
1951	339.3
1952	358.3
1953	379.4
1954	380.4
1955	414.8
1956	437.5
1957	461.1
1958	467.2
1959	506.6
1960	526.4
1961	544.7
1962	585.6
1963	617.7
1964	663.6
1965	719.1
1966	787.8
1967	832.6
1968	910.0
1969	984.6
1970	1,038.5
1971	1,127.1
1972	1,238.3
1973	1,382.7
1974	1,500.0
1975	1,638.3
1976	1,825.3
1977	2,030.9
1978	2,294.7
1979	2,563.3
1980	2,789.5
1981	3,128.4
1982	3,255.0
1983	3,536.7
1984	3,933.2

1985	4,220.3
1986	4,462.8
1987	4,739.5
1988	5,103.8
1989	5,484.4
1990	5,803.1
1991	5,995.9
1992	6,337.7
1993	6,657.4
1994	7,072.2
1995	7,397.7
1996	7,816.9
1997	8,304.3
1998	8,747.0
1999	9,268.4
2000	9,817.0
2001	10,100.8
2002	10,480.8
GDP Growth	6.5%

http://www.bea.doc.gov/

2003 Mergent Public Utility Manual

Dividend Rate - Weigl	DPS
2000	8.27
1960	2.68
Growth '60 - '00 DPS	2.9%
Market Price - Weight	Market Price
2000	167.69
1960	69.82
Growth '60 - '00 Market Pri	2.2%
Earnings - Weighted /	EPS
2000	8.36
1960	4.12
Growth '60 - '00 EPS	1.8%
Book Value at End of	Book Value
2000	166.4
1960	40.25
Growth '60 - '00 Book Valu	3.6%

http://data.bls.gov/

CPI	CPI
2000	172.2
1960	29.6
Growth CPI	4.5%
GDP	GDP
2000	9,817.0
1960	526.4
Growth '60 GDP	7.6%

Chart 3: Electric Utility Growth Rates Versus Consumer Pı
1960 - 2000

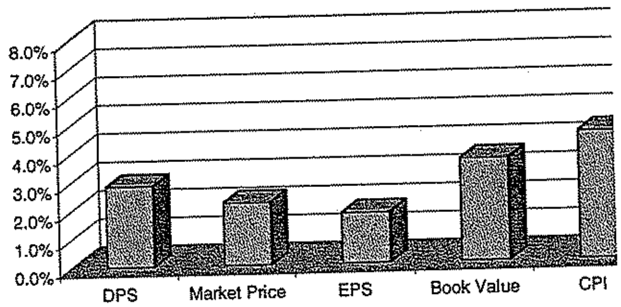


Exhibit 1917
Page 17 of 268

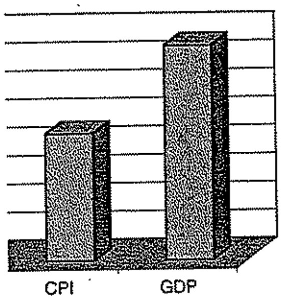
All	Future
'98-'07	FERC-BR

2.20%	3.0%
2.21%	2.5%
3.86%	3.6%
3.30%	4.6%
2.93%	3.0%
5.16%	5.1%
3.02%	2.5%
8.26%	9.4%
4.69%	5.6%
2.08%	3.0%
5.23%	4.1%
4.94%	5.1%
4.41%	4.6%
5.82%	5.6%
7.10%	6.2%
3.12%	3.6%
3.41%	2.0%
3.26%	4.6%
3.86%	4.1%
5.20%	6.2%
4.88%	5.6%
7.17%	8.3%
4.80%	3.6%
5.30%	3.6%
4.23%	4.6%
3.00%	4.6%
4.79%	5.1%
8.91%	9.9%
4.20%	5.1%
5.47%	7.2%
6.00%	6.2%
5.35%	6.7%
2.36%	2.5%
4.56%	4.90%
All '98-'07	Future FERC-BR

v	vs
0.13	0.8%
0.40	1.7%
0.06	0.0%
0.28	0.1%
0.34	0.0%
0.36	0.7%
0.30	0.0%
0.63	8.9%
0.22	0.4%
0.33	3.0%
0.25	0.1%
0.31	0.2%
0.24	0.3%
0.42	0.5%
0.13	0.2%

0.33	0.9%
0.15	0.1%
0.53	1.8%
0.17	6.8%
0.07	0.0%
0.46	0.0%
0.53	3.6%
0.15	0.2%
0.10	0.0%
0.32	1.3%
0.28	1.3%
0.41	0.6%
0.48	0.5%
0.57	5.4%
0.10	1.8%
0.24	0.4%
0.37	2.5%
0.36	1.7%
30.4%	1.4%

umer Price Index & GDP



Arizona Public Service
Selected Financial Data of Sample Electric Utilities

	[A]	[B]			[C]	[D]	[E]	[F]	[G]
Line No.	Company	Symbol			Spot Price 10/9/03	Book Value 10/9/03	Mkt To Book	*Value Line* Beta β	Raw Beta β_{raw}
1	Alliant Energy	LNT	A	A2	23.08	20.09	1.1	0.70	0.52
2	Ameren	AEE	A-	A1	43.50	26.03	1.7	0.65	0.45
3	Avista	AVA	BBB-	Baa3	16.12	15.08	1.1	0.75	0.60
4	Cent. Vermont P.S.	CV	BBB+	nr	23.65	17.04	1.4	0.45	0.15
5	CH Energy Group	CHG	A	A2	44.90	29.53	1.5	0.70	0.52
6	Cleco Corporation	CNL	BBB+	A3	16.81	10.71	1.6	0.90	0.82
7	Con. Edison	ED	A	A1	40.73	28.62	1.4	0.55	0.30
8	DPL Inc.	DPL	BBB-	Baa1	18.35	6.74	2.7	0.80	0.67
9	DTE Energy Co.	DTE	A-	A2	36.25	28.10	1.3	0.60	0.37
10	Empire District	EDE	BBB	Baa1	22.30	14.87	1.5	0.60	0.37
11	Energy East Corp.	EAS	BBB+	A3	23.44	17.53	1.3	0.70	0.52
12	Entergy Corp.	ETR	BBB	Baa2	54.08	37.57	1.4	0.65	0.45
13	FirstEnergy	FE	BBB	A3	32.58	24.60	1.3	0.70	0.52
14	FPL Group, Inc.	FPL	A	Aa3	64.48	37.50	1.7	0.60	0.37
15	Green Mtn. Power	GMP	BBB	Baa1	22.35	19.39	1.2	0.60	0.37
16	Hawaiian Electric	HE	BBB+	Baa1	44.13	29.41	1.5	0.55	0.30
17	IDACORP, Inc.	IDA	A	A2	26.70	22.69	1.2	0.75	0.60
18	MGE Energy Inc.	MGEE	AA-	Aa3	31.33	14.84	2.1	0.55	0.30
19	NiSource Inc.	NI	BBB	Baa2	21.34	17.76	1.2	0.65	0.45
20	Northeast Utilities	NU	A-	A3	18.86	17.58	1.1	0.65	0.45
21	NSTAR	NST	A	A1	46.90	25.50	1.8	0.65	0.45
22	P.S. Enterprise Gp.	PEG	A-	A3	40.74	19.09	2.1	0.75	0.60
23	Pinnacle West	PNW	**A-**	**A3**	35.64	30.18	1.2	0.70	0.52
24	PNM Resources	PNM	BBB-	Baa3	28.71	25.71	1.1	0.70	0.52
25	Progress Energy	PGN	BBB	A2	44.49	30.10	1.5	0.85	0.75
26	Puget Energy, Inc.	PSD	BBB	Baa2	22.90	16.60	1.4	0.65	0.45
27	SCANA Corp.	SCG	A-	A1	35.25	20.77	1.7	0.60	0.37
28	Sempra Energy	SRE	A+	A1	28.80	15.07	1.9	0.80	0.67
29	Southern Co.	SO	A+	A1	29.60	12.73	2.3	0.65	0.45
30	TECO Energy,Inc.	TE	BBB-	Baa1	14.71	13.27	1.1	0.75	0.60
31	Westar Energy	WR	BBB-	**Ba1**	18.98	14.39	1.3	0.60	0.37
32	Wisconsin Energy	WEC	A-	Aa2	31.28	19.76	1.6	0.60	0.37
33	WPS Resources	WPS	AA-	Aa2	41.82	26.77	1.6	0.70	0.52
34									
35	Average						1.5	0.67	0.48
36									
37	Source: Yahoo Finance, Value Line								

	Company		P_0 Current	D_1	D_1/P_0
1	Alliant Energy	$	23.080	1.00	4.33%
2	Ameren	$	43.500	2.54	5.84%
3	Avista	$	16.120	0.50	3.10%
4	Cent. Vermont P.S.	$	23.650	0.91	3.85%
5	CH Energy Group	$	44.900	2.16	4.81%
6	Cleco Corporation	$	16.810	0.90	5.35%
7	Con. Edison	$	40.730	2.26	5.55%
8	DPL Inc.	$	18.350	0.94	5.12%
9	DTE Energy Co.	$	36.250	2.06	5.68%
10	Empire District	$	22.300	1.28	5.74%
11	Energy East Corp.	$	23.440	1.03	4.39%
12	Entergy Corp.	$	54.080	1.82	3.37%
13	FirstEnergy	$	32.580	1.50	4.60%
14	FPL Group, Inc.	$	64.480	2.46	3.82%
15	Green Mtn. Power	$	22.350	0.80	3.58%
16	Hawaiian Electric	$	44.130	2.48	5.62%
17	IDACORP, Inc.	$	26.700	1.20	4.49%
18	MGE Energy Inc.	$	31.330	1.35	4.31%
19	NiSource Inc.	$	21.340	0.92	4.31%
20	Northeast Utilities	$	18.860	0.61	3.23%
21	NSTAR	$	46.900	2.19	4.67%
22	P.S. Enterprise Gp.	$	40.740	2.19	5.38%
23	Pinnacle West	$	35.640	1.80	5.05%
24	PNM Resources	$	28.710	0.95	3.31%
25	Progress Energy	$	44.490	2.30	5.17%
26	Puget Energy, Inc.	$	22.900	1.00	4.37%
27	SCANA Corp.	$	35.250	1.44	4.09%
28	Sempra Energy	$	28.800	1.00	3.47%
29	Southern Co.	$	29.600	1.41	4.76%
30	TECO Energy,Inc.	$	14.710	0.76	5.17%
31	Westar Energy	$	18.980	0.76	4.00%
32	Wisconsin Energy	$	31.280	0.80	2.56%
33	WPS Resources	$	41.820	2.19	5.24%
34					
35					
36	**AVERAGE**				4.49%
37					
38					
39					
40					
41					
42					
43					

UE 180
Attachment 648-B

Dr. Zepp's Testimony in recent Arizona Public Service Case as filed

REBUTTAL TESTIMONY OF

THOMAS M. ZEPP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF THOMAS M. ZEPP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION AND QUALIFICATIONS.

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Thomas M. Zepp. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am an economist and Vice President of Utility Resources, Inc. ("URI"), a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing URI in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commissioner between 1976-1982. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels at the University of Florida, Central Michigan University and the Joint Graduate Program of Armstrong State and Savannah State Colleges.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees before two Canadian regulatory authorities, before four Federal agencies and in the states of Alaska, Arizona, California, Colorado, Georgia, Hawaii, Idaho, Illinois, Iowa, Kentucky, Minnesota, Montana, Nebraska, Nevada, New Mexico, Oklahoma, Oregon, Tennessee, Utah, Washington, West Virginia and Wyoming. In addition to cost of capital studies, I have testified as to values of utility property, estimated incremental costs of energy and telecommunications services, and have presented rate design testimony.

Q. WHAT COST OF CAPITAL STUDIES HAVE YOU PREPARED BEFORE?

A. I have testified on cost of capital or other financial issues before the Interstate Commerce Commission, Bonneville Power Administration and in thirteen states. My studies and testimony have included a consideration of the financial health and fair rates of return for Nevada Bell Telephone, Illinois Bell Telephone, General Telephone of the Northwest, Pacific Northwest Bell, U S WEST, Anchorage Municipal Light & Power, Pacific Power & Light, Portland General Electric, Commonwealth Edison, Northern Illinois Gas, Iowa-Illinois Gas and Electric, Puget Sound Power & Light, Idaho Power, Cascade Natural Gas, Mountain Fuel Supply, Northwest Natural Gas, Arizona Water Company, Arizona-American Water Company, California-American Water Company, California Water Services, Dominguez Water Company, Hawaii-American Water Company, Kentucky-American Water Company, Mountain Water Company, Oregon Water Company, New Mexico - American Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, Southern California Water Company, Tennessee-American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. DO YOU HAVE OTHER PROFESSIONAL EXPERIENCE RELATED TO COST OF CAPITAL ISSUES?

A. Yes. My article, "Utility Stocks and the Size Effect - Revisited," was published in the Quarterly Review of Economics and Finance, Vol. 43, Issue 3, Autumn 2003, pp. 578-582. Also, I published an article "Water Utilities and Risk," Water: the Magazine of the National Association of Water Companies Vol. 40, No. 1 Winter 1999 and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper "Application of the Capital Asset Pricing Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Meetings and published an article "On the Use of the CAPM in Public Utility Rate Cases: Comment," Financial Management, Autumn 1978, pp. 52-56. While on the staff of the Oregon Public Utility Commissioner (Oregon had a one member commission at the time), I established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was an invited lecturer at Stanford University to discuss that research.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Arizona Public Service Company ("APS") asked me to review the testimonies and numerical calculations of Staff witness Joel M. Reiker and RUCO witness Stephen

G. Hill and report any errors or restatements of those numbers that I found to be appropriate.

Q. **HAVE YOU REVIEWED THE TESTIMONY AND EXHIBITS OF STAFF WITNESS JOEL M. REIKER AND RUCO WITNESS STEPHEN G. HILL FILED IN THIS CASE IN FEBRUARY?**

A. Yes, I have.

Q. **DO YOU ENDORSE EITHER OF THE WITNESSES ROE METHODOLOGIES?**

A. No. But as indicated above, I was asked to review the application of those methodologies.

Q. **WHAT DID YOU DETERMINE FROM YOUR REVIEW?**

A. I determined that Mr. Reiker made conceptual errors in his estimates of dividend per share ("DPS") growth and earnings per share growth "(EPS"). Once corrected, Mr. Reiker's equity cost estimate based on his DCF models increases from 9.1% to 9.6%. But I also disagree with Mr. Reiker's use of "blended" estimates of growth rates that are based on past growth as well as estimated future growth for the period 1997 to 2007. Using only Mr. Reiker's own estimates of forward-looking growth to revise his DCF equity cost estimates, Mr. Reiker's DCF cost of equity estimate increases from 9.6% to 10.4%, without allowance for issuance costs.

I also examined Mr. Reiker's capital asset pricing model ("CAPM") estimates of the cost of equity. I made two appropriate revisions to his estimates. First, I updated Mr. Reiker's current market risk premium estimate ("MRP"). Second, I used just one measure of Treasury rates to determine the CAPM equity cost estimates. Mr. Reiker's use of two different measures of Treasury rates (intermediate-term and long-term) creates a systemic and negative (downward) bias in his CAPM results. In making my restatement of his CAPM estimates, I have used just long-term Treasury rates, the more appropriate measure of the risk-free rate. With these two changes, Mr. Reiker's CAPM cost of equity estimate increases from 8.7% to 10.6%, again without consideration of financing costs.

My review of Mr. Hill's testimony indicated he has used an inappropriate method to estimate one of the two components of sustainable growth. (Mr. Reiker calls this growth rate "intrinsic growth"). There are two components of sustainable growth. One is called BR growth. BR growth comes from retaining earnings. The other is called VS growth. This source of growth comes from selling shares of common stock at price in excess of book value. Mr. Hill's error is with the inappropriate method he uses to estimate VS growth that again systematically understates the actual VS growth indicated by market data. In revising Mr. Hill's estimate of VS growth, I used estimates of VS growth determined by Mr. Reiker for companies that were in Mr. Reiker's DCF sample, when available. Otherwise, to be conservative, I use Mr. Hill's original understated estimate of VS growth. Once VS growth estimates are based, even partly, on Mr. Reiker's estimates, Mr. Hill's DCF estimate increases from 9.69% to 10.4%.

Mr. Hill also presents CAPM equity cost estimates based on his *ad hoc* estimates of market risk premiums ("MRP") derived with data compiled by Ibbotson Associates. Once the <u>actual</u> MRP calculated by Ibbotson Associates is substituted for Mr. Hill's *ad hoc* MRP, his CAPM equity cost estimate increases to 9.9%. Both this figure and the 10.4% DCF are before financing costs.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND RESTATEMENTS OF MR. REIKER'S AND MR. HILL'S EQUITY COST ESTIMATES.

A. Based on my analyses and restatements using Mr. Reiker's own data, models and electric utilities sample, the cost of equity for a typical electric utility falls in a range of 10.4% to 10.6%, if financing costs are not recognized in authorized ROEs. Even if DCF growth is based on Mr. Reiker's "blended" growth concept, the DCF equity cost is no less than 9.6 percent and the indicated minimum ROE range without financing costs being recognized (which I believe should be recognized) is 9.6% to 10.6%.

Based on my analyses and restatements of Mr. Hill's DCF and CAPM approaches, the cost of equity for APS falls in a minimum range of 9.9 percent to 10.4 percent.

Q. HAVE YOU INDEPENDENTLY DETERMINED A REASONABLE ALLOWANCE FOR FINANCING COSTS?

A. No, I have not conducted a study of financing costs in this case. But based on studies I have conducted in the past, I have no reason to dispute Dr. Olson's determination that 50 basis points are required for financing costs. Including financing costs, Mr. Reiker's methods, data and sample indicate an appropriate ROE for APS falls in a range of 10.9 percent to 11.1 percent and Mr. Hill's analyses indicate the cost of equity is in a range of 10.4 percent to 10.9 percent.

III. <u>RESPONSE TO STAFF WITNESS JOEL M. REIKER'S TESTIMONY</u>

Q. PLEASE TURN TO YOUR ANALYSES AND RESTATEMENTS OF STAFF WITNESS JOEL M. REIKER'S TESTIMONY. HAVE YOU USED HIS SAMPLE, DATA AND MODELS TO RESTATE HIS EQUITY COST ESTIMATES?

A. Yes. I do not agree that his sample of electric utilities is an appropriate sample. In particular, I have concerns with his inclusion of utilities with below investment grade debt ratings and utilities that have recently cut dividends. In both situations, it is difficult to determine how investors react to such bad news and application of methods that are expected to provide reasonable estimates of the cost of equity may not.

Q. **DID YOU THEN CHANGE MR. REIKER'S SAMPLE?**

A. No, notwithstanding my concerns, I have based my restatements on his sample, data, and methods presented in his electronic work papers with one exception. I used current *Value Line* estimates of EPS to obtain estimates of EPS for 2004 that Mr. Reiker did not report and, for consistency, also updated for current *Value Line* estimates of future earnings per share. *Value Line* now expects five of the utilities in Mr. Reiker's sample to have lower future earnings and four to have higher future earnings. Other than that one update, I have relied exclusively on data, models and the sample of utilities provided by Mr. Reiker.

Q. **BRIEFLY EXPLAIN WHY YOU DID NOT CONSTRUCT A MORE RESPRESENTATIVE SAMPLE.**

A. I did not use my own sample and equity cost estimation approaches because that would constitute a new study. Although such a new study may be appropriate, it would be more difficult to compare to the analyses Mr. Reiker and Mr. Hill presented in support of their recommendations. Also, as indicated earlier, APS merely asked me to critique Mr. Reiker's and Mr. Hill's results.

In making my restatements, I provide two scenarios. The first is a straightforward restatement of Mr. Reiker's results in which I only correct errors in data and make his estimates internally consistent. In the second restatement, I present revised DCF estimates that are based on -- as they should be -- only Mr. Reiker's forward-looking estimates of growth, which is what DCF theory requires. In the next section of my testimony, I address Mr. Hill's analyses.

Q. MR. REIKER USES "SPOT" DIVIDEND YIELDS BASED ON PRICES REPORTED FOR OCTOBER 9, 2003. HAVE YOU USED THOSE SPOT PRICES IN YOUR RESTATEMENTS OF HIS EQUITY COST ESTIMATES?

A. Yes. It is preferable to base dividend yields in the DCF model on an average of dividend yields during a recent time period for a number of reasons. The purpose here, however, is to restate Mr. Reiker's equity cost estimates, and thus I have used his spot dividend yields in my restatements.

Q. AT PAGE 13, LINES 2 – 6, MR. REIKER SAYS THAT HE ESTIMATED DIVIDEND GROWTH FOR HIS 33 COMPANIES BY CALCULATING THE AVERAGE GROWTH RATE IN DIVIDENDS PER SHARE FROM 1997 – 2007. ARE THERE PROBLEMS WITH THE DATA HE RELIED UPON?

A. Yes. Mr. Reiker reports a 0.2 percent average growth rate for DPS for the 1997 to 2007 period. This calculation is misleading because nine of the thirty-three companies in Mr. Reiker's sample cut dividends during this period. If historic data are given any weight by investors in a DCF analysis, those data would be considered only if investors expect the future to be similar to the past. Investors do not expect negative future growth to continue for an indefinite period of time nor do they expect future dividend growth to be reduced time and time again in a pattern similar to dividend cuts in recent years. If investors give any weight to growth for those nine companies, they would look at the future growth prospects <u>after</u> the dividends had been cut. If the nine utilities that cut dividends during this period are not included in the "blended" 1997 to 2007 average, the 0.2 percent reported by Mr. Reiker increases to 2.2 percent. See Schedule TMZ-1RB.

Schedule TMZ-1RB also shows a restatement of Mr. Reiker's estimate of "blended" 1997 to 2007 EPS that is based on two revisions. First, I have included data for EPS in 2004 and updated the *Value Line* estimates of future EPS to be consistent with that current information. Mr. Reiker reports DPS for 2004 but not EPS for 2004 for his sample utilities. With the EPS update, five EPS estimates for 2007 decrease and four increase. I also have based the EPS estimates for Avista, IDACORP, Northeast Utilities and Westar on forecasts of EPS growth from 2004 to 2007 presented by *Value Line*. Mr. Reiker did not include Northeast Utilities or Westar in his analysis. The other two utilities had what appear to be permanent reductions in EPS (leading to dividend cuts), and thus it is unrealistic to assume investors would compare EPS in 1997 and 2007 to determine EPS growth for the constant growth DCF model.

Q. HAVE YOU REVISED MR. REIKER'S ESTIMATE OF INTRINSIC GROWTH?

A. Yes. Intrinsic growth is computed as the sum of growth expected from internal sources (from retained earnings, called BR growth) and from external sources (from sales of stock in excess of book value, called VS growth). The "B" in BR growth stands for the utility's retention ratio and the "R" stands for the utility's expected return on equity. The "S" in VS growth is the expected growth in shares of common stock and the "V" represents the proceeds in excess of book value that are expected to be received when common shares are issued. I have used Mr. Reiker's estimate of average VS growth of 1.4 percent in my restatements. Mr. Reiker did not include Westar in his estimate of average BR growth because data are only available to estimate BR growth in the future. I included Westar in my restatement of his BR growth rate by including an estimate for Westar based on the future BR growth reported by Mr. Reiker but for some reason, not used. This revision increases the average BR growth rate slightly, but the BR + VS growth rate of 5.9 percent stays the same.

Q. HAVE YOU USED THE REVISED GROWTH RATES IN SCHEDULE TMZ-1RB AND SCHEDULE TMZ-2RB TO RESTATE MR. REIKER'S CONSTANT GROWTH DCF ANALYSIS ESTIMATES?

A. Yes, column [B] of Schedule TMZ-3RB shows a basic restatement of his DCF growth rates for the period 1997 to 2007. As discussed above, the 2.2 percent DPS growth rate is determined from data for the utilities that did not cut dividends during the period. The 5.9 percent intrinsic growth rate I computed by including all thirty-three utilities in the analysis is the same as Mr. Reiker's estimate. The 4.3 percent EPS growth rate is Mr. Reiker's EPS growth rate estimate revised by including forward-looking EPS growth estimates for Northeast Utilities, Westar, Avista, and IDACORP.

Q. WHERE DO YOU REPORT YOUR RESTATED ESTIMATE OF MR. REIKER'S DCF ANALYSIS?

A. I show the restatement in Schedule TMZ-5RB. I adopt Mr. Reiker's dividend yield and my restatement of his average growth rate of 4.2% to estimate the constant growth DCF equity cost estimate of 8.7 percent. Combining that estimate with Mr. Reiker's multi-stage DCF estimate of 10.6% produces an average DCF of 9.6 percent.

I have also provided more detailed estimates of restated constant growth costs of equity in Schedules TMZ-1RB, TMZ-2RB and TMZ-3RB. Combining the forward-looking growth rates with Mr. Reiker's 10.6% multi-stage DCF equity cost estimate indicates a range of DCF estimates based Mr. Reiker's data and sample and conceptually appropriate measures of growth is 10.2 percent to 10.7 percent without consideration of financing costs.

Q. DO YOU HAVE RESERVATIONS WITH THE CONSTANT GROWTH DCF ESTIMATE PRESENTED IN SCHEDULE TMZ-5RB?

A. Yes. Growth should be based on forward-looking measures of growth. Based on the sample of 33 utilities Mr. Reiker has chosen for analysis, *Value Line* forecasts of EPS for 2004 and 2007 for those 33 utilities, and forward-looking estimates of BR and VS growth Mr. Reiker presented in his work papers, I computed estimates of forward-looking EPS growth and forward-looking intrinsic growth that are reported in column [C] of Schedule TMZ-3RB that average 5.7 percent. That growth rate is far more appropriate for an analysis of the cost of equity for Mr. Reiker's sample of 33 utilities than is his blend of historical and future growth rates restated in column [B] of Schedule TMZ-3RB. I do not include the forward-looking estimate of DPS growth in that average because it is smaller than expected EPS growth. Whenever DPS is initially expected to grow slower than EPS, future long-term DPS growth can be expected to increase as retention ratios increase in the future. Including estimated DPS growth would thus understate long-term average growth expected by investors relying on the constant growth DCF model.

Q. WHAT IS YOUR RESTATED DCF ESTIMATE FOR MR. REIKER'S SAMPLE IF YOU BASE THE ESTIMATE ON FORWARD-LOOKING ESTIMATES OF GROWTH?

A. The constant growth DCF equity cost estimate is 10.2 percent. Averaging that with Mr. Reiker's multi-stage DCF estimate of 10.6 percent, the average DCF equity cost is found to be 10.4 percent. When financing costs estimated by Dr. Olson are included, the cost of equity is 10. 9 percent. See Schedule TMZ-6RB.

Q. DOES MR. REIKER ALSO PRESENT CAPM ESTIMATES OF THE COST OF COMMON EQUITY CAPITAL FOR APS?

A. Yes, his study is discussed at pages 20-24 of Mr. Reiker's testimony and his equity cost estimate of 8.7 percent is presented in Schedule JMR-7.

Q. HAVE YOU UPDATED AND REVISED HIS CAPM ESTIMATES?

A. Yes. I restate his results with an update of his current market risk premium ("MRP") and correcting a flaw in his approach.

Q. **WHAT IS YOUR UPDATE OF THE CURRENT MRP?**

A. I have updated the current MRP as the difference between a current estimate of expected market returns and the February 2004 long-term Treasury rate of 5.25 percent. Mr. Reiker estimated his current market risk premium with a DCF analysis of *Value Line* forecasts of dividend yields and growth for 1700 stocks. My estimate of the current market return is derived with a DCF analysis of *Value Line's* Industrial Composite. Mr. Reiker's long-term average MRP is derived by Ibbotson Associates from data for the S&P 500. The *Value Line* Industrial Composite contains 690 industrial, retail and transportation companies that represent 75 of *Value Line's* 98 industry groups and should be generally comparable to the 500 stocks in the S&P 500. I computed intrinsic growth for the Industrial Composite with data published by *Value Line* that was dated March 19, 2004. Based on that current estimate of market returns, the indicated current MRP is 9.12%. The calculations for this current MRP are shown in Schedule TMZ-4RB.

Q. **WHAT IS THE FLAW YOU IDENTIFIED?**

A. The flaw is Mr. Reiker relies on both long-term Treasury rates and intermediate-term Treasury rates to prepare his CAPM estimates. This mixing of yields for Treasury securities with different maturities biases downward his equity cost estimate. Only one of the two maturities should be used to avoid this bias. Of the two measures of interest rates, the long-term Treasury rate is preferred. Utility stocks are long-term investments and thus the longer-term Treasury rate is more appropriate. Also, Professor William Sharpe, one of the original developers of the CAPM, has acknowledged that higher rates rather than lower rates for the risk-free rate are appropriate when attempting to actually implement the model (Sharpe, Alexander and Bailey, *Investments,* Prentice Hall (Sixth Edition, 1999) pp. 246-247)

Q. WHAT IS THE RESULT OF YOUR RESTATEMENT OF HIS CAPM ESTIMATES?

A. The result of my restatement is shown in Schedule TMZ-5RB. The historical market risk premium based on long-term Treasury bonds of 7.0 percent comes from the same table in the Ibbotson Associates 2003 SBBI Yearbook as did the 7.4% historical market risk premium over intermediate term Treasury securities adopted by Mr. Reiker. With the adoption of long-term Treasury rates, the indicated cost of equity is 9.9%. The CAPM estimate using the current market risk premium is 11.4%. Giving equal weight to each, as does Mr. Reiker, the indicated CAPM cost of equity is 10.6% prior to recognition of financing costs. I have relied on these restatements of Mr. Reiker's CAPM equity cost estimates in Schedule TMZ-6RB as well as in Schedule TMZ-5RB.

Q. DO YOU HAVE ANY CONCERNS WITH USING CURRENT TREASURY RATES TO MAKE CAPM ESTIMATES?

A. Yes. It is not realistic for APS to have new tariffs in place prior to 2005. Financial experts expect Treasury rates to be higher then than they are now. Blue Chip surveys many financial institutions and reports the individual forecasts of interest rates as well as a consensus of those forecasted rates. The March 2004 consensus forecast of long-term Treasury rates for the second quarter of 2005 is 5.9 percent. *Value Line* also presents forecasts of future rates. Based on the most recent quarterly forecast (February 27, 2004), *Value Line* estimates the long-term Treasury rate will also be 5.9% in 2005. If a 5.9 percent Treasury rate were adopted in the CAPM analysis, the CAPM cost of equity range would overlap the 11.25% to 11.75 percent equity cost range Dr. Olson originally estimated.

Q. **ARE YOU AWARE OF OTHER RISK PREMIUM APPROACHES OTHER THAN THE CAPM?**

A. Yes. In this method, the risk premium equity costs are based on the spread between equity costs and the cost of debt. Schedule TMZ-7RB is such a study. In making that study, I relied upon 545 equity costs determined in litigated cases for electric utilities during the period 1983 to 2003, determined risk premiums as the difference between those equity costs and Baa corporate bond rates and estimated the statistical relationship between those risk premiums and the bond rates. I found that costs of equity move in the same direction as interest rates, but by less and thus the risk premium increases as interest rates decrease. This suggests that risk premium varies over the interest rate cycle. Schedule TMZ-7RB shows two equity costs made with this approach before financing costs are considered. The more relevant cost of equity estimate is 11.0%. It is more relevant because it is based on expected interest rates at the time APS rates will go into effect. The other equity cost of 10.3% is based on current Baa bond rates. I prefer this risk premium approach to the CAPM risk premium approach because it provides a direct estimate of the cost of equity and does not require the numerous assumptions required to implement the CAPM. Once financing costs are recognized, the indicated fair ROEs are between 11.5 % and 10.8%.

Q. PLEASE SUMMARIZE YOUR RESTATEMENTS OF MR. REIKER'S EQUITY COST ESTIMATES.

A. I have made two restatements of Mr. Reiker's equity cost estimates. Schedule TMZ-5RB contains a basic restatement of his constant growth DCF analysis in which I have include all thirty-three of his sample companies in the EPS growth and intrinsic growth rate estimates and restated his DPS growth estimates with only the utilities that had not cut dividends during the period under consideration. I have not revised Mr. Reiker's multi-stage DCF analysis. This schedule also presents a recalculation of Mr. Reiker's CAPM estimates with long-term Treasury rates and an update of the current market risk premium. Combined, the restated and updated equity cost estimates average 10.1 percent prior to recognition of financing costs and 10.6 percent when financing costs are recognized.

Schedule TMZ-6RB is the same as Schedule TMZ-5RB except for the constant growth DCF equity cost estimates. The estimates of constant growth DCF in Schedule TMZ-6RB are preferred because the growth rates focus on forward-looking estimates of EPS and intrinsic growth for Mr. Reiker's sample companies. Combined, the restated and updated equity cost estimates average 10.5 percent prior to recognition of financing costs and 11.0 percent when financing costs are recognized. The estimates I present in Schedule TMZ-6RB better reflect investor requirements than the estimates in Schedule TMZ-5RB because they are based on the forward-looking estimates of growth investors would rely upon to implement the DCF model. While I still have concerns with the sample and methods Mr. Reiker has chosen to make his equity cost estimates, the analyses I present in Schedule TMZ-6RB correct obvious flaws and provide a more accurate indication of investor requirements than do the original estimates presented by Mr. Reiker.

Q. **IN SCHEDULES JMR-9, JMR-12 AND JMR-11, AND IN SUPPORTING TESTIMONY, MR. REIKER OFFERS A TECHNICAL ARGUMENT THAT HE CONTENDS SUPPORTS THE NEED TO REDUCE APS' ROE BY 30 BASIS POINTS IF HIS RECOMMENDED COMMON EQUITY RATIO OF 45% IS NOT ADOPTED TO SET RATES. DO YOU HAVE A REPONSE?**

A. Yes, I have four responses. First, the calculation made by Mr. Reiker implicitly assumes APS and the firms in his sample all have the same level of business risk. That simply is not the case. Dr. Olson explained numerous reasons APS has more business risk than other electric utilities. Mr. Reiker's "technical" analysis has the effect of punishing a utility with above average business risk that must maintain a higher than average common equity ratio to be able to obtain debt at a reasonable cost.

Second, regulatory risks are important to investors. APS' cost of equity may increase if regulators decide to use a hypothetical capital structure with 45%

equity but there is no way to know if it will increase by 30 basis points. Investors will be far more concerned with the long run implication that regulators may now decide not to follow past practice of using the real capital structures associated with rate-based assets to set rates. If Mr. Reiker's analysis can be relied upon -- which I do not think it can -- APS' authorized ROE should be increased by 30 basis points if the 50 percent common equity ratio is not adopted. Mr. Reiker thus has it backward.

Third, Mr. Reiker's analysis requires all of the utilities in his sample to have the same level of business risk when his own evidence shows that is not the case. Pinnacle West, for example, has an above average common equity ratio of 50 percent but also has a beta (Mr. Reiker's measure of market risk) that is above average. While I am skeptical about the reliability of beta estimates for electric utilities, if, as Mr. Reiker contends, beta should be used to estimate risk, his own data show Pinnacle West has above average business risk. If business risks vary for the various utilities in his sample – as they do -- CAPM cannot be used to fine-tune equity cost estimates, See Schedule TMZ-8RB.

Fourth, if Mr. Reiker's analysis were always appropriate, utilities with below (above) average betas would also have above (below) average common equity ratios. Based on the betas and common equity ratios Mr. Reiker reports, thirteen of the thirty-three utilities in his sample violate the requirement that beta risk varies inversely with common equity ratios. Pinnacle West is one of those thirteen utilities. See Schedule TMZ-8RB. This suggest that either the theory Mr. Reiker relies upon does not apply to electric utilities or that the beta estimates are not reliable enough (a real possibility) to fine-tune equity costs in the way Mr. Reiker recommends. The evidence provided by Mr. Reiker is not strong enough to penalize APS for having a capital structure it believes is required to provide service at reasonable cost.

Q. DO YOU HAVE ANY DATA THAT PUT YOUR RESTATEMENTS OF MR. REIKER'S EQUITY COSTS IN PERSPECTIVE?

A. Yes. Schedule TMZ-9RB provides that perspective. It provides averages of actual earned ROEs and authorized ROEs reported by *C. A. Turner Utility Reports* in March 2004 for the utilities in Mr. Reiker's sample of electric utilities. One of the tests of a fair rate of return is whether the ROE authorized for APS is in line with ROEs investors could expect to earn from comparable risk utilities. If the utilities in Mr. Reiker's sample are of comparable risk, ROEs actually earned and authorized provide two measures of returns investors can expect to earn. If Mr. Reiker does not believe some of those utilities are of comparable risk, he should not have included them in his sample. Based on the average of earned and authorized ROEs, the indicated fair ROE for APS is in the range of 10.3 percent to 11.4 percent. My restatements of Mr. Reiker's equity cost estimates fall within that range. Mr. Reiker's recommended ROE of just 9.0% falls very much below it.

IV. <u>RESPONSE TO RUCO WITNESS STEPHEN G. HILL'S TESTIMONY</u>

Q. PLEASE TURN TO RUCO WITNESS STEPHEN G. HILL'S TESTIMONY. WHAT COST OF COMMON EQUITY CAPITAL DID MR. HILL DERIVE USING HIS DCF ANALYSIS?

A. 9.69 percent. Mr. Hill reached his conclusion using his concept of "sustainable growth" (a concept Mr. Reiker refers to as "intrinsic growth") to estimate the growth rate component in his DCF approach.

Q. WHAT IS THE PRIMARY PROBLEM WITH MR. HILL'S SUSTAINABLE GROWTH APPROACH?

A: Mr. Hill has based his sustainable growth rate estimate on a hypothetical estimate of VS growth that is inconsistent with market data. On the one hand, he bases his VS growth rate estimate on a hypothetical "market" price that is an average of current market prices and book value. But on the other hand, he does not adjust dividend yields upward to reflect the hypothetical lower "market" price.

Q. DOES SUCH AN APPROACH MAKE ANY SENSE?

A. No. DCF equity cost estimates should be based on real market prices, not speculation. Mr. Hill suggests his approach is reasonable because regulation will ultimately "force" market prices back to book values. But let's examine that thesis. If indeed investors thought prices might someday move back to book values – an expectation I do not believe is held by investors – the market prices would already reflect the discounted present value of the future price after a drop in prices and current market prices would be somewhat lower than if that were not expected. Mr. Hill's approach, however, assumes investors are not smart enough to understand factors that may impact future prices. Mr. Hill's estimates of VS growth attempt to compensate for a potential future change in prices that –if they expect such changes in prices --undoubtedly are already priced by investors. Mr. Hill's estimates of VS growth are inconsistent with market data and should be revised to reflect market data.

Q. HAVE YOU MADE SUCH A REVISION?

A. Yes, I have. Most of the utilities in Mr. Hill's sample of electric utilities are also in Mr. Reiker's sample. I adopt Mr. Reiker's estimates of VS growth when they are available to make that revision. All other data used in the restatement of Mr. Hill's DCF equity cost estimate are data provided by Mr. Hill. In making the revision, I have left unchanged the sample Mr. Hill has used, his estimates of dividend yields, his estimates of BR growth and estimates of VS growth that were not replaced with Mr. Reiker's VS growth rate estimates.

Q. WHAT IS THE RESULT OF YOUR RESTATEMENT? 1,07%

A. Schedule TMZ-10RB provides that restatement. I found average VS growth for Mr. Hill's sample of twelve utilities to be 1.04%, slightly less than average VS growth of 1.4% Mr. Reiker estimated for his sample. With the more appropriate estimate of VS growth combined with Mr. Hill's estimates of BR growth and dividend yields, the indicated cost of equity is 10.4% without recognition of financing costs and 10.9% with recognition of financing costs estimated by Dr. Olson. In making this restatement, I have not addressed my concerns with his choice of sample companies or the way he determined BR growth.

Q. HAVE YOU RESTATED MR. HILL'S CAPM ANALYSIS?

A. Yes. Mr. Hill uses an incorrect market risk premium estimate of 6.4% that he attributes to Ibbotson Associates. Ibbotson Associates estimate a long-term average market risk premium for large company total stock returns minus long-term government bond income returns of 7.0%. It is presented in Table 9-1 of the SBBI 2003 Yearbook. Mr. Hill's *ad hoc* risk premium estimate is 60 basis points less than the one determined by the authority that published the data Mr. Hill used to determine his own version of that risk premium. Using the Ibbotson Associates

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risk premium and a current long-term Treasury bond rate of 5.25%, his CAPM equity cost estimate would be 9.9 percent. I have already provided that analysis in Schedule TMZ-6RB.

Mr. Hill's CAPM estimate based on short-term Treasury rates should be given no weight. Dr. Sharpe (again, one of the original developers of CAPM) advises his students that empirical tests of CAPM indicate the use of such short-term Treasury rates is <u>not</u> supported when real world data for stocks are tested. (William Sharpe, *Investments*, Prentice Hall (Third Edition, 1985) page 401). If Mr. Hill had used a CAPM estimate to "mitigate" his DCF equity cost estimate of 9.69 percent, he should have increased that estimate, not reduced it.

Q. PLEASE SUMMARIZE YOU RESPONSE TO MR. HILL'S EQUITY COST ESTIMATES.

A. I showed that with more appropriate estimates of VS growth, even with Mr. Hill's own estimates of BR growth and dividend yields, the indicated cost of equity is 10.4 percent without recognition of financing costs and 10.9 percent with recognition of Dr. Olson's estimate of financing costs. I also explained that if Mr. Hill had used market risk premiums published by Ibbotson Associates instead of a market risk premium he fabricates, his CAPM equity cost would have been 9.9 percent without financing costs and 10.4 percent with Dr. Olson's estimate of financing costs.

Q. DOES THIS COMPLETE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

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Schedule TMZ-1RB

Arizona Public Service Company
Growth in Earnings and Dividends and Indicated Costs of Equity
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B] Growth Estimate	[C] Dividends Yield	[D] Indicated Cost of Equity
1	Dividends per Share growth from 1997 to 2007	2.2%	4.5%	6.7%
2	Dividends per Share growth from 2004 to 2007	3.3%	4.5%	7.8%
3	Earnings per Share growth from 1997 to 2007	4.3%	4.5%	8.8%
4	Earnings per Share growth from 2004 to 2007	5.2%	4.5%	9.7%

Source: Mr. Reiker's electronic work papers and Value Line.

3/25/2004

Schedule TMZ-2RB

Arizona Public Service Company
Intrinsic Growth and Indicated Costs of Equity
Mr. Reiker's Sample of Electric Utilities

Line No.	[A] Company	[B]	[C]	[D]	[E]	[F]
		Retention Growth 1998 to 2007 br	Stock Financing Growth vs	Intrinsic Growth 1998 to 2007 br + vs	Dividend Yield	Indicated Cost of Equity
1	Mr. Reiker's Estimate for his complete sample	4.6%	1.4%	5.9%	4.5%	10.4%
		Retention Growth 2007 br	Stock Financing Growth vs	Intrinsic Growth 2007 br + vs	Dividend Yield	Indicated Cost of Equity
2	Forward-looking Estimate	4.8%	1.4%	6.2%	4.5%	10.7%

Source: Mr. Reiker's work electronic papers.

3/25/2004

Schedule TMZ-3RB

Arizona Public Service Company
Revised Calculation of Expected Annual Growth in Dividends and Indicated Costs of Equity
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B] Growth rate	[C] Dvidend Yield	[D] Indicated Equity Cost
	Blended (1997-2007) estimates of growth			
1	DPS Growth	2.2%		
2	EPS Growth	4.3%		
3	Intrinsic Growth	5.9%		
4	Average	4.2%	4.5%	8.7%
	Forward-looking Estimates of Growth			
5	DPS Growth	3.3%		
6	EPS Growth	5.2%		
7	Intrinsic Growth	6.2%		
8	Average	5.7% _n/	4.5%	10.2%

Note
n/ Average of forward-looking estimates of EPS growth and Intrinsic growth.

3/25/2004

UE 180
PGE's Response to OPUC Data Request No. 648
Attachment 648-B

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Schedule TMZ-4RB

Arizona Public Service Company
Update of Calculation of Current Market Risk Premium
Based on DCF Analysis of the *Value Line* Industrial Composite
Dated March 19, 2004.

BR growth	B 0.680	R 0.170	BR 11.6%	
VS growth	S 0.017	V 0.709	VS 1.2%	
Intrinsic Growth				12.77%
Dividend Yield				1.60%
Expected market return				14.37%
Long Term Treasury Yield				5.25%
Current market risk premium				9.12%

Source: *Value Line Selection & Opinion,* March 19, 2004.

3/25/2004

Schedule TMZ-5RB

Arizona Public Service Company
Revised Cost of Equity Estimates
Correct Errors and Inconsistencies in Mr. Reiker's Constant Growth DCF Analysis and Revise CAPM
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B]		[C]		[D]		[E]
1	**Constant Growth DCF**			D_1/P_0	+	g	=	k
2	Constant Growth DCF Estimate			4.5%	+	4.2%	=	8.7%
3	Multi-Stage DCF Estimate						=	10.6%
4	**Average of DCF Estimates**							**9.6%**
5	**CAPM Method**	**Rf**	+	β	x	**(Rp)**	=	**k**
6	Historical Market Risk Premium	5.25%	+	0.67	x	7.00%	=	9.9%
7	Current Market Risk Premium	5.25%	+	0.67	x	9.12%	=	11.4%
8	**Average of CAPM Estimates**							**10.6%**
9						**Average**		**10.1%**
10						**Include Financing Costs**		**10.6%**

Source: Mr. Reiker's electronic work papers, Ibbotson Associates 2003 SBBI Yearbook, and Schedule CEO-4RB.

Note: CAPM revised to base estimates of Rf and MRP on current long-term Treasury rate. Current MRP is derived in Schedule CEO-4RB.

3/25/2004

Schedule TMZ-6RB

Arizona Public Service Company
Revised Cost of Equity Estimates
Based on an Average of Forward-Looking Estimates of DCF Growth and Revised CAPM
Mr. Reiker's Sample of Electric Utilities

Line No.	[A]	[B]		[C]		[D]		[E]
1	**Constant Growth DCF**			D_1/P_0	+	g	=	k
2	Constant Growth DCF Estimate			4.5%	+	5.7%	=	10.2%
3	Multi-Stage DCF Estimate						=	10.6%
4	**Average of DCF Estimates**							**10.4%**
5	**CAPM Method**	**Rf**	+	β	x	**(Rp)**	=	**k**
6	Historical Market Risk Premium	5.25%	+	0.67	x	7.00%	=	9.9%
7	Current Market Risk Premium	5.25%	+	0.67	x	9.12%	=	11.4%
8	**Average of CAPM Estimates**							**10.6%**
9						**Average**		**10.5%**
10						**Include Financing Costs**		**11.0%**

Source: Mr. Reiker's electronic work papers, Ibbotson Associates 2003 SBBI Yearbook, and Schedule CEO-4RB.

Note: CAPM revised to base estimates of Rf and MRP on current long-term Treasury rate. Current MRP is derived in Schedule CEO-4RB.

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Arizona Public Service Company
Risk Premiums Computed as Difference Between
Authorized ROEs and Baa Corporate Bond Rates[a]
During the Period 1983-2003

Regression Output:

Constant ("A_0")		0.065
Std Err of Y Est		0.008
R Squared		0.619
No. of Observations		545
Degrees of Freedom		543
Slope ("A_1")	-0.399	
Std Err of Coef.	0.013	
t-statistic	-29.7	

Equity Cost Estimate		Predicted Risk Premium		Baa Rate[b]	
11.0%	=	3.6%	+	7.4%	Forecast
10.3%	=	4.0%	+	6.3%	Current

Formula: Risk Premium = A_0 + (A_1 x Baa Corporate Rate)[c]

Sources and Notes:

_a/ Source of Data: Oregon PUC Response to NW Natural Data request in UG 132 updated with data in Phillip Cross, "Rate of Return: Still an Issue at PUCs," *Public Utilities Fortnightly*, December 1998 and 2000 plus decisions reported by Regulatory Research Associates.

_b/ Blue Chip Financial consensus forecast for Second Quarter 2005 as of March 1, 2004 and current Baa rate as reported by the Federal Reserve.

_c/ 8-month lag between order date and Baa yield adopted based on the results of an Oregon PUC Staff study.

3/24/2004

Arizona Public Service Company
Comparison of Betas and Common Equity Ratios
To Examine If Mr. Reiker's Leverage Argument Holds for All
Utilities in His Sample of Electric Utilities

		Beta	Common Equity Ratio	Inconsistent Companies
1	Alliant Energy	0.70	45.9%	1
2	Ameren	0.65	49.3%	
3	Avista	0.75	42.3%	
4	Cent. Vermont P.S.	0.45	58.9%	
5	CH Energy Group	0.70	63.7%	2
6	Cleco Corporation	0.90	36.6%	
7	Con. Edison	0.55	50.0%	
8	DPL Inc.	0.80	33.8%	
9	DTE Energy Co.	0.60	37.6%	3
10	Empire District	0.60	45.1%	
11	Energy East Corp.	0.70	40.3%	
12	Entergy Corp.	0.65	51.3%	
13	FirstEnergy	0.70	39.3%	
14	FPL Group, Inc.	0.60	50.2%	
15	Green Mtn. Power	0.60	49.1%	
16	Hawaiian Electric	0.55	45.9%	
17	IDACORP, Inc.	0.75	50.1%	4
18	MGE Energy Inc.	0.55	57.3%	
19	NiSource Inc.	0.65	46.9%	
20	Northeast Utilities	0.65	34.1%	5
21	NSTAR	0.65	37.7%	6
22	P.S. Enterprise Gp.	0.75	27.6%	
23	Pinnacle West	0.70	50.6%	7
24	PNM Resources	0.70	50.3%	8
25	Progress Energy	0.85	41.6%	
26	Puget Energy, Inc.	0.65	39.5%	9
27	SCANA Corp.	0.60	43.5%	10
28	Sempra Energy	0.80	39.3%	
29	Southern Co.	0.65	48.7%	
30	TECO Energy,Inc.	0.75	29.1%	
31	Westar Energy	0.60	27.9%	11
32	Wisconsin Energy	0.60	38.7%	12
33	WPS Resources	0.70	52.4%	13
	Mean	0.67	44.1%	

Source : Mr. Reiker's electronic work papers.

3/25/2004

Arizona Public Service Company

Authorized and Earned Returns on Equity for
Mr. Reiker's Sample Utilities

		Earned ROE	Authorized ROE
1	Alliant Energy	6.20%	11.54%
2	Ameren	12.30%	11.14%
3	Avista	6.60%	10.96%
4	Cent. Vermont P.S.	9.10%	11.00%
5	CH Energy Group	9.00%	10.30%
6	Cleco Corporation	nm	12.25%
7	Con. Edison	8.50%	10.80%
8	DPL Inc.	15.30%	nr
9	DTE Energy Co.	10.10%	13.50%
10	Empire District	8.40%	nr
11	Energy East Corp.	8.80%	11.15%
12	Entergy Corp.	10.80%	11.19%
13	FirstEnergy	3.00%	12.20%
14	FPL Group, Inc.	13.40%	nr
15	Green Mtn. Power	11.10%	10.50%
16	Hawaiian Electric	10.20%	11.22%
17	IDACORP, Inc.	5.40%	nr
18	MGE Energy Inc.	11.80%	11.06%
19	NiSource Inc.	12.20%	11.97%
20	Northeast Utilities	5.50%	10.43%
21	NSTAR	14.90%	11.63%
22	P.S. Enterprise Gp.	22.10%	9.88%
23	Pinnacle West	6.20%	11.25%
24	PNM Resources	5.20%	10.25%
25	Progress Energy	11.30%	12.75%
26	Puget Energy, Inc.	8.40%	11.00%
27	SCANA Corp.	12.60%	11.93%
28	Sempra Energy	20.70%	10.90%
29	Southern Co.	16.50%	12.87%
30	TECO Energy,Inc.	nm	11.25%
31	Westar Energy	2.80%	11.02%
32	Wisconsin Energy	10.90%	12.20%
33	WPS Resources	10.20%	11.70%
		10.3%	11.4%

Notes: nm/ no meaningful value
nr/ not reported.
Source: CA Turner Utiltiy Reports, March 2004.

3/25/2004

Schedule TMZ-10RB

Arizona Public Service Company

Revised Schedule 7: Mr. Hill's DCF Equity Cost Estimate Based on Mr. Reiker's Estimates of VS Growth

		Dividend	Growth Rate			DCF Cost of
	Company	Yield[a]	BR[b]	VS[c]	BR+VS	Equity Capital
CV	Central Vermont P.S.	3.96%	4.75%	0.06%	4.81%	8.77%
EAS	Energy East	4.62%	4.50%	0.07%	4.57%	9.19%
FE	FirstEnergy	4.40%	4.50%	0.34%	4.84%	9.24%
SO	Southern Company	4.74%	5.00%	5.45%	10.45%	15.19%
AEE	Ameren	5.76%	3.00%	1.66%	4.66%	10.42%
CNL	Cleco	5.34%	4.75%	0.66%	5.41%	10.75%
DPL	DPL, Inc.	5.05%	5.75%	0.00% -[b]	5.75%	10.80%
EDE	Empire District	5.90%	3.50%	2.99%	6.49%	12.39%
ETR	Entergy Corp	3.35%	6.00%	0.23%	6.23%	9.58%
GXP	Great Plains	5.23%	4.25%	0.31% -[b]	4.56%	9.79%
HE	Hawaiian Electric	5.49%	3.00%	0.86%	3.86%	9.35%
PNW	Pinnacle West	4.86%	4.50%	0.24%	4.74%	9.60%
	Average	4.89%	4.46%	1.07%	5.53%	10.42%
	Equity cost with Financing Costs					10.92%

Sources of data:
a/ Mr. Hill Schedule 6.
b/ Mr. Hill Schedule 5 page 1 of 2.
c/ Mr. Reiker's estimates of VS growth from Staff work paper tab CoDATA except for the two indicated.

3/25/2004

Exhibit 1917
Page 58 of 268

UE 180
Attachment 648-C

Dr. Zepp's testimony in the Municipal Power & Light case

Exhibit 1917
Page 59 of 268

pre-filed - December 19, 2002

STATE OF ALASKA
THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Revenue Requirement, Cost-of-Service, and Equity Management Plan Studies and Request for Rate Relief Designated as TA260-121, and Tariff Revision Filings Designated as TA240-121, TA243-121, and TA245-121, Filed by the MUNICIPALITY OF ANCHORAGE d/b/a MUNICIPAL LIGHT & POWER DEPARTMENT	)	U-99-139

PREFILED REPLY TESTIMONY OF THOMAS M. ZEPP

I. Introduction and Qualifications:

Q.1. Please state your name and address.

A.1. My name is Thomas M. Zepp. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q.2. What is your profession and background?

A.2. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing URI in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commissioner between 1976-1982. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in 20 states, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I

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have testified as to the values of utility properties, rate design and incremental costs of energy and telecommunications services.

Q.3. Where have you testified on financial issues?

A.3. I have submitted studies or testified on financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in Alaska, Arizona, California, Idaho, Illinois, Kentucky, Montana, Nevada, Oregon, Tennessee, Utah, Washington and Wyoming.

My studies and testimony have included consideration of the financial health and fair rates of return for Nevada Bell Telephone, Illinois Bell Telephone, General Telephone of the Northwest, Pacific Northwest Bell, U S WEST, Pacific Power & Light, Portland General Electric, Commonwealth Edison, Northern Illinois Gas, Iowa-Illinois Gas and Electric, Anchorage Municipal Light & Power, Puget Sound Power & Light, Idaho Power, Cascade Natural Gas, Mountain Fuel Supply, Northwest Natural Gas, Arizona Water Company, California-American Water Company, Dominguez Water Company, Kentucky-American Water Company, Mountain Water Company, Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, Southern California Water Company, Tennessee-American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q.4. Do you have any other professional experience related to cost of capital issues?

A.4. Yes. My note, "Utility Stocks and the Size Effect -- Revisited," has been accepted for publication in the Quarterly Review of Economics and Finance. I published an article, "Water Utilities and Risk," Water the Magazine of the National Association of Water Companies, Vol. 40, No. 1 Winter 1999, and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility

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Commissioners in June 1998. I also presented a paper, "Application of the Capital Asset Pricing Model in the Regulatory Setting," at the 47th Annual Southern Economic Association Meetings and published an article, "On the Use of the CAPM in Public Utility Rate Cases: Comment," Financial Management, Autumn 1978, pp. 52-56. While on the Staff of the Oregon PUC, I conducted a number of quantitative studies on the usefulness of various methods to estimate costs of equity for utilities. I was invited to lecture at Stanford University to discuss that research. Exhibit TMZ-1 is a more complete resume of my past experience.

II. Purpose of Testimony, Summary and Conclusions

Q.5. What is the purpose of your testimony in this proceeding?

A.5. Last year in Docket U-96-36, I presented detailed analyses and testimony regarding the Municipality of Anchorage ("MOA") d/b/a Anchorage Municipal Light & Power's ("ML&P's") cost of capital and reasonable rate of return on equity. In his prefiled direct testimony in this current docket, Mr. Reagan referenced my earlier analyses as additional support for ML&P's continued use of a 12 percent rate of return on equity using a 65 %/35 % debt/equity structure.

ML&P has asked me to review the cost of capital/rate of return testimony of Katherine C. Koch in this docket and to respond to her rate of return approach and calculations.

Q.6. Please provide an overview of your testimony.

A.6. In this Section II, I outline and summarize my testimony. In Section III, I address the primary shortcoming in Ms. Koch's testimony: She does not agree that ML&P is entitled to a rate of return expected to be earned by comparable risk utilities. And though she acknowledges there are several traditional methods that are used to determine fair rates of return for regulated utilities, she ignores them when preparing her estimate of the return she recommends for ML&P. The return she does recommend is based on an ad hoc approach I have never seen used to determine a fair

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equity return for a regulated utility. Her approach does not reflect market data and the opportunity cost of capital, ignores ML&P's business risk, and does not recognize ML&P's above-average financial risk. She suggests that ML&P is less risky because it does not issue stock. Her position is inconsistent with regulatory treatment of the many small investor-owned utilities that are privately-held and do not have publicly-traded stock. Those firms, just like ML&P, must also rely upon retained earnings to obtain additional equity. It is common practice for regulatory commissions to determine reasonable equity returns for such privately-held utilities based on data for comparable risk publicly-traded utilities.

In Section IV, I discuss ML&P's risk as it compares to larger, less leveraged electric utilities for which there is market data to determine equity costs. I explain that utilities with greater leverage have more financial risk and thus require higher equity returns than other utilities with the same level of business risk. I also present evidence that small companies like ML&P are more risky than larger companies such as the companies adopted to determine benchmark equity costs.

In the next three sections of my testimony, I present equity cost estimates based on the methods Ms. Koch does not use but acknowledges are traditionally used to determine equity costs in regulated proceedings. Section V presents equity cost estimates based on the Discounted Cash Flow ("DCF") model. Section VI presents equity cost estimates based on risk premium models that are more general specifications of the capital asset pricing model ("CAPM") Ms. Koch mentions in her testimony. Section VII presents equity cost estimates based on the comparable earnings approach. In Section VIII, I derive equity cost for electric utilities with the information developed in Sections V, VI and VII, but assuming the enterprises are more highly leveraged.
In Section IX, I discusses three points Ms. Koch raises in her testimony that I did not address in other sections of my testimony. I explain why I agree with Ms. Koch that a 65%/35% debt/equity capital structure is reasonable for rate-making purposes in this

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proceeding, explain why ML&P's debt used to finance the Beluga River Unit ("the BRU") should not be included in the weighted average cost of debt in this proceeding and discuss the relevance of the ROE this Commission found reasonable for ENSTAR as another measure of comparable earnings to be considered when setting the return for ML&P. In Section X, I summarize my testimony.

Q.7. Have you prepared any exhibits to accompany your testimony?

A.7. Yes. I have prepared 19 exhibits identified as Exhibit TMZ-2 through Exhibit TMZ-20.

Q.8. Please summarize your testimony?

A.8. My findings and recommendations are the following:

1. The method Ms. Koch uses to determine her recommended equity return for ML&P is not based on finance principles, is arbitrary and should be rejected.

2. The size of an enterprise has an impact on risk: Smaller enterprises have higher costs of equity than larger enterprises even if the smaller enterprises have larger-than-average equity ratios. The relatively small size of ML&P indicates the required ROE for ML&P is higher than the ROE required for a benchmark sample of electric utilities.

3. Financial theory and principles are very clear that enterprises which are more highly leveraged have more financial risk and thus have a higher cost of equity.

4. A consideration of two DCF models and ML&P's higher than average leverage indicates ML&P's required equity return falls in a range of 12.0% to 13.1% at this time.

5. A consideration of the results of three risk premium models and ML&P's higher than average leverage indicates ML&P's required equity return falls in a range of 12.2% to 13.1% at this time.

6. A consideration of realized and authorized comparable earnings and ML&P's higher than average leverage indicates ML&P's required equity return falls in a range of 12.6% to 13.9% at this time.

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7. With an equity ratio of 35%, the reasonable equity return for ML&P is no less than 12% at this time.

8. A 35% target equity ratio is reasonable in this case.

9. Debt used to finance the BRU should not be included in the weighted cost of debt in this proceeding. To do so would double-count this low cost debt because the transfer price of gas will already reflect that cost.

III. Ms. Koch's Approach does not recognize Finance Principles, is Arbitrary and Should be Given No Weight in the Determination of ML&P's Fair Rate of Return

Q.9. Please discuss what is meant by a fair rate of return.

A.9. A fair rate of return ("ROR") is achieved when a utility is permitted to set rates for services at levels where the expected return provides owners of an enterprise a reasonable opportunity to earn the cost of equity. That cost of equity is the highest return that funds invested in utility equity could earn if they were invested elsewhere in an equally risky asset. Decisions by the U.S. Supreme Court set forth in the Bluefield Waterworks decision and Hope decision have been cited by Ms. Koch. Those decisions require that rates be set so that the expected return on equity ("ROE") will be commensurate with returns on investments in other enterprises having corresponding risks, and be sufficient to assure confidence in the financial integrity of the enterprise and enable the enterprise to attract capital. In 1989, the U.S. Supreme Court reaffirmed those standards in its Duquesne Light decision [488 U.S. 310] and acknowledged the important role of state laws. It stated "[i]t cannot seriously be contended that the Constitution prevents state legislatures from giving specific instructions to their utility commissions. We have never doubted that state legislatures are competent bodies to set utility rates." [488 U.S. 313]. In Alaska, AS 42.05.381 (b) provides such additional requirements. It states, in part, "In establishing the revenue requirements of a municipally owned and operated utility the municipality is

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entitled to include a reasonable rate of return." A reasonable rate of return is the weighted cost of capital discussed above and includes an authorized ROE equal to the cost of equity.

Q.10. Did the U. S. Supreme Court state that the principles it adopted in Hope, Bluefield and Duquesne regarding a fair rate of return were limited to particular types of enterprises or particular types of owners?

A.10. No.

Q.11. How does Ms. Koch characterize ML&P equity?

A.11. At pages 30-31 of her testimony, Ms. Koch correctly points out that equity is required to finance ML&P because debt holders require a cushion that gives them assurance that they will receive timely payments of interest and ultimately repayment of principal, reduces financial risk, and provides reserve borrowing capacity.

Q.12. Does knowledge of the role played by equity tell us what it costs to attract and retain equity?

A.12. No. The roles Ms. Koch describes for equity do not provide a basis to determine the forward-looking cost of equity. It is true that a consideration of debt service coverage provides a useful "check" on whether the capital structure chosen for rate-making combined with a proposed equity return is deficient. But such a consideration does not tell us if the proposed equity return is a fair rate of return. There are many levels of debt service coverage and no satisfactory method to determine if one or another produces an equity return that is the cost of equity. Too high a level of debt service coverage could lead to an ROE that is above the reasonable rate of return and too low a level of debt service coverage -- even if it provides coverage of contractual minimums -- could lead to an equity return that is below the reasonable rate of return.

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Q.13. What is a reasonable rate of return for ML&P?

A.13. A reasonable rate of return is the return that investors (in this case, residents of the MOA) require to invest in equally risky assets. It is the highest ROE a resident of the MOA could expect from an equally risky asset. The MOA purchased ML&P from the Alaska Railroad with equity capital. Subsequently, ML&P has retained earnings and added to the equity in the enterprise. The reasonable rate of return for ML&P should be set to give its owners (the MOA and, indirectly, taxpayers in the MOA) a reasonable chance to earn that opportunity cost of capital. Limitations on ML&P paying dividends set by this Commission or the lack of any additional infusion of equity from the MOA do not change the financial principle that equity in ML&P should be allowed to earn the cost of equity for comparable risk enterprises.

The set of ML&P's customers is not identical to the set of the MOA's taxpayers. Some MOA taxpayers are customers of Chugach Electric Association and some are customers of Matanuska Electric Association. Furthermore, some large customers are small taxpayers, and some large taxpayers are small customers. All customers should pay rates that reflect costs of service and one of those economic costs is a reasonable level of "profits." In economic terms, such profits are the opportunity cost of capital. A rate of return on ML&P equity below the cost of equity is not only unfair to the MOA, it subsidizes ML&P's customers at the expense of taxpayers who are not customers.

Q.14. Ms. Koch disagrees with you. What is her position?

A.14. She states that ML&P does not require an equity return as high as investors require for investor-owned utilities. At pages 36-38, Ms. Koch acknowledges that the cost of equity is generally determined in a regulatory proceeding with the DCF method, a form of the risk premium method (called the CAPM) and with the comparable earnings approach. But she does not use those approaches to determine a reasonable return for ML&P. Instead, she rejects them and adopts an ad hoc approach in which

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she adds 4% to her estimate of ML&P's embedded cost of debt to recommend a return on equity of 10.71% and overall ROR of 8.11%.

Q.15. Have you been able to determine why Ms. Koch has rejected traditional methods to determine a fair rate of return for ML&P?

A.15. No. It appears, however, that she believes her statement at page 44 supports that position. She states:

> It is important to remember that ML&P and the MOA do not issue stock. The "equity" represents ML&P's investments in its assets through funds generated internally. ML&P's equity does not carry the risk that the equity of an investor-owned utility carries. ML&P does not need to be compensated for that risk in order to obtain a "reasonable" profit.

This paragraph appears to be the keystone for her contention that a fair rate of return for ML&P is less than the equity return investors require for comparable risk investor-owned utilities.

Q.16. Let's consider the specific points she has raised in this paragraph on page 44. First, is all of ML&P's equity the result of internally generated funds?

A.16. No. The MOA acquired ML&P from the Alaska Railroad with equity and debt financing, thus her statement is factually incorrect. Part of ML&P's current equity was originally invested by the MOA when it purchased ML&P.

Q.17. Leaving that aside, is there some financial principle that says equity associated with the original purchase of a utility should be provided a different return than equity that results from retained earnings?

A.17. No, of course not. Equity is equity. Generally, a substantial portion of equity in any utility is in fact retained earnings. Such retained earnings are kept by the various utilities and thus must be provided the opportunity cost of capital. If not, investors

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would demand such funds be paid out and they would invest them elsewhere at the fair rate of return.

Q.18. Does Ms. Koch explain why she has put the term "equity" in quotation marks?

A.18. No. Apparently, she chose to enclose the word "equity" in quotation marks to suggest that ML&P's equity is somehow fundamentally different than equity of investor-owned utilities because ML&P does not issue stock.

Q.19. Please address Ms. Koch's contention that ML&P and the MOA do not issue stock and thus ML&P does not carry the risk of an investor-owned utility. Does the form of ownership change the underlying risk of an enterprise?

A.19. No. There are many thousands of business enterprises, reflecting many different forms of ownership, in which the equity is not held in the form of stock. The sole proprietor of a construction company or owner of a restaurant may not have stock but certainly each has equity in his/her enterprise that carries risk. To justify taking such risk, those non-stock-issuing persons need to expect to receive a reasonable profit.

Risk of an enterprise is conveniently partitioned into business risk (which does not depend on leverage) and financial risk (which increases as leverage, the debt ratio, increases). Knowledge about ownership does not change the underlying business risk of an enterprise. And owners of that enterprise should be compensated for the business and financial risk of their investment, be it a municipal utility, a sole proprietor, an investor-owned utility with publicly-traded stock, or a privately-owned investor utility with no access to equity from financial markets.

Q.20. Ms. Koch also implies that all investor-owned utilities issue stock, and that in some way this means ML&P has a lower return requirement than the investor-owned utilities. Please comment.

A.20. As I understand her testimony, Ms. Koch does not realize that there are many investor-owned utilities that have never issued publicly-traded shares of stock. Such utilities

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are similar to ML&P because both types of enterprises have initially invested in utility assets and have added equity over time by retaining earnings. Arizona Water Company, for example, has never sold stock to the public and its owners have never sold stock to the public. It is privately owned. Its owner purchased a large portion of Arizona Water Company's assets from Arizona Public Service and has increased equity over time with retained earnings. Such a situation is similar to ML&P in that the MOA originally purchased ML&P and has grown equity by retaining earnings.

For utilities with no publicly-traded stock, like privately-held investor-owned utilities and municipal utilities, as well as those that do issue stock to the public, the fair rate of return is the return required by comparable risk enterprises. To estimate that fair rate of return, market data are required and thus data for publicly-traded enterprises are usually used to make proxy estimates of the forward-looking cost of equity for enterprises without publicly-traded stock.

Q.21. Do regulators routinely determine required returns for utilities with no publicly-traded shares of equity by determining opportunity costs of capital?

A.21. Yes. There are numerous utilities that are privately-owned and have no publicly-traded shares of equity (such as Arizona Water discussed above) and others (such as ENSTAR mentioned by Ms. Koch) that do not have publicly-traded shares but do have a parent with publicly-traded shares of equity. I have testified in rate cases in Arizona, California and Montana regarding the costs of equity for enterprises that do not have publicly-traded shares of stock and that have owners who do not have publicly-traded shares of stock. In such cases, the regulators turn to proxy companies with publicly-traded common stock to determine equity costs. The Florida Public Service Commission has also recently determined fair rates of return for privately-held water utilities by consideration of market information for publicly-traded natural gas distribution utilities. (Florida PSC Order No. PSC-01-2514-FOF-WS). Generally, regulators have determined fair rates of return for such enterprises by recognizing the

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opportunity cost of equity determined for proxy groups of utilities with publicly-traded shares of stock and thus market information to determine the fair rates of return.

Q.22. At page 44, Ms. Koch also discusses flotation costs of common stocks. Do such costs have anything to do with a fair rate of return for ML&P?

A.22. No. This discussion appears to be left-over from her testimony in the ENSTAR case in which she proposed such flotation costs not be included in ENSTAR's authorized ROE. ML&P has not proposed that its authorized ROE include flotation costs and thus I do not understand why she has included this discussion in her testimony.

Q.23. On page 45 of her testimony, in answer to Question 79, Ms Koch compares an investment in ML&P to a long term AA rated municipal bond. Is this comparison appropriate?

A.23. No, it is not. It confuses equity investments with bonds, and second, it confuses AA rated municipal bonds which are generally backed by the full faith and credit of the municipality with ML&P's A rated revenue bonds, which are backed by nothing more than ML&P's net revenue.

Q.24. Have you ever seen any expert witness propose a fair rate of return based on the method Ms. Koch presents at page 46?

A.24. No. Her method is ad hoc. It is not forward-looking, is not based on finance principles and is arbitrary. It is not forward-looking because her recommended ROE depends on an embedded cost of debt, not incremental cost of debt. A forward-looking risk premium approach would determine the fair rate of return based on information about current and future costs of debt that is consistent with the risk premium being added to it. At page 40, Ms. Koch criticizes ML&P for not providing a forward-looking approach to estimating the return on equity. Based on her own testimony, the ML&P approach is more appropriate than the one she presents at page

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46. I wrote the testimony in Docket U-96-36 to which Ms. Koch refers at page 40 and know it provided forward-looking costs of equity. Her analysis does not.

Her 4% risk premium adder is arbitrary and inconsistent with historical data. A risk premium should reflect the added return above the debt cost included in the analysis. Ms. Koch has chosen to compute her risk premium analysis using tax-exempt revenue bond costs (albeit an embedded debt cost). Below I present evidence that the average equity risk premium for electric utilities above the Bond Buyer Index for Revenue Bonds falls in a range of 6.15% to 6.63% (see Exhibit TMZ-17). Thus, an equity risk premium above tax-exempt revenue bonds is substantially higher than the 4% Ms. Koch adopted in her analysis. The issue I raise here is not that she has chosen to use tax-exempt bonds in her risk premium analysis. The issue is that her 4% premium combined with such bond rates will substantially understate a fair rate of return on equity. That fair rate of return is an opportunity cost of equity that is not tax-exempt and the premium should reflect a difference large enough for ML&P to achieve such a return. ML&P's customers receive the benefit of tax-exempt bond cost through lower revenue requirements. The cost of equity, however, should reflect the opportunity cost of capital to MOA's taxpayers and that cost is a fully taxable return.

IV. Risk of ML&P Compared to the Risks of Electric Utilities

Q.25. As a preliminary matter, please discuss the sample of electric utilities you have used in your DCF analyses.

A.25. I have adopted the sample of 15 companies listed in Exhibit TMZ-2 to make benchmark DCF estimates of the cost of equity. The utilities in this sample are all but one of the investor-owned electric utilities covered by *C. A. Turner Utility Reports* and *Value Line* which also have at least one bond rating that is "single A" or higher, have at least 63 percent of revenues derived from domestic electric utility operations, and are utilities for which there are complete and reliable data for the analyses being

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made[1]. I explain below that considerations of size and leverage make equity costs determined for this sample a floor for the cost of equity for ML&P.

Q.26. How does information for this sample of large investor-owned utilities help in the determination of a fair rate of return on common equity for ML&P?

A.26. The basic economic concept of opportunity cost makes this information useful in the determination of a benchmark cost of equity. The opportunity cost concept tells us that investment dollars will flow to the enterprise that offers the best opportunity, i.e., highest risk-adjusted return. In competitive financial markets there will be but one risk-adjusted return for comparable risk companies that is the "highest expected return." All enterprises must offer that risk-adjusted expected return or not be able to attract capital on reasonable terms. This means that a municipally-owned enterprise must offer the same risk-adjusted return as the return that is offered by other enterprises in the industry or investors will not willingly provide capital to that enterprise. Investors in a municipal utility may not "willingly" provide capital to the utility. That does not, however, change the principle that such taxpayer-investors should be compensated at a level that would make them just as willing to invest in a municipal utility as a private utility. If anything, limitations on distributions to such taxpayer-owners make it all the more important for the Commission to give the MOA a fair rate of return.

Save for differences in risk, the cost of equity and, thus, the fair rate of return for investments owned by a municipality should be the same as the cost of equity for the typical electric utility in a sample of investor-owned electric utilities. If this were not the case, the owners of the municipally-owned utility would be better off if all

1 To be conservative, I have not included DPL in my analysis because Value Line has estimated it will have a much higher future ROE than the other utilities in the sample. This exclusion of DPL is conservative because it reduces the expected future growth rate in the DCF analysis.

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earnings were paid out to them in the form of lower taxes so that the taxpayers-owners could invest those earnings in publicly-traded investor-owned enterprises of comparable risk.

Q.27. You mentioned risk-adjusted returns. If one enterprise is more risky than another, what happens to the required return of the more risky enterprise?

A.27. More risky enterprises require higher expected returns than less risky enterprises.

Q.28. How does the risk of an investment in ML&P compare to the risk of holding shares of common stock of an average electric utility in your sample in Exhibit TMZ-2?

A.28. ML&P is more risky than the sample utilities because it is smaller (see Exhibit TMZ-2) and more leveraged (see Exhibit TMZ-3). Exhibit TMZ -2 shows that by two measures of size, operating revenues and net plant, ML&P is much smaller than the sample electric utilities. Exhibit TMZ-3 reports estimates of common equity ratios for 2002 and common equity ratios forecasted by *Value Line* for the electric utility sample as compared to the target equity ratio for ML&P. Based on a target equity ratio of 35% that Ms. Koch and I agree is reasonable for rate-making purposes, ML&P has more financial risk.

Q.29. Please explain how size has an impact on risk.

A.29. Size matters when the Commission considers an appropriate target capital structure for rate-making, and a fair rate of return on common equity that is consistent with that capital structure. ML&P on a consolidated basis has net plant that is but 3.6 percent as large as net plant of the average large electric utility and operating revenues that are but 1.5 percent as large as the average for the larger electric utilities. Because ML&P is smaller, it requires a higher authorized ROE.

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Q.30. Is there evidence that shows size has an impact on the cost of equity?

A.30. Yes, evidence for companies in general and utilities in particular indicates smaller companies have higher costs of equity. Formal academic studies have addressed the issue of company size and risk and have found that, in general, smaller enterprises are more risky. Finance textbooks generally discuss risk with a presentation of the CAPM. The risk measure in the CAPM is called "beta." An above-average risk enterprise has a beta larger than 1.0 and a below-average risk enterprise has a beta less than 1.0. Eugene Fama and Kenneth French ("Industry Costs of Equity," *Journal of Financial Economics* 43 (1997) pp. 153-193) and Ibbotson Associates (*Stocks, Bonds, Bills and Inflation*, 2002 Yearbook) conducted empirical studies that show when beta risk is the same, smaller companies are generally more risky than larger ones. Two of the tables from the 2002 Ibbotson Associates study are reproduced here as Exhibit TMZ-4 and Exhibit TMZ-5[2]. Those tables show that, in general, smaller companies have more beta risk than larger companies and that if two companies have the same level of beta risk, but one company is smaller than the other, the smaller company requires a higher return than the larger one. Exhibit TMZ-5 shows that the size differential between Micro-cap and Low-cap firms indicates the smaller firms require an equity cost adder of 113 basis points. See note "a" on Exhibit TMZ-5. The market value of the MOA's investment in ML&P would fall somewhere in the Micro-cap category if equity in ML&P was valued by the market at less than $269 million.

Q.31. Have any regulatory commissions studied the differences in risk of small and large utilities?

A.31. Yes, the California PUC made such a study for water utilities. The California Commission found that small (Class C and Class D) water utilities required equity returns higher than the larger Class A water utilities, even though those small water

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[2] Ibbotson Associates, <u>Stocks, Bonds, Bills and Inflation, 2002 Yearbook Valuation Edition,</u> Tables 7-2 and 7-8, which are reproduced as Exhibits TMZ-4 and TMZ-5.

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utilities were financed with 100% equity. Business risk increases as the size of an enterprise decreases. This increase in business risk more than offsets the lower financial risk that would accompany 100% equity. (*Staff Report on Issues Related to Small Water Utilities*, June 10, 1991 and CPUC Decision 92-03-093).

Q.32. Have you conducted any studies that show small utilities have higher costs of equity than larger ones?

A.32. Yes. Generally, market information is required to estimate equity costs. It is difficult to find useful market information for small utilities because few are publicly traded. Market data required to make discounted cash flow ("DCF") equity cost estimates[3] for four water utilities in the same state for a number of years, however, were available to conduct such an analysis. In this analysis, I compared the average cost of common equity for the two smaller water utilities with the average cost of equity for two larger water utilities for the period 1987 to 1997. The results of my study are forthcoming in the *Quarterly Review of Economics and Finance* and are provided in Exhibit TMZ-6[4]. The table shows that, on average, the smaller utilities had a cost of equity that was 99 basis points higher than the average cost of equity for the larger utilities. This market information provides further evidence that smaller utilities require higher equity returns than larger ones. As seen in Exhibit TMZ-2, ML&P is much smaller than the average electric utility used to determine the benchmark equity cost estimates and thus would require a higher equity return.

Q.33. Will an increase in leverage (debt ratio) increase risk?

A.33. Yes. Financial principles indicate unequivocally that if two enterprises have the same

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[3] The DCF method generally adopted by members of Staff of the California PUC was adopted for the equity cost estimates.

[4] Thomas M. Zepp, "Utility stocks and the size effect – revisited," *Quarterly Review of Economics and Finance* (forthcoming).

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level of business risk, the enterprise with more debt has a higher cost of equity. As leverage (debt ratio) increases, so does the cost of equity. In relative terms, the greater the amount of debt, the greater the fixed charges and thus the more uncertain the equity return. As that uncertainty increases, risk and the cost of equity increase.

Q.34. Does ML&P have more leverage than the typical electric utility in your benchmark sample?

A.34. Yes, it does. Now and for a reasonable period into the future, ML&P will be more leveraged than the typical electric utility in Exhibit TMZ-2. More importantly for our purposes here, the hypothetical capital structure proposed for ML&P's cost of capital determination is more leveraged than the typical electric utility in Exhibit TMZ-2.

Q.35. Does an enterprise's overall incremental cost of capital change with changes in leverage?

A.35. There are two different schools of thought about what happens to the overall incremental cost of capital when there are differences in leverage:

The <u>"U-shaped" school of thought</u> is that the overall cost of capital initially declines as debt is issued until the enterprise attains an optimal (lowest cost) capital structure and then the overall cost of capital increases as more debt is added[5].

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[5] With the "U-shaped" school of thought, if the firm has more leverage or less leverage than the optimal amount, the overall cost of capital will be higher. The cost of capital is at a minimum at the bottom of the "U" when cost of capital (on the vertical axis of a diagram) is plotted against the common equity percentage (on the horizontal axis of a diagram).

Traditional finance principles originally supported this "U-shape" by noting that if a firm has little debt, the cost of debt will tend to be lower than the cost of equity and also that there are tax advantages to issuing some debt (for most firms). But, once leverage is increased past the optimal level, however, the cost of equity will increase at an increasing rate and bond costs will increase as coverage falls and bankruptcy risk would increase. More recent analyses based on an extension of the concepts underlying financial derivatives also support a "U-shape" cost of capital based on different considerations (Robert A Jarow, "In

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The "straight-line" school of thought is that, within a reasonable range of common equity ratios, changes in leverage do not impact the overall cost of capital for publicly-traded companies because investors could combine shares of common stock, company debt or loans to "re-leverage" the firm to their own satisfaction[6].

With either school of thought, however, the cost of equity always increases as leverage is increased.

Q.36. Pleases provide examples which show how the cost of equity would change with these alternative explanations of the impact of leverage on overall cost of capital.

A.36. The examples below show conceptually both the "straight-line" and "U-shaped" theories of capital structure and the indicated changes in cost of equity and overall rate of return that are implied by differences in leverage. In the case of the "U-shaped" approach, it is assumed the 55%/45% debt/equity ratio is optimal and any changes in leverage would increase the overall cost of capital:

Honor of the Nobel Laureates Robert C. Merton and Myron S. Scholes: A Partial Differential Equation That Changed the World," *Journal of Economic Perspectives,* 13, no. 4, Fall 1999, pp. 229-248).

[6] The "straight-line" theory is that, within a reasonable range of common equity ratios "leverage may not matter" and that the cost of capital will stay the same. This theory is usually explained by noting that investors could make deals among themselves and thus the proportions of debt and equity chosen by the firm may be irrelevant. For example, if an investor would like a leveraged version of the firm's capital structure and the firm had chosen to issue no debt, he/she could buy the stock on the margin with borrowed funds. Alternatively, if the investor would prefer an "unleveraged" version of the firm, the investor could buy both debt and equity and "put the firm back together." Such arbitrage opportunities keep the overall cost of capital independent of leverage, at least within a reasonable range. With this theory, the cost of equity increases in proportion to changes in leverage. The original basis for this "straight-line" theory came from Franco Modiglinani and Merton Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investment," *American Economic Review*, 48 No. 3 (June 1958), 261-297.

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"U-shaped" Explanation:

	Base Case		More Leverage	
	Weight	Cost	Weight	Cost
Debt	55%	7.1%	65%	7.2%
Equity	45%	12.4%	35%	14.5%
Overall Cost		9.5%		9.8%

"Straight-line" Explanation:

	Base Case		More Leverage	
	Weight	Cost	Weight	Cost
Debt	55%	7.1%	65%	7.1%
Equity	45%	12.4%	35%	14.0%
Overall Cost		9.5%		9.5%

With the straight-line explanation, both the cost of equity and overall cost of capital are estimated to be lower when leverage is increased than if the "U-shape" explanation were appropriate.

Q.37. Which of these concepts was used to develop your testimony?

A.37. To be conservative, I have adopted the "straight-line" approach to estimate the increase in the cost of equity that would result from increasing leverage. If the "U-shape" concept is appropriate, the evidence in Exhibit TMZ-3 indicates that ideal capital structure for utilities in the sample has more common equity than is now the case. Thus, if there is an optimal capital structure (and thus the "U-shaped" theory of capital structure applies), increases in leverage to a 35% common equity ratio would indicate larger increases in the cost of common equity than I determine with the straight-line approach.

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Q.38. Does the fact that ML&P is a municipally-owned utility mean it should have a smaller equity ratio?

as well as 40%

A.38. No. Exhibit TMZ-7 shows equity ratios for municipally-owned electric utilities in the Pacific Northwest. All but one have equity ratios much larger than the target of 35% Ms. Koch and I conclude is reasonable for rate-making purposes for ML&P. Only Seattle, one of the largest municipally-owned utilities, has an equity ratio smaller than 35% – and this result is not inconsistent with larger enterprises having relatively less business risk than smaller enterprises and being able to carry more financial risk. To the extent that the actions of other municipalities reflect prudent business practices and attempts to minimize costs, the data in Exhibit TMZ-7 further support the need for ML&P to have a stronger equity position.

Q.39. Have you incorporated differences in leverage in your determination of the fair rate of return on equity for ML&P?

A.39. Yes. In Exhibit TMZ-19, I revise the equity cost estimates based on data for the publicly-traded electric utilities to reflect the risk and the return that would be required for those electric utilities if they had an equity ratio of 35%. I then use those adjusted equity costs as a proxy for ML&P's required ROE.

Q.40. Have you recognized differences in size when making your equity cost estimates?

A.40. No. To be conservative, I have not adjusted the proxy equity cost estimates to reflect ML&P's smaller size. As a result, my estimated equity cost range is very conservative.

V. DCF Equity Cost Estimates for a Sample of Large Electric Utilities

Q.41. Please turn to your equity cost estimates. Please provide an overview of the approaches you have taken to estimate proxy equity costs for ML&P.

A.41. I have used the three equity cost estimation approaches Ms. Koch lists at page 36 of her testimony to determine the reasonable rate of return for ML&P. As discussed

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above, the reasonable rate of return on equity for ML&P is the cost of equity. To estimate that cost of equity, the analyst requires market data that reveal investors' required returns. Such data are not available for municipally-owned electric utilities.[7] In this section V and in section VII, I have estimated equity costs with data for the sample of electric utilities in Exhibit TMZ-2 with the discounted cash flow model and comparable earnings approaches. There are no "pure play" enterprises that are perfectly comparable to ML&P. The electric utilities in Exhibit TMZ-2, however, are providing the same service as ML&P and thus provide a useful basis to determine benchmark costs of equity estimates. In Section VI, I estimate equity costs with larger samples of electric utilities and risk premium approaches. A risk premium approach is a more general equity cost estimation approach than is the CAPM Ms. Koch lists at page 36 of her testimony.

In making my equity cost estimates, I determine a range of benchmark costs of equity using the models to establish estimates of the floor for the risk-adjusted ROE required to fairly compensate the MOA for its investment in ML&P. My equity cost estimates for ML&P are based upon upward adjustments to those benchmark equity cost estimates to reflect higher leverage represented by a 35% equity ratio.

Q.42. Please explain the DCF method of estimating the cost of equity.

A.42. The DCF model computes the cost of equity as the sum of an expected dividend yield (D_{2003}/P_0) and expected dividend growth (g). The expected dividend yield is computed as the ratio of next year's expected dividend (D_{2003}) divided by the current stock price (P_0). Generally, the single period model is computed with formula (1) or (2):

(1) Equity Cost $= D_0/P_0 \times (1 + g) + g$

(2) Equity Cost $= D_{2003}/P_0 + g$

[7] Such market data are not available for investor-owned utilities with no publicly-traded stock, either.

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where D_0/P_0 is the current dividend yield and D_{2003}/P_0 is the expected dividend yield computed with dividends estimated to be paid in 2003. The DCF model is derived from the valuation model shown in equation 3 below:

(3) $P_0 = D_{2003}/(1+k) + D_{2004}/(1+k)^2 + \ldots + D_\infty/(1+k)^\infty$,

or, alternatively,

(4) $P_0 = D_{2003}/(1+k) + D_{2004}/(1+k)^2 + \ldots$

$+ D_{2005}/(1+k)^3 + (D_{2006} + P_{2006})/(1+k)^4$,

where k is the cost of equity; P_0 is the stock price paid today, D_{2003}, D_{2004}, . . . D_∞ are the cash flows expected to be received in years 2003, 2004, . . . ∞, respectively; and P_{2006} is the price the investor expects to receive at the end of 2006 (be it a sale price or the price offered in merger). Conceptually, P_{2006} can also be thought of as the present value of all dividends and other cash distributions in periods after the 2006. Below, I have used the specifications of the DCF model in equation (2) and equation (4) to make equity cost estimates.

Q.43. What sample have you used to make your benchmark DCF equity cost estimates?

A.43. The sample of companies in Exhibit TMZ-2. These 15 companies are all but one of the electric utilities covered by *C.A. Turner Utility Reports* and *Value Line* which have at least 63% of their operating revenues from domestic electric operations, have a bond rating of single A or higher from S&P or Moody's, and for which reliable data are available[8].

Q.44. Conceptually, what are the steps taken by investors that are being assumed with the DCF model?

A.44. There are three steps. First, the investor finds out what dividend is being paid. Second, the investor determines what he/she believes are the growth prospects for the

[8] As explained above, to be conservative, DPL is not included in the sample used to make the equity cost estimates.

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stock. Third, the investors who buy or sell the stock set the market price and thus the dividend yield.

Q.45. How did you estimate growth for the DCF estimates?

A.45. I used two different methods that investors can be expected to use. Both methods rely upon information provided in publicly-available forecasts of future growth. To the extent that past dividends per share ("DPS") growth, and past earnings per share ("EPS") growth provide an indication of future growth prospects, available evidence indicates investors expect the analysts to have taken such past information into account when they formed their forecasts of the future[9]. With the first method (based on the DCF specification in equation 4), I assume investors determine growth as an average of expected near-term growth in dividends and subsequent future sustainable growth. With the second approach (based on the DCF specification in equation 2), I assume investors adopt analysts' forecasts of future of EPS growth for the next five years as the average expected growth in all future periods.

Once such growth estimates are made, investors buy or sell shares of each stock until the expected return from the dividend yields plus the growth projections equal the investors' discount rate for that stock.

[9] See David A. Gordon, Myron J. Gordon and Lawrence I. Gould "Choice Among Methods of Share Yield," *Journal of Portfolio Management (Spring 1989), pp. 50-55.* They found that a consensus of analysts' forecasts of earnings per share for the next five years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. They explain that this result makes sense because investor analysts would take into account such past growth as indicators of future growth as well as any new information. As a result, one should expect investor analysts' forecasts of growth to be superior measures of growth required by the DCF model.

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Q.46. What do you mean by the "investor's discount rate"?

A.46. An investor's discount rate for a particular stock is the discount rate that will make the present value of all expected future cash distributions to the investor equal to the market price for a share of stock. That discount rate is also the cost of equity.

Q.47. Please discuss your first method and the data you need to implement it.

A.47. The first method relies on the DCF model as specified in equation (4). The method approximates the investors' discount rate (k) that will make the present value of the dividends and price in 2006 on the right-hand side of equation (4) equal the current stock price (P_o). The future dividends are estimated from forecasts of dividends for 2003, growth in dividends from 2003 to 2006 and estimates of future sustainable growth in the period after 2006.

Q.48. How do you estimate the expected dividend yield?

A.48. The expected dividend yield (D_{2003}/P_o) adopts estimates of dividends that will be paid in 2003 and is computed as the average of the highest and lowest dividend yields during the three-month period ending October 31, 2002. The estimates of 2003 dividends (D_{2003}) are taken from *Value Line* forecasts of dividends for the year 2003. Exhibit TMZ-8 shows estimates of average dividend yields (D_{2003}/P_o) for each utility during the last three months and an average for the sample.

Q.49. How did you determine your estimates of DPS growth during the period 2003 to 2006?

A.49. I relied upon *Value Line* forecasts of DPS for 2003 and 2006 shown in Exhibit TMZ-9 to estimate the near-term DPS growth shown in Exhibit TMZ-10 of 2.0%. The electric utility industry is becoming more competitive and thus many of the companies are in the process of increasing their financial strength by delaying increases in dividends or cutting dividends. In such a situation, near-term DPS growth will be

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small but will enable the companies to retain more earnings and thus to provide much higher growth in the future

Q.50. How did you determine your estimates of growth after 2006?

A.50. I have based that growth rate estimate on an estimate of longer-term average sustainable growth. Growth after 2006 will determine the future value of the stock prices. That price is noted as "P_{2006}" in equation 4.

Q.51. Has this sustainable growth been discussed in the finance literature?

A.51. Yes, it has. Myron Gordon is sometimes called the father of the DCF model. In his 1974 book[10], Gordon explains that sustainable growth can be expected to come from internal and external sources. The internal growth comes from retained earnings (called "BR" growth); the external growth comes from selling shares of common stock when prices exceed book value (called "VS" growth).

Q.52. Have you included VS growth in your DCF growth estimates?

A.52. No, to be conservative, I have not. Investors would expect many of the utilities in the sample to have VS growth because they have market to book ratios above 1.0 and are expected to issue more shares of common stock at prices above book value. But, to avoid over-estimating the growth investors now expect when they price the electric utility stocks, I do not include VS growth in my estimate of sustainable growth.

Q.53. How do you estimate expected growth from retained earnings?

A.53. It is investors' expectations of what the retention ratio ("B") and the expected future earned return on common equity ("R") will be in the future which determine this

[10] M.J. Gordon, The Cost of Capital to a Public Utility, Michigan State University, East Lansing, Michigan, 1974.

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portion of expected sustainable growth[11]. Multiplying B times R gives the estimate of future sustainable growth from retained earnings. Investors look for measures of future growth when pricing stocks. I have used *Value Line* projections of future returns on equity to estimate values of "R" for each utility (see Exhibit TMZ-11) and have used *Value Line*'s estimates of future DPS and future EPS for each utility to determine estimates of "B" (see Exhibit TMZ-9). Combined, these forecasts of B and R provide forecasts of sustainable growth for the utilities during the period 2005 to 2007 shown in Exhibit TMZ-11. These *Value Line* data are probably the most widely available source of forecasted earnings and retention ratios available to investors and are adopted here for my analyses. Exhibit TMZ-10 shows electric utilities are expected to have more rapid growth in EPS than in DPS. As a result, retention ratios are expected to be larger in the future than they are today and thus electric utilities will be able to sustain higher growth in the future. For the analysis in Exhibit TMZ-12, I assume the average level of sustainable growth developed in Exhibit TMZ-11 continues for years after 2006.

Q.54. What is your estimate of average sustainable growth?

A.54. 5.2%. That value is developed in Exhibit TMZ-11. Company-specific estimates of retention ratios are multiplied by forecasts of future ROEs to estimate sustainable growth for each utility. The average of those growth rate estimates is 5.2%.

Q.55. Where do you report your estimate of the cost of equity with this first approach?

A.55. It is provided in Exhibit TMZ-12. The table shows the discount rate ("k") that equates the investment of $100 ($P_0$ in equation 4) equal to the present value of the cash flows from current and future dividends growing first at 2.0% (between 2003 and 2006) and subsequently growing at 5.2% (after 2006). Combined these growth rate

[11] The retention ratio is computed as (1 - the ratio of dividends divided by earnings).

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estimates indicate investors expect an average growth rate of 4.7% and an equity cost benchmark of 11.0%

Q.56. Please turn to your second approach. How did you determine growth?

A.56. In this approach I have assumed investors rely upon an average of analysts' forecasts of EPS growth for the next five years as their estimate of average growth for all future years. Exhibit TMZ-13 shows analysts' average forecasts as compiled by *First Call, Multex* and the *S&P Earnings Guide,* and as reported by *Value Line*. The average of those forecasts falls in a range of 4.6% to 5.5% with an overall average of 5.0%.

Q.57. What is the range of benchmark equity costs indicated by this range of averages of analysts' forecasts of growth?

A.57. The cost of equity range is 11.0% to 11.9%. In making those estimates I have used the *Value Line* forecasts of DPS in 2003 to determine my estimates of average expected dividend yields (D_{2003}/P_0). See Exhibit TMZ-14.

Q.58. Do these benchmark equity cost ranges provide a basis to estimate an equity cost range for ML&P?

A.58. Yes, but not directly. These benchmark cost of equity estimates first need to be adjusted for differences in financial risk to provide useful estimates of the cost of equity for ML&P. The companies in the electric utility sample are expected to have an average equity ratio of 43.6% in 2002 and are forecasted by *Value Line* to increase their equity ratios to an average of 48.7% in the next several years. See Exhibit TMZ-3. I have explained how benchmark equity cost estimates can be adjusted to determine estimates of the cost of equity for a typical electric utility with the same business risk as the average company in the sample but more leverage. In Section VIII, I determine what the cost of equity range would be for a typical electric utility with the same business risk as the companies in Exhibit TMZ-3 but greater financial risk that would result if it had an equity ratio of 35%. Those estimated equity costs provide a floor for

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the fair rate of return on equity for ML&P because, even with the same level of financial risk, ML&P is more risky than the electric utilities because ML&P is smaller.

VI. Risk Premium Estimates of the Benchmark Cost of Equity

Q.59. Is there theoretical support for estimating the cost of equity with a risk premium model?

A.59. Yes. The finance principle that equity is more risky than bonds provides that support. The capital asset pricing model listed by Ms. Koch at page 36 of her testimony as one of the several theoretical approaches for determining the cost of equity also provides such support. The CAPM is a risk premium model.

Q.60. Do you expect risk premiums to be constant?

A.60. No. The theoretical work of Gordon and Halpern,[12] and numerous empirical studies, including studies by the Staff of the Oregon Public Utility Commission and Staff of the Virginia State Corporation Commission, indicate that risk premiums change in the opposite direction to changes in interest rates. Thus changes in the cost of equity, while moving in the same direction as changes in interest rates, are generally smaller than associated changes in interest rates. In the past, I have conducted empirical studies for gas utilities, telecommunications companies, and electric utilities which corroborate the Gordon and Halpern theory.

Q.61. Are there data available to estimate how risk premiums change with changes in interest rates?

A.61. Yes. The least controversial source of data for such an analysis is past decisions by regulatory commissions[13]. One should expect authorized ROEs for investor-owned

[12] "Bond Share Yield Spreads Under Uncertain Inflation," American Economic Review, 66 4 (September 1976) 559-565.

[13] It is also possible to estimate equity costs at various points in time to make such an analysis, but then the study depends upon the method used to estimate the equity costs.

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utilities, which were not determined as a part of a settlement, to provide an unbiased measure of the cost of equity at the time the case was heard. Such commission determinations would take into account equity costs made with the DCF model and other equity cost estimation approaches and the various stakeholders in a contested proceeding. Thus, the adopted ROEs would be expected to be high enough to provide companies the ability to attract capital on reasonable terms and maintain financial integrity, but would take ratepayers' interests into account and not authorize more than a fair rate of return. The ROE that balances the interests of both ratepayers and investors is the cost of equity. Every commission decision will not provide every company its cost of equity, but given the goals and responsibilities of regulatory commissions, one should expect that, on average, the cost of equity is awarded and thus the various commission determinations provide an unbiased source of data to conduct the risk premium analysis.

Q.62. What model is used to make this risk premium estimate?

A.62. I used the following model:

(5) $RP_i = A_0 + A_1 \times BaaR_i$

where RP_i is the risk premium computed by subtracting the Baa corporate bond rate ($BaaR_i$) from the authorized ROE for the particular commission decision, and A_0 and A_1 are the parameters estimated with a statistical regression. If -- as expected -- risk premiums increase when interest rates fall, the estimated "A_1" term will be negative. There are 532 past commission determinations of ROEs during the period 1983 to 2002 that are available to estimate risk premiums for electric utilities.

Q.63. Why have you adopted the Baa corporate bond rate as the measure of interest rates?

A.63. I have adopted the Baa corporate bond rate for a number of reasons. The interest rates for such bonds are widely reported and forecasts of future rates for Baa bonds are readily available. *Value Line* and the Federal Reserve report recent Baa bond rates.

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Forecasts of Baa corporate bond rates are made by many institutions and a consensus of those forecasts is reported by *Blue Chip*.

Recently, yields for Treasury securities have become unsuitable for such a risk premium analysis because the relative spread between corporate bond rates and Treasury rates has increased. The risk premium analysis presumes that the relationship between equity costs and bond costs that occurred in the past continues. There has been, however, a substantial change in the spread between corporate bond rates and Treasury security yields. From 1983 to 1998, the spread between Baa bond rates and 10-year Treasury security yields averaged 193 basis points. In the last two years that spread has increased to 264 basis points as a result of a "flight to quality" with investors favoring Treasury securities. Ultimately, the goal is to determine the cost of equity of utilities. Thus, the relationship between Baa corporate bonds and utility equity costs provides a better basis for such a risk premium analysis at this time.

Q.64. What were the results of this risk-premium analysis?

A.64. The results of my analysis are shown in Exhibit TMZ-15. The -.40 value for the "A_1" coefficient means that as Baa corporate bond rates fall, the risk premium goes up. Another way of interpreting that result is that if the Baa corporate bond rate drops by 100 basis points, the cost of equity will drop by about 60 basis points. The large absolute value of the t-statistic of -29.6 indicates the Gordon and Halpern theory is supported by the data.

Q.65. What is the cost of equity predicted with this risk premium approach?

A.65. The cost of equity prediction is shown in Exhibit TMZ-15. Blue Chip Financial Forecasts reports consensus forecasts of Baa corporate bond rates for various periods that are made by the various financial institutions being polled. Based on this consensus forecast for Baa rates of 7.7% for mid-2003, the risk premium approach indicates a cost of equity of 11.2% for the investor-owned electric utilities.

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Q.66. Have you prepared a second risk premium analysis?

A.66. Yes. This second risk premium estimate is made from historical data on actual returns for Moody's electric utility stock index and Baa corporate bond rates for the period 1932 to 2000. The analysis is displayed in Exhibit TMZ-16. In this analysis, I recognized that while realized risk premiums over short periods may differ substantially from investor expectations, over a long period such as 1932 to 2000, the average difference between realized premiums and expected premiums is expected to converge and thus to reflect the average premium required by investors. Thus, the average of annual total market returns on the electric utility stock index less the yield on Baa corporate bonds for the period provides data to derive an estimate of the average risk premium investors have demanded in the past. If investors require the same risk premium in the future as in the past, with a forecasted Baa rate of 7.7% for Baa corporate bonds, the estimate of the cost of equity for the electric utilities is 11.65%.

Q.67. Please explain your third risk premium analysis.

A.67. My third risk premium analysis is presented in Exhibit TMZ-17. In this analysis I compute the equity risk premium using rates for the tax-exempt Bond Buyer Revenue Bond Index ("RBI") as an alternative to rates for Baa corporate bonds used to prepare the analyses in Exhibits TMZ-15 and TMZ-16. In making this estimate I followed a three-step procedure. First, in panel A of Exhibit TMZ-17, I estimated the averaged difference in rates for the RBI and Baa corporate bonds for the period 1980 to 2002. Second, in Panel B, I added that average difference of 2.68% to the equity risk premiums computed in Exhibits TMZ-15 and TMZ-16 to determine comparable equity risk premiums above the RBI of 6.15% and 6.63%%, respectively. In effect, this step substitutes the average RBI rate for the average Baa rate used in the prior two studies. Third, also in Panel B, I added the current Bond Buyer Revenue Bond Index

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rate reported by *Value Line* of 5.24% to estimate the current cost of equity for less leveraged electric utilities falls in a range of 11.4% to 11.9%.

This analysis provides a third equity cost estimate based on the risk premium approach and a basis to consider the reasonableness of the 4% risk premium above tax-exempt bonds Ms. Koch assumed to make her 10.71% equity cost estimate. Based on the analysis made here, Ms. Koch's 4% is inconsistent with historical data and is substantially below the risk premium that would be required above tax-exempt revenue bonds. A risk premium approach is valid only if the risk premium is consistent with the bond rates used in the analysis. Whatever the basis for the 4% adopted by Ms. Koch, it is inconsistent with historical rates for the Bond Buyer Revenue Bond Index.

VII. Comparable Earnings Analyses

Q.68. What is the third equity cost estimation approach listed by Ms. Koch?

A.68. The third equity cost estimation approach is comparable earnings. The comparable earnings approach discussed by Ms. Koch is based on recorded earnings and is usually provided as a supplement to equity cost estimates based on market data. Recorded ROEs in any particular period may differ from returns that investors require but do provide a measure of earnings investors can expect from comparable risk enterprises. Comparable earnings estimates may also be based on averages of authorized ROEs. With that choice of data, the ROEs that result from litigated cases would reflect market equity costs considered by the commissions. On a forward-looking basis, the average of authorized returns provides another measure of the return comparable risk utilities are expected to earn.

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Q.69. Where do you report the results of your comparable earnings analyses?

A.69. It is reported in Exhibit TMZ-18. The average of authorized ROEs reported by *C. A. Turner Utility Reports* is 11.5%. ROEs actually earned by the sample companies in 2001 had an average of 12.5%.

VIII: Leverage and the Cost of Equity

Q.70. What is the purpose of this section of your testimony?

A.70. In this section of my testimony, I restate the equity cost estimates made with the DCF, risk premium and comparable earnings approaches for the sample electric utilities to reflect what those equity costs would be if those enterprises were more leveraged.

Q.71. Have you prepared a table that shows how you have restated your cost of equity estimates for the electric utilities to reflect differences in leverage?

A.71. Yes. I have prepared the three-page exhibit, Exhibit TMZ-19, to provide that information. I present one page showing the impact of leverage on the range of equity costs made with each of the equity cost estimation approaches presented above. The information on the different pages varies only because of differences in estimated equity costs.

Panel A of page 1 of Exhibit TMZ-19 develops the overall incremental cost of capital for the electric utilities listed in Exhibit TMZ-2 assuming the incremental cost of debt is 7.0%, and the equity cost range is 11.0% to 11.9% when the average common equity ratio is 43.6%. The debt cost of 7.0% is the incremental cost of A-rated utility bonds as reported by *Value Line*, November 15, 2002. This A-rated bond rate is chosen to be consistent with the criteria I used in selecting the sample of electric utilities used to prepare the DCF analysis. The equity cost range on page 1 of Exhibit TMZ-19 was estimated with the DCF approach. With this information, the overall incremental cost of capital (weighted average cost of debt and equity) for the sample of 15 electric utilities falls in a range of 8.74% to 9.14%.

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Panel B shows the leverage-adjusted benchmark cost of equity range if the common equity ratio were 35 percent and the straight-line concept discussed above were adopted to estimate the revised cost of equity. In making those estimates, I assume the incremental cost of debt and overall cost of capital stay the same as in Panel A. In that scenario, with a common equity ratio of 35%, the leverage-adjusted cost of equity range is 12.0% to 13.1%.

Page 2 of Exhibit TMZ-19 differs from page 1 only in that the estimated equity cost range found with the three risk premium approaches of 11.2% to 11.9% is substituted for the range of equity costs made with the DCF approach. In this case, the re-leveraged benchmark cost of equity range is 12.2% to 13.1%.

Page 3 of Exhibit TMZ-19 differs from page 1 only in that the estimated equity cost range found with the comparable earnings approach of 11.5% to 12.5% is substituted for the range of equity costs made with the DCF approach. In this analysis, the re-leveraged benchmark cost of equity range is 12.6% to 13.9%.

IX. Other Comments About Ms. Koch's Testimony on Cost of Capital.

Q.72. Do you agree with Ms. Koch's recommendation of a 65%/35% debt/equity capital structure for rate-making purposes?

A.72. Yes, I do, but for other reasons. Evidence based on other municipalities (Exhibit TMZ-7) and investor owned utilities (Exhibit TMZ-3) I presented indicates that if there is an optimal, least cost capital structure for ML&P, it has at least 35% equity in it. I thus recommend that the Commission encourage ML&P to increase its common equity and attempt to obtain a capital structure with at least 35% equity. For the immediate future, adopting a target equity ratio of 35% gives the correct signal and encourages ML&P to move in the correct direction.

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Q.73. At page 38, Ms. Koch proposes to include the cost of debt used to finance the BRU in the weighted average cost of debt in this docket. Do you agree with her proposal?

A.73. No. It would lead to an under-recovery of costs of service. The Commission is setting the transfer price for gas from the BRU in a separate docket. Mr. Reagan advises me that the cost of the BRU debt is less than the 6.46% cost of debt ML&P has requested be recognized in this case. If this low cost debt is first used to set the transfer price of gas and then is also used to set the cost of capital in this docket, the low cost of debt will be double-counted and ML&P will not be able to recover its cost of service.

Q.74. In responding to Question 71 on page 41 of her testimony, Ms. Koch suggests that ENSTAR's cost of equity as developed in Docket No. U-00-88 is a relevant comparable to ML&P's cost of equity. Do you agree with this suggestion?

A.74. Yes, ENSTAR's cost of equity provides another useful benchmark. Obviously there are many differences between ENSTAR and ML&P, but ENSTAR has enough similarities to ML&P to be relevant, and the effect of the differences can be recognized by examining differences in business and financial risks of the two enterprises.

Q.75. Do you agree with Ms Koch that "The floor of the range that was appropriate for ENSTAR should be considered one step above the ceiling of the range for ML&P"? [Prefiled Testimony of Katherine C. Koch at page 43].

A.75. No. To the contrary, relevant theory and facts of the comparison lead one to the opposite conclusion that ENSTAR's cost of equity represents a lower bound on the cost of equity of ML&P.

Q.76. Why do you say that?

A.76. I say it based on a consideration of differences in business risks and financial risk. In every respect, these differences suggest a lower cost of equity for ENSTAR than for

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ML&P.

Q.77. Please start with your observations about differences in financial risk.

A.77. In her prefiled testimony in the ENSTAR case, in response to Q.100, Ms. Koch proposed adoption of a hypothetical capital structure for rate-making purposes for ENSTAR that contained 51.4% equity. In this case Ms. Koch and I are both proposing a capital structure for ML&P with but 35% equity. Unequivocally, ML&P has more financial risk than ENSTAR.

Q.78. How do business risks of the enterprises compare?

A.78. Competition increases risk. With respect to potential competition, ENSTAR appears to have less business risk than ML&P in at least two respects:

First, ENSTAR does not invest in gas production property or facilities, and its gas purchase costs are automatically passed through to its customers, thus ENSTAR's business risks relate only to its distribution function. ML&P, on the other hand, is a generating electric utility with large investments in generation facilities. Because the generation function is more likely to become competitive than is distribution, ML&P is more subject to the risk of competition than is ENSTAR.

Second, electric transmission and distribution are much more likely to experience competition than is gas distribution. This is because pipeline distributed natural gas enjoys a very large cost advantage over all possible alternatives in every location to which ENSTAR's distribution system has been extended. While the same is true of most of ML&P's investments, there are many special cases where customers have viable potential alternatives, such as self generation, or in some cases, competing distribution systems.

Additionally, the Commission has historically been careful to assign as nearly as possible all supply risk to ENSTAR's customers rather than to ENSTAR. Because there is a more obvious natural boundary between the supply function and the

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distribution function in the natural gas industry than there is in the electric industry, this is possible, but it results in lower risks faced by ENSTAR than are faced by ML&P.

Other business risks are primarily related to state regulation. Because both ENSTAR and ML&P are regulated by the same state regulatory agency, I expect these business risks to be approximately the same.

Q.79. So, does ML&P have higher business risk than ENSTAR?

A.79. Yes. Business risks beyond the control of regulation for ML&P are greater for ML&P than for ENSTAR.

Q.80. Are you saying that ML&P's cost of equity must be at least as high as ENSTAR's?

A.80. Yes. Based on differences in financial risk and business risk, ML&P has a higher equity cost than ENSTAR.

Q.81. At page 42, Ms. Koch lists several reasons she believes ML&P does not require as high a return as ENSTAR. Do you have a response to her comments?

A.81. Yes. As I understand her testimony, her primary reasons are (1) ENSTAR must be able to attract equity capital but ML&P does not and (2) ML&P "does not have to pay dividends" but ENSTAR does. While it is technically true that ML&P does not pay dividends, it is equally true that investor-owned companies do not have to pay dividends. There is no obligation for investor owned companies to pay dividends, and many of them do not. Her position, however, does not mean ML&P should be authorized a return lower than one required to attract equity. She does not consider that equity has an opportunity cost and it should be authorized a return that reflects the alternative that could be earned if there were no restrictions on ML&P. The U.S. Supreme Court has made it clear that utilities should be authorized returns high enough to attract capital. The Court did not say that the capital attraction standard was

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limited to investor-owned utilities that directly or indirectly (through a parent) have access to publicly-traded equity markets. Regulators throughout the United States routinely authorize equity returns designed to meet the U.S. Supreme Court's capital attraction standard for privately-held investor-owned utilities that do not have publicly-traded shares of stock as well as for enterprises with access to external equity markets. Ms. Koch's opinion about why ML&P and ENSTAR should be authorized different equity returns ignores the principle that equity returns should be authorized to compensate for risk. ENSTAR's 12.55% authorized ROE provides comparable return evidence that the 12% ROE requested by ML&P is reasonable.

Q.82. Do you agree that ML&P's reasonable rate of return falls between its cost of debt and a fair rate of return for ENSTAR as Ms. Koch contends at page 45?

A.82. No, I do not. Ms. Koch has not offered any financial evidence that ML&P is less risky than ENSTAR. I have already explained that, if anything, after a consideration of differences in financial risk and business risk, ML&P is more, not less, risky than ENSTAR. I note, however, that ML&P's requested ROE of 12% does indeed fall within the range of 12.55% (ENSTAR's authorized ROE) and various measures of debt costs. I do not agree that ML&P's reasonable equity return should be based on consideration of such a range, but observe that the 12% proposed by ML&P falls inside it at this time.

X. Summary, Conclusions and Perspective

Q.83. Please summarize your equity cost estimates.

A.83. Ms. Koch offered no evidence based on finance principles to determine a fair rate of return for ML&P. As part of my response to her testimony, I provided evidence based on financial models she agrees are generally used to determine equity costs. There are no pure play companies that could be examined to determine ML&P's cost of equity, and thus the sample of electric utilities in Exhibit TMZ-2 was adopted to determine benchmark estimates of the cost of equity. ML&P is more risky than those benchmark

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companies because it is smaller and more leveraged. Finance principles were applied to restate the cost of equity for the electric utilities as costs of equity for a typical electric utility with a common equity ratio of 35%. These leverage-adjusted costs of equity, however, still understate ML&P's cost of equity because ML&P is much smaller than the companies adopted to make the cost of equity estimates. To be conservative, however, I made no upward adjustment in my recommended ROE to reflect ML&P's smaller size. I estimated three equity cost ranges with the three equity cost approaches Ms. Koch agrees are generally used in regulatory proceedings. See Exhibit TMZ-20. Based on those estimates and a consideration of leverage, I conclude that ML&P's reasonable rate of return on equity is no less than 12% at this time.

Q.84. Does this complete your prefiled reply testimony?

A.84. Yes.

DATED this 19th day of December, 2002.

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THOMAS M. ZEPP

Vice President
Utility Resources, Inc.

EDUCATION

University of Florida	Ph.D. Economics M.A. Economics
Wofford College	A.B. Economics (Magna Cum Laude, Phi Beta Kappa)

SELECTED CONSULTING EXPERIENCE

- Finance

Sponsored testimony on the cost of capital faced by electric utilities in court cases and before regulatory commissions in Alaska Idaho, Illinois, Nevada, Oregon, and Washington.

Sponsored testimony on the cost of capital faced by natural gas utilities before regulatory commissions in Illinois, Oregon, Washington and Wyoming.

Sponsored testimony on the cost of capital faced by water utilities before regulatory commissions in Arizona, California, Kentucky, Montana, Oregon, and Tennessee.

Estimated costs of capital for Bell operating companies and General Telephone local companies in Illinois, Nevada, Oregon and Washington.

Presented estimates of cost of capital of U. S. railroads to the Interstate Commerce Commission.

Estimated cost of capital for a large insurance company.

Presented testimony on the cost of capital of for-profit hospitals in Washington on behalf of Washington State Hospital Commission.

- Telecommunications and Cable

Testified on economic principles and costs of paging on behalf of AirTouch Paging in Colorado and Washington.

Testified on economic principles and costs of wireless service on behalf of AT&T Wireless Services in arbitrations with U S WEST in Colorado, Minnesota, Oregon, and Washington.

Testified on economic principles and an analysis of U S WEST cost studies on behalf of AT&T Communications or AT&T and MCIMetro in arbitrations and permanent cost dockets in nine states.

Prepared analyses of local costs of telecommunication service and presented testimony on appropriate rates in Idaho, Nevada, Oregon and Washington.

Sponsored testimony in support of resale of local telecommunications services in California, Iowa, Minnesota, Oregon and Washington.

Presented testimony on the benefits of intraLATA competition in Nebraska.

Presented analyses of private line costs and appropriate rates in Colorado, Idaho, Oregon and Washington.

Estimated costs of local telephone service for a study commissioned by the Oregon legislature.

Reviewed cost studies and negotiated Enhanced 9-1-1 rates with Washington telecommunications companies on behalf of the State of Washington.

Presented a review of telephone depreciation rates to the Federal Communications Commission.

Prepared econometric estimates of telephone usage costs and sponsored testimony on appropriate cost-based usage rates.

Sponsored testimony on the appropriate costs and prices for pole attachments in Washington.

- Court Proceedings

Expert witness in Umatilla County, Oregon, Circuit Court on the harms to PacifiCorp and benefits to the City of Hermiston of a condemnation of property in the City of Hermiston.

Expert witness in Linn County, Oregon, Circuit Court regarding the harms to an electric utility compared to the benefits of two mills and a People's Utility District of an annexation resulting in a condemnation of electric facilities.

Expert witness in Superior Court of California regarding the value of water company facilities that were made inoperative or otherwise reduced in value after a sanitation district duplicated those facilities.

Expert witness in District Court on the present value of economic benefits/harms of transferring hydroelectric plants from Pacific Power & Light Company to a PUD in Oregon.

Rebuttal witness for the Illinois Attorney General in a court appeal on the cost of capital and need for a stay in rates for an electric utility.

Estimated the present values of severance damages resulting from condemnation of a distribution system in California.

Determined the value of facilities to be taken by a City from Strawberry Electric Service District in Utah.

Witness in District Court on rates that would have been charged by electric utilities if markets had been more competitive.

Presented an affidavit in Federal Court in Georgia on the cost of service of a municipal water utility.

- Energy and Water

Estimated avoided costs for two Pacific Northwest electric utilities on behalf of the City of Portland and Northwest Natural Gas Company.

Sponsored expert testimony on potential export revenues for BC Hydro to the British Columbia Utility Commission based upon analysis of Canadian and Pacific Northwest hydroelectric records.

Presented forecasts of commercial and industrial load growth for two major Northwest utilities.

Estimated costs and benefits of moving a combustion turbine from Portland, Oregon to alternative sites.

Analyzed the costs and benefits of improved efficiency of a BPA system dam based upon the Northwest System Analysis Model and export prices on behalf of Hitachi America.

Designed tariffs for two major electric utilities.

Presented an analysis of cost of service methods to the Public Utilities Board of the Northwest Territories, Canada on behalf of a gold mine owned by NERCO.

PREVIOUS POSITIONS

Zinder Companies, Inc.	Senior Consultant
Oregon Public Utility Commissioner	Senior Economist
Central Michigan University	Assistant Professor of Econometrics
Armstrong State College and Savannah State College, the Joint Graduate Program	Assistant Professor of Business and Economics

PROFESSIONAL AFFILIATIONS AND ACTIVITIES

Published papers in Water, Financial Management and Explorations in Economic History.

Read papers at the Southern Economic Association meetings.

Invited lecturer at Stanford University seminar.
Member, American Economic Association.

Journal Referee for Financial Management

Past Member, NARUC Subcommittee on Economics

Municipal Light & Power

Electric Utilities Sample for DCF Analyses[a/]

	% Electric Revenues	Bond Ratings S&P	Bond Ratings Moody's	Operating Revenues ($millions)	Net Plant ($million)
1 Alliant Energy	66%	A+	Aa3	$2,564	$3,075
2 Ameren	93%	A+	Aa3	$4,451	$8,689
3 CINergy	63%	A	A2	$10,258	$8,443
4 Consolidated Edison	74%	A+	A1	$8,452	$12,160
5 Empire District	99%	A-	Baa1	$279	$764
6 Energy East	70%	A	A3	$3,383	$4,794
7 FPL Group	87%	A	Aa3	$8,460	$12,964
8 Great Plains Energy	75%	A	A1	$1,677	$2,619
9 Hawaiian Electric	75%	BBB+	A3	$1,637	$2,600
10 NSTAR	84%	A	A3	$2,920	$2,726
11 Pepco Holdings	66%	A	A2	$2,366	$2,787
12 Pinnacle West	90%	A-	A3	$3,655	$6,126
13 Progress Energy, Inc.	79%	BBB+	A3	$8,186	$10,821
14 Public Service Enerprise Group	69%	A-	A3	$9,122	$10,289
15 Southern Company	86%	A+	A1	$10,168	$23,955
Average for 15 utilities				$5,172	$7,521
ML&P				$80	$273
ML&P as a percentage of sample average				1.5%	3.6%

Note:
a/ DPL excluded from sample because the Value Line forecast of future ROE of 27.5% is much larger than forecasts for other utilities. Including DPL would increase DCF equity cost estimate.

Municipal Light & Power

Equity Ratios for Companies in Electric Utility Sample

		2002 Common Equity Ratio	2006 Common Equity Ratio
1	Alliant Energy	40.5%	43.5%
2	Ameren	50.5%	52.0%
3	CINergy	45.5%	51.0%
4	Consolidated Edison	49.0%	53.5%
5	Empire District	47.5%	51.0%
6	Energy East	38.5%	42.5%
7	FPL Group	52.5%	56.0%
8	Great Plains Energy	40.5%	57.5%
9	Hawaiian Electric	47.5%	52.5%
10	NSTAR	43.0%	47.0%
11	Pepco Holdings	43.0%	48.5%
12	Pinnacle West	47.0%	51.5%
13	Progress Energy, Inc.	39.0%	45.0%
14	Public Service Enerprise Group	27.0%	35.0%
15	Southern Company	43.5%	43.5%
	Average for 15 utilities	43.6%	48.7%
	ML&P		35.0%

Data Sources:
_a/ *Value Line Investment Survey* estimates as of November 22, 2002.
_b/ Target equity ratio.

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Largest Companies in Each of Ten Deciles

Table 7-2

Size-Decile Portfolios of the NYSE/AMEX/NASDAQ, Largest Company and Its Market Capitalization by Decile

September 30, 2001

Decile	Market Capitalization of Largest Company (in thousands)	Company Name
1-Largest	$484,237,211	General Electric Co.
2	12,379,336	TXU Corp.
3	5,252,063	Equifax Inc.
4	2,599,543	Bergen Brunswig Corp.
5	1,656,910	Pentair inc.
6	1,114,792	La-Z-Boy Inc.
7	717,946	Cabot Oil & Gas Corp.
8	462,105	Star Gas Partners LP
9	269,275	Ackerley Group Inc.
10-Smallest	104,356	Huttig Building Products Inc.

Source: Center for Research in Security Prices, University of Chicago.

Source: Ibbotson Associates, 2002 SBBI Yearbook, Valuation Edition, Page 119.

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Betas Estimated with Annual Data

Table 7-8

Long-Term Returns in Excess of CAPM Estimation for Decile Portfolios of the NYSE/AMEX/NASDAQ, with Annual Beta
1926–2001

Decile	Annual Beta*	Arithmetic Mean Return	Realized Return in Excess of Riskless Rate**	Estimated Return in Excess of Riskless Rate†	Size Premium (Return in Excess of CAPM)
1-Largest	0.94	11.69%	6.46%	6.96%	-0.50%
2	1.05	13.27%	8.04%	7.77%	0.27%
3	1.09	13.94%	8.71%	8.09%	0.63%
4	1.17	14.44%	9.21%	8.67%	0.54%
5	1.21	14.92%	9.69%	8.96%	0.73%
6	1.20	15.37%	10.15%	8.92%	1.23%
7	1.30	15.66%	10.43%	9.66%	0.77%
8	1.38	16.66%	11.43%	10.22%	1.22%
9	1.46	17.61%	12.38%	10.82%	1.55%
10-Smallest	1.65	21.11%	15.89%	12.23%	3.65%
Mid-Cap, 3-5	1.13	14.25%	9.02%	8.42%	0.60%
Low-Cap, 6-8	1.27	15.70%	10.47%	9.43%	1.04% _a/
Micro-Cap, 9-10	1.51	18.63%	13.40%	11.23%	2.17%

*Betas are estimated from annual portfolio total returns in excess of the 30-day U.S. Treasury bill total return versus the S&P 500 index total returns in excess of the 30-day U.S. Treasury bill, January 1926–December 2001.

**Historical riskless rate is measured by the 76-year arithmetic mean income return component of 20-year government bonds (5.23 percent).

†Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (12.65 percent) minus the arithmetic mean income return component of 20-year government bonds (5.23 percent) from 1926–2001.

Note: a/ 2.17% - 1.04% = 1.13% risk adder for being in Micro-Cap instead of Low-Cap.

Source: Ibbotson Associates, 2002 SBBI Yearbook, Valuation Edition, Page 131.

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Small Firm Equity Cost Differential: Case Study
Based on a Comparison of DCF Equity Costs for
Smaller and Larger California Class A Water Utilities

1987-1997[a]

	Larger California Class A's[b]			Smaller California Class A's[c]			
	Do/Po	Estimated Growth[d]	Equity Cost Estimate[e]	Do/Po	Estimated Growth[d]	Equity Cost Estimate[e]	Smaller Utilities Minus Larger Utilities
1987	6.60%	7.17%	14.24%	5.38%	10.06%	15.98%	1.74%
1988	6.75%	6.30%	13.48%	5.81%	9.08%	15.42%	1.94%
1989	7.10%	6.30%	13.84%	6.47%	7.00%	13.93%	0.09%
1990	7.24%	6.19%	13.87%	6.96%	7.51%	14.99%	1.11%
1991	6.94%	6.29%	13.67%	6.64%	6.24%	13.30%	-0.36%
1992	6.18%	5.96%	12.50%	6.50%	6.71%	13.65%	1.14%
1993	5.32%	5.68%	11.30%	5.49%	6.31%	12.15%	0.85%
1994	6.03%	4.40%	10.70%	5.80%	4.86%	10.94%	0.25%
1995	6.44%	3.86%	10.55%	6.44%	4.88%	11.64%	1.09%
1996	5.60%	4.06%	9.88%	5.77%	5.58%	11.67%	1.79%
1997	4.93%	3.31%	8.40%	4.52%	4.89%	9.64%	1.23%
				Average Difference:			0.99%
				t-statistic			(1.405)[f]

Notes:

_a/ Limited to the period for which Dominguez Water Company data were available. 1998 excluded due to pending buyout.
_b/ American States and California Water Service.
_c/ Dominguez Water Company and SJW Corporation.
_d/ Averages past dividend per share growth, earnings per share growth and sustainable growth.
_e/ DCF equity cost computed as $k = (D_0/P_0) \times (1+g) + g$.
_f/ Significant at the 90% level.

Municipal Light & Power

Capital Structure of Pacific Northwest Municipalities

($ X 1,000)

Utility	Electric Utility Income	Equity Capital	Long Term Debt	Equity Percent
Oregon:				
City of Eugene	9,519	146,161	121,917	54.52
City of Forest Grove	931	13,226	0	100.00
City of McMinnville	2,367	36,720	1,363	96.42
City of Springfield	(7,439)	57,416	0	100.00
Washington:				
City of Centralia	1,528	17,578	7,476	70.16
City of Ellensburg	709	12,244	0	100.00
City of Port Angeles	1,460	18,444	5,000	78.67
City of Richland	5,979	19,125	23,929	44.42
City of Seattle	1,429	247,991	1,165,972	17.54
City of Tacoma	54,850	354,187	363,882	49.32

Source: Energy Information Administration, Form EIA-412
"Annual Report of Public Electric Utilities."

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Dividends and Forward Dividend Yields

	Average D_{2003}/P_0	Forecast of D_{2003} [a]	3-Month High Stock Price [b]	3-Month Low Stock Price [b]
1 Alliant Energy	10.81%	$2.00	$21.19	$16.43
2 Ameren	6.09%	$2.54	$45.13	$38.75
3 CINergy	5.69%	$1.80	$35.99	$28.25
4 Consolidated Edison	5.42%	$2.24	$45.15	$38.07
5 Empire District	7.58%	$1.28	$19.19	$15.06
6 Energy East	4.96%	$1.00	$22.49	$18.27
7 FPL Group	4.48%	$2.40	$60.00	$48.35
8 Great Plains Energy	8.31%	$1.66	$22.98	$17.66
9 Hawaiian Electric	5.57%	$2.48	$48.29	$41.24
10 NSTAR	5.47%	$2.20	$44.27	$36.90
11 Pepco Holdings	5.17%	$1.03	$21.88	$18.30
12 Pinnacle West	6.45%	$1.73	$35.00	$21.74
13 Progress Energy, Inc.	5.72%	$2.26	$49.64	$32.84
14 Public Service Enerprise Group	8.32%	$2.16	$36.95	$20.00
15 Southern Company	4.85%	$1.39	$31.14	$26.51
Average	6.33%			

Notes:

a/ Value Line Forecasts of DPS for 2003.

b/ Highest and lowest prices during the period August 2002 to October 2002.

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Value Line Forecasts of DPS, EPS and Retention Ratios for 2003 and 2006[b]

	Current[a] Value Line Forecast of DPS in 2003	Current[a] Value Line Forecast of EPS in 2003	Forecasted Retention Ratio in 2003	Value Line Forecast of DPS in 2006	Value Line Forecast of EPS in 2006	Forecasted Retention Ratio in 2006
1 Alliant Energy	$2.00	$2.60	0.23	$2.00	$2.90	0.31
2 Ameren	$2.54	$3.30	0.23	$2.62	$3.75	0.30
3 CINergy	$1.80	$2.85	0.37	$1.92	$3.15	0.39
4 Consolidated Edison	$2.24	$3.20	0.30	$2.30	$3.40	0.32
5 Empire District	$1.28	$1.50	0.15	$1.28	$1.75	0.27
6 Energy East	$1.00	$1.90	0.47	$1.12	$2.25	0.50
7 FPL Group	$2.40	$5.00	0.52	$2.64	$5.35	0.51
8 Great Plains Energy	$1.66	$2.15	0.23	$1.66	$2.50	0.34
9 Hawaiian Electric	$2.48	$3.25	0.24	$2.50	$3.50	0.29
10 NSTAR	$2.20	$3.60	0.39	$2.38	$4.00	0.41
11 Pepco Holdings	$1.03	$2.40	0.57	$1.10	$2.80	0.61
12 Pinnacle West	$1.73	$3.25	0.47	$2.03	$3.70	0.45
13 Progress Energy, Inc.	$2.26	$4.10	0.45	$2.44	$4.60	0.47
14 Public Service Enerprise Group	$2.16	$4.10	0.47	$2.32	$4.90	0.53
15 Southern Company	$1.39	$1.85	0.25	$1.51	$2.35	0.36
Average	$1.88	$3.00	0.36	$1.99	$3.39	0.40

Notes:

_a/ Data from *Value Line Investment Surveys* dated August 16, September 6, and October 4, 2002.
_b/ The period noted "2006" is an average for the period 2005 to 2007.

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Value Line Forecasts of EPS, DPS and Retention Ratio Growth for 2003 to 2006

	DPS growth 2003-2006	EPS growth 2003-2006	Retention Ratio growth 2003-2006
1 Alliant Energy	0.0%	3.7%	10.4%
2 Ameren	1.0%	4.4%	9.4%
3 CINergy	2.2%	3.4%	2.0%
4 Consolidated Edison	0.9%	2.0%	2.5%
5 Empire District	0.0%	5.3%	22.3%
6 Energy East	3.8%	5.8%	2.0%
7 FPL Group	3.2%	2.3%	-0.9%
8 Great Plains Energy	0.0%	5.2%	13.8%
9 Hawaiian Electric	0.3%	2.5%	6.4%
10 NSTAR	2.7%	3.6%	1.4%
11 Pepco Holdings	2.2%	5.3%	2.1%
12 Pinnacle West	5.5%	4.4%	-1.2%
13 Progress Energy, Inc.	2.6%	3.9%	1.5%
14 Public Service Enerprise Group	2.4%	6.1%	3.6%
15 Southern Company	2.8%	8.3%	12.9%
Average	2.0%	4.4%	5.9%

Notes:

_a/ The period noted "2006" is an average for the period 2005 to 2007.

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Forecasts of Sustainable BR Growth

	Retention Ratios Implied by Value Line Forecasts for 2006_a/	Forecasted ROE_a/	Forecast of BR_b/ Growth for 2006
1 Alliant Energy	0.31	12.0%	3.79%
2 Ameren	0.30	12.5%	3.84%
3 CINergy	0.39	13.0%	5.21%
4 Consolidated Edison	0.32	10.5%	3.46%
5 Empire District	0.27	11.0%	3.00%
6 Energy East	0.50	10.5%	5.42%
7 FPL Group	0.51	11.0%	5.73%
8 Great Plains Energy	0.34	15.3%	5.28%
9 Hawaiian Electric	0.29	10.5%	3.05%
10 NSTAR	0.41	14.0%	5.84%
11 Pepco Holdings	0.61	12.0%	7.56%
12 Pinnacle West	0.45	10.0%	4.62%
13 Progress Energy, Inc.	0.47	12.0%	5.80%
14 Public Service Enerprise Group	0.53	17.0%	9.37%
15 Southern Company	0.36	15.5%	5.70%
Average of Column	0.40	12.5%	5.18%

NOTES:

_a/ As forecasted by *Value Line* as of November 22, 2002.
_b/ BR growth adjusted for year-end ROE forecast by Value Line.

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Multi-Stage DCF Equity Cost Analysis[a/]
Based on Sample of 15 Electric Utilities

Equity Cost	11.00%
Dividend next year (D_{2003})	$6.33
Price paid for stock today	$100.00
yield	6.33%
initial growth (2003 to 2006)	1.97%
terminal growth (after 2006)	5.18%
average growth	4.67%
PV of dividends paid during 2003, 2004, 2005 and 2006	$20.17
PV of Expected Price in 2006	$79.89
Computed PV of cash flows	$100.06

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Constant growth DCF Analysis: Analysts' Forecasts
of Future Earnings Growth for Electric Utilities Sample

	First Call_a/	Multex_a/	Value Line_b/	S&P Earnings Guide_c/	Average
1 Alliant Energy	4.5%	4.3%	3.5%	5.0%	4.3%
2 Ameren	5.0%	3.9%	3.0%	4.0%	4.0%
3 CINergy	5.0%	4.8%	4.5%	5.0%	4.8%
4 Consolidated Edison	4.0%	3.6%	2.0%	4.0%	3.4%
5 Empire District	4.0%	6.5%	9.5%	6.0%	6.5%
6 Energy East	6.0%	4.3%	2.0%	7.0%	4.8%
7 FPL Group	6.0%	5.9%	4.0%	6.0%	5.5%
8 Great Plains Energy	4.5%	4.0%	7.5%	5.0%	5.2%
9 Hawaiian Electric	3.5%	3.6%	3.5%	4.0%	3.7%
10 NSTAR	6.5%	5.3%	4.5%	6.0%	5.6%
11 Pepco Holdings	5.0%	5.1%	5.0%	5.0%	5.0%
12 Pinnacle West	6.0%	4.8%	2.0%	7.0%	5.0%
13 Progress Energy, Inc.	6.5%	5.4%	6.0%	7.0%	6.2%
14 Public Service Enerprise Group	6.0%	6.1%	6.0%	6.0%	6.0%
15 Southern Company	5.0%	4.6%	6.5%	6.0%	5.5%
Averages	5.2%	4.8%	4.6%	5.5%	5.0%

Notes and Sources:
_a/ Multex and First Call average forecasts reported on Internet on Nov. 13, 2002.
_b/ *Value Line* forecasts published Oct. 4, Sept. 6, and Nov. 15, 2002.
_c/ S&P Earnings Guide, November 2002.

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DCF Estimate Based on Constant Growth DCF Model

	Bottom of Range	Top of Range
Future Dividend Yield (D_1/P_0)	6.3%	6.3%
Average growth	4.6%	5.5%
Equity Cost Estimate	11.0%	11.9%

Municipal Light & Power

Risk Premium Analysis
Regression Analysis of Risk Premiums Based on Authorized Returns
for Electric Utility Stocks-[a/] and Baa Corporate Bond Rates
1983-2002

Regresssion Formula-[c/]: Risk Premium = A_0 + A_1 x Baa Corporate Rate

Regression Output:	
Constant (A_0)	0.0656
Std Err of Y Est	0.0081
R Squared	0.6224
No. of Observations	532
Degrees of Freedom	530
Slope Coefficient (A_1)	-0.4015
Std Err of Coef.	0.0136
t-statistic	-29.6

Equity Cost Estimate		Predicted Premium-[c/]	Forecasted Baa Corporate Bond Rate-[b/]
11.2%	=	3.47% +	7.7%

Notes and Data Sources:

_a/ Sources: Annual Surveys of Electric Rate Cases, *Public Utilities Fortnightly,* Regulatory Research Associates and the Federal Reserve.

_b/ Consensus forecast of rates for Baa Corporate bonds for 3rd Quarter 2003 as reported by Blue Chip, November 2002.

_c/ Regression analysis assumes 8-month lag between Baa bond rate and the date of respective commission orders.

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Risk Premium Analysis: Comparison of Returns on Moody's Electric Utility Stock Index and Baa Utility Bond Rates

	January Baa Utility Rate	Year-end Price index	Average dividend	gain/loss	Yield	Annual Total Return	Annual Risk Premium
1931		43.23					
1932	8.18%	39.42	2.63	-8.81%	6.08%	-2.73%	-10.91%
1933	8.14%	28.73	1.95	-27.12%	4.95%	-22.17%	-30.31%
1934	8.86%	21.06	1.60	-26.70%	5.57%	-21.13%	-29.99%
1935	6.60%	36.06	1.32	71.23%	6.27%	77.49%	70.89%
1936	4.88%	41.60	1.48	15.36%	4.10%	19.47%	14.59%
1937	4.50%	24.24	1.74	-41.73%	4.18%	-37.55%	-42.05%
1938	5.59%	27.55	1.50	13.66%	6.19%	19.84%	14.25%
1939	4.66%	28.85	1.48	4.72%	5.37%	10.09%	5.43%
1940	4.30%	22.22	1.54	-22.98%	5.34%	-17.64%	-21.94%
1941	3.87%	13.45	1.44	-39.47%	6.48%	-32.99%	-36.86%
1942	3.83%	14.29	1.26	6.25%	9.37%	15.61%	11.78%
1943	3.65%	21.01	1.28	47.03%	8.96%	55.98%	52.33%
1944	3.54%	21.09	1.31	0.38%	6.24%	6.62%	3.08%
1945	3.50%	31.14	1.30	47.65%	6.16%	53.82%	50.32%
1946	3.07%	32.71	1.43	5.04%	4.59%	9.63%	6.56%
1947	3.05%	25.60	1.56	-21.74%	4.77%	-16.97%	-20.02%
1948	3.30%	26.20	1.60	2.34%	6.25%	8.59%	5.29%
1949	3.42%	30.57	1.66	16.68%	6.34%	23.02%	19.60%
1950	3.18%	30.81	1.76	0.79%	5.76%	6.54%	3.36%
1951	3.21%	33.85	1.88	9.87%	6.10%	15.97%	12.76%
1952	3.57%	37.85	1.91	11.82%	5.64%	17.46%	13.89%
1953	3.51%	39.61	2.01	4.65%	5.31%	9.96%	6.45%
1954	3.72%	47.56	2.13	20.07%	5.38%	25.45%	21.73%
1955	3.37%	49.35	2.21	3.76%	4.65%	8.41%	5.04%
1956	3.50%	48.96	2.32	-0.79%	4.70%	3.91%	0.41%
1957	4.26%	50.30	2.43	2.74%	4.96%	7.70%	3.44%
1958	4.60%	66.37	2.50	31.95%	4.97%	36.92%	32.32%
1959	4.71%	65.77	2.61	-0.90%	3.93%	3.03%	-1.68%
1960	5.20%	76.82	2.68	16.80%	4.07%	20.88%	15.68%
1961	4.79%	99.32	2.81	29.29%	3.66%	32.95%	28.16%
1962	4.86%	96.49	2.97	-2.85%	2.99%	0.14%	-4.72%
1963	4.65%	102.31	3.21	6.03%	3.33%	9.36%	4.71%
1964	4.74%	115.54	3.43	12.93%	3.35%	16.28%	11.54%
1965	4.71%	114.86	3.86	-0.59%	3.34%	2.75%	-1.96%
1966	4.99%	105.99	4.11	-7.72%	3.58%	-4.14%	-9.13%
1967	5.83%	98.19	4.34	-7.36%	4.09%	-3.26%	-9.09%
1968	6.76%	104.04	4.50	5.96%	4.58%	10.54%	3.78%

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Risk Premium Analysis: Comparison of Returns on Moody's Electric Utility Stock Index and Baa Utility Bond Rates

	January Baa Utility Rate	Year-end Price index	Average dividend	gain/loss	Yield	Annual Total Return	Annual Risk Premium
1969	7.42%	84.62	4.61	-18.67%	4.43%	-14.23%	-21.65%
1970	9.00%	88.59	4.70	4.69%	5.55%	10.25%	1.25%
1971	8.76%	85.56	4.77	-3.42%	5.38%	1.96%	-6.80%
1972	8.37%	83.61	4.87	-2.28%	5.69%	3.41%	-4.96%
1973	7.77%	60.87	5.01	-27.20%	5.99%	-21.21%	-28.98%
1974	8.58%	41.17	4.83	-32.36%	7.93%	-24.43%	-33.01%
1975	11.57%	55.66	4.97	35.20%	12.07%	47.27%	35.70%
1976	10.55%	66.29	5.18	19.10%	9.31%	28.40%	17.85%
1977	9.17%	68.19	5.54	2.87%	8.36%	11.22%	2.05%
1978	9.27%	59.75	5.81	-12.38%	8.52%	-3.86%	-13.13%
1979	10.29%	56.41	6.22	-5.59%	10.41%	4.82%	-5.47%
1980	12.92%	54.42	6.58	-3.53%	11.66%	8.14%	-4.78%
1981	15.30%	57.20	6.99	5.11%	12.84%	17.95%	2.65%
1982	17.83%	70.26	7.43	22.83%	12.99%	35.82%	17.99%
1983	14.56%	72.03	7.87	2.52%	11.20%	13.72%	-0.84%
1984	14.05%	80.16	8.26	11.29%	11.47%	22.75%	8.70%
1985	13.36%	94.98	8.61	18.49%	10.74%	29.23%	15.87%
1986	11.24%	113.66	8.89	19.67%	9.36%	29.03%	17.79%
1987	9.27%	94.24	9.12	-17.09%	8.02%	-9.06%	-18.33%
1988	11.34%	100.94	8.87	7.11%	9.41%	16.52%	5.18%
1989	10.38%	122.52	8.82	21.38%	8.74%	30.12%	19.74%
1990	9.74%	117.77	8.79	-3.88%	7.17%	3.30%	-6.44%
1991	9.96%	144.02	8.95	22.29%	7.60%	29.89%	19.93%
1992	8.98%	141.06	9.05	-2.06%	6.28%	4.23%	-4.75%
1993	8.57%	146.70	8.99	4.00%	6.37%	10.37%	1.80%
1994	7.66%	115.50	8.96	-21.27%	6.11%	-15.16%	-22.82%
1995	9.15%	142.90	9.02	23.72%	7.81%	31.53%	22.38%
1996	7.64%	136.00	9.06	-4.83%	6.34%	1.51%	-6.13%
1997	8.18%	155.73	9.06	14.51%	6.66%	21.17%	12.99%
1998	7.28%	181.84	7.83	16.77%	5.03%	21.79%	14.51%
1999	7.30%	137.30	8.10	-24.49%	4.45%	-20.04%	-27.34%
2000	8.40%	227.09	8.27	65.40%	6.02%	71.42%	63.02%
Average	7.17%					10.52%	3.95%
				Baa Rate [d/]		7.70%	11.65%

Sources and Notes:

a/ Table A-9, Ibbotson Associates, SBBI 2001 Yearbook
b/ Computed
c/ Mergent, Moody's 2001 Public Utility Manual.
d/ Consensus forecast reported by Blue Chip.

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Risk Premium Analysis Based on Average Differences in Baa Bond Rates and Rates for the Bond Buyer Revenue Bond Index and Risk Premium Analyses Presented in Exhibits TMZ-15 and TMZ-16

Panel A:

Date	Baa Bond Rate	Revenue Bond Rate	Difference
January-80	12.42%	8.18%	4.24%
January-81	15.03%	10.81%	4.22%
January-82	17.10%	14.23%	2.87%
January-83	13.94%	10.37%	3.57%
January-84	13.65%	10.13%	3.52%
January-85	13.26%	10.31%	2.95%
January-86	11.44%	8.72%	2.72%
January-87	9.72%	7.19%	2.53%
January-88	11.07%	8.29%	2.78%
January-89	10.65%	7.73%	2.92%
January-90	9.94%	7.36%	2.58%
January-91	10.45%	7.32%	3.13%
January-92	9.13%	6.68%	2.45%
January-93	8.67%	6.40%	2.27%
January-94	7.65%	5.56%	2.09%
January-95	9.08%	6.94%	2.14%
January-96	7.47%	5.63%	1.84%
January-97	8.09%	5.96%	2.13%
January-98	7.19%	5.41%	1.78%
January-99	7.29%	5.27%	2.02%
January-00	8.33%	6.25%	2.08%
January-01	7.93%	5.40%	2.53%
January-02	7.87%	5.57%	2.30%
Column Average	10.32%	7.64%	2.68%

Panel B:

Risk Premium Analysis Based on Baa/RBI Spread and Analyses in Exhibit TMZ-15 and Exhibit TMZ-16.

	Exhibit TMZ-15	Exhibit TMZ-16
Risk premium above Baa Rates	3.47%	3.95%
Baa/RBI Spread	2.68%	2.68%
Risk Premium above RBI Rate	6.15%	6.63%
Current Revenue Bond Index Rate	5.24%	5.24%
Equity Cost Estimate for Less Leveraged Utilities	11.39%	11.87%

12/03/02

Municipal Light & Power

Comparable Earnings for Electric Utilities Sample

		Authorized ROEs[a]	ROEs Earned in 2001[b]
1	Alliant Energy	11.3%	9.8%
2	Ameren	11.4%	14.0%
3	CINergy	11.3%	15.0%
4	Consolidated Edison	12.1%	12.0%
5	Empire District	10.0%	3.9%
6	Energy East	11.0%	13.1%
7	FPL Group	na	13.0%
8	Great Plains Energy	na	12.6%
9	Hawaiian Electric	11.2%	11.6%
10	NSTAR	11.6%	13.7%
11	Pepco Holdings	12.0%	11.8%
12	Pinnacle West	11.3%	12.5%
13	Progress Energy, Inc.	12.4%	11.5%
14	Public Service Enerprise Group	11.0%	18.6%
15	Southern Company	13.0%	14.0%
	Column Average	11.5%	12.5%

Data Sources:
_a/ CA Turner Utility Reports, November 2002.
_b/ Most recent issues of Value Line Ratings and Reports.

12/03/02

Municipal Light & Power

Recognition of Impact of Differences in Leverage:
Based on Results for DCF Models

Panel A: Average for Sample Utilities

		Capitalization Ratio	Incremental Cost-[a/]	Weighted Cost
Bottom	debt	0.56	7.00%	3.95%
	equity	0.44	11.0%	4.80%
				8.74%
Top	debt	0.56	7.00%	3.95%
	equity	0.44	11.9%	5.19%
				9.14%

Panel B: Increase Leverage:

		Capitalization Ratio	Incremental Cost-[b/]	Weighted Cost
Bottom	debt	0.65	7.00%	4.55%
	equity	0.35	12.0%	4.19%
				8.74%
Top	debt	0.65	7.00%	4.55%
	equity	0.35	13.1%	4.59%
				9.14%

Notes:

_a/ Incremental cost of debt as reported November 15, 2002 by *Value Line* for A-rated utility bonds. Cost of equity range as estimated and reported in Exhibits TMZ-12 and TMZ-14.

_b/ Assumes no change in incremental debt cost but increases the cost of equity to reflect more financial risk.

12/03/02

Municipal Light & Power

Recognition of Impact of Differences in Leverage:
Based on Results for Risk Premium Models

Panel A: Average for Sample Utilities

		Capitalization Ratio	Incremental Cost[a]	Weighted Cost
Bottom	debt	0.56	7.00%	3.95%
	equity	0.44	11.2%	4.88%
				8.83%
Top	debt	0.56	7.00%	3.95%
	equity	0.44	11.9%	5.19%
				9.14%

Panel B: Increase Leverage:

		Capitalization Ratio	Incremental Cost[b]	Weighted Cost
Bottom	debt	0.65	7.00%	4.55%
	equity	0.35	12.2%	4.28%
				8.83%
Top	debt	0.65	7.00%	4.55%
	equity	0.35	13.1%	4.59%
				9.14%

Notes:

_a/ Incremental cost of debt as reported November 15, 2002 by *Value Line* for A-rated utility bonds. Cost of equity range as estimated and reported in Exhibits TMZ-15, TMZ-16 and TMZ-17.

_b/ Assumes no change in incremental debt cost but increases the cost of equity to reflect more financial risk.

12/03/02

Municipal Light & Power

Recognition of Impact of Differences in Leverage:
Based on Comparable Earnings

Panel A: Average for Sample Utilities

		Capitalization Ratio	Incremental Cost[a]	Weighted Cost
Bottom	debt	0.56	7.00%	3.95%
	equity	0.44	11.5%	5.01%
				8.96%
Top	debt	0.56	7.00%	3.95%
	equity	0.44	12.5%	5.45%
				9.40%

Panel B: Increase Leverage:

		Capitalization Ratio	Incremental Cost[b]	Weighted Cost
Bottom	debt	0.65	7.00%	4.55%
	equity	0.35	12.6%	4.41%
				8.96%
Top	debt	0.65	7.00%	4.55%
	equity	0.35	13.9%	4.85%
				9.40%

Notes:

_a/ Incremental cost of debt as reported November 15, 2002 by *Value Line* for A-rated utility bonds. Cost of equity range as estimated and reported in Exhibit TMZ-18.

_b/ Assumes no change in incremental debt cost but increases the cost of equity to reflect more financial risk.

12/03/02

Municipal Light & Power

Summary of Reasonable Equity Return Estimates for ML&P

	Bottom of Range	Top of Range
Based on DCF Models	12.0%	13.1%
Based on Risk Premium Models	12.2%	13.1%
Based on Comparable Earnings	12.6%	13.9%

Notes:
Equity cost estimates derived from a consideration of ML&P's above average financial risk but do not include any premium for ML&P being smaller than the electric utilities adopted to make benchmark equity cost estimates.

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UE 180
Attachment 648-D

Dr. Zepp's testimony and workpapers from Arizona water utility rate case

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF CHAPARRAL CITY WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02113A-04-_______

DIRECT TESTIMONY OF

THOMAS M. ZEPP

I. INTRODUCTION AND QUALIFICATIONS:

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Thomas M. Zepp. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commission between 1976-1982. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in 22 states, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to incremental costs of energy and telecommunications services, determined values of utilities properties and have presented rate design testimony.

Q. WHAT COST OF CAPITAL STUDIES HAVE YOU PREPARED BEFORE?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in Alaska, Arizona, California, Hawaii, Idaho, Illinois, Kentucky, Montana, Nevada, New Mexico, Oregon, Tennessee, Utah, Washington and Wyoming.

My studies and testimony have included consideration of the financial health and fair rates of return for Nevada Bell Telephone, Illinois Bell Telephone,

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General Telephone of the Northwest, Pacific Northwest Bell, US West, Anchorage Municipal Light & Power, Pacific Power & Light, Portland General Electric, Commonwealth Edison, Northern Illinois Gas, Iowa-Illinois Gas and Electric, Puget Sound Power & Light, Idaho Power, Cascade Natural Gas, Mountain Fuel Supply, Northwest Natural Gas, Arizona Water Company, Arizona-American Water Company, California-American Water Company, California Water Service, Dominguez Water Company, Hawaii-American Water Company, Kentucky-American Water Company, Mountain Water Company, New Mexico-American Water Company, Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, Southern California Water Company, Tennessee-American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. DO YOU HAVE OTHER PROFESSIONAL EXPERIENCE RELATED TO COST OF CAPITAL ISSUES?

A. Yes. My article, "Utility Stocks and the Size Effect - Revisited," was published in *The Quarterly Review of Economics and Finance*, Vol. 43, Issue 3 (Autumn 2003) 578-582. Also, I published an article "Water Utilities and Risk," in *Water: The Magazine of the National Association of Water Companies*, Vol. 40, No. 1 (Winter 1999), and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper entitled "Application of the Capital Asset Pricing Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Conference and published an article entitled "On the Use of the CAPM in Public Utility Rate Cases: Comment," in *Financial Management* (Autumn 1978) 52-56.

While on the staff of the Oregon Public Utility Commission, I also established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was invited to Stanford University to discuss that research.

II. PURPOSE OF TESTIMONY, BASIC PRINCIPLES, SUMMARY AND CONCLUSIONS

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Chaparral City Water Company ("Chaparral City" or "Company") has asked me to estimate its cost of equity and the fair rate of return on common equity. My study is based on data available to investors in June 2004.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In this Section II, the concept of a fair rate of return and a summary of my analysis is presented.

In Section III, the general risks of water utility common stocks and specific additional risks faced by Chaparral City are discussed. I explain why the Company's cost of equity should be increased by at least 50 basis points above the cost of equity for samples of water utilities used to determine benchmark estimates of the cost of equity to account for added risk of regulatory procedures in Arizona, Chaparral City's sources of water, new, inverted tier rate design, and an additional 60 basis points if the Company's proposed power cost and purchased water cost adjusters are not approved. I also explain that my equity cost estimates are based on market data, are independent of the rate base used to determine revenue requirements, and thus should be applied to the rate base the Arizona

Corporation Commission (the "Commission") adopts to determine those revenue requirements.

Section IV provides an overview and perspective on what one should expect the fair rate of return to be in 2005 and 2006, the initial period when new rates for Chaparral City will be approved, and develops my discounted cash flow ("DCF") equity cost estimates. In making my DCF equity cost estimates I have recognized that the Administrative Law Judges and subsequently the Commission relied exclusively on estimates of the cost of equity made by the Commission's Utilities Division ("Staff") in *Arizona Water Company*, Decision No. 66849, Docket No. W-1445A-02-0619, and in *Arizona-American Water Company*, Decision No. 67093, Docket No. WS-01303A-02-0867, et al. I have acknowledged that fact by determining my DCF equity cost estimates with methods used by the Federal Energy Regulatory Commission ("FERC") instead of methods I presented in those cases. The extremely low DCF equity cost estimates adopted by the Commission for water utilities in 2004 depended on the way Staff implemented the capital asset pricing model ("CAPM") and DCF model based on interest rates and data in 2003. While I believe the methods the FERC uses to implement the DCF model are conservative and may understate the cost of equity, the FERC approaches are based upon many years of deliberations and are clearly superior to the approaches taken by Staff in 2003.

Section V presents equity cost estimates based on the risk premium approach. In the two Commission water utility cases listed above, Staff relied upon the original version of the CAPM to make its risk premium equity cost estimates. To make my risk premium equity cost estimates, I rely on the methods and data the California Public Utility Commission Staff ("CPUC Staff") has used for many years to make risk premium equity cost estimates for water utilities.

These risk premium estimates are transparent and straightforward, and they do not depend on the many choices and assumptions required to implement the CAPM. In my opinion, equity cost estimates based on the risk premium methods and data relied upon by the CPUC Staff are clearly superior to risk premium equity cost estimates based on the version of CAPM that the Commission Staff relied on in 2003.

Section VI present a summary of the equity cost estimates based on the FERC DCF approaches and the CPUC Staff risk premium approaches. I also present additional information on past Commission decisions that corroborates my equity cost estimates. This information shows that since December 2001, Staff's revised methods of estimating the cost of equity have caused a substantial decrease in the authorized returns on equity when compared to the equity returns authorized by the Commission during previous 10-year period.

Q. HAVE YOU PREPARED ANY TABLES AND ATTACHMENTS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared 15 tables and three attachments that support my testimony.

Q. PLEASE PROVIDE SOME PERSPECTIVE AND AN OVERVIEW OF THE ISSUES YOU ADDRESS IN YOUR TESTIMONY.

A. Investors can choose to invest in many different types of assets with varying degrees of risk. Those investments might be in real estate, or gold, or collections of fine art, or financial securities. The financial assets run the gamut from relatively low risk assets such as Treasury securities to somewhat higher risk investment grade corporate bonds to relatively high-risk shares of common stocks. As the level of risk increases, investors require higher expected returns. Common stocks of utilities are generally more risky and thus require higher returns than investment grade bonds, which are secured debt instruments with fixed repayment terms. Operating expenses, interest on debt and repayment of principal take precedence over payments to common stock holders, and thus it is the common equity shareholder of the utility who bears the greatest risk of receiving expected returns. Conceptually,

Required return for common stock	=	Return on a risk-free asset	+	risk premium

where the risk premium required for common stocks will be higher than it is for investment grade bonds.

Regulators generally set rates to recover a utility's costs of service. One of those costs of service is the cost of common equity, the required return for the utility's common stock. Rates that give a utility a reasonable opportunity to earn the cost of equity are fair to customers of the utility because the cost of equity is another cost of service. Such rates are also fair to owners of the utility because the cost of equity is equal to returns expected to be earned by other companies of comparable risk, is high enough to attract capital, and allows the utility to maintain its financial integrity.

Q. HAS THE U.S. SUPREME COURT SET FORTH ANY STANDARDS THAT APPLY TO EQUITY RETURNS?

A. Yes. In 1923, the U.S. Supreme Court set forth the following standards in *Bluefield Waterworks & Improvement Co. v. Public Utility Commission of West Virginia,* 262 U.S. 679 (1923):

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure

> confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

262 U.S. at 692-93.

In *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), the U.S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments 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.

320 U.S. at 603.

Q. ARE THERE MORE SPECIFIC CONSIDERATIONS THAT SHOULD BE RECOGNIZED?

A. Yes. In determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities. The Arizona Constitution, as applied by the Commission, creates a particular rate setting system that limits the ability of Arizona utilities to make out-of-period adjustments. The Commission uses an historic test year with limited out-of-period adjustments. With the use of an historic test year and limited out-of-period adjustments, it is more difficult for a utility to earn its cost of equity. The return to the equity owner is the last claimant of revenues the utility earns; thus, risk will unavoidably be higher in Arizona than in jurisdictions that have rate setting systems which offer a better opportunity for the utility to recover costs of service during the period in which new rates are in place. Chaparral City faces more risk than the water utilities I use to make benchmark equity cost estimates because the use of an historic test year with limited out-of-period adjustments reduces the chance it will make its cost of equity when new rates are established.

Chaparral City also faces the risk that it will have unexpected costs in the period in which new rates are in effect but will not be able to recover such unexpected costs without a costly and lengthy general rate case. This particular rate setting system increases risk and thus requires the Commission to authorize higher rates of return on common equity ("ROE") than would be the case in jurisdictions such as California, which use forecasted or projected test periods and allow utilities to implement surcharges and other mechanisms to recover unexpected costs without going through a general rate case.

Finally, Chaparral City has risks associated with its water supply and with the Commission's recent policy of requiring water utilities to implement inverted block rate structures to encourage water conservation. These added risks should be recognized when setting the fair rate for return for the Company.

Q. **WHAT ARE THE IMPLICATIONS OF THESE PRINCIPLES IN THE DETERMINATION OF A FAIR RATE OF RETURN FOR CHAPARRAL CITY?**

A. The principles are important to customers and equity owners of Chaparral City. From the perspective of customers, the cost of equity is another cost of service, and customers' rates should cover that cost just as rates should recover other costs of service. The rates customers pay should provide a reasonable opportunity for

Chaparral City to earn that cost of equity but not guarantee that it will be earned.

From the perspective of equity owners, the principles require rates that provide a reasonable opportunity to earn a return for its owners that maintains the utility's financial integrity, is commensurate with returns on investments in other enterprises having corresponding risks, and is sufficient to attract capital on reasonable terms. As I discuss further below, Chaparral City is more risky than the water utilities sample I rely upon to determine benchmark estimates of the cost of equity and thus its required common equity return is higher.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. My findings and recommendations are the following:

1. The cost of common equity faced by Chaparral City is greater than the cost of common equity that faces my water utilities sample:

   (a) The Company faces risk that stems from the use of an historical test year with limited opportunities for out-of-period adjustments.

   (b) Chaparral City faces risk related to its supply of water.

   (c) Chaparral City faces risk due to the Commission's policy of requiring inverted block rates to encourage reductions in water use, which may destablize and reduce revenues.

   (d) Based on the risks discussed in (a), (b) and (c) that face Chaparral City but not the water utilities sample, the Company has an equity cost that is at least 50 basis points higher than the benchmark water utilities.

   (e) Currently, Chaparral City is more risky because it does not have mechanisms to recover unexpected costs beyond its control for purchased power and purchased water that are available to water utilities in the benchmark sample. If the purchased power and purchased water adjusters proposed by Chaparral City are not approved, its cost of equity will be at least 60 basis points higher than the water utility sample.

2. The market cost of common equity faced by the benchmark water utilities falls in a range of 10.2% to 11.4% at this time:

   - Conservative estimates of the cost of equity derived with DCF methods used by the FERC indicate the cost of equity for the benchmark water utilities falls in a range of 10.2% to 10.4%;

   - Costs of equity derived from methods and data used by the CPUC Staff to determine risk premium equity costs for water utilities indicates the cost of equity for benchmark water utilities falls in the range of 10.6% to 11.4%.

   - Past Commission decisions for water and gas utilities indicate an average cost of equity of 11.0%.

3. The Company has proposed that an ROE of 10.4% be approved if its purchased power and purchased water adjusters are approved as filed and 11.0% if the purchased power and purchased water adjusters are not approved. Based on my analyses, the Company's request is conservative and I recommend it be approved. (See Summary Table 15.)

4. My equity cost estimates are based on market data and thus are independent of the rate base adopted to determine revenue requirements.

III. <u>RISKS OF WATER UTILITY STOCKS AND CHAPARRAL CITY</u>

Q. AS A PRELIMINARY MATTER, PLEASE DISCUSS THE SAMPLE OF WATER UTILITIES YOU HAVE USED IN YOUR DCF ANALYSIS.

A. My sample of water utilities is composed of American States Water, Aqua America (formerly named Philadelphia Suburban), California Water Service Group, Connecticut Water Service, Middlesex Water and SJW Corp., which are the water utilities the Staff relied upon to determine benchmark equity costs in two general rate cases for Class A water utilities in 2003. Table 1 lists bond ratings, operating revenues and net plant for the six water utilities as reported by C. A. Turner Utility Reports in June 2004.

Q. DO YOU HAVE ANY GENERAL CONCERNS WITH THE DATA AVAILABLE TO MAKE DCF EQUITY COST ESTIMATES FOR WATER UTILITIES?

A. Yes. Table 2 shows premiums that investors in water utilities have received when water utilities were either acquired or merged with other firms. At the time mergers or acquisitions were completed, investors received premiums that ranged between 35% and 55%. Value Line has advised investors to expect such acquisitions and mergers to continue and to expect prices from an acquisition to be as much as four times book value. (See Attachment 1.) As a result, it is reasonable to expect that investors have bid up prices for all water utility stocks to some extent to reflect the probability they may be acquired at a premium, which lowers the result produced by the DCF model.

Table 3 suggests this has happened. It shows that common stock prices for the water utilities in the sample have had an annual average percentage increase during the last five years that exceeded annual average percentage increases in dividends per share ("DPS"), earnings per share ("EPS") and book value per share. The annual average increase in common stock prices also exceeds an average of analysts' forecasts of future growth in EPS. With the constant growth DCF model, in equilibrium, book values, common stock prices, EPS and DPS would grow at the same rate. If investors have bid up those stock prices in anticipation that some of the utilities may be targets for favorable mergers or acquisitions, dividend yields have been bid down and expected future growth rates may not reflect the anticipated higher future prices. In such a situation, application of the constant growth DCF model may produce negatively biased estimates of the cost of equity for water utilities.

Q. DO YOU HAVE OTHER CONCERNS WITH MAKING DCF EQUITY

COSTS FOR UTILITIES IN THE ACC STAFF SAMPLE?

A. Yes. There are no forecasts of forward-looking growth for either Connecticut Water Service or SJW Corp at this time. Staff has used past DPS growth, past EPS growth and past sustainable growth (Staff call sustainable growth "intrinsic growth") as part of its measure of growth to be used in the DCF model. If an average of those measures of growth for Connecticut Water Service is adopted to make an equity cost estimate, that equity cost estimate would be 200 basis points *below* the cost of investment grade debt expected during 2005. Table 3 shows past DPS growth has been 1.1% and past EPS growth has been 3.1% for Connecticut Water Service. Past growth from retained earnings has been 3%. Adding an average of those growth rates to an average of the high and low dividend yields of 3.1% (see Table 4) produces an indicated equity cost of *only 5.6%* ((3.1% x 1.024) + 2.4%), which is not credible when the cost of Baa bonds is expected to be 7.6% during 2005 and even higher during 2006, when the Company's new rates will be in effect. Various institutions that report investor analysts' forecasts of growth (shown in Table 7) do not report such forecasts for Connecticut Water Service at this time. For my implementation of the FERC DCF approach, I assume investors expect Connecticut Water Service to have growth equal to the average growth expected for other water utilities. This is the approach Staff took in past cases.

SJW Corp. poses the same problem. If an average of past growth in DPS, EPS and growth indicated by past retained earnings are used to estimate growth, SJW Corp. has an indicated equity cost that is 90 basis points below the expected cost of investment grade bonds in 2005 and thus is not realistic. Table 3 shows past DPS growth has been 3.9% and past EPS growth has been 1.1% for SJW Corp. Past growth from retained earnings has been 5.2%. Adding an average of those growth rates to an average of the high and low dividend yields of 3.2% (see Table 4) produces an indicated equity cost of *only 6.7%* ((3.2% x 1.034) + 3.4%), which is not credible when the cost of Baa bonds is expected to be 7.6% during 2005 and even higher during 2006. Various institutions that report investor analysts' forecasts of growth (shown in Table 7) do not report such forecasts for SJW Corp. at this time. For my implementation of the FERC DCF approach, I assume investors expect SJW Corp. to have growth equal to the average growth expected for other water utilities. Again, Staff has used the same approach in past cases.

Q. DO YOU HAVE THE SAME CONCERNS WITH INCLUDING CONNECTICUT WATER SERVICE AND SJW CORP. IN THE RISK PREMIUM EQUITY COST ANALYSES?

A. No. In those risk premium analyses, the data problems with the application of the DCF model are not an issue.

Q. IN GENERAL, DOES A WATER UTILITY FACE MORE RISK WHEN IT HAS TO MAKE ADDITIONAL INVESTMENTS TO MEET STATE AND FEDERAL WATER QUALITY STANDARDS AND OTHER REGULATORY MANDATES?

A. Yes. First, expected or unexpected requirements for additional capital spending means the water utilities have to request rate increases more often and for larger percentage increases in order to maintain fair rates of return. Regulatory procedures are expensive, time consuming, increase uncertainty, and raise doubts in investors' minds that regulators will authorize high enough rates and/or rate adjustment mechanisms to enable the water utilities to earn fair rates of return. This increases uncertainty about future returns and thus increases risk.

Second, investors are concerned that regulators will delay inclusion of new plant in rate base or not allow part of the dollars invested or operating costs to be recovered. In Arizona, because there are limitations on out-of-period adjustments, investments may not only be challenged but also may not be allowed in rate base because they are not considered appropriate out-of-period adjustments. If such investments are challenged and there is any chance that the Commission will disallow part of the dollars invested or will delay recovery of the costs of those investments, risk increases. From an investor's point of view, it is the *potential* for such disallowances, delays or exclusion from consideration in setting new rates that increases risk. If additional investments were never required there would be no potential disallowances, delays or possible exclusions and investor concerns would never arise; thus risk would not increase. With the need for increased investments, uncertainty arises and the risk increases.

With the need for a rate increase, delay in setting new rates as well as uncertainty related to what those rates will be increases risk above the level of risk faced by water utilities that can expect new rates to better match future costs of service and have less delay in obtaining rate increases.

Q. HAVE YOU STUDIED THE IMPACT OF FINANCING REQUIREMENTS ON THE RISK AND COSTS OF CAPITAL FACED BY UTILITIES?

A. Yes, I have. Several years ago, before recent events in western power markets occurred, I conducted a study of expected differences in bond costs and common equity costs that faced electric utilities with different financing requirements. I found that utilities with above average financing requirements required an ROE that was approximately 80 basis points higher than was required by an average utility. Higher financing requirements pushed up bond costs, too.

Q. DOES CHAPARRAL CITY FACE ANY SPECIFIC RISKS UNDER THE RATE SETTING SYSTEM USED IN ARIZONA REQUIRING THAT THE

AUTHORIZED ROE BE SET ABOVE THE MARKET COST OF EQUITY YOU DERIVE BELOW FROM DATA FOR WATER COMPANIES WHICH OPERATE IN OTHER STATES?

A. Yes, it does. In its *Duquesne* decision, the U. S. Supreme Court stated:

> [T]he impact of certain rates can only be evaluated in the context of the system under which they are imposed . . . . The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks.

Duquesne Light Company v. Barasch, 488 U.S. 299, 314-15 (1989). Two "state-specific factors" in Arizona make Chaparral City more risky than the utilities in the water utilities sample I rely upon to determine benchmark cost of equity estimates. One factor is the legal constraint on Arizona water utilities that limits their ability to obtain rate relief outside of general rate cases. The Arizona Constitution, as interpreted in recent court decisions, limits the ability of Arizona utilities to utilize adjustment mechanisms, advice letter filings and other streamlined procedures to obtain recovery of costs outside a general rate case, in contrast to many other jurisdictions. For example in *RUCO v. Arizona Corporation Commission*, 199 Ariz. 588, 20 P.3d 1169 (App. 2001), the court held the Commission violated the Arizona Constitution because it authorized a water utility to implement a surcharge to recover increased purchased water costs without finding the utility's "fair value." These limitations on obtaining rate relief in Arizona make it more risky for Chaparral City to do business than utilities in the states that permit utilities to implement surcharges and other cost recovery mechanisms outside a general rate case.

Second, even in a general rate case, Arizona requires the use of historic test

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years with limitations on the amount of out-of-period adjustments. This requirement creates another state-specific factor that increases risk and thus required ROEs for utilities in Arizona. Other states, such as California, use future test years or partially-projected test years to better reflect future costs and to match plant, expenses and revenues on a going-forward basis. The constraints on the determination of new rates in a general rate case in Arizona make it difficult to construct rates that allow Chaparral City to recover the costs of service it will actually incur during the period when new rates are in effect.

These risks increase Chaparral City's required return on equity above the level required by the water utilities used to determine equity costs that operate in states other than Arizona that do not have such limitations imposed, either by law or by agency policy, on the rate setting system. Under the *Duquesne* decision, the additional risk associated with the particular rate setting system must be compensated with an ROE that is higher than would be appropriate for the utilities in the water utilities sample. Because rate relief in Arizona is generally limited to decisions made during general rate cases, there are unavoidably delays in receiving such rate relief. If it takes the same amount of time for Chaparral City to obtain rate relief as it did in the recent Arizona Water Company and Arizona-American Water cases, it will be late 2005 or even early 2006 before new rates for Chaparral City go into effect.

Q. DOES CHAPARRAL CITY FACE OTHER ADDITIONAL RISKS NOT FACED BY UTILTIES IN THE WATER UTILTY SAMPLE?

A. Yes. Chaparral City has risks related to its supply of water. The Company relies on the Central Arizona Project ("CAP") for approximately 90 percent of its water supply. The CAP has vulnerability to its very long canal system because there is no redundancy. When its aqueduct is shut down there is no alternative means of delivering the water beyond a small amount of storage. The CAP also has a relatively low priority on the Colorado River. So, if there is a period of chronic drought, California, Nevada, certain Indian tribes and various water districts near the Colorado River would be entitled to receive water before the CAP. Obviously, this poses a risk for Chaparral City as well as others that rely on the CAP.

Chaparral City has only a limited ability to produce and procure water from other sources. Chaparral City recently completed a study of the water it could obtain from its wells, but pumping that water requires the payment of withdrawal fees (which would not be in rate case expenses). In addition, the Company has a contract with the Central Arizona Groundwater Replenishment District ("CAGRD"), which also collects tax based on groundwater withdrawals. Such a contract, however, ultimately depends upon being able to secure excess CAP water or other water rights equal to the amount of its contracts. In other words, ultimately the right to pump groundwater also depends upon the continued availability of CAP water, and thus Chaparral City clearly has risk related to this supply. **[Please check with Rob – this doesn't sound right. I think his point was somewhat different. I would rather emphasize that groundwater is not available to supply customer demand.]**

Q. ARE THERE ANY OTHER ASPECTS OF ARIZONA'S RATE SETTING SYSTEM THAT INCREASE RISK?

A. Yes. In the past several years, the Commission has placed increased emphasis on water conservation. The Commission has generally been requiring water utilities to have inverted block rate structures, which are intended to cause customers to use less water. Inverted block rates were an issue in both the Arizona Water Company and Arizona-American Water rate cases, and in both cases, the

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Commission required those utilities to adopt an inverted block rate design, in which the commodity rate increases with increasing consumption. Based on these decisions, and recent statements by the Commissioners that they want water utilities to emphasize water conservation, Chaparral City is proposing an inverted block rate design in this case.

Because the primary objective of this type of water rate design is to reduce water use, the adoption of inverted block rates creates additional risk. Inverted block rates may cause revenue erosion and instability. American Water Works Association, *Alternative Rates* (1992) 18. At a minimum, it is reasonable to expect some reduction in water use, and therefore a reduction in the utility's revenues, which may prevent it from earning its rate of return. However, the magnitude of these reductions is often difficult to predict. This uncertainty makes it more difficult to develop rates that allow the utility a reasonable opportunity to recover its cost of service, including its cost of equity. This uncertainty creates additional risk that increases Chaparral City's required return on equity.

Q. **DO YOU HAVE AN OPINION ABOUT HOW MUCH THE RISK POSED BY THE RATE SETTING SYSTEM IN ARIZONA, ACC POLICY REQUIRING INVERTED RATES, AND CHAPARRAL CITY'S SOURCE OF SUPPLY INCREASE CHAPARRAL CITY'S REQUIRED ROE?**

A. Yes. These factors increase the Company's risk and thus its required ROE by at least 50 basis points above the ROE required by the benchmark water utilities.

Q. **DOES CHAPARRAL CITY FACE OTHER RISKS?**

A. Yes. Chaparral City faces the risk of cost increases beyond its control. After completion of a rate case, a third party, the Central Arizona Water Conservation District ("CAWCD"), which is the primary contractor with the U. S. Bureau of Reclamation, could increase substantially the amount Chaparral City is required to

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pay for water. These charges are not regulated and are outside the Company's control. Increases would depend on CAWCD's determination of financial requirements to run the system.

Additionally, Chaparral City faces uncertain purchased power costs. The Company buys power for its office, wells, treatment plant and boosters from an unregulated provider, the Salt River Project ("SRP"), which could increase its rates at any time. Such potential increases in power rates are beyond the control of Chaparral City and could be implemented by SRP without the lengthy rate-setting process required of regulated utilities. Chaparral City also buys power from Arizona Public Service that is used to take raw CAP water from the canal. APS has filed for rate increase but the magnitude of the increase in Chaparral City's cost of power purchased APS, however, is not known at this time. Thus, Chaparral City faces not only uncertain purchased power costs, but also may be unable to include such cost increases in a general rate case due to the time required to prepare and complete a general rate case in Arizona. Such potential, unknown increases in purchased water and purchased power costs are beyond the control of Chaparral City and thus increase risk.

Q. CAN THESE RISKS RELATED TO PURCHASED POWER AND PURCHASED WATER COSTS BE MITIGATED?

A. Yes. Adoption of purchased power and purchased water adjustment mechanisms similar to those some Arizona water utilities have in place can mitigate this risk. Chaparral City has proposed such adjustment mechanisms in this case. A utility that has no adjustment mechanisms is clearly more risky than utilities in the water utilities sample that do have adjustment mechanisms that allow them to recover unexpected increases in costs.

Q. HAVE YOU STUDIED THE IMPACT ON REQUIRED ROES OF RATE

ADJUSTMENT MECHANISMS THAT MITIGATE THE IMPACT OF CHANGES IN COSTS BEYOND THE CONTROL OF WATER UTILITIES?

A. Yes, I have. In California, prior to November 2001, unexpected outlays for purchased water, purchased power and pump taxes were booked to balancing accounts and ultimately either refunded to customers or collected from customers in the future independent of an earnings test. The California Office of Ratepayer Advocates ("ORA") proposed a modification of the balancing account mechanism that would continue the balancing accounts, but base recovery of unexpected higher costs on an earnings test. I conducted company-specific simulation analyses and found that the modification of the balancing account mechanism proposed by ORA had a large negative impact on expected ROEs and indicated increases in required ROEs of 75 basis points for California Water Service, 90 basis points for Southern California Water Company and 110 basis points for San Gabriel Valley Water Company. These increases in required ROEs were the result of a proposed modification of the balancing account mechanism, not the elimination of it.

Q. **IF CHAPARRAL CITY'S PROPOSED PURCHASED POWER AND PURCHASED WATER ADJUSTMENT MECHANISMS ARE NOT ADOPTED, WILL THE COMPANY HAVE A HIGHER COST OF EQUITY?**

A. Yes, it will. My studies of California utilities show that balancing accounts are important and reduce utilities costs of equity without placing any added burden on ratepayers.[1] In California, I found that even with a modification of the balancing account procedures, the required ROEs increased by more than 75 basis points. If Chaparral City is not allowed to implement the purchased power and purchased water adjustment mechanisms it has proposed, the Company's required ROE is higher. Based on my prior studies and my opinion, I expect that the cost of equity will be at least 60 basis points higher than the ROE required by utilities in the water utilities sample I use to determine benchmark costs of equity.

Q. DO THE EQUITY COST ESTIMATES YOU DEVELOP BELOW DEPEND UPON THE TYPE OF RATE BASED EMPLOYED IN ARIZONA?

A. No. The equity cost estimates I develop below are independent of the rate base employed to determine revenue requirements and are based on well established finance models which use publicly available information. The rate bases of the utilities in the sample group are not relevant to my analysis. If Arizona were an original cost jurisdiction, the equity cost estimates would be applied to an original cost rate base. But since Arizona requires rates be based on a "fair value" rate base, my equity cost estimates should be applied to that type of rate base.

IV. OVERVIEW AND DCF EQUITY COST ESTIMATES

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS THAT PUT YOUR EQUITY COST ESTIMATES IN PERSPECTIVE?

A. Yes. Equity costs move in the same direction as interest rates. In 2003, Treasury rates dropped to the lowest level in close to forty years. From 1964 to 2002, annual average yields on 10-year Treasury securities, for example, ranged from 4.19% to 13.92%. For the most recent ten-year period ending in 2002, the annual

[1] There is no added burden if ratepayers are expected to pay their actual costs of service. A balancing account recovers or refunds only unexpected changes in the cost of water or power.

averages of 10-year Treasury rates ranged from 4.61% to 7.09%. By contrast, in 2003, that annual average was only 4.01%.

At present, however, interest rates, and thus costs of equity for Chaparral City, are rising and expected to continue rising. As of June 14, 2004, the 10-year Treasury rate reported by the Federal Reserve was 4.89% and the June 2004 Blue Chip long term consensus forecast for the 10-year rate for 2005 was 5.6%, rising to 5.9% in 2006. Value Line forecasts of Treasury rates made in May 2004 also indicate that interest rates are increasing and expected to be higher in 2005 and 2006 than they are today and much higher than they were in 2003. (See Table 9.) Recently, the Federal Reserve increased its target rate for short-term interest rates for the first time in several years. Most analysts expect further increases. Based on interest rate forecasts alone, the Commission should anticipate reasonable estimates of the cost of equity for water utilities are higher today than in 2003.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR DCF EQUITY COST ESTIMATES.

A. An ROE for Chaparral City that is fair to ratepayers, yet still provides a satisfactory return for investors, is the Company's cost of equity. To estimate that cost of equity, the analyst requires market data that reveal investors' required returns, but such data are not available for Chaparral City. It is not publicly traded, and there is no "pure play" company that is perfectly comparable to Chaparral City. Equity costs based on data for the sample of water utilities, however, are for companies that provide the same service and thus provide a useful starting point in the determination of Chaparral City's cost of equity.

In this section of my testimony, I determine DCF equity costs for water utilities based on the two methods the FERC uses to determine DCF equity costs in different situations. When the FERC determines an equity cost for an electric utility, it uses a "one-step" model. Conceptually, the one-step model is the same as the constant growth DCF model the Staff employed in Arizona Water Company's recent rate case for its Eastern Group, Docket W-01445A-02-0619. When the FERC determines equity costs for gas transmission companies, it uses a "two-step" DCF model. The two-step model is conceptually the same as the multi-stage DCF equity model Staff presented in Docket No. W-01445A-02-0619.[2]

Q. PLEASE EXPLAIN THE DCF METHOD OF ESTIMATING THE COST OF EQUITY.

A. The constant growth DCF model computes the cost of equity as the sum of an expected dividend yield ("D_1/P_0") and an expected long-term average dividend growth rate ("g"). The expected dividend yield is computed as the ratio of next period's expected dividend ("D_1") divided by the current stock price ("P_0"). Generally, the constant growth model is computed with formula (1) or (2):

(1) Equity Cost = $D_0/P_0 \times (1 + g) + g$

(2) Equity Cost = $D_1/P_0 + g$

where D_0/P_0 is the current dividend yield and D_1/P_0 is found by increasing the current yield by the growth rate. The DCF model is derived from the valuation model shown in equation 3 below:

(3) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + Dn/(1+k)^n$,

where k is the cost of equity; n is a very large number; P_0 is the current stock price, $D_1, D_2, \ldots Dn$ are the cash flows expected to be received in periods 1, 2, . . . n, respectively. Equation (3) can be re-written to show that the current price (P_0) is also equal to

[2] Direct Testimony of Joel M. Reiker, Docket No. W-01445A-02-0619, Schedule JMR-6.

$$(4) \quad P_0 = D_1/(1+k) + D_2/(1+k)^2 + P_2/(1+k)^2,$$

where P_2 is the price expected to be received at the end of the second period. When the multi-stage DCF model is used to estimate the cost of equity, it is assumed investors expect different rates of growth in the initial period and subsequent period.

If the future price (P_2) included a premium, the price the investor would pay today in anticipation of receiving that premium would increase. Table 2 reports premiums investors have recently received from mergers and acquisitions. Attachments 1 and 2 to this testimony explain why such premiums are expected to continue. If investors expect a water utility is a potential merger/acquisition candidate they will bid up its stock price to reflect the probability and present value of the future price expected from the merger/acquisition. In such a situation, the dividend yield would be lower and thus either the constant growth (one-step) DCF model or the multi-stage (two-step) DCF model may understate the cost of equity. In making my DCF equity cost estimates below, I do not account for this bias in the DCF equity cost estimates, and thus my DCF equity cost estimates are conservative.

Q. **PLEASE BEGIN WITH YOUR DCF ESTIMATES BASED ON THE FERC ONE-STEP MODEL. HOW DOES FERC IMPLEMENT THAT MODEL?**

A. The FERC implements the one-step (or constant growth) DCF model by initially combining the lowest and highest dividend yields for individual utilities in the sample during the most recent six month period with two estimates of forward-looking growth to estimate a range of DCF equity costs for the utilities in its sample. Next, the FERC eliminates from consideration any of those equity cost estimates that imply the cost of equity is below the cost of investment grade bonds. Then the FERC determines a range of equity costs for the sample and a mid-point of that range to determine the cost of equity. This method is fully discussed in *Southern California Edison Company*, Opinion No. 445, 92 F.E.R.C. 61,070 (2000). This opinion is included as Attachment 3 to this testimony. More recent FERC decisions refer back to the *Southern California Edison* decision. For example, see FERC findings in *Midwest Independent Transmission System Operator*, 100 F.E.R.C. 61,292 (2002).

Q. HOW DID YOU COMPUTE CURRENT DIVIDEND YIELDS?

A. The FERC one-step method determines a range of dividend yields based on the lowest and the highest dividend yields during the last six months. Table 4 reports those dividend yields for the water utilities sample.

Q. WHAT GROWTH RATES ARE CONSIDERED IN THE FERC ONE-STEP METHOD?

A. The FERC considers estimates of both sustainable growth (growth Staff has called "intrinsic growth") and analysts' forecasts of growth. I agree with the choice of growth rates relied upon by the FERC. The DCF model requires estimates of growth that investors expect in the future. No weight should be given to historical measures of growth. Logically, financial institutions and analysts would have taken such past information into account, and other more recent information, when they make their forecasts for the future.[3] To the extent that past, recorded results provide useful indications of future growth prospects, the forecasts would already incorporate the past and any further recognition of the past will double-

[3] See David A. Gordon, Myron J. Gordon and Lawrence I. Gould, "Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management* (Spring 1989). 50-55. Gordon, Gordon and Gould found that a consensus of analysts' forecasts of earnings per share growth for the next five years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. They explain that this result makes sense because analysts would take into account such past growth as indicators of future growth as well as any new information.

count what has already occurred. When there is no estimate of forward-looking growth for a utility in the water utilities sample, I have followed the method Staff adopted in the past and assumed investors expect the growth for that utility to equal the average of growth rates for the other water utilities in the sample, as explained above.

Q. WHAT IS SUSTAINABLE GROWTH?

A. Sustainable growth is derived by combining expected growth from future retained earnings and expected future growth from sales of common stock above book value. The FERC defines sustainable growth as follows:

> 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 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.

Southern California Edison, 92 F.E.R.C. at p. 61,269 (citing *Connecticut Light and Power Co.* 45 F.E.R.C. 62,370 at p. 62,161, n. 15 (1988)).

The retention ratio "b" is equal to (1 - the ratio of dividends divided by earnings) and the equity accretion rate "v" is equal to (1 - (book value divided by market value)). Myron Gordon developed this concept of growth in his book, *The Cost of Capital to a Public Utility* (Michigan State University 1974). Gordon explains why sv growth can be expected when market prices exceed book value but why "sv" growth is not expected to come into play when market prices are below book values.

Q. HOW DO YOU ESTIMATE EXPECTED "br" GROWTH?

A. Investors' expectations of what the retention ratio and the expected ROE will be in the future that determine this portion of expected sustainable growth. Multiplying "b" times "r" gives the estimate of future sustainable growth from retained earnings. Investors look for measures of future growth when pricing stocks. When the data are available, I have used Value Line projections of future ROEs, future DPS and future EPS to make the forecasts of "br" growth. The available estimates of br growth are reported in Table 5 as well as the average for those water utilities.

Q. HAVE YOU ESTIMATED "sv" GROWTH FOR THE WATER UTILITIES SAMPLE?

A. Yes. My estimates of sv growth for the water utilities are presented in Table 6. I have used Value Line projections of new issues of shares of common stock to estimate "s." The estimates of "v" are based on reported book values and respective averages of the prices used to compute the dividend yields. Some of the utilities in the water utilities sample have sold stock at prices in excess of book value in recent years and have thus achieved "sv" growth. Knowledgeable investors would expect such growth in the future. Available forecasts indicate investors expect some of the sample water utilities to issue more shares of stock over time. Thus there will be a positive "s" term in "sv" growth. Also, the average market-to-book ratio for the sample of water utility stocks is over 2.0. Unless stock prices drop to less than half of their current values, there will be a positive "v" for the foreseeable future.

Q. DOES THE FERC SPECIFICALLY INCLUDE ESTIMATES OF "sv" GROWTH IN THE ESTIMATES OF SUSTAINABLE GROWTH?

A. Yes, it does.

Q. DO MARKET-TO-BOOK RATIOS GREATER THAN 1.0 IMPLY INVESTORS EXPECT THE UTILITIES IN THE WATER UTILITIES SAMPLE TO EARN BOOK RETURNS ON EQUITY GREATER THAN

THE COSTS OF EQUITY?

A. No. There are many reasons investors may bid up market prices for stocks above book values other than an expectation that a water utility will earn more than its cost of equity. Investors may expect a city or some other public entity to condemn all or part of a water utility and that the public entity will be required by the court to pay the utility the fair market value for it. Water utilities typically have assets that have a value based on reproduction cost that is well in excess of book value. I have testified on the values of water utility properties and electric utility properties in various court cases in California, Utah and Oregon. Based on my experience, in situations where only a portion of the utility is being condemned, valuations based on both reproduction cost new less depreciation and the income approach indicate utility property has a value well in excess of book value. Investors would be aware that courts may award potential condemnation values well in excess of book values even if the utility earns no more than its cost of equity.

Q. **ARE THERE OTHER REASONS?**

A. Yes. Investors may anticipate a merger or acquisition that produces premium prices similar to those reported in Table 2, which have been well above book values. With such anticipated sale prices well above book values, a water utility would also be priced above book value even if the water utility made no more than its cost of equity. There are other reasons as well.[4]

[4] An Oregon Public Utility Commission staff witness listed the following six reasons a market price could exceed book value even if the utility was expected to earn its authorized ROE: (1) public utility commissions do not issues orders simultaneously in all jurisdictions, (2) not all of a company's earnings are regulated, (3) regulatory expenses, revenue and rate base adjustments may cause accounting returns to differ from those calculated on a rate case basis, (4) actual sales do not equal sales assumed in a rate case, (5) market expected ROEs change frequently while rate-case authorized ROEs do

Q. **WHERE DO YOU REPORT YOUR ESTIMATE OF AVERAGE SUSTAINABLE GROWTH?**

A. That value is developed in Table 5.

Q. **IS THERE ANOTHER INDICATOR OF FUTURE GROWTH THAT THE FERC RELIES UPON WHEN IT IMPLEMENTS THE ONE-STEP DCF APPROACH?**

A. Yes. The other estimates of forward-looking growth relied upon by the FERC are analysts' forecasts of future five-year EPS growth. Table 7 reports analysts' five-year forecasts of EPS growth reported by a number of financial institutions and the average of those analysts' forecasts. The first two columns of Table 7 show analysts' consensus forecasts of future EPS growth rates reported by Zacks and Thomson First Call that were available for the utilities in the water utilities sample. The third column shows available analysts' growth forecasts for the same water utilities that are reported in the S&P Earnings Guide. Column 4 shows forecasts of EPS growth reported by Value Line at April 30, 2004. The average of analysts' forecasts of growth is 7.0%. For my implementation of the FERC one-step method, I have used the average of these analysts' forecasts of growth for each of the utilities when such forecasts were available. If forecasts were not available, I followed Staff's past practice of assuming investors expect the missing growth rate to equal the average growth expected for the other water utilities in the sample, as explained previously.

Q. **HOW DID YOU UTILIZE THIS INFORMATION ON DIVIDEND YIELDS**

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not, and (6) regulated subsidiaries constitute only a piece of a holding company pie. Testimony of John Thornton in Oregon Docket UM 903 (filed November 9, 1998). Mr. Thornton's testimony was filed in Oregon prior to joining the Staff of the Commission.

AND ESTIMATED FUTURE GROWTH TO MAKE YOUR BENCHMARK DCF ESTIMATES WITH THE FERC ONE-STEP METHOD?

A. I adopted the approach shown in Table 4. First, adjusted high and low dividend yields were computed for each of the utilities by increasing the current dividend yields shown in columns in "a" by one-half the average of the two estimates of growth presented in columns "c" and "d". The FERC method increases the current dividend by only one-half of the expected future growth and thus produces a value for D_1/P_0 that is conceptually only six months (instead of one full year) into the future. In my view this results in conservative estimates of the cost of equity, but I have adopted this method in my implementation of the FERC one-step approach because the FERC uses that method.

Next, I computed the low equity cost estimates shown in column "e" of Table 4 for each of the utilities by combining the lowest estimate of growth for each utility with the respective low estimates of the adjusted dividend yield. The equity cost estimates in column "f" were then made by combining the highest estimate of growth with the high dividend yields.

The last step of the FERC one-step method is to estimate the mid-point of the indicated equity cost range as the benchmark cost of equity. Both the mid-point and the average of the various equity cost estimates are 10.2%. This equity cost for the sample understates the Company's cost of equity because Chaparral City is more risky for the reasons discussed above.

Q. **DID YOU CONSIDER ALL TWELVE EQUITY COST ESTIMATES WHEN YOU DETERMINED THE MIDPOINT OF THE EQUITY COST RANGE?**

A. Yes, I did. As I mentioned above when I described the one-step method, the FERC deletes any individual utility equity cost estimate that is not at least 40 basis points above the cost of investment grade bonds. Based on the estimates made here, none of the indicated costs of equity is that small and thus none was deleted from the range used to determine the mid-point equity cost for the benchmark sample.

Q. PLEASE TURN TO YOUR IMPLEMENTATION OF THE FERC'S TWO-STEP APPROACH. HOW DOES THE TWO-STEP APPROACH DIFFER FROM THE ONE-STEP APPROACH?

A. The FERC two-step approach differs from the one-step approach in that it assumes that investors will expect terminal growth to be different than initial growth. In deriving its two-step approach, the FERC recognized that investment houses use more complex three-stage models in which the first and second stages could have a length of possibly 20 years and the final stage growth is the long-term growth rate of the economy. The FERC also noted that determining the length of such stages requires judgment on the part of the analyst. In Opinion 396-B, the FERC expressed its preference for the simpler two-step model that, in effect, combined the first two stages of the more complicated three-stage model used by investment houses. *Northwest Pipeline Company*, 79 F.E.R.C. 61,309 (1997). The FERC specifically rejected the use of the "investment house approach" in which a complicated three-stage model that required solving for the ROE with an iterative process was used to determine ROE. Such models are not only complicated but require judgments as to how long initial growth will continue, and whether the transitional growth rate would decline (increase) towards the terminal growth rate slowly, quickly or at a steady rate.

Q. HOW DOES THE FERC DETERMINE GROWTH WITH THE TWO-STEP MODEL?

A. The FERC adopts analysts' forecasts of EPS growth as the growth rate in the first stage, forecasted growth of GDP for growth for the final stage and took an average of those growth rates to compute growth for the two-step model. More recently, in *Southern California Edison*, the FERC indicated it gives a weight of two-thirds to analysts' forecasts of growth and a weight of one-third to GDP growth to compute that average growth rate. *Southern California Edison*, 92 F.E.R.C. at 61, 257 and n.19 (citing *Northwest Pipeline Company*).

Q. **HOW DOES THE FERC TWO-STEP MODEL DIFFER FROM THE MULTI-STAGE DCF APPROACH PRESENTED BY STAFF IN THE 2003 ARIZONA WATER AND ARIZONA-AMERICAN WATER CASES?**

A. Conceptually, the multi-stage DCF model presented by Staff in water utility rate cases in 2003 is similar to the FERC two-step model, but the choices made by Staff to implement the model lead to significantly lower estimated costs of equity. Both the FERC and Staff assumed terminal growth should ultimately be assumed to equal GDP growth. The distinction between the Staff multi-stage analysis and the FERC two-step method can be boiled down to two significant differences. First, the FERC assumes the initial period before reaching terminal growth is much longer than the four or five years that Staff assumed in its multi-stage model. FERC wisely assumes it will take many years before the terminal growth for a utility will be the same as growth in GDP. Second, the FERC assumes investors rely on EPS growth in the longer, initial period, when they price common stocks. The FERC approach correctly recognizes that it is earnings that permit dividends to be paid and thus bases growth in its longer, initial period on EPS growth, not short-term DPS growth used by Staff in its model.

Q. **WHERE DO YOU REPORT YOUR TWO-STEP EQUITY COST ESTIMATE?**

A. It is reported in Table 8. In preparing this estimate, I have relied on spot prices instead of an average of prices. Staff has indicated its preference for spot prices.[5] The values for the DCF dividend yield (D_1/P_0) are based on the FERC convention of increasing current dividends by only one-half the growth rate. As I indicated in my discussion of the one-step approach, it is my view that this method of computing dividend yields produces very conservative estimates of the cost of equity. Consistent with the FERC two-step approach described in the *Northwest Pipeline Company* opinion, the initial growth rates are the analysts' forecasts of growth. (See Table 4.) The terminal growth rate I have relied upon is 6.5%, which is the estimate of the long-term growth in GDP relied upon by Staff in the Arizona Water Company and Arizona-American Water cases in 2003. That growth rate provides a conservative estimate of the long-term estimate of GDP growth. The more appropriate growth estimate to use in this analysis would be the long-term arithmetic average growth rate of 6.8%. The 6.5% value is the long-term geometric average and thus understates the forward-looking growth required by investors.[6] To potentially eliminate an issue with Staff, the smaller value of GDP growth of 6.5% is used in my analysis. Based on the FERC two-step approach, the indicated cost of equity for the water utilities sample is 10.4%. Because Chaparral City is more risky, its cost of equity is higher.

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[5] It is my view that average dividend yields are preferred to spot yields when making DCF equity cost estimates. But, in a multi-stage analysis, typically one price is adopted. To eliminate an issue with Staff, the numbers in Table 8 are closing prices at the time this testimony was written.

[6] This issue is discussed in Ibbotson Associates, *SBBI 2003 Yearbook* 100-101. The geometric average is used to report what has happened not what is expected to happen and only applies for the future if year-to-year growth in GDP is not expected to fluctuate. If GDP growth varies – even slightly – from year to year in the future, the past GDP growth will not be realized if the geometric average is used to set the growth. If year-to-year variation is the same as in the past, the required growth rate is the arithmetic average growth rate.

V. RISK PREMIUM EQUITY COST ESTIMATES

Q. PLEASE TURN TO YOUR RISK PREMIUM EQUITY COST ESTIMATES FOR WATER UTILITIES. CAN YOU PROVIDE AN OVERVIEW OF THE RISK PREMIUM METHOD OF ESTIMATING THE COST OF EQUITY?

A. Yes. Under the risk premium approach, the risk premium is directly estimated by comparing authorized and actual returns on equity with the current yields of investment grade bonds or other debt instruments:

> The risk premium method of determining the cost of equity, sometimes referred to as the "stock-bond-yield spread method" or the "risk positioning method," or again the "bond-yield plus risk-premium" method, recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: First, determine the historical spread between the return on debt and the return on equity. Second, add this spread to the current debt yield to derive an estimate of current equity return requirements.
>
> The risk premium approach to estimating the cost of equity derives its usefulness from the simple fact that while equity return requirements cannot be readily quantified at any given time, the returns on bonds can be assessed precisely at every instant in time. If the magnitude of the risk premium between stocks and bonds is known, then this information can be used to produce the cost of common equity. This can be accomplished retrospectively using historical risk premiums or prospectively using expected risk premiums.

Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital* (1994) at 269. There is no need to estimate betas or market risk premiums, as required in implementing the CAPM, and there is no reason to determine if "beta risk" is the only risk of relevance to investors holding shares of water utilities. It is a simpler and less subjective approach. For these reasons, regulatory commissions use the risk premium approach in setting rates far more frequently than the CAPM.

Q. WHAT ARE THE SOURCES FOR YOUR RISK PREMIUM ESTIMATES?

A. The sources are the methods and data presented by the CPUC Staff in various general rate cases. I have made three risk premium analyses.

Q. EXPLAIN YOUR FIRST ANALYSIS.

A. My first analysis is an update of the method presented by CPUC Staff in California-American Water Company's Los Angeles district rate case (Docket No. A03-07-036) in January 2004. The only difference in my first analysis and the one relied upon by CPUC Staff in that case is the updated forecasts of interest rates. CPUC Staff has used this risk premium approach to determine costs of equity in numerous cases during the last three years. With this approach, CPUC Staff adopted annual averages of actual realized ROEs for the six water utilities in my sample as proxies for the costs of equity for the period 1993-2002, subtracted contemporaneous Treasury rates from those equity cost proxies to determine annual average risk premiums, then added the 5-year and the 10-year averages of those risk premiums to forecasts of the respective Treasury rates to determine an equity cost range.

Q. WHAT HAVE YOU DONE TO UPDATE THE CPUC STAFF'S RISK PREMIUM ANALYSIS?

A. I have updated the CPUC Staff's analysis by updating the forecasts of the Treasury rates with an average of Treasury rate forecasts for the period 2005-2006 made by Blue Chip and Value Line. This is the only change from the risk premium analysis CPUC Staff presented in Table 2-7 of its Cost of Capital Report for California-American Water Company in Docket No. A.03-07-036. The interest rate forecasts I have relied upon to make this update are averages of Blue Chip's consensus forecast of interest rates for 2005 and 2006 reported in June 2004 and Value Line's most recent quarterly forecasts of interest rates made May 28, 2004. I report those Treasury rate forecasts and forecasts for Baa bond rates in Table 9.

Q. **HAS ACC STAFF RELIED UPON FORECASTS OF INTEREST RATES TO DETERMINE THE REASONABLENESS OF EQUTIY COST ESTIMATES IN PAST CASES?**

A. Yes, it has. For example, in Docket No. U-1656-91-134, Staff relied upon Blue Chip Financial forecasts of interest rates, GNP and inflation during the next year to describe the economic environment that influenced its cost of capital estimates (Testimony of Linda A. Jaress, dated December 2, 1991, pages 9-11). Also, in testimony dated April 19, 1993, Docket No. U-1303-92-286, ACC Staff relied upon Blue Chip forecasts of interest rates for the first quarter of the following year to determine the appropriate level of interest rates for the determination of costs of equity. (Supplemental Testimony of J. David Daer, page 6). Relying on forecasts of interest rates to determine costs of equity is not a new concept to ACC Staff and thus the fact that the CPUC Staff method relies on forecasts of interest rates to determine costs of equity is not unusual.

Q. **WHY HAVE YOU USED INTEREST RATE FORECASTS FOR THE PERIOD 2005 TO 2006 IN YOUR ANALYSIS?**

A. I have used this period because it is the period in which Chaparral City's new rates will first be put into place. August 2005 is the earliest the new rates could be approved and put in place. But based on the amount of time it has recently taken to complete rate cases in Arizona, it could be as late as 2006 before new rates are in place. The CPUC Staff method relies upon forecasts of interest rates for the future periods when new rates for the utility will be in place. To be consistent with the CPUC Staff approach, it is appropriate to adopt forecasts of interest rates for the period when Chaparral City's new rates will be in place.

Q. WHY NOT USE CURRENT RATES FOR TREASURY SECURITIES?

A. There are two reasons. First, the CPUC Staff does not use current rates and thus to be consistent with the CPUC Staff approach, forecasted rates should be adopted. Second, the goal is to determine the cost of capital for Chaparral City when new rates are in effect, not the cost of capital 18 months before such new rates are approved.

The Commission Staff provided evidence in the recent Arizona-American Water case that showed forecasts of interest rates reported by Blue Chip were sometimes higher and sometimes lower than the interest rates that actually occurred and that the projected interest rates were, on average, lower than the actual interest rates that subsequently occurred.[7] CPUC Staff has determined that such forecasts of interest rates are preferred to using current interest rates as proxies for future rates. Current interest rates are also sometimes higher and sometimes lower than interest rates during future periods. It is especially inappropriate to adopt current interest rates as proxies for future interest rates when those current interest rates are close to 40-year lows and are expected to increase.

Q. WHAT IS THE RESULT OF THIS ANALYSIS?

A. This analysis indicates the cost of equity for the water utilities sample falls in a range of 10.6% to 10.9%. (See Table 10.) Chaparral City's indicated cost of equity is higher because it is more risky.

[7] Direct Testimony of Joel M. Reiker, Docket No. WS-01303A-02-0867, et al., at 49

Q. TURN TO YOUR SECOND RISK PREMIUM ANALYSIS. HOW DOES IT DIFFER FROM THE FIRST ANALYSIS?

A. CPUC Staff chose to use earned ROEs instead of authorized ROEs as the proxies for the costs of equity in its analysis. If regulators attempt to authorize ROEs that are equal to the utilities' costs of equity, and adopt rates and rate adjustment mechanisms that give those utilities a reasonable opportunity to earn those authorized ROEs, on average, earned as well as authorized ROEs might provide proxies for the costs of equity. The second risk premium analysis adopts authorized ROEs instead of earned ROEs as the proxies for the costs of equity in the risk premium analysis. This change is the only change from the first risk premium analysis.

Q. WHAT ARE THE RESULTS OF THE SECOND RISK PREMIUM ANALYSIS?

A. Table 11 presents the results of this second analysis. This analysis indicates the cost of equity for the water utilities sample falls in a range of 11.0% to 11.4%. The indicated cost of equity for Chaparral City is higher because it is more risky. During the period of the study, on average, utilities in the water utilities sample earned less than their authorized ROEs, and thus it is expected that this second risk premium analysis will indicate a higher equity cost range than was found in the first risk premium analysis.

Q. TURN TO YOUR THIRD RISK PREMIUM ANALYSIS. WHAT DATA HAVE YOU USED TO PREPARE THIS ANALYSIS?

A. In a number of cases, the CPUC Staff has adopted averages of realized ROEs for samples of water utilities as proxies for costs of equity. My third risk premium analysis is based on averages of realized ROEs for water utilities samples that the CPUC Staff adopted as proxies for the costs of equity, Baa bond yields reported

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by the Federal Reserve, and the expectation that when bond costs decrease, equity costs will also decrease, but by less. In effect, the risk premium increases as interest rates decrease. This expectation is generally consistent with the theoretical work of Gordon and Halpern, "Bond Share Yield Spreads Under Uncertain Inflation," *American Economic Review*, Vol. 66, No. 4 (September 1976) 559-565. It is also consistent with empirical studies such as a 1989 study conducted by Staff at the Oregon Public Utility Commission and a statement by the California Public Utility Commission in decisions in 1997 (D.97-12-089) and 2002 (D.02-11-027) that its practice is to adjust ROEs for energy utilities by one-half to two-thirds of the change in the benchmark interest rate.

Q. PLEASE EXPLAIN THIS RISK PREMIUM ESTIMATE.

A. I followed the three-step procedure shown in Table 12. Panel A of Table 12 shows earned ROEs for samples of publicly traded water utilities for the period 1985 to 2002. CPUC Staff adopted these ROEs as proxies for the costs of equity for water utilities in San Gabriel Valley Water Company's 1995 rate case (Table 3-4 A95-09-010), in California-American Water Company's 2003 rate case (Table 2-7, A02-09-030), and in San Gabriel Valley Water Company's 2003 rate case (Table 2-7, A02-11-044). Lines 19 and 20 of Panel A of Table 12 show the average risk premium increased from 2.12% to 3.13% as the average Baa rate decreased from 10.48% to 7.99%. This result indicates that, on average, returns for water utilities dropped by 59 basis points for each 100-basis point drop in the Baa bond rate. Thus, on average, the risk premium increased by 41 basis points for every 100-basis point drop in the Baa bond rate. (See line 22 of Panel A of Table 12.) This result is consistent with equity costs moving in the same direction as interest rates, but by less.

Q. DID YOU USE THE DATA IN PANEL A TO ESTIMATE THE COST OF

EQUITY FOR CHAPARRAL CITY?

A. Yes. First, I recognized that the relationship between risk premiums and interest rates implies the following:

Risk premium = constant - slope x Baa bond rate.

Then, in Panel A, I solved for the slope in this equation by dividing the difference in risk premiums by the difference in bond rates (shown on line 21). Next, in Panel B, I solved for the constant in the equation that is consistent with the derived slope, the most recent average risk premium of 3.13% for the period 1993-2002, and the average Baa rate of 7.99% for the period 1993-2002.

Q. **HOW DID YOU USE THAT RESULT TO ESTIMATE THE COST OF EQUITY?**

A. I combined the slope of -0.41 and the constant of 6.39% derived in Panel B of Table 12 with the forecast of 7.68% for Baa bond rates during 2005-2006 reported in Table 9, to derive the current risk premium of 3.3%. Adding this current risk premium to the forecasted Baa rate of 7.68%, the indicated cost of equity for the sample of water utilities is 10.9%. Again, the indicated cost of equity for Chaparral City is higher than 10.9% because it is more risky than the sample water utilities. (See Table 12, Panel C.)

Q. **WHAT IS SHOWN IN TABLE 13?**

A. Table 13 is the same as Table 12 but uses 10-year Treasury rates to conduct the risk premium analysis instead of Baa bond rates. In testimony filed in 2003 in Arizona-American Water's rate case, Staff claimed Baa rates should not be used in a risk premium analysis because such rates include default risk premiums.[8] I subsequently provided evidence showing that Baa rates provided better forecasts

[8] Direct Testimony of Joel M. Reiker, Docket No. WS-01303A-02-0867, et al., at 50-52.

of equity costs than Treasury rates and explained that Staff's contention had no merit if investors require the same default risk premium today as in the past.[9] I have prepared Table 13 to show that the choice of interest rates to conduct this risk premium analysis is not an important issue. Whether Treasury rates or corporate bond rates are used in this analysis, the equity cost estimate for the water utilities sample rounds to the same number, 10.9%.

VI. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR EQUITY COST ESTIMATES.

A. The Commission adopted Staff's estimates of costs of equity in the recent Arizona Water Company and Arizona-American Water Company general rate cases without giving any consideration to estimates I provided or restatements of Staff estimates that showed the costs of equity for those water utilities were much higher. In response, I have prepared equity cost estimates in this case that are not based on the methods I have presented in past cases (even though I believe my methods are theoretically sound and provided reasonable results), but instead are based on the methods and inputs relied upon by the Federal Energy Regulatory Commission to determine DCF equity costs and by the staff of the California Public Utility Commission to determine risk premium equity cost estimates.

A straightforward application of the FERC one-step and two-step DCF approaches indicates an equity cost range of 10.2% to 10.4% for the water utility sample. These DCF equity cost estimates probably understate the cost of equity for water utilities for two reasons. First, some water utilities' stock prices may be bid up in anticipation of a favorable buyout or merger. In such a situation, dividend yields drop but growth rates do not fully reflect expected future growth

[9] Rebuttal Testimony of Thomas M. Zepp, Docket No. WS-01303A-02-0867, et al., at 21-23 and Rebuttal Tables 2 and 3.

in cash flows. Second, the FERC method determines conservative measures of equity costs by increasing the dividend to determine D_1/P_0 that is only six months into the future instead of a full year. I explained why unique risks faced by Chaparral City require it be authorized an ROE that is at least 50 basis points higher than the appropriate ROE for the sample water utilities. Thus, the conservative DCF estimates based on the FERC DCF equity cost approaches and the premium for the Company's additional risk indicates Chaparral City's equity cost falls in a range of 10.7% to 10.9%.

I have also used methods and data the staff of the California Public Utilities Commission has used to determine equity costs with the risk premium approach. Those estimates indicate the cost of equity for the water utility sample falls in a range of 10.6% to 11.4% and the cost of equity for Chaparral City falls in a range of 11.1% to 11.9%. Combined, all of the DCF and risk premium approaches indicate the cost of equity for the water utility sample falls in a range of 10.2% to 11.4%, and Chaparral City's equity cost falls in a range of 10.7% to 11.9%. Based on these equity cost estimates, I conclude that the equity return of 10.4% requested by Chaparral City if its proposed purchased power and purchased water adjusters are approved is extremely conservative.

I have also estimated that if those purchased power and purchased water adjusters are not approved, Chaparral City's cost of equity will be at least 60 basis points higher. If the requested adjustors are not approved, an authorized ROE of 11.0% is also extremely conservative. I have prepared Table 15, in which this information has been summarized.

Q. **IS THERE OTHER INFORMATION THAT CORROBORATES YOUR ESTIMATES AND RECOMMENDATIONS?**

A. Yes. Current Staff has devised ways to implement the CAPM and DCF models that, after accounting for differences in the level of interest rates, produce equity cost estimates that are much lower than this Commission authorized prior to December 2001. Table 14 lists nine decisions for large water and gas utilities in Arizona and concurrent 10-year Treasury rates. Adding the average risk premium above 10-year Treasury rates of 5.43% to the current forecast of Treasury rates indicates an ROE consistent with past orders of 11.0%, an ROE that is more than 60 basis points above the ROE Chaparral City has requested. Chaparral City, however, faces higher risks today because it must comply with more stringent state and federal regulations than those that existed in the past and has added risk related to its supply of water. The data in Table 14 corroborate my conclusion that a 10.4% ROE is a very conservative request and should be approved.

The past decisions also put in perspective recent Staff recommended ROEs of 9.0% for Arizona Water Company and Arizona-American Water Company and an even lower recommendation of 8.0% for Rio Rico Utilities (*Rio Rico Utilities, Inc.*, Docket No. WS-02676A-03-0434). Implementation of finance models that lead to such low ROEs are inconsistent with ROEs this Commission authorized before the Staff revised the methods it uses to determine equity costs in 2001.

Q. IS THERE OTHER EVIDENCE THAT A 10.4% ROE IS REASONABLE TODAY?

A. Yes. On May 7, 2003, when Staff prepared its direct testimony in the Arizona-American Water rate case, the yield on 10-year Treasury securities was 3.8%, while Staff determined the average equity cost for its sample of water utilities was 9.2%.[10] The earliest new rates could be in place for Chaparral City is 2005 when 10-year Treasury rates are forecasted to be 5.45% (see Table 9). Based on a

[10] Direct Testimony of Joel M. Reiker, Docket No. WS-01303A-02-0867, et al., at 23, n. 11.

simple change in interest rates of 165 basis points, Staff's determination of a 9.2% ROE in May 2003 now supports an equity cost of 10.85%. This clearly shows that the 10.4% ROE requested by the Company is reasonable at this time.

Q. DO YOUR EQUITY COST ESTIMATES DEPEND UPON THE TYPE OF RATE BASE ADOPTED TO DETERMINE REVENUE REQUIREMENTS?

A. No. My equity cost estimates are based on market data and are independent of the type of rate base used to set revenue requirements.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

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Chaparral City Water Company

Table 1

Selected Characteristics of Water Utilities

	% Water Revenues-[a/]	S&P Bond Rating-[a/]	Moody's Bond Rating-[a/]	Operating Revnues-[a/] ($ millions)	Net Plant-[a/] ($ millions)
1 American States	88%	A-	A2	$212.6	$545.7
2 Aqua America	92%	AA-	NR	$386.5	$1,629.6
3 California Water	97%	NR	A2	$286.1	$672.2
5 Connecticut Water Service	92%	A	NR	$51.1	$189.0
4 Middlesex Water	87%	A+	NR	$65.0	$212.3
6 SJW Corp	97%	NR	NR	$153.0	$274.2

Source: C.A. Turner Utility Reports, June 2004.

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Chaparral City Water Company

Table 2

Premiums Received by Investors from Recent Mergers and Acquistions of Water Utilities

Company	Approximate Date of Aquisition or Merger	Price Prior to Announcement	Value at Time of Merger or Acquistion	Basis	Premium
United Water Resources	July 2000	$23.13	$35.30	cash	53%
E-Town	Year-end 2000	$50.38	$68.00	cash	35%
Dominguez	May 2000	$22.75	$33.75	stock	48%
Consumers Water	March 1999	$21.38	$33.10	stock	55%
American Water Works	January 2003	$34.00	$46.00	cash	35%
Average Premium					45%

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Announcement data

Month ending July 1999. Price jump to 33 5/8 in Aug 99

Month-end for Aug-99

Month-end October 98, announced Nov 1998

Month-end May 98 --announced June 29, 1998

Specificed a 35% markup at time of announcement

Chaparral City Water Company

Table 3

Comparison of Past and Future Estimates of Growth for the Water Utilites Sample

		Five-year average annual changes				Average
		Price[a]	Book Value[b]	DPS[b]	EPS[b]	Future EPS Growth[c]
1	American States Water	8.8%	4.6%	0.9%	6.2%	5.2%
2	Aqua America, Inc.	9.5%	9.0%	6.2%	9.6%	9.4%
3	California Water Service	0.5%	0.2%	1.1%	-6.0%	6.8%
5	Connecticut Water Service	11.4%	4.8%	1.1%	3.1%	na
4	Middlesex Water	11.2%	4.3%	2.8%	4.0%	6.7%
6	SJW Corporation	9.1%	3.7%	3.9%	1.1%	na
	Average for DCF sample	8.4%	4.4%	2.7%	3.0%	7.0%

Sources:
a/ Change in average of high and low prices for 1999 to 2003.
b/ Annual Reports to Stockholders or *Value Line* for 1998-2002.
c/ Source Table 7.

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Source: MSNMoney.com (from ORA) and Thomson First Call

	AWR	CWT	CTWS	MSEX	PSC/WTR
2003	25.26	27.54	27.21	24.66	23.83
2002	24.63	23.67	25.72	22.51	20.51
2001	22.70	25.74	25.86	22.28	20.15
2000	20.98	26.44	20.25	19.65	15.26
1999	20.65	27.28	18.67	20.17	15.84
1998	16.79	27.25	16.17	15.00	15.66
1997	15.29	24.11	13.67	12.96	10.76

	AWR	CWT	CTWS	MSEX	PSC
2003	2.6%	16.3%	5.8%	9.6%	16.2%
2002	8.5%	-8.0%	-0.5%	1.1%	1.8%
2001	8.2%	-2.6%	27.7%	13.4%	32.1%
2000	1.6%	-3.1%	8.5%	-2.6%	-3.7%
1999	23.0%	0.1%	15.5%	34.4%	1.1%
1998	9.8%	13.0%	18.3%	15.8%	45.6%
5-year growth	50%	1%	68%	64%	52%
Average 5-Year Growth	8.8%	0.5%	11.4%	11.2%	9.5%

SJW
82.55
83.20
88.25
108.50
89.13
59.75
53.25

SJW
-0.8%
-5.7%
-18.7%
21.7%
49.2%
12.2%

38%	41%
9.1%	7.8%

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Table 4
FERC One-Step (Constant Growth) Discounted Cash Flow Model

		6 Mo. Div. Yield		Adjusted Div. Yield		Growth Rates		Implied Cost of Equity		
		Low	High	Low	High	br+sv	Analysts' Forecasts	Low		High
		a		b		c	d	e		f
1	American States Water Co.	3.3%	4.2%	3.4%	4.4%	7.6%	5.2%	8.6%	-	11.9%
2	Aqua America Inc.	2.1%	2.9%	2.2%	3.0%	7.7%	9.4%	9.8%	-	12.4%
3	California Water Service Group	3.8%	4.4%	3.9%	4.5%	4.2%	6.8%	8.1%	-	11.3%
4	Connecticut Water Service	2.8%	3.4%	2.8%	3.5%	6.5%	7.0%	9.3%	-	10.5%
5	Middlesex Water Company	3.0%	3.5%	3.1%	3.6%	6.5%	6.7%	9.6%	-	10.3%
6	SJW Corp.	2.7%	3.6%	2.8%	3.7%	6.5%	7.0%	9.3%	-	10.7%
	Average	2.9%	3.7%	3.0%	3.8%	6.5%	7.0%			
	Full range of equity cost estimates							8.1%		12.4%
	Midpoint of range								10.2%	

Notes and Sources
a/ Six-month average dividend yields for December 2003 to May 2004.
b/ Six-month dividend yield adjusted for one-half years' growth.
c/ Based on averages of projections made by *Value Line Investment Survey* (April 30, 2004) if available. See Table 5.
use ACC Staff method and adopt the average for the utilities that are available.
d/ Average of analysts' forecasts for growth. See Table 7.
e/ Sum of lowest growth rate and lowest adjusted dividend yield.
f/ Sum of highest growth rate and highest adjusted dividend yield.

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Table 5

Estimates of Sustainable Growth for the Water Utilities Sample

		Retention Ratios	Estimated Future ROE	Forecast of br-[b] Growth	sv Growth-[c]	Average Sustainable Growth
1	American States Water Co.	0.52	11.5%	6.2%	1.4%	7.6%
2	Aqua America Inc.	0.48	11.0%	5.4%	2.2%	7.7%
3	California Water Service Group	0.44	7.0%	3.1%	1.1%	4.2%
4	Connecticut Water Service-[d]					6.5%
5	Middlesex Water Company-[d]					6.5%
6	SJW Corp.-[d]					6.5%
	Average	0.48	9.8%	4.9%	1.8%	6.5%

Notes and Sources:
_a/ FERC method: br growth based on *Value Line* forecasts of DPS, EPS and ROE for the period 2007-2009 published April 30, 2004.
_b/ FERC method: br growth adjusted for year-end ROE forecast by Value Line.
_c/ Estimated sv growth derived in Table 6.
_d/ Growth estimate is average for other water utilities.

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Table 6

Estimates of "sv" Growth for the Water Utilities Sample

		Stock Financing Rate (s)[a/] (a)	Market to Book Ratio[b/] (b)	v (c)	sv growth (d)
1	American States Water Co.	3.43%	1.70	0.41	1.42%
2	Aqua America Inc.	3.51%	2.76	0.64	2.24%
3	California Water Service Group	2.33%	1.94	0.49	1.13%
4	Connecticut Water Service				na
5	Middlesex Water Company				na
6	SJW Corp.				na
	Average	3.09%	2.14	0.51	1.60%

Notes and Sources:
a/ From Value Line data reported April 30, 2004.
b/ Based on average of prices in Table 4 and book values in 2003.

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Table 7

Analysts' Forecasts of Future Earnings Growth for the Water Utilities Sample

		Zacks[a]	Thomson First Call[a]	S&P[b]	Value Line[c]	Average
1	American States Water Co.		3.0%	3.0%	9.5%	5.2%
2	Aqua America Inc.	8.9%	10.0%	9.0%	9.5%	9.4%
3	California Water Service Grou	8.3%	4.0%	4.0%	11.0%	6.8%
4	Connecticut Water Service					7.0%
5	Middlesex Water Company	6.0%	7.0%	7.0%		6.7%
6	SJW Corp.					7.0%
	Column average	7.7%	6.0%	5.8%	10.0%	7.0%

Source:

a/ As reported on the Internet May 14 and June10, 2004.

b/ May 2004 S&P Earnigs Guide for Middlesex Water. Others from June 2004 S&P Earnings Guide.

c/ Reported by *Value Line* April 30, 2004.

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Table 8

FERC Two-Step (Multi-Stage Growth) Discounted Cash Flow Model

		Spot Price[a/]	Current D_0[a/]	FERC Yield D_1/P_0	Growth Rates: Near Term[b/]	Growth Rates: Long Term[c/]	Growth Rates: Average[d/]	Indicated Cost of Equity
		a	b	c	d	e	f	(c+ f)
1	American States Water Co.	$22.15	$0.88	4.1%	5.2%	6.5%	5.6%	9.7%
2	Aqua America Inc.	$20.35	$0.48	2.5%	9.4%	6.5%	8.4%	10.9%
3	California Water Service Group	$27.50	$1.13	4.3%	6.8%	6.5%	6.7%	11.0%
4	Connecticut Water Service	$25.06	$0.83	3.4%	7.0%	6.5%	6.8%	10.3%
5	Middlesex Water Company	$19.31	$0.66	3.5%	6.7%	6.5%	6.6%	10.2%
6	SJW Corp.	$31.90	$1.02	3.3%	7.0%	6.5%	6.8%	10.1%
	Average			3.5%	7.0%	6.5%	6.9%	10.4%

Notes and Sources:

a/ Indicated dividends and closing prices June 15, 2004. Yields based on spot prices are preferred by ACC Staff.

b/ Average of analysts' forecasts of growth or the average of available forecasts of growth.

c/ GDP growth as estimated by ACC Staff.

d/ Weight given to short-term growth rate is 67%. Source: FERC Opinion 445, note 19, Attachment 3.

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Table 9

Forecasted rates for Treasury Securities and
Baa Corporate Bonds for 2005-2006

	2005	2006	Average
10-Year Treasury Securities			
Blue Chip_a/	5.60%	5.90%	5.75%
Value Line_b/	5.30%	5.40%	5.35%
Average	5.45%	5.65%	5.55%
Long-term Treasury Securities			
Blue Chip_a/	6.10%	6.50%	6.30%
Value Line_b/	5.90%	6.00%	5.95%
Average	6.00%	6.25%	6.13%
Baa Corporate Bonds			
Blue Chip_a/	7.70%	8.00%	7.85%
Value Line_c/	7.50%	7.50%	7.50%
Average	7.60%	7.75%	7.68%

Sources and Notes:
_a/ Blue Chip consensus forecasts, June 2004.
_b/ Value Line Quarterly Forecast, May 28, 2004.
_c/ No forecast made by V*alue Line*. Assume
the difference in Baa rate forecast and long-term
Treasury forecasts would be the same.

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Table 10

Risk Premium Equity Cost Analysis
Realized ROEs Adopted as Equity Cost Proxies

	Return on Equity[a]	Annual Averages: Long-term Treasury[a]	Annual Averages: 10-Year Treasury[a]	Risk Premiums: Long-term Treasury	Risk Premiums: 10-Year Treasury
1993	11.57%	6.60%	5.87%	4.97%	5.70%
1994	10.87%	7.35%	7.09%	3.52%	3.78%
1995	11.20%	6.88%	6.57%	4.32%	4.63%
1996	12.02%	6.70%	6.44%	5.32%	5.58%
1997	11.82%	6.60%	6.35%	5.22%	5.47%
1998	10.90%	5.58%	5.26%	5.32%	5.64%
1999	10.59%	5.87%	5.65%	4.72%	4.94%
2000	9.75%	5.94%	6.03%	3.81%	3.72%
2001	10.27%	5.49%	5.02%	4.78%	5.25%
2002	10.58%	5.41%	4.61%	5.17%	5.97%
10-Year Average Premium[a]				4.71%	5.07%
5-year Average Premium[a]				4.76%	5.10%
Forecasted Interest Rates for 2005-2006[b]				6.13%	5.55%
Projected Returns on Equity					
10-Year Average				10.8%	10.6%
5-Year Average				10.9%	10.7%

Notes and Sources:

_a/ CPUC Staff Cost of Capital Report, Table 2-7, A.03-07-036, January 2004.

_b/ Source is Table 9.

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Chaparral City Water Company

Table 11

Risk Premium Equity Cost Analysis
Authorized ROEs Adopted as Equity Cost Proxies

	Authorized Returns on Equity[a/]	Annual Averages		Risk Premiums	
		30-Year Treasury[b/]	10-Year Treasury[b/]	30-Year Treasury	10-Year Treasury
1993	12.13%	6.60%	5.87%	5.53%	6.26%
1994	12.13%	7.35%	7.09%	4.78%	5.04%
1995	11.51%	6.88%	6.57%	4.63%	4.94%
1996	11.58%	6.70%	6.44%	4.88%	5.14%
1997	11.18%	6.60%	6.35%	4.58%	4.83%
1998	11.06%	5.58%	5.26%	5.48%	5.80%
1999	11.12%	5.87%	5.65%	5.25%	5.47%
2000	11.12%	5.94%	6.03%	5.18%	5.09%
2001	10.86%	5.49%	5.02%	5.37%	5.84%
2002	10.62%	5.41%	4.61%	5.21%	6.01%
	10-Year Average Premium			5.09%	5.44%
	5-year Average Premium			5.30%	5.64%
	Forecasted Interest Rates for 2005-2006[c/]			6.13%	5.55%
	Projected Returns on Equity				
	10-Year Average			11.2%	11.0%
	5-Year Average			11.4%	11.2%

Notes and Sources:
_a/ CA Turner *Utility Reports,* issues for December for various years.
_b/ CPUC Staff Cost of Capital Report, Table 2-7, A.03-07-036, January 2004.
_c/ Source is Table 9.

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Chaparral City Water Company

Table 12

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historic Data

		Earned ROE			Baa Rate			Risk Premium
1	1985	14.40%	a/		12.72%	d/		1.68%
2	1986	13.28%	a/		10.39%	d/		2.89%
3	1987	14.58%	a/		10.58%	d/		4.00%
4	1988	12.42%	a/		10.83%	d/		1.59%
5	1989	10.39%	a/		10.18%	d/		0.21%
6	1990	11.07%	a/		10.36%	d/		0.71%
7	1991	12.82%	a/		9.80%	d/		3.02%
8	1992	11.80%	b/		8.98%	d/		2.82%
9	1993	11.90%	b/		7.93%	d/		3.97%
10	1994	10.76%	b/		8.63%	d/		2.13%
11	1995	11.30%	b/		8.20%	d/		3.10%
12	1996	12.21%	b/		8.05%	d/		4.16%
13	1997	11.93%	b/		7.87%	d/		4.06%
14	1998	11.34%	b/		7.22%	d/		4.12%
15	1999	11.02%	b/		7.88%	d/		3.14%
16	2000	9.91%	b/		8.37%	d/		1.54%
17	2001	10.25%	b/		7.95%	d/		2.30%
18	2002	10.58%	c/		7.80%	d/		2.78%
19	Average 1985-1992	12.60%			10.48%			2.12%
20	Average 1993-2002	11.12%			7.99%			3.13%
21	Difference	1.48%			2.49%			-1.02%
22	Slope			0.59			-0.41	

Panel B: Solve for constant in formula (risk premium = constant - slope x Baa rate):

constant	=	risk premium	+	slope-[e/]	x	Baa rate
constant	=	3.13%	+	0.41-[e/]	x	7.99%
constant	=	6.39%				

Panel C: Solve for current risk premium and equity cost:

Risk Premium	=	constant	-	slope	x Baa rate			
Risk premium	=	6.39%	-	.41	x	7.68%-[f/]	=	3.3%

Estimated cost of equity = bond rate + risk premium = 10.9%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: CPUC Staff Table 2-7, Application 02-11-044 (San Gabriel Valley Water).
d/ Annual average reported by the Federal Reserve.
e/ Slope of -.41 = change in risk premium divided by change in bond rates.
Derived from data derived at lines 20, 21, and 22 above.
f/ Source: Table 9.

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forecast of
Baa average
7.68%

Chaparral City Water Company

Table 13

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historic Data

		Earned ROE		10-Year Treasury		Risk Premium
1	1985	14.40%	a/	10.62%	d/	3.78%
2	1986	13.28%	a/	7.67%	d/	5.61%
3	1987	14.58%	a/	8.39%	d/	6.19%
4	1988	12.42%	a/	8.85%	d/	3.57%
5	1989	10.39%	a/	8.49%	d/	1.90%
6	1990	11.07%	a/	8.55%	d/	2.52%
7	1991	12.82%	a/	7.86%	d/	4.96%
8	1992	11.80%	b/	7.01%	d/	4.79%
9	1993	11.90%	b/	5.87%	d/	6.03%
10	1994	10.76%	b/	7.09%	d/	3.67%
11	1995	11.30%	b/	6.57%	d/	4.73%
12	1996	12.21%	b/	6.44%	d/	5.77%
13	1997	11.93%	b/	6.35%	d/	5.58%
14	1998	11.34%	b/	5.26%	d/	6.08%
15	1999	11.02%	b/	5.65%	d/	5.37%
16	2000	9.91%	b/	6.03%	d/	3.88%
17	2001	10.25%	b/	5.02%	d/	5.23%
18	2002	10.58%	c/	4.61%	d/	5.97%
19	Average 1985-1992	12.60%		8.43%		4.17%
20	Average 1993-2002	11.12%		5.89%		5.23%
21	Difference	-1.48%		-2.54%		1.07%
22	Slope		0.58		-0.42	

Panel B: Solve for constant in formula (risk premium = constant - slope x 10 yr Treas rate):

constant	=	risk premium	+	slope-[e/]	x	10 Year Treasury rate
constant	=	5.23%	+	0.42-[e/]	x	5.89%
constant	=	7.70%				

Panel C: Solve for current risk premium and equity cost:

Risk Premium	=	constant	-	slope	x	10 yr Treasury rate		
Risk premium	=	7.70%	-	.42	x	5.55%-[f/]	=	5.4%

Estimated equity cost = bond rate + risk premium = 10.9%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: CPUC Staff Table 2-7, Application 02-11-044 (San Gabriel Valley Water).
d/ Annual average reported by the Federal Reserve.
e/ Slope of -.42 = change in risk premium divided by change in bond rates.
Derived from data derived at lines 20, 21, and 22 above.
f/ Source: Table 9.

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forecast of
10 Yr Treasry
5.55%

Chaparral City Water Company

Table 14

Returns on Equity for Larger Arizona Water
Sewer and Gas Utilities Prior to December 2001
and
Indicated Current Cost of Equity

Company	Decision Number	Decision Date	Authorized ROE	Average Annual 10-Year Treasury Rate
Citizens Utilities Company; Agua Fria Water Division; Sun City Water Company; Sun City Sewer Company and Sun City West Utilities Company	60172	May 7, 1997	10.50%	6.35%
Paradise Valley Water Company	60220	May 27, 1997	11.00%	6.35%
Far West Water Company	60437	Sept 29, 1997	11.50%	6.35%
Saddlebrooke Utility Company	61008	July 16, 1998	11.30%	5.26%
Paradise Valley Water Company	61831	July 20, 1999	11.00%	5.65%
Bermuda Water Company	61854	July 21, 1999	12.00%	5.65%
Pima Utility Company (Sewer)	62184	Jan 5, 2000	11.75%	6.03%
Far West Water & Sewer Co. (Water)	62649	June 13, 2000	11.50%	6.03%
Southwest Gas Corporation	64172	Oct. 30, 2001	11.00%	5.02%
Average			11.28%	5.85%
Equity cost indicated by forecasted 10-Year Treasury rate				5.55%

06/29/2004

Risk Premium
4.15%
4.65%
5.15%
6.04%
5.35%
6.35%
5.72%
5.47%
5.98%
5.43%
11.0%

Chaparral City Water Company

Table 15

Summary Table: Estimated Cost of Equity for Chaparral City
With Approval of Purchased Power and Purchased Water Adjusters

	Equity Cost Estimates For Sample Water Utilities			Equity Cost Estimates[a] With Added Risk of Arizona Restrictions and Water Supply		
<u>DCF Analyses Based on FERC Methods and data for Water Utilities:</u>						
One Step -- Table 4		10.2%			10.7%	
Two Step -- Table 8		10.4%			10.9%	
<u>Risk Premiums Estimates based on CPUC Staff Methods and Data:</u>						
Risk premium -- Table 10	10.6%	to	10.9%	11.1%	to	11.4%
Risk premium -- Table 11	11.0%	to	11.4%	11.5%	to	11.9%
Risk premium -- Table 12		10.9%			11.4%	
<u>Estimated Range and Average Equity Cost</u>						
Range	10.2%	to	11.4%	10.7%	to	11.9%
Average		10.8%			11.3%	
Requested ROE[a]					10.4%	

<u>Note:</u>
a/ Assumes proposed purchased water and purchased power adjusters are approved. Otherwise Chaparral City's cost of equity is 60 basis points higher and the requested ROE increases to 11.0%.

06/29/2004

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Attachment 648-E

Dr. Zepp's testimony and workpapers from California water utility rate case

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Thomas M. Zepp. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commissioner between 1976-1982. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in twenty-two states, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to incremental costs of energy and telecommunications services and have presented rate design testimony.

Q. WHAT COST OF CAPITAL STUDIES HAVE YOU PREPARED BEFORE?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in Alaska, Arizona, California, Hawaii, Idaho, Illinois, Kentucky, Montana, Nevada, New Mexico, Oregon, Tennessee, Utah, Washington and Wyoming.

My studies and testimony have included consideration of the financial health and fair rates of return for General Telephone of the Northwest, Illinois Bell Telephone, Nevada Bell Telephone, Pacific

Northwest Bell, U S WEST, Anchorage Municipal Light & Power, Commonwealth Edison, Idaho Power, Iowa-Illinois Gas and Electric, Pacific Power & Light, Portland General Electric, Puget Sound Power & Light, Cascade Natural Gas, Mountain Fuel Supply, Northern Illinois Gas, Northwest Natural Gas, Anchorage Water Utility, Anchorage Wastewater Utility, Arizona Water Company, Arizona-American Water Company, California-American Water Company, California Water Service, Dominguez Water Company, Hawaii-American Water Company, Kentucky-American Water Company, Mountain Water Company, New Mexico-American Water Company, Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, Southern California Water Company (now Golden State Water Company), Suburban Water System, Tennessee-American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. DO YOU HAVE OTHER PROFESSIONAL EXPERIENCE RELATED TO COST OF CAPITAL ISSUES?

A. Yes. My article, "Utility Stocks and the Size Effect - Revisited," was published in the *Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582. Also, I published an article "Water Utilities and Risk," *Water the Magazine of the National Association of Water Companies* Vol. 40, No. 1 Winter 1999 and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper "Application of the Capital Asset Pricing Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Conference and published an

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article "On the Use of the CAPM in Public Utility Rate Cases: Comment," *Financial Management* Autumn 1978, pp. 52-56. I have been a journal referee for the *International Review of Economics and Finance* and *Financial Management.* While on the staff of the Oregon PUC, I also established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was invited to Stanford University to discuss that research.

II. Purpose of Testimony, Principles, Summary and Conclusions

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS PROCEEDING?

A. San Jose Water Company ("San Jose", or "Company") has asked me to estimate its cost of equity and the fair rate of return on common equity. My study is based on data available to investors in early December 2005.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In this Section II, the concept of a fair rate of return and a summary of my analysis is presented.

In Section III, I compare the risks of the water utilities sample I rely upon to determine benchmark equity costs to the additional specific risks faced by San Jose. I explain why the Company's cost of equity exceeds the cost of equity of my water utilities sample by 40 basis points.

Section IV provides an overview and perspective on what one should expect the fair rate of return on common equity for San Jose to be in years 2007 to 2009 and develops my equity cost estimates for a benchmark sample of water utilities. My equity cost estimates are based on three risk premium ("RP") analyses, the traditional version of the capital asset pricing model ("CAPM") and the discounted cash flow ("DCF") model. My water utilities sample is the sample of six water utilities ORA relied upon to determine costs of equity in San Jose's last general rate case ("GRC") (A.03-05-035) and a number of recent cases. The risk premium analyses are (1) an update of the risk premium analysis ORA presented in California-American's Sacramento District general rate case ("GRC") in November 2004 (A.04-04-040), (2) a modified version of the ORA risk premium method based on data I believe provide equally useful proxies for the historic costs of equity for those sample companies and (3) a RP approach based on an analysis of realized returns on common equities ("ROEs") for sample water utilities that ORA has relied upon as measures of the cost of equity in prior GRCs. The traditional CAPM approach has been presented by California PUC Staff in the past. To these benchmark equity cost estimates, I add 40 basis points to recognize San Jose's higher risk.

Section V presents my estimates of effective costs for SJW's projected series H, I and J bond issues.

Section VI provides a summary of my analysis and my recommended return on common equity for San Jose.

Q. HAVE YOU PREPARED ANY TABLES AND ATTACHMENTS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared 17 tables and three attachments that support my testimony.

Q. PLEASE DISCUSS WHAT IS MEANT BY A FAIR RATE OF RETURN.

A. A fair rate of return is achieved when a utility is permitted to set charges for services at levels where the expected return provides common stock investors a reasonable opportunity to earn the cost of common equity. Since operating expenses and interest on debt take precedence over payments to common stock holders, it is the common equity shareholder of the company who bears the greatest risk of receiving expected returns. In 1923, the U.S. Supreme Court set forth the following standards in the Bluefield Waterworks decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. 262 U.S. 679, 692-93 (1923).

In the Hope Natural Gas Company decision, issued in 1944, the U. S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments 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. 320 U.S. 591, 603.

In 1989, in Duquesne Light Co. v Barasch the U. S. Supreme Court also recognized two important economic concepts: First, it found that regulatory commissions may need to adjust the risk premium element of the rate of return on equity to provide a fair return. It said:

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> [W]hether a particular rate is "unjust" or "unreasonable" will depend to some extent on what is a fair rate of return given the risks under a particular rate setting system . . . . 488 U.S. 299, 310.

Therefore, in determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities. Additional risk faced by San Jose should be recognized when setting the fair rate for return for the Company. Below, I explain unique additional risks of San Jose and why the Company is more risky than utilities not operating primarily in California. These added risks increase the equity return required by San Jose by at least 40 basis points above the ROE required by the benchmark sample.

Q. WHAT ARE THE IMPLICATIONS OF THESE PRINCIPLES IN THE DETERMINATION OF A FAIR RATE OF RETURN FOR SAN JOSE?

A. The principles are important to bondholders, customers and equity owners of San Jose. From the perspective of bondholders, authorized rates need to be sufficient to assure current and prospective bondholders that San Jose will have interest coverage comparable to other utilities having similar risk. Otherwise, the acceptance of San Jose's bonds will decline and bond costs will increase. Such increases in bond costs will require rate increases and disadvantage the Company's customers.

From the perspective of customers and equity owners, the principles require rates which provide a reasonable opportunity for San Jose to earn a return that is commensurate with returns on investments in other enterprises having corresponding risks, that are sufficient to attract capital on reasonable terms and that are high enough to assure confidence in the financial integrity of the firm. As I discuss further below, San Jose is more risky than the water utilities sample I rely upon to determine benchmark estimates of the cost of equity and thus its required common equity return is higher. From the perspective of customers, the cost of equity is another cost of service and thus the rates customers pay should provide a reasonable opportunity for San Jose to earn that fair rate of return. That fair rate of return on common equity is the cost of common equity.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. My findings and recommendations are the following:

1. The cost of common equity faced by San Jose is greater than the cost of common equity that faces the average utility in my water utilities sample:

   (a) Investor services have determined California utilities are more risky than utilities primarily operating in states other than California due to higher than average regulatory risks.

   (b) Changes in regulatory procedures reduce San Jose's opportunity to earn its authorized ROE and increase risk. D.03-06-072 has greatly limited the risk-reducing benefits of balancing accounts that the Commission made available prior to November 2001. New mandates to use uniform models to forecast future test year sales also increase risk. And, limitations placed on San Jose from the 3 year GRC cycle increase risk.

   (c) San Jose purchases a substantial portion of its water on a take-or-pay contract that is of benefit to ratepayers but increases its risk.

   (d) SJW Corporation is smaller than some of the water utilities in the benchmark sample and most other utilities. Its relatively small size increases its risk.

(e) Combined, these additional risks increase San Jose's cost of equity by no less than 40 basis points above the cost of equity for my benchmark water utilities sample.

2. The market cost of common equity faced by benchmark water utilities falls in a range of 10.4% to 11.4% at this time:

- DCF model estimates for the water utilities sample indicate the cost of equity falls in a range of 10.5% to 10.6%;

- Costs of equity derived from three risk premium analyses indicate the cost of equity for the water utilities sample falls in the range of 10.4% to 11.4%.

- A cost of equity derived with the traditional version of the capital asset pricing model indicate the cost of equity for the water utilities sample is 11.0%.

3. I conclude that San Jose's cost of equity falls in a range of 10.8% to 11.8% and recommend San Jose be authorized an ROE of 11.2%, an ROE slightly below the mid-point of my estimated cost of equity range. See Summary Table 17.

III. San Jose Risks Compared to Risks for the Water Utilities Sample

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR DISCUSSION OF RISK.

A. Investors can choose to invest in many different types of assets with varying degrees of risk. Those investments might be in real estate, or gold, or collections of fine art, or financial assets. The financial assets run the gamut from relatively low risk assets such as Treasury securities and somewhat higher risk investment grade corporate bonds to relatively high-risk shares of common stocks. As the level of risk increases, investors require higher expected returns. Common stocks of utilities are generally more risky and thus require higher returns than investment grade bonds, which are secured debt instruments with fixed repayment terms. Operating expenses, interest on debt and repayment of principal take precedence over payments to common stock owners, and thus it is the common equity shareholder of the utility who bears the greatest risk of receiving expected returns. Conceptually,

$$\text{Required return for common stock} = \text{Expected Return on a Baa bond} + \text{risk premium}$$

Baa bonds are investment grade bonds.

Regulators generally set rates to recover a utility's costs of service. One of those costs of service is the cost of common equity, the required return for the utility's common stock. Rates that give a utility a reasonable opportunity to earn the cost of equity are fair to customers of the utility. Such rates are also fair to owners of the utility because the cost of equity is equal to returns expected to be earned by companies of comparable risk, is high enough to attract capital, and allows the utility to maintain its financial integrity.

Q. AS A PRELIMINARY MATTER, PLEASE DISCUSS THE SAMPLE OF WATER UTILITIES YOU HAVE USED IN YOUR ANALYSES.

A. My sample of water utilities is composed of American States Water, Aqua America (formerly, Philadelphia Suburban), California Water Service Group, Connecticut Water Service, Middlesex Water, and SJW Corp. These water utilities are the water utilities ORA Staff relied upon to determine benchmark equity costs in San Jose's last GRC (A.03-05-o35) and numerous other

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GRCs for water utilities since 2003. In ORA's Cost of Capital Report dated November 28, 2005, Staff again relied on this sample to determine benchmark equity costs in the Suburban Water System GRC (A.05-08-034). Table 1 lists bond ratings, percentages of revenues from water operations, operating revenues, net plant and two *Value Line* measures of risk for utilities in the water utilities sample.

Q. DO YOU HAVE ANY GENERAL CONCERNS WITH THE DATA AVAILABLE TO MAKE DCF EQUITY COST ESTIMATES FOR WATER UTILITIES?

A. Yes. There are a number of concerns with relying on the data for water utilities to make DCF equity cost estimates.

The underlying basis for the constant growth DCF model requires that, in equilibrium, book values per share ("BV"), common stock prices ("P"), earnings per share ("EPS") and dividends per share ("DPS") grow at the same rate, but that has not been the case during the last ten years. While none of the variables grew at the same rate, the data in Table 2 show that stock prices, in particular, grew more rapidly than EPS, BV or DPS. One possible explanation for the more rapid growth in common stock prices is that investors expect higher growth of EPS and DPS in the future than in the past. If that is the case, historic growth rates for BV, DPS and EPS understate expected future growth and such past growth rates provide negatively biased indicators of growth rates expected by investors and required by the DCF model.

Alternatively, investors may have bid up stock prices in anticipation that some of the utilities in the water utilities sample are targets for favorable mergers or acquisitions. Table 3 shows premiums that investors in publicly traded water utilities received when the utilities were either acquired or merged with other firms. At the time mergers or acquisitions were completed, investors received premiums that ranged between 35% and 55% over market values prior to the announcement of the respective mergers and acquisitions. For a number of years, *Value Line* has pointed out that there are solid economic reasons to expect such acquisitions and mergers to continue. Those reasons include acquisitions help diversify larger companies with respect to weather and regulatory environments, economies of scale and other synergies can be achieved, and larger companies have lower costs of financing than smaller utilities which may have limited, if any, access to financial markets. (For example, *Value Line* Analyses of Water Utility Industries, in *Value Line investment Surveys* dated August 6, 1999 (page 1405), August 4, 2000 (page 1394) and January 28, 2005 (page 1420))

The data in Table 2 are consistent with either reason past growth in stock prices has exceeded growth in BV, EPS and DPS. But with either explanation, if the past data are used to determine estimates of future growth, there is a potential for negatively biased DCF estimates. This occurs because, with either explanation, stock prices have been bid up and dividend yields have been bid down (to reflect either expected higher future growth or favorable prices from mergers) but historic growth rates may not reflect the higher future growth in cash flows (from dividends and higher stock prices) expected by investors.

Q. COULD THE RELATIVELY RAPID INCREASE IN STOCK PRICES BE THE RESULT OF WATER UTILTIES BEING LESS RISKY TODAY THAN IN THE PAST?

A. No. Available market estimates of risk indicate water utilities are more risky—not less risky—than in the past. Beta is the measure of risk in the traditional capital asset pricing model. An average risk stock has a beta of 1.0 and lower risk companies have betas less than 1.0. Table 4 provides evidence on beta risk estimated by *Value Line* over the last ten years that indicates risk for water utilities has increased. *Value Line* estimates of betas are not available for all of the utilities in the water utilities sample for the entire ten year period. Data are, however, available for American States, Aqua America and California Water for at least some of the past years[1]. Based on these market measures of risk, the water utilities are more risky today than in the past. Average beta risk has increased from .58 in December 1997, to .60 in December 2001, to .73 in December 2004, to .77 in December 2005.

Investor services also conclude that risks of water utilities have increased. Moody's (see Attachment 1) notes risk has increased because of large capital spending requirements due to compliance with new water quality standards, the need to replace and improve infrastructure, new investments due to expanding customer bases and installation of security systems. Moody's also notes future business risks are expected to escalate and debt service protection may be threatened as the water utilities pursue strategies to grow earnings and expand service. It concludes a supportive regulatory environment and timely recovery of costs are critical factors to assure credit quality.

Q. DO YOU HAVE ANY OBSERVATIONS ABOUT DATA THAT MIGHT BE USED TO DETERMINE EQUITY COSTS WITH THE DCF MODEL?

A. Yes, I have two observations:

[1] *Value Line* estimates of betas for SJW Corp have increased from .50 at October 31, 2003 to .65 at December 2, 2005, a 30% increase in beta risk. I explain below that *Value Line* estimates of betas are expected to understate the true beta for SJW Corp and other relatively small companies.

First, in past cases ORA has determined growth rates for its DCF equity cost estimates as an average of past growth in DPS, EPS and past retained earnings as well as growth forecasted by investor analysts. If indeed investors believe future growth will be similar to growth in the past—as is implied by prior approaches taken by ORA—average growth in stock prices must also be considered. This is required because investors know that, in equilibrium, P, BV, DPS and EPS will all grow at the same rate and would take information about changes in stock prices into account when they priced utilities' stocks.

Second, available evidence indicates investors now expect more rapid growth in the future than in the past. Table 5 is a compilation of past growth rates reported by Staff of the CPUC in various GRCs during the period 1992-1998 and the period 2000-2005. In the earlier period, analysts expected approximately the same growth in the future as had occurred in the past. But in the more recent period, analysts expected and expect future growth rates to be higher than in the past. Table 5 provides evidence that investors now expect higher growth in the future than growth which occurred in the past.

Q. DO YOU HAVE ANY CONCERNS WITH INCLUDING CONNECTICUT WATER SERVICE IN DCF EQUITY COST ESTIMATES?

A. Yes. There are no widely-available forecasts of forward-looking growth for Connecticut Water Service and thus, if Connecticut Water Service is included in the DCF analysis, growth rates must somehow be determined by looking at evidence for other stocks or past growth in P, BV, EPS and DPS for Connecticut Water Service and making an assumption about how investors consider such past data to forecast growth for the future.

If estimates of future growth are based on past data for Connecticut Water Service but do not include past growth in stock prices—as has been the case with prior ORA Staff studies—the equity cost estimates produced will be implausible. In Section IV, I explain that the constant growth DCF model estimates the cost of equity with the following formula

$$\text{Equity cost} = D_0/P_0 \times (1 + g) + g$$

where D_0/P_0 is the current dividend yield and g is the expected future growth rate. Using historic growth rate data used by ORA in past cases, the equity cost estimate for Connecticut Water Service would fall in a range of 5.92% to 6.12%[2] when the expected cost of Baa bonds during 2007-2009 is 7.67%. (See Table 11) This result is not credible because it implies the implausible result that Connecticut Water Service has a cost of equity that is more than 150 basis points *below* the cost of investment grade bonds. To be conservative, however, I have included Connecticut Water Service in my DCF analysis.

Q. ARE SIMILAR PROBLEMS ENCOUNTERED IF CONNECTICUT WATER SERVICE IS INCLUDED IN THE SAMPLE OF WATER UTILTIES USED TO MAKE YOUR OTHER EQUITY COST ESTIMATES?

A. No. In the risk premium analyses and the CAPM analysis, the data problems with the application of the DCF model are not an issue

Q. PLEASE TURN TO YOUR COMPARISON OF SAN JOSE RISK TO RISK OF THE WATER UTILITIES SAMPLE. WHAT IS THE PRIMARY RISK FACED BY SAN JOSE WATER COMPANY AND OTHER WATER UTILITIES?

A. The primary risk is regulatory risk.

[2] The 5.92% is computed as 3.22% dividend yield (from my Table 6) times 1.0262 + 2.62% growth rate. The 2.62% growth rate is the average of DPS, EPS and BV growth reported in my Table 2. The 6.12% is computed as 3.41% dividend yield (from Table 6) times (1.0262) + 2.62% growth rate.

Q. DOES ORA STAFF AGREE THAT REGULATOY RISK IS THE PRIMARY RISK OF CONCERN?

A. Yes. In its last Cost of Capital Report for San Jose (A.03-05-035, dated November 2003, page 10) and the recent Cost of Capital report for Suburban Water System (A.05-08-034, dated November 28, 2005, page 3-1), ORA Staff states "Given the nature of the industry, the business risk of a regulated utility consists primarily of regulatory risk".

Q. HOW DOES THE REGULATORY RISK FACED BY SAN JOSE COMPARE TO THE REGULATORY RISKS OF THE WATER UTILITES SAMPLE?

A. It is higher. Three of the utilities in the water utilities sample do not primarily operate in California. Both *Value Line* and Regulatory Research Associates ("RRA") report the regulatory climate in California is more risky than average. RRA evaluates the regulatory climates in 49 states and places the regulatory environments in those states in one of six risk categories. In the past, when ORA was pressing for negative changes in policies and procedures that included the change in water utilities' balancing accounts discussed below, RRA placed California in the highest-risk category. By January 2005, RRA apparently concluded there would be more balanced regulatory approaches in California but still placed the regulatory environment in California in the second-to-the-highest risk category.

Value Line also ranks the regulatory climates for larger utilities. Ten years ago, it ranked California as having an above-average (lower risk) regulatory climate. Currently, *Value Line* has ranked the regulatory environment in California as below-average (higher risk). As recently as November 11, 2005, *Value Line* reiterated its view that the regulatory climate in California is more risky than average. In discussing consideration of upgrading the regulatory environment in California, it said, "Likewise, we want to see the outcome of some rate cases in California before we raise the climate to Average [Risk]". (Value Line Investment Survey, Ratings & Report, Issue 11, November 11, 2005, page 1996.)

Q. WHAT ARE SOME OF THE UNDERLYING REASONS THE REGULATORY ENVIRONMENT IN CALIFORNIA IS MORE RISKY?

A. There are at least four reasons:

One reason is the three year GRC cycle increases risk. It effectively precludes water utilities in California from filing for rate increases when they deem such filings are required. By contrast, water utilities primarily operating in other states do not have such restrictions. Also, the new rate case plan seriously restricts San Jose's ability to present the best available evidence on expenses and required investments it expects in the second and third years of the cycle. This limitation also increases risk. Additionally, the three-year rate case cycle may delay inclusion of required investments in rate base for up to three years. For example, additional investments to meet ever more stringent water quality requirements may be mandated during the three year cycle that were not anticipated, and thus not authorized, during the GRC. And, the three year rate case cycle also eliminates San Jose's ability to file for higher rates if bond costs or equity costs increase. The Commission does not authorize a higher ROE for San Jose to compensate for these above average risks of the three year rate case cycle.

Second, risk is higher in California and the opportunity to earn the cost of equity is reduced by new regulatory rules determined in CPUC Decision 03-06-072 that make recovery of water supply expenses (power costs, purchased water costs and pump taxes) contingent on earnings.

With the new rules, refunds of savings from lower than expected water supply expenses are always made but recovery of unexpected high water supply expenses are contingent upon the level of ROE that otherwise would be earned. This change of memorandum and balancing account rules creates a situation where unexpected savings are refunded but unexpected expenses are sometimes not allowed to be collected. Thus, the expected ROE will be lower than it would be if investors and ratepayers neither benefit nor are harmed by unexpected water supply expenses. This new rule treats the authorized ROE as a ceiling rather than a target ROE. It does not recognize that a utility should be expected to earn <u>more</u> than the authorized ROE just as often as it earns <u>less</u> than its authorized return if the rate-making systems give a water utility a fair chance to earn its authorized ROE. If, instead, the regulator treats the authorized ROE as a cap on the ROE during periods of higher than expected water supply expenses, the utility is not afforded a fair chance to earn its cost of equity, risk increases and the chance to earn the cost of equity is reduced. I prepared a simulation analyses for Golden State Water Company based on the new rules promulgated in D.03-06-072 and found the new rules reduce the expected future ROE by 25 basis points. I expect a similar impact on San Jose's expected future ROE. The Commission has not allowed a higher ROE to compensate for this above average risk.

Q. WHAT IS THE THIRD REASON?

A. Under the recently adopted GRC plan, water utilities must use a standard model to forecast future sales. If future earnings depend on sales, anything as important as estimated future test year sales volumes should be determined with the best available model, most appropriate inputs to that model and the best choice of time period to estimate the parameters of the model. Use of a standard model reduces a utility's flexibility to make the best available forecasts of future sales and will unavoidably reduce San Jose's ability to make its case to the Commission. Utilities still bear the burden of forecast risk but now have limited control over the model and inputs being used to make such forecasts. This increases risk and the Company's required ROE. The Commission has not authorized a higher ROE to compensate for this above average risk.

Q. WHAT IS THE FOURTH REASON?

A. In past cases, I presented testimony to the CPUC that demonstrated utilities facing the risk of tort cases related to water quality had higher costs of equity than those that did not face such risks. Even though San Jose is not currently involved in such litigation, court decisions have not eliminated the risk of such lawsuits in the future. The California Supreme Court said that plaintiffs could file claims against regulated water utilities if they could show the utilities did not comply with safe drinking water standards. As a result, the uncertainty of future litigation and risks of its potential costs continue. The California Commission has not increased San Jose's ROE for this additional risk.

Q. ARE THERE OTHER COMPANY-SPECIFIC RISKS THAT MAKE SAN JOSE MORE RISKY THAN THE SAMPLE WATER UTILITES?

A. Yes. SJW Corp (San Jose) is a relatively small company and thus is more risky than larger utilities. Aqua America and most gas and electric utilities are either Mid-Cap or Low-Cap companies while SJW Corp is a Micro-Cap company[3]. But even though SJW Corp is smaller than other utilities and other companies, it must compete in the capital market with the larger

[3] Ibbotson Associates define a Micro-Cap company as one with less than $505 million in market capitalization, a Low-Cap company as one with between $505 million and $1,608 million of market capitalization and a Mid-Cap company as one with $1,608 and $6,242 million in market capitalization. Ibbotson Associates, *2005 SBBI Yearbook Valuation Edition*, page 129. SJW Corp has a market capitalization that is smaller than $500 million and thus is a Micro-cap company.

players. Because it is smaller, it requires a higher ROE to attract capital on reasonable terms.

Academic studies have addressed the issue of company size and risk and have found that, in general, smaller firms are more risky. The seminal version of CAPM, developed in the mid-1960's, relied upon only beta as the measure of risk. Eugene Fama and Kenneth French ("The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, No. 3, Summer 2004 pp. 25-46) provide evidence that questions the usefulness of the simple CAPM and explain that other variables such as company size and various price ratios add to the explanation of stock returns. Fama and French explain that even after recognizing differences in beta risk, smaller companies generally are more risky than larger ones. Ibbotson Associates have also studied this issue and found that smaller firms require higher and higher returns as size becomes smaller and smaller. Ibbotson Associates, *2005 SBBI Yearbook Valuation Edition*, Chapter 7.

Studies for water utilities further support smaller utilities requiring higher ROEs. Staff of the CPUC made such a study for water utilities in 1991 based on estimated proxies for risk for 58 small water utilities and found that smaller water utilities (Class C and Class D) required equity returns higher than Class A water utilities, even though those small water utilities were financed with 100% common equity. (*Staff Report on Issues Related to Small Water Utilities*, June 10, 1991 and CPUC Decision 92-03-093). I also published an article, "Utility Stocks and the Size Effect - Revisited," *The Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582, which showed smaller Class A water utilities are more risky than larger utilities. All of this information shows there is no "bright line" that separates low risk water utilities from higher risk water utilities, but that risk and required ROEs increase as water utilities are smaller.

Q. SHOULD SAN JOSE'S ROE BE INCREASED TO COMPENSATE FOR IT BEING SMALL?

A. Yes. Analyses published in the prestigious *Journal of Finance* indicate companies the size of SJW Corp are riskier than is suggested by the traditional CAPM[4]. One reason is beta estimates for small, infrequently traded companies, are expected to be biased downward when short interval data—such as weekly data used by *Value Line*—are used to estimate betas[5]. The other reasons is that even after adopting statistical methods to mitigate such expected bias in beta estimates, a small firm effect remains[6]. The latter means that even after accounting for bias in beta risk estimates for small companies, those smaller companies still require higher returns than are indicated by the simple CAPM. Both reasons indicate the traditional CAPM estimate of the cost of equity I make below is conservative.

In Ibbotson Associates analyses, two different methods are used to mitigate the expected negative bias in beta estimates for small companies when short interval data are used to make those estimates. For example, based on the Ibbotson Associates analyses, a typical company in the ninth decile requires a risk premium in the range of 58 to 59 basis points higher than the risk premium required by companies in the Low-Cap category (Ibbotson Associates, Table 7-10 and Table 7-11). This evidence supports

[4] For example, Richard Roll "A Possible Explanation of the Small Firm Effect," *Journal of Finance*, Vol XXXVI, No. 4, (September 1981).

[5] For this reason, I expect the beta estimate for SJW Corp of .65 reported in Table 1 is biased downward.

[6] Marc Reinganum "A Direct Test of Roll's Conjecture on the Firm Size Effect," *Journal of Finance*, Vol. XXXVII, No. 1 (March 1982) found that even after accounting for the negative bias in beta estimates, part of the small firm effect remained.

SJW Corp receiving a higher ROE than is indicated by the simple version of the CAPM I present below. The Commission has not increased San Jose's ROE to reflect that San Jose is smaller than Aqua America and other large players with whom it must compete for capital.

Q. DOES SAN JOSE HAVE OTHER COMPANY-SPECIFIC RISKS?

A. Yes. San Jose purchases 40% to 45% of its water from the Santa Clara Valley Water District on a long-term take-or-pay contract. While the contract is of benefit to the Company's ratepayers, it poses a risk to San Jose because it is a fixed obligation. This risk also supports the need for an equity cost risk premium for San Jose.

Q. DO YOU HAVE ANY OTHER INFORMATION THAT SHOWS SAN JOSE IS AN ABOVE-AVERAGE RISK WATER UTILITY?

A. Yes. Because SJW Corp is small and has relatively few investors, it is not followed by investor analysts generally known to investors. Investor analysts do, however, follow American States and California Water Services, and many of the risks faced by those California water utilities are also risks faced by San Jose. A September 10, 2005 Standard & Poor's report for American States advises investors about a number of risks of California utilities. I have attached that report as Attachment 2. S&P states its target price for American States includes risks due to unexpectedly stringent regulations despite expectations for a more favorable regulatory environment in California, higher supply costs resulting from further additional contamination of groundwater supplies that requires American States to rely on more high-cost purchased water, potential severe droughts and volatile electric and natural gas prices. This report is widely available and thus SJW Corp investors would be aware of this discussion of risks.

I have also attached a Research Note from Janney Montgomery Scott (as Attachment 3) in which the firm comments on California Water Service's rate increase this year. This service notes California Water has risks due to weather, potential changes in regulatory environment, changes in environmental stands, ability to attain an adequate water supply, integration risk and concerns regarding changes in interest rates. These are risks also faced by San Jose. Janney states that it was disappointed in the settlement ROE of only 10.1% for Cal Water but says it realizes an improvement in the ROE will depend on the Commission perceptions of water utilities and an evolutionary process that will include changes in how Commission staff functions. SJW Corp investors would also have access to that publicly available report by Janney Montgomery Scott.

Q. WHAT IS YOUR RECOMMENDED RISK PREMIUM FOR SAN JOSE?

A. Taking into account San Jose's exposure to the various risks I discussed above, including the high risk regulatory environment in California, new rules for balancing and memorandum accounts related to recovery of water supply costs, San Jose's take-or-pay contract for water supplies, limitations on the models used to forecast test year sales, restrictions on being able to file rate cases, and its size compared to other utilities, I conclude San Jose Water requires an equity cost risk premium above the cost of equity estimates for water utilities sample of no less than 40 basis points at this time.

IV. Equity Cost Estimates

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR EQUITY COST ESTIMATES.

A. An ROE for San Jose that is fair to ratepayers, yet still provides a satisfactory return for investors, is San Jose's cost of equity. The cost of equity is fair for ratepayers because it is a cost of service. That return is also satisfactory for investors because it is commensurate with returns investors likely expect to earn on investments of comparable risk. To estimate that cost of equity, the analyst requires market data that reveal investors' required returns. Though there are limited market data for SJW Corp, the preferred approach (for statistical reasons) is to determine average equity costs for a sample of water utilities and then consider if San Jose is more or less risky than that sample. Data for the water utilities sample are for utilities that provide the same service and thus provide a useful starting point in the determination of San Jose's cost of equity.

In 2003, interest rates dropped to the lowest level that had occurred in close to forty years. From 1964 to 2002, annual average yields on 10-year Treasury securities, for example, ranged from 4.19% to 13.92%. And, for the ten-year period ending in 2002, the annual averages of 10-year Treasury rates ranged from 4.61% to 7.09%. In 2003, that annual average was only 4.01%. But interest rates and thus equity costs for San Jose are rising and expected to continue to rise. For 2004, the 10-year Treasury rate reported by the Federal Reserve was 4.27% and is currently approximately 4.5%. The Commission has relied upon forecasts of interest rates made by DRI to determine equity costs for future test years. The November 2005 DRI long term forecast indicates interest rates are expected to continue to increase and 10-year and 30-year Treasury securities will average 5.47% and 5.69%, respectively during 2007-2009. See Table 11.

Q. WHAT HAS HAPPENED TO EQUITY COST ESTIMATES MADE WITH THE FINANCIAL MODELS ORA STAFF TYPICALLY RELIES ON?

A. The indicated cost of equity has increased since November 2003 when ORA presented its cost of equity estimate in San Jose's last GRC (A.03-05-035, dated November 2003). In November 2003, ORA Staff determined a recommended ROE for its water utilities sample of 9.18%. ORA Staff's most recent Cost of Capital report for Suburban Water System (A.05-08-034, dated November 28, 2005) contains a recommended ROE that becomes 9.90% when the ORA RP equity cost estimate is restated with the DRI interest rate forecast for November 2005, an increase of 72 basis points. Of particular note is the 104 basis point increase in the ORA DCF equity cost estimate from 8.23% presented by ORA Staff in San Jose's last case to the ORA estimate of 9.27% in the Suburban case. While I do not agree with the methods ORA Staff typically uses to determine costs of equity for water utilities, the increases in those ORA equity cost estimates provide strong support for San Jose having a higher cost of equity today than it did when its authorized ROE was last determined.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this section of my testimony, I determine five benchmark equity cost estimates based on data for water utilities samples. Initially, I estimate the constant growth DCF model with data for the water utilities in Table 1. See Tables 6, 7, 8, 9 and 10. Next, I present two versions of the ORA risk premium method in Tables 12 and 13. Table 12 is an update of the analysis ORA presented in November 2004 in California-American's Sacramento GRC (A.04-04-040); Table 13 is based on the same method but adopts authorized ROEs instead of earned ROEs favored by ORA for such an analysis. I also present an alternative risk premium approach in Table 14 that combines risk premiums derived from 10-year Treasury rates and historical earned ROEs for water utilities over a longer period than the one presented in the first approach. This third analysis shows risk premiums tend to rise as interest rates decline. Finally, I present an equity cost estimate based on the traditional version of the CAPM in Table 16. I add 40 basis points to each of these equity cost estimates to account for San Jose's above-average risk.

Q. PLEASE EXPLAIN THE DCF METHOD OF ESTIMATING THE COST OF EQUITY.

A. The constant growth DCF model computes the cost of equity as the sum of an expected dividend yield ("D_1/P_0") and expected dividend growth ("g"). The expected dividend yield is computed as the ratio of next period's expected dividend ("D_1") divided by the current stock price ("P_0"). Generally, the constant growth model is computed with formula (1) or (2):

(1) Equity Cost $= D_0/P_0 \times (1 + g) + g$

(2) Equity Cost $= D_1/P_0 + g$

where D_0/P_0 is the current dividend yield and D_1/P_0 is found by increasing the current yield by the growth rate. The DCF model is derived from the valuation model shown in equation 3 below:

(3) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D_n/(1+k)^n$,

where k is the cost of equity; n is a very large number; P_0 is the current stock price if no premium is expected, $D_1, D_2, \ldots D_n$ are the cash flows expected to be received in periods 1, 2, . . . n, respectively. In the case of an expected acquisition or merger, P_0 increases because investors expect a premium price (be it cash or the value of securities offered in a merger) that would have a present value larger than the present value of the growth in dividends and earnings.

Q. DO YOU HAVE ANY SPECIAL CONCERNS WITH USING THE CONSTANT GROWTH DCF MODEL TO ESTIMATE EQUITY COSTS FOR WATER UTILITIES AT THIS TIME?

A. Yes. In discussing Tables 2 and 3 above, I explained my concern that dividend yields may be biased downward in anticipation of higher future growth in cash flows than are revealed in estimates of future growth. I have not, however, adjusted for such a possibility and thus my DCF equity cost estimates may understate the cost of equity.

Q. HOW DID YOU COMPUTE CURRENT DIVIDEND YIELDS?

A. My current dividend yield (D_o /P_o) estimates are the estimates reported by ORA in Table 2-2 of A.05-08-034, dated November 28, 2005. Given the short period between the time my testimony was written and the ORA study was filed, I chose to adopt the ORA Staff estimates in this case. I agree with ORA Staff that the time value of money should be taken into account when determining dividend yields. In past cases, I have reviewed the method ORA has used to adjust dividend yields for the time value of money and agree it provides estimates of dividend yields that are very close to the ones I compute with a method I prefer. I adopt the ORA estimates to reduce the number of issues in this case. Estimates of current dividend yields (i.e, in equation 1, D_0/P_0) are reported in Table 6.

Q. HOW DID YOU ESTIMATE GROWTH RATES?

A. The DCF model requires estimates of growth that investors expect in the future. To make my DCF estimates, I have used two different measures of future growth when these data are available. One measure is an average of forecasts of future sustainable growth derived from *Value Line* data. The other is an average of analysts' forecasts of future EPS growth.

Q. DO ANY FEDERAL AGENCIES RELY UPON THE MEASURES OF GROWTH YOU USE TO MAKE YOUR DCF EQUITY COST ESTIMATES?

A. Yes, the Federal Energy Regulatory Commission ("FERC") relies on both analysts' forecasts of growth and estimates of br + sv growth when it determines equity costs for electric utilities with the constant growth DCF model. See *Southern California Edison Company,* Opinion No. 445, Docket No. ER97-2355-000, et. al., 92 FERC ¶ 61,070 (July 26, 2000). More recent FERC decisions refer back to the *Southern California Edison* Decision. For example, see FERC findings in *Midwest independent Transmission System Operator*, 100 FERC ¶ 61,292 Docket No. ER02-485-000 (September 2002).

Q. DO YOU GIVE ANY WEIGHT TO ESTIMATES OF GROWTH BASED ON HISTORICAL DATA?

A. No. I give no weight to historical measures of growth if either analysts' forecasts of EPS growth are available or *Value Line* data are available to estimate future sustainable growth. Gordon, Gordon and Gould ("GG&G") found that a consensus of analysts' forecasts of EPS growth provided better forecasts of growth for the DCF model than did three measures of growth based on past recorded data. GG&G concluded it is logical for financial institutions and investment analysts to take such historical information into account -- and other more recent information -- when they determine their forecasts for the future. (David A. Gordon, Myron J. Gordon, and Lawrence I. Gould "Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management* (Spring 1989), pp. 50-55). To the extent that past, recorded results provide useful indications of future growth prospects, the forecasts would already incorporate the past and any further recognition of the past will "double-count" what has already occurred.

The study of CPUC Staff's prior cost of capital studies for water utilities that I provide in Table 5 provides additional support for relying on forward-looking estimates of growth whenever they are available. In the period 1992-1998, investors and analysts may well have expected future growth to be similar to growth that had occurred in the past, but Table 5 shows that is not the case during the 2000-2005 period when investors and analysts expect more rapid future growth.

Once investors make such growth estimates, they buy or sell shares of the utility's common stock until the expected return from the dividend yield plus the growth projections equal the investors' discount rate.

Q. WHAT DO YOU MEAN BY THE "INVESTORS' DISCOUNT RATE"?

A. The investors' discount rate for a particular stock is the discount rate for marginal[7] investors that will make the present value of all expected future cash distributions to those investors equal to the market price for a share of stock. That discount rate is also the cost of equity. It is the discount rate where the supply of shares of the stock equals the demand for shares of the stock.

Q. WHAT IS SUSTAINABLE GROWTH?

A. Sustainable growth is a useful indicator of DCF growth that can continue for a relatively long future period of time. Generally, it is derived by combining expected growth from future retained earnings and expected future growth from sales of common stock above book value.

[7] Marginal investors are those investors who last bought or sold shares of the stock. Other investors, not on the margin, may have higher discount rates (and thus do not buy the stock) or lower discount rates and thus retain their positions in the stock.

Q. HAS THIS MEASURE OF DCF GROWTH BEEN DISCUSSED IN FINANCE LITERATURE?

A. Yes, it has. Myron Gordon is sometimes called the father of the DCF model. In his 1974 book (M. J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, East Lansing, Michigan, 1974), Gordon explains that sustainable growth can be expected to come from internal and external sources: Internally from retained earnings (called "br" growth) and externally from sales of common stock when prices exceed book value (called "sv" growth) in the following formula:

$$g = br + sv,$$

where

g = sustainable growth,

b = the retention ratio[8],

r = the expected rate of return on common equity,

v = 1 - (book value/market value), and

s = the fraction of new common equity investors expect a water utility to raise from selling more common stock.

Gordon explains why sv growth can be expected when market prices exceed book value but why sv growth is not expected to come into play when market prices are below book values.

Q. HOW DO YOU ESTIMATE EXPECTED br GROWTH?

A. It is investors' expectations of what the retention ratio ("b") and the expected earned return on common equity ("r") will be in the <u>future</u> which determine this portion of expected sustainable growth. Multiplying b times r gives the estimate of future sustainable growth from retained earnings. Investors look for measures of future growth when pricing stocks. Where available, I have

[8] The retention ratio is computed as (1 - the ratio of dividends divided by earnings).

used *Value Line* projections of ROEs, dividends per share and earnings per share to make the forecasts of br growth. This information is probably the most widely available source of forecasted earnings and retention ratios available to investors and is adopted here for my analyses. There are data to make estimates of br growth for three of the water utilities. See Table 7.

Q. HAVE YOU ESTIMATED sv GROWTH FOR THE WATER UTILITIES SAMPLE?

A. Yes. My estimates of sv growth for the water utilities sample are presented in Table 8. Some of the utilities in the water utilities sample have sold stock at prices in excess of book value in recent years and have thus achieved sv growth. Knowledgeable investors would expect such sv growth in the future. Available *Value Line* forecasts indicate investors expect some of the sample water utilities to issue more shares of stock over time. Thus there will be a positive "s" term in sv growth. Also, the average current market-to-book ratio for the sample of water utility stocks is over 2.0. Unless stock prices drop to less than half of their current values, there will be a positive "v" for the foreseeable future.

Q. DID THE FERC SPECIFICALLY INCLUDE ESTIMATES OF sv GROWTH IN THE ESTIMATES OF SUSTAINABLE GROWTH IT ADOPTED IN THE CASES YOU REVIEWED?

A. Yes, it did. FERC stated:

> "g" is the sustainable growth rate of DPS . . . [where] 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 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. (*Southern California Edison* referring to note 37 to *Connecticut Light and Power Co.* 45 FERC P 61370 at page 62,161 n 13 (1988)).

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Q. DOES A MARKET-TO-BOOK RATIO IN EXCESS OF 1.0 IMPLY INVESTORS EXPECT WATER UTILITIES TO EARN MORE THAN THEIR COSTS OF EQUITY?

A. No. There are many reasons investors may bid up market prices for stocks above book values. One reason is investors may expect a city or some other public entity to condemn all or part of a water utility and the public entity will be required by the court to pay the utility the fair market value for it. Water utilities typically have assets that have a value based on reproduction cost new that is well in excess of book value. I have testified on the values of water utility properties and electric utility properties in various court cases in California, Utah and Oregon. Based on my experience, in situations where only a portion of the utility is being condemned, valuations based on both reproduction cost new less depreciation and the income approach indicate utility property has a value well in excess of book value. Investors would be aware that courts are expected to award potential condemnation values well in excess of book values even if the utility earns no more than its cost of equity.

Another reason is investors may anticipate a merger or acquisition that produces premium prices similar to those reported in Table 3, that have been well above book values. With such anticipated sale prices well above book values, a water utility would also be priced above book value even if the water utility made no more than its cost of equity. There are numerous other reasons I have heard in other proceedings.[9] It is reasonable to expect

[9] For example, an Oregon PUC Staff witness listed the following six reasons a market price could exceed book value even if the utility was expected to earn its authorized ROE. They are: (1) public utility commissions do not issue orders simultaneously in all jurisdictions, (2) not all of a company's earnings are regulated, (3) regulatory expenses, revenue and rate base adjustments may cause accounting returns to differ from those calculated on a rate case basis, (4) actual sales do not equal sales assumed in a rate case, (5) market expected ROEs change frequently while rate-case authorized ROEs do not, and (6) regulated subsidiaries constitute only a piece of a holding company pie. Testimony filed by John Thornton in Oregon docket UM 903, dated November 9, 1998.

a positive value for "v" even if water utilities are expected to earn no more than their costs of equity.

Q. IF YOU DID NOT INCLUDE AN ESTIMATE OF sv GROWTH IN YOUR ESTIMATES OF SUSTAINABLE GROWTH, WOULD YOU HAVE TO ADJUST YOUR EQUITY COST ESTIMATES?

A. Yes. If the utilities in the water utilities sample are expected to issue more shares of common stock in the future (i.e., "s" is expected to be positive), but sv growth is excluded by the analyst, the exclusion of sv growth implies a hypothetical market price equal to book value and thus a value for "v" of zero. But if such a hypothetical assumption is made for the utilities in the water utilities sample, for consistency, the hypothetical price should also be assumed to be equal to book value to compute dividend yields. In that case, the hypothetical price would be lower and the dividend yield would have to more than double. This increase in average dividend yield (by more than 300 basis points) would more than offset the elimination of sv growth. Therefore, if consistent assumptions are made and only br growth is recognized in the DCF analysis for water utilities, the implied average cost of equity increases.

Q. DO YOU ADVOCATE USING SUCH HYPOTHETICAL PRICES IN THE DCF ANALYSIS?

A. No. A market-based cost of equity estimate should recognize sv growth and real market prices. The evidence indicates that investors can realistically expect both v and s to be positive, and thus stock prices (and dividend yields) already reflect expected sv growth. If investors expect sv growth for the utilities in the water utilities sample and it is not recognized by the analyst, the analyst's estimate of the cost of equity will be biased downward.

Q. WHERE DO YOU REPORT YOUR ESTIMATE OF AVERAGE SUSTAINABLE GROWTH?

A. That value is developed in Table 7. There are no data to make estimates of forward-looking sustainable growth for Middlesex Water; thus, I have adopted an average of analysts' forecast of future growth for Middlesex Water reported in Table 9. There are no data to make forward-looking estimates of sustainable growth or any analysts' forecast of growth for Connecticut Water Service or SJW Corp. Thus for Connecticut Water Service and SJW, I have assumed investors would adopt an average of past growth rates for stock prices, EPS, DPS and BV reported in Table 2 to estimate the future. The average of these six estimates of future growth is 7.1%.

Q. TURN TO YOUR ESTIMATES OF FUTURE GROWTH THAT ARE BASED ON ANALYSTS' FORECASTS.

A. Certainly. Table 9 reports analysts' forecasts of EPS growth for the next five years reported by several financial institutions. The first two columns of Table 9 show available analysts' consensus forecasts of future EPS growth rates reported by *Zacks* and *Thomson First Call* on November 28, 2005 for the utilities in the water utilities sample. The third column shows available analysts' forecasts reported in the November 2005 S&P *Earnings Guide*. Column 4 shows forecasts of EPS growth reported by *Value Line* at October 28, 2005. The average of analysts' forecasts of growth is 7.3%.

Q. HOW DID YOU UTILIZE THIS INFORMATION ON DIVIDEND YIELDS AND ESTIMATED FUTURE GROWTH TO MAKE YOUR BENCHMARK DCF ESTIMATES?

A. I adopted an average of my estimate of sustainable growth and analysts' forecasts of growth to determine an overall average growth of 7.21%. I then used the constant growth DCF model specified in equation (1) to compute the DCF equity cost range for the water utilities sample. Table 10 shows the application of this specification of the DCF model to determine the estimated equity cost range of 10.5% to 10.6% for the water utilities sample. This range of equity costs for the water utilities sample does ***not***, however, account for the additional risk faced by San Jose. In Section III above, I explained why an additional equity return of no less than 40 basis points is required by San Jose at this time. Recognizing that risk premium, this benchmark DCF equity cost range indicates the cost of equity for San Jose falls in a range of 10.9% to 11.0%.

Q. ABOVE YOU STATED YOUR CONCERN WITH INCLUDING CONNECTICUT WATER SERVICE IN THE DCF ANALYSIS. WHAT IS THE INDICATED DCF EQUITY COST RANGE IF CONNECTICUT WATER SERVICE WERE NOT INCLUDED IN THE DCF SAMPLE?

A. That DCF equity cost range would be 10.6% to 10.9% and would indicate San Jose's cost of equity falls in a range of 11.0% to 11.3%.

Q. PLEASE TURN TO YOUR RISK PREMIUM EQUITY COST ESTIMATES. HOW MANY RISK PREMIUM ANALYSES HAVE YOU MADE?

A. I have made three risk premium analyses.

Q. EXPLAIN YOUR FIRST ANALYSIS?

A. My first analysis is presented in Table 12. It is an update of the risk premium analysis ORA presented in California-American Water Company's Sacramento GRC (A.04-04-040) in November 2004. In that case, ORA adopted annual averages of actual realized ROEs for the six water utilities in its sample as proxies for the costs of equity for the period 1994-2003, subtracted contemporaneous Treasury rates from those equity cost proxies to determine annual average risk premiums, then added the 5-year and the

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10-year averages of those risk premiums to forecasts of the respective Treasury rates to determine an equity cost range.

Q. WHAT HAVE YOU DONE TO UPDATE THAT ORA RISK PREMIUM ANALYSIS?

A. In my update, I have adopted the same method as ORA, but have updated the data with realized ROEs for the water utilities sample for 2004 and adopted currently available forecasts of Treasury rates for the period 2007-2009 made by DRI in November 2005. The forecasts of interest rates I rely upon are reported in Table 11. These are the only changes from the risk premium analysis ORA presented in Table 2-7 of its Cost of Capital Report for California-American in November 2004.

Q. WHAT IS THE RESULT OF THIS UPDATE?

A. This update indicates the cost of equity for the benchmark water utilities falls in a range of 10.4% to 10.8%, and the range of forecasted costs of equity for San Jose based on that benchmark range of equity costs is 10.8% to 11.2%. See Table 12.

Q. ARE THERE ANY POTENTIAL BIASES IN THE RISK PREMIUM ANALYSIS PRESENTED IN TABLE 12?

A. Yes. I explained above that D.03-06-072 (which changed balancing account rules) reduced the opportunity for California water utilities to earn their authorized ROEs. Also, in recent years, there have been delays in timely rate relief for California water utilities and poor weather that have further depressed realized ROEs. Thus, we have the ironic result that as equity costs have increased due to changes in CPUC policy and delayed rate increases, the RP method used by the ORA actually indicates equity costs have decreased. The method creates a circular result where lower realized ROEs support even lower future ROEs. As a general proposition, the ORA approach is one of several reasonable methods that can be applied to obtain risk premium equity cost estimates when there are no known biases in the data and the sample is large. Unfortunately that is not the case for the water utilities sample at this time. California water utilities are half of the utilities in the sample and they have been negatively affected by recent changes in CPUC policies, weather and delays in rate increases.

Q. TURN TO YOUR SECOND RISK PREMIUM ANALYSIS. HOW DOES IT DIFFER FROM THE FIRST ANALYSIS?

A. ORA chose to use earned ROEs instead of authorized ROEs as the proxies for the costs of equity in its analysis. If regulators attempt to authorize ROEs that are equal to the utilities' costs of equity, and adopt rates and rate adjustment mechanisms that give those utilities a reasonable opportunity to earn those authorized ROEs, earned as well as authorized ROEs might provide proxies for the costs of equity. The second risk premium analysis adopts authorized ROEs instead of earned ROEs as the proxies for the costs of equity in the risk premium analysis. This change is the only change from the first risk premium analysis.

Q. WHAT ARE THE RESULTS OF THE SECOND RISK PREMIUM ANALYSIS?

A. Table 13 presents the results of this second analysis. This analysis indicates the cost of equity for the water utilities sample falls in a range of 10.8% to 11.4% and the indicated cost of equity for San Jose is 11.2% to 11.8%. During the period of the study, on average, utilities in the water utilities sample earned less than their authorized ROEs, and thus this second risk premium analysis indicates a higher equity cost range than was found in the first risk premium analysis. Compare Tables 12 and 13.

Q. TURN TO YOUR THIRD RISK PREMIUM ANALYSIS. WHAT IS THE BASIS FOR THIS RISK PREMIUM ANALYSIS?

A. In 1997, the Commission found that costs of equity for energy utilities move in the same direction as interest rates but by less. The table below summarizes Table 3 of Decision 97-12-089, which established costs of capital for Pacific Gas and Electric Company ("PG&E").

Year	Forecasted Interest Rate	Change	Authorized ROE	Change
1991	9.76%		12.92%	
1992	9.10%	-66	12.65	-27
1993	8.32%	-78	11.85	-80
1994	6.76%	-156	10.92	-90
1995	8.37%	+161	12.05	+110
1996	7.29%	-108	11.60	-45
1997	7.92%	+63	11.60	0
1998	7.81%	-74	11.20	-40

The CPUC determined that "[t]he DCF, RPM and CAPM financial models are useful in establishing a range of required returns to consider in selecting the authorized return and in evaluating trends of investor expectations when consistent assumptions and data sets are used in the analysis" Decision 97-05-016, page 9 quoted from 33 CPUC2d 525, 5474 (1989). In all but one case, the CPUC found that the change in the cost of equity was less than the change in interest rates.

More recently, in D.02-11-027, an interim opinion on rates of return on equity for PG&E, Southern California Edison, Sierra Pacific Power Company, and San Diego Gas & Electric Company for the year 2003, the Commission confirmed that its practice is to adjust ROEs for energy utilities by one-half to two-thirds of the change in the benchmark interest rate. This Commission practice is generally consistent with the theoretical work of Gordon and Halpern ("Bond Share Yield Spreads Under Uncertain

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Inflation," *American Economic Review*, 66: 4 (September-1976) pp. 559-565) and empirical studies such as a 1989 study conducted by Staff at the Oregon Public Utility Commission. My third risk premium analysis found a similar relationship existed between earned ROEs for water utilities and interest rates.

Q. WHAT DATA DID YOU USE TO MAKE THIS THIRD RISK PREMIUM ESTIMATE?

A. I followed the three-step procedure in Table 14 to determine the current cost of equity for the benchmark utilities using data ORA adopted in past cases as proxies for the costs of equity to determine a current risk premium estimate of the cost of equity for the benchmark water utilities.

Q. WHAT IS SHOWN IN PANEL A OF TABLE 14?

A. Panel A of Table 14 shows average earned ROEs for samples of publicly-traded water utilities for the period 1985 to 2004. ORA adopted these ROEs as proxies for the costs of equity for water utilities in the 1995 San Gabriel Valley Water Company GRC (Table 3-4, A.95-09-010), and in two of California American Water Company's GRCs (Table 2-7, A.02-09-030 and Table 2-7, A.04-03-023). I have determined a comparable ROE value for 2004. Line 22 in Panel A of Table 14 shows the average of proxies for the cost of equity dropped by 165 basis points as the average 10-year Treasury rate dropped by 262 basis points. This result is consistent with the CPUC's prior findings in D.97-12-089 and D.02-11-027 for energy utilities and demonstrates that equity costs—in this instance, for water utilities -- move in the same direction as interest rates, but by less.

Q. DID YOU USE THE DATA IN PANEL A TO ESTIMATE THE COST OF EQUITY FOR SAN JOSE?

A. Yes. First, I recognized that the relationship between risk premiums and interest rates implies the following:

(4) Risk premium = constant - slope x 10-year Treasury rate

Then, I performed a statistical regression of risk premiums on 10-year Treasury bond rates that is reported in Panel B. The regression results indicate that the risk premium is expected to decrease by 40 basis points for every 100 basis point increase in the 10-year Treasury bond rate.

Q. DID YOU USE THAT RESULT TO ESTIMATE THE COST OF EQUITY?

A. Yes. I combined the regression results with the forecasted 10-year Treasury rate from Table 11 to estimate the expected cost of equity for the water utilities sample. Based on this analysis, the expected risk premium is 5.3%. Adding that risk premium to the forecasted 10-year Treasury rate of 5.47%, I found the expected cost of equity is 10.8% for the water utilities sample and the indicated cost of equity for San Jose of 11.2%. See Table 14, Panel C.

Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The CAPM is a model that was originally developed by William Sharpe and John Lintner in the mid-1960's, was tested with data for common stocks in the early 1970's and is now a common topic in college finance textbooks. The traditional version of CAPM says the cost of equity is explained by the following relationship:

(5) Equity cost = RF + β x MRP,

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where RF is a risk-free asset (usually taken to be no less than the expected return for a long-term Treasury security), the beta ("β") is the risk of the security at issue and the MRP ("market risk premium") is the additional return that is required by investors to hold an average risk asset instead of the long-term Treasury security.

Ibbotson Associates explain that the appropriate choice for RF is a return that is no less than the expected return for long-term Treasury securities.

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury security should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If the investor plans to hold a stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years. . . . Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite. Ibbotson Associates, *SBBI Valuation Edition, 2005 Yearbook*, page 57 and page 73.

For consistency, the MRP is also computed as the expected difference in returns for the market and the long-term Treasury security.

An average risk common stock has a beta of 1.0 and companies with below average risk have betas less than 1.0. Other versions of CAPM include not only beta risk but also parameters designed to reflect risks related to size of companies and other factors.

Q. HAVE YOU PREPARED AN EQUITY COST ESTIMATE WITH THE TRADITIONAL CAPM?

A. Yes, I have. It is provided in Table 15. The estimate is based on an RF of 5.69% from Table 11, an average beta of .74 from Table 1 and the long-term average market risk premium for the period 1926-2004 reported by Ibbotson Associates in Table 9-1 of the *2005 SBBI Yearbook* of 7.2%. These data indicated the average cost of equity for the water utilities sample is 11.0% and the required ROE for San Jose is 11.4% at this time.

Q. IS THERE EVIDENCE THAT THIS TRADITIONAL CAPM ESTIMATE PRODUCES CONSERVATIVE EQUITY COST ESTIMATES FOR WATER UTILITIES?

A. Yes. First, the traditional model does not included a factor to recognize that investors price stocks to recognize smaller companies are more risky than larger companies. SJW Corp is smaller than an average size company and thus a more complete model would indicate a higher cost of equity for SJW Corp.

Second, the betas used to compute the average beta of .74 for the water utilities sample are *Value Line* beta estimates reported in Table 1. I explained above that there is an expected downward bias in *Value Line* beta estimates for small, infrequently-traded, companies such as SJW Corp and most other water utilities. Given this expected bias, the correct average beta for the water utilities sample is probably closer to 1.0 than .74 and the cost of equity is higher.

Third, the estimate of the MRP appears to understate the market risk premium currently required by investors. Table 16 reports DCF estimates of equity costs and expected MRPs from forward-looking data *Value Line* presented in twenty-six different studies of its Industrial Composite for the period 1987 to 2005. The *Value Line* Industrial Composite is based on a wide cross-section of companies and thus is expected to reflect required returns for an average risk company. These data show that though the average MRP is somewhat sensitive to the time period examined, data for the most recent fifteen-year, ten-year and five-year periods indicate the current required MRP is in excess of 7.9%.

For all three reasons, the cost of equity estimate made with the traditional CAPM is conservative.

V. Projected SJW Corp Bond Costs

Q. HAVE YOU ESTIMATED THE COSTS FOR SJW'S PROJECTED BOND ISSUES?

A. Yes, I have. San Jose projects it will issue series H, I and J bonds in 2006, 2007 and 2008, respectively.

As shown in Table 1, Moody's and S&P have given ratings to utilities in the water utilities sample in the range of A to Aa (AA). SJW Corp is not rated by either S&P or Moody's, but I would expect it will be able to issue bonds at rates that fall in the range of rates that A-rated and AA-rated utilities would be able to achieve. Currently the spread between rates for A and Baa utility bonds is 41 basis points. I estimate the spread between A and AA bond rates during 2006-2008 will be 20 basis points.

Based on that information, I forecast SJW Corp will be able to issue its series H, I and J bonds somewhere between the rate that an A-rated utility and an AA-rated utility would be able to achieve, thus, SJW's expected bond costs are forecasted to be 51 basis points (41 basis points plus one-half of 20 basis points) less than the expected bond rates that DRI is forecasting for Baa utilities. I also expect that San Jose will have issuance expenses for its projected bond issues of 15 basis points and have determined effective costs for the Series H, I, and J bonds that include such issuance expenses. See Table 11.

VI. Summary and Conclusions

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The fair rate of return for San Jose should be determined by recognizing that San Jose faces a number of risks not faced by some of the water utilities in the sample used to determine benchmark equity costs. It operates in a regulatory environment that RRA and *Value Line* have advised investors has above-average risk and thus investors interested in SJW Corp common stock would demand higher returns to offset the higher risk. I explained that a number of factors have increased San Jose's regulatory risks. D.03-06-072, which required an earnings test before higher than expected water supply expenses could be recovered, limitations on models used to forecast test year sales and a limited ability to file new rate cases all help to explain why regulatory risk is higher in California. San Jose also has a long-term take-or-pay contract for water supply that benefits ratepayers but increases its risk. Additionally, the Company is more risky because it is smaller than Aqua America and most gas and electric utilities but must compete with the larger utilities and other larger companies for capital needed to comply with state and federal water quality requirements and to replace aging infrastructure. Based on my analyses, I recommend that the Commission add 40 basis points to the benchmark cost of equity estimates made for the water utilities sample to account for San Jose's additional risks.

The equity cost estimates are summarized in Table 17. I have made five equity cost estimates. The first is a DCF equity cost estimate made with the constant growth DCF model and data from my water utilities sample. Using that sample, the estimated benchmark equity cost falls in a range of 10.5% to 10.6% and San Jose's estimated equity cost falls in a range of 10.9% to 11.0%. Second, I updated the risk premium approach ORA presented in November 2004 with an average of realized ROEs for 2004 and November 2005 forecasts of interest rate data for 2007-2009. That update indicated an equity cost range of 10.4% to 10.8% for the water utilities sample and 10.8% to 11.2% for San Jose. I explained why recent changes in regulatory policies, delays in rate relief and poor weather in California may have biased downward the equity cost estimates made with that RP approach. Third, I modified the ORA risk premium approach using authorized ROEs for the six utilities in the water utilities sample as the proxies for equity costs instead of earned ROEs. With that modification and the same interest rate forecast, the indicated cost of equity range is 10.8% to 11.4% for the sample and 11.2% to 11.8% for San Jose. Fourth, I provided a risk premium analysis based on recorded ROEs for samples of water utilities ORA has relied upon as proxies for equity costs in past cases and 10-year Treasury rates to estimate equity costs for the benchmark water utilities sample of 10.8% and for San Jose of 11.2%. Finally, I presented a CAPM equity cost estimate determined with the traditional version of the model. With that approach, the indicated cost of equity for the water utilities sample is 11.0% and the indicated cost of equity for San Jose is 11.4%. I provided several reasons that CAPM estimate may be conservative. All of these estimates indicate the cost of equity for San Jose falls within a range of 10.8% to 11.8%. My recommended ROE of 11.2% is slightly below the mid-point of 11.3% for that equity cost range.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes.

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Table 1

Selected Characteristics of Water Utilities Sample

	Companies in Sample	Bond Ratings[a] S&P	Bond Ratings[a] Moody's	Percentage Revenue from Regulated Water Operations	Operating Revenues[a] ($ millions)	Net Plant[a] ($ millions)	Measures of Risk: Beta[c]	Measures of Risk: Safety Rank[c,d]
1	American States	A-	A2	87%	$233	$611	0.75	3
2	Aqua America	AA-	NR	81%	$473	$1,846	0.80	3
3	California Water	NR	A2	98%	$308	$724	0.75	2
4	Connecticut Water Service	AA+	NR	93%	$52	$194	0.75	3
5	Middlesex Water	A+	NR	86%	$73	$243	0.75	3
6	SJW Corporation	NR	NR	97%	$166	$292	0.65	2
	Average	--	--	90%	$218	$652	0.74	2.7

	price	shares
American States	$0.00	16.77
Aqua America	0	95.38
California Water	$0.00	18.37
Connecticut Water Service	$0.00	8.04
Middlesex Water	0	11.36
SJW Corporation	0	9.14

Notes and Sources:
a/ AUS Utility Reports, November 2005.
b/ Company 10-K's, Annual Reports to Stockholders or Value Line.
c/ As reported by *Value Line* December 2, 2005.
d/ An average risk stock has a safety rank of 3; therefore with an average safety rank of 2.7, the water utilities sample is 90% (2.7 divided by 3) as risky as the average stock.

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Table 2

Comparison of Past and Future Estimates of Growth for the Water Utilites Sample

		Average annual changes 1994 -2004					Forecasted Average EPS Growth-[c/]
		Price-[a/]	Book Value-[b/]	DPS-[b/]	EPS-[b/]	Average	
1	American States Water	8.8%	3.8%	1.1%	4.6%	4.6%	6.9%
2	Aqua America	23.8%	8.7%	5.8%	9.4%	11.9%	9.4%
3	California Water Service	10.4%	3.2%	1.3%	3.9%	4.7%	6.6%
4	Connecticut Water Service	11.5%	3.8%	1.4%	2.6%	4.9%	na
5	Middlesex Water	9.9%	3.2%	2.3%	2.5%	4.5%	6.0%
6	SJW Corporation	16.9%	6.7%	3.9%	10.8%	9.6%	na
	Sample Average	13.5%	4.9%	2.6%	5.6%	6.7%	7.3%

Notes and Sources:
a/ Average percentage changes in year-end market prices.
b/ Data from Annual Reports to Stockholders or Value Line.
c/ Source is Table 9.

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Table 3

Premiums Received by Investors from Recent Mergers and Acquistions of Water Utilities

Company	Approximate Date of Aquisition or Merger	Price Prior to Announcement	Value at Time of Merger or Acquistion	Basis	Premium	Announcement data
United Water Resources	July 2000	$23.13	$35.30	cash	53%	Month ending July 1999. Price jump to 33 5/
E-Town	Year-end 2000	$50.38	$68.00	cash	35%	Month-end for Aug-99
Dominguez	May 2000	$22.75	$33.75	stock	48%	Month-end October 98, announced Nov 199
Consumers Water	March 1999	$21.38	$33.10	stock	55%	Month-end May 98 --announced June 29, 19
American Water Works	January 2003	$34.00	$46.00	cash	35%	Specificed a 35% markup at time of announ
Average Premium					45%	

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Table 4

Value Line Beta Estimates for 3 Largest Water Utilites (1996 to 2005)

		December 1996	December 2001	December 2004	December 2005
1	American States		0.60	0.70	0.75
2	Aqua America	0.65	0.60	0.75	0.80
3	California Water	0.50	0.60	0.75	0.75
	Average	0.58	0.60	0.73	0.77

Notes and Sources:
a/ Various December issues of *Value Line Summary & Index.*

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Table 5

Comparison of Analysts' Forecasts of Future Growth
With Estimates of Growth Based on Past Growth in
DPS, EPS and Retained Earnings Made by CPUC Staff[a/]

		Application Number	Date	CPUC Staff Estimates of Growth Based on Past Data: Retained Earnings	CPUC Staff Estimates of Growth Based on Past Data: DPS and EPS Growth	Average of Analysts' Forecasts of Growth	Are Forecasts Comparable to Past Growth?
	Period: 1992 to 1998						
1	Valencia Water Company	A.92-01-022	June 1992	3.6%	5.9%	3.9%	yes
2	Dominguez Water Corp	A.92-03-040	June 1992	3.6%	5.9%	4.1%	yes
3	California-American Water	A.92-03-030	July 1992	3.6%	5.9%	4.1%	yes
4	San Gabriel Valley Water	A.92-09-032	April 1993	3.5%	6.0%	4.5%	yes
5	Park Water Company	A.94-03-038	June 1994	2.7%	4.5%	4.2%	yes
6	Valencia Water Company	A.94-04-033	Aug 1994	3.3%	4.5%	4.2%	yes
7	Southern Calif Water	A.95-03-013	July 1995	2.7%	4.6%	3.3%	yes
8	San Gabriel Valley Water	A.95-09-010	Dec 1995	3.6%	4.6%	4.0%	yes
9	California -American Water	A.95-02-016	May 1995	3.0%	4.6%	3.8%	yes
10	California -American Water	A.96-03-008	June 1996	2.8%	3.8%	3.6%	yes
11	Park Water Company	A.97-03-032	August 1997	2.9%	4.5%	3.4%	yes
12	Southern Calif Water	A.98-03-029	July 1998	2.7%	4.6%	3.6%	yes
	Period: 2000 to 2005						
1	California -American Water	A.00-04-023	Sept 2000	2.5%	4.8%	5.2%	no
2	California Water Service	A.01-09-062	March 2002	3.1%	4.2%	6.3%	no
3	Park Water	A.02-03-046	July 2002	3.3%	2.9%	5.4%	no
4	Valencia Water Company	A.02-05-013	Sept 2002	3.4%	2.9%	6.5%	no
5	California-American Water	A.02-09-030	March 2003	3.1%	2.4%	6.2%	no
6	Southern Calif Water	A.02-11-007	April 2003	3.1%	2.4%	5.6%	no
7	San Gabriel Valley Water	A.02-11-044	July 2003	3.0%	3.3%	6.2%	no
8	San Jose Water	A-03-05-035	November 2003	3.0%	3.3%	6.1%	no
9	California -American Water	A.03-07-036	January 2004	2.9%	3.4%	6.3%	no
10	California -American Water	A.04-03-023	July 2004	2.9%	2.8%	6.7%	no
11	California-American Water	A.04-04-040	November 2004	2.8%	2.9%	7.0%	no
12	Suburban Water System	A.05-08-034	November 2005	2.8%	4.2%	8.3%	no

Notes and Sources:
a/ All growth rates are growth rates based on data reported in CPUC Staff Cost of Capital Reports.

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Table 6

Current Annualized Average Dividend Yields
for Water Utilities Sample

		3-Month Average D_0/P_0	6-Month Average D_0/P_0	12-Month Average D_0/P_0
1	American States	2.96%	3.19%	3.39%
2	Aqua America	2.25%	2.36%	1.97%
3	California Water	3.32%	3.63%	3.32%
4	Connecticut Water Service	3.22%	3.30%	3.41%
5	Middlesex Water	3.50%	3.66%	3.59%
6	SJW Corporation	2.95%	3.07%	2.71%
	Average	3.03%	3.20%	3.06%

Notes and Sources:
a/ Reported by ORA Staff in Table 2-2, ORA Report on the Cost of Capital of Suburban Water System, A.05-08-034, November 28, 2005.

12/14/05

San Jose Water Company

Table 7

Estimates of Sustainable Growth for the Water Utilities Sample

		Retention Ratios	Future ROE	Forecast of br-[a, b] Growth	sv Growth-[c]	Average Sustainable Growth
1	American States	0.54	12.0%	6.7%	1.7%	8.5%
2	Aqua America	0.49	12.5%	6.3%	0.4%	6.7%
3	California Water	0.42	11.0%	4.8%	2.5%	7.3%
4	Connecticut Water Service-[d]	--	--	--	--	4.9%
5	Middlesex Water-[e]	--	--	--	--	6.0%
6	SJW Corporation-[d]	--	--	--	--	9.6%
	Average					7.1%

Notes and Sources:

a/ BR growth based on *Value Line* forecasts of DPS, EPS and ROE for the period 2008-2010 published October 28, 2005 if available.
b/ BR growth adjusted for year-end ROE forecast by Value Line with FERC method.
c/ Estimated sv growth derived in Table 8.
d/ Average of past measures of growth during last ten years from Table 2.
e/ Based on average of analysts' forecasts from Table 9.

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San Jose Water Company

Table 8

Estimates of sv Growth for the Water Utilities Sample

		Stock Financing Rate (s) [a] (a)	Market to Book Ratio [b] (b)	v (c)	sv growth (d)
1	American States	3.59%	1.94	0.48	1.74%
2	Aqua America	0.54%	3.88	0.74	0.40%
3	California Water	4.60%	2.19	0.54	2.50%
4	Connecticut Water Service	--	--	--	na
5	Middlesex Water	--	--	--	na
6	SJW Corporation	--	--	--	na
	Column Average	2.91%	2.67	0.59	0.77%

Notes and Sources:
_a/ From Value Line data reported October 25, 2005.
_b/ From AUS Utility Reports, November 2005.

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San Jose Water Company

Table 9

Analysts' Forecasts of Future Earnings Growth for the Water Utilities Sample

		Zack's[a]	Thomson First Call[a]	S&P[b]	Value Line[c]	Average
1	American States	6.0%	4.5%	5.0%	12.0%	6.9%
2	Aqua America	8.9%	9.5%	9.0%	10.0%	9.4%
3	California Water	7.7%	5.0%	5.0%	8.5%	6.6%
4	Connecticut Water Service	na	na	na	na	na
5	Middlesex Water	6.0%	6.0%	6.0%	na	6.0%
6	SJW Corporation	na	na	na	na	na
	Average of Estimates					7.3%

Notes and Sources:
a/ Reported on the Internet, November 28, 2005.
b/ S&P Earnings Guide, November 2005.
c/ Value Line October 28, 2005.

12/14/05

San Jose Water Company

Table 10

DCF Estimates Based on the Water Utilities Sample

3-month Current Yield	3.03%	a/
Growth Rate	7.21%	b/
Expected Yield	3.25%	c/
ROE	10.5%	d/
6-month Current Yield	3.20%	a/
Growth Rate	7.21%	b/
Expected Yield	3.43%	c/
ROE	10.6%	d/
12-month Current Yield	3.06%	a/
Growth Rate	7.21%	b/
Expected Yield	3.28%	c/
ROE	10.5%	d/

Range of ROE Estimates for Water Utilities Sample	10.5%	to	10.6%
Adjust for San Jose's Additional Risks	10.9%	to	11.0%

Notes and Sources:

a/ From Table 6.
b/ Average of estimated growth from Tables 7 and 9.
c/ Expected yield = $D_1/P_0 = D_0/P_0 * (1 + g)$
d/ ROE = $D_1/P_0 + g$

12/14/05

San Jose Water Company

Table 10a

DCF Estimates Based on the Water Utilities Sample without Connecticut Water Service in Sample

3-month Current Yield	3.00%	a/
Growth Rate	7.44%	b/
Expected Yield	3.22%	c/
ROE	10.7%	d/
6-month Current Yield	3.18%	a/
Growth Rate	7.44%	b/
Expected Yield	3.42%	c/
ROE	10.9%	d/
12-month Current Yield	2.99%	a/
Growth Rate	7.44%	b/
Expected Yield	3.21%	c/
ROE	10.6%	d/

Range of ROE Estimates for Benchmark Water Utilities	10.6%	to	10.9%
Adjust for GSWC's Added Risks	11.0%	to	11.3%

Notes and Sources:

a/ From Table 6.
b/ Average of estimated growth from Tables 7 and 9.
c/ Expected yield = $D_1/P_0 = D_0/P_0 * (1 + g)$
d/ ROE = $D_1/P_0 + g$

12/14/05

0.004

San Jose Water Company

Table 11

Forecasts SJW Debt Costs, Treasury Securities Rates and
Baa Corporate Bond Rates for 2006-2009[a/]

Description	2006	2007	2008	2009
10-Year Treasury Securites		5.32%	5.43%	5.67%
Long-term Treasury Bonds		5.51%	5.66%	5.90%
Seasoned Baa Corporate Bonds	7.24%	7.42%	7.61%	7.98%

Estimate of Effective Costs of SJW Bonds[c/]

	Year	Cost[b/]
Series H	2006	6.88%
Series I	2007	7.06%
Series J	2008	7.25%

Notes and Sources:
a/ November 2005 DRI forecasts of interest rateds.
b/ DRI forecast of Baa Corporate Bond rates less 51 basis points.
c/ Includes 15 basis points for issuance costs.

12/14/05

Average for 2007 to 2009
5.47%
5.69%
7.67%

San Jose Water Company

Table 12

Update of ORA Staff Risk Premium Analysis

	Return on Equity[a]	Annual Averages		Risk Premiums	
		Long-term Treasury[b]	10-Year Treasury[b]	Long-term Treasury	10-Year Treasury
1995	11.20%	6.88%	6.57%	4.32%	4.63%
1996	12.02%	6.71%	6.44%	5.31%	5.58%
1997	11.82%	6.61%	6.35%	5.21%	5.47%
1998	10.90%	5.58%	5.26%	5.32%	5.64%
1999	10.59%	5.87%	5.65%	4.72%	4.94%
2000	9.88%	5.94%	6.03%	3.94%	3.85%
2001	10.37%	5.49%	5.02%	4.88%	5.35%
2002	10.63%	5.43%	4.61%	5.20%	6.02%
2003	9.53%	5.02%	4.01%	4.51%	5.52%
2004	9.98%	5.12%	4.27%	4.86%	5.71%
	10-Year Average Premium			4.83%	5.27%
	5-year Average Premium			4.68%	5.29%
	Forecasted Interest Rates for 2007-2009[c]			5.69%	5.47%
	Projected Returns on Equity				
	10-Year Average			10.52%	10.74%
	5-Year Average			10.37%	10.77%
	Estimated Cost of Equity for San Jose			10.8%	11.2%

Notes and Sources:

_a/ California PUC ORA Cost of Capital Report, Table 2-7, A.04-04-040, dated November 2004 November 2004 for 1995-2003. Data for 2004 from Utilities' Annual Reports to Stockholders and 10-K Reports.

_b/ Source: Federal Reserve and DRI .

_c/ See Table 11.

12/14/05

0.004

Exhibit 1917
Page 258 of 268

Earned Return on Common Equity (%)--from CPUC ORA work papers

	AWR	WTR	CWT	CTWS	MSEX	SJW	Average
1995	10.00	11.70	10.60	12.30	12.00	10.60	11.20
1996	9.20	11.80	12.80	12.20	10.60	15.50	12.02
1997	9.30	12.10	14.50	12.10	11.50	11.40	11.82
1998	9.50	12.40	10.80	11.80	9.70	11.20	10.90
1999	7.95	9.90	11.50	12.00	11.20	11.00	10.59
2000	9.40	13.20	10.10	11.70	7.50	7.40	9.88
2001	10.20	13.30	7.60	11.90	9.70	9.50	10.37
2002	9.70	13.90	9.70	10.90	10.20	9.40	10.63
2003	5.60	12.30	9.10	11.00	8.01	11.20	9.53
2004	8.14	11.40	9.80	10.70	9.14	10.71	9.98
	StkRpt	10-k	10-k	StkRpt	Stkrpt	reported	

San Jose Water Company

Table 13

Risk Premium Analysis Using Authorized Returns on Equity
As the Proxies for the Costs of Equity for the Water Utilties Sample

	Authorized Returns on Equity[a/]	Annual Averages 30-Year Treasury[b/]	Annual Averages 10-Year Treasury[b/]	Risk Premiums 30-Year Treasury	Risk Premiums 10-Year Treasury
1995	11.51%	6.88%	6.57%	4.63%	4.94%
1996	11.58%	6.71%	6.44%	4.87%	5.14%
1997	11.18%	6.61%	6.35%	4.57%	4.83%
1998	11.06%	5.58%	5.26%	5.48%	5.80%
1999	11.12%	5.87%	5.65%	5.25%	5.47%
2000	11.12%	5.94%	6.03%	5.18%	5.09%
2001	10.86%	5.49%	5.02%	5.37%	5.84%
2002	10.62%	5.43%	4.61%	5.19%	6.01%
2003	10.62%	5.02%	4.01%	5.60%	6.61%
2004	10.48%	5.12%	4.27%	5.36%	6.21%
	10-Year Average Premium			5.15%	5.59%
	5-year Average Premium			5.34%	5.95%
	Forecasted Interest Rates for 2007-2009[c/]			5.69%	5.47%
	Projected Returns on Equity				
	10-Year Average			10.84%	11.07%
	5-Year Average			11.03%	11.42%
	Estimated equity costs for San Jose			11.2%	11.8%

Notes and Sources:

a/ Sources are Year-end AUS (formerly CA Turner) *Utility Reports* for various years for the water utilties sample.

b/ Sources of data are DRI and the Federal Reserve.

c/ See Table 11.

12/14/05

0.40%

Year	AWR	CWT	CTWS	MSEX	PSC	SJW
1995	10.10	11.00	12.70	11.50	12.00	11.75
1996	10.50	11.00	12.70	11.50	12.00	11.75
1997	10.40	10.30	12.70	11.50	12.00	10.20
1998	10.40	10.30	12.70	11.50	11.25	10.20
1999	10.40	10.30	12.70	12.05	11.05	10.20
2000	10.40	10.30	12.70	12.05	11.05	10.20
2001	10.00	10.48	12.70	11.15	10.65	10.20
2002	10.00	10.48	12.70	10.25	10.32	9.95
2003	10.00	10.48	12.70	10.25	10.32	9.95
2004	10.00	9.70	12.70	10.38	10.15	9.95

Average
11.51
11.58
11.18
11.06
11.12
11.12
10.86
10.62
10.62
10.48

San Jose Water Company

Table 14

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historical Data	Earned ROE	10-Year Treasury	Risk Premium
1 1985	14.40% a/	10.62% d/	3.78%
2 1986	13.28% a/	7.67% d/	5.61%
3 1987	14.58% a/	8.39% d/	6.19%
4 1988	12.42% a/	8.85% d/	3.57%
5 1989	10.39% a/	8.49% d/	1.90%
6 1990	11.07% a/	8.55% d/	2.52%
7 1991	12.82% a/	7.86% d/	4.96%
8 1992	11.80% b/	7.01% d/	4.79%
9 1993	11.90% b/	5.87% d/	6.03%
10 1994	10.76% b/	7.09% d/	3.67%
11 1995	11.20% c/	6.57% d/	4.63%
12 1996	12.02% c/	6.44% d/	5.58%
13 1997	11.82% c/	6.35% d/	5.47%
14 1998	10.90% c/	5.26% d/	5.64%
15 1999	10.59% c/	5.65% d/	4.94%
16 2000	9.88% c/	6.03% d/	3.85%
17 2001	10.37% c/	5.02% d/	5.35%
18 2002	10.63% c/	4.61% d/	6.02%
19 2003	9.53% c/	4.01% d/	5.52%
20 2004	9.98% c/	4.27% d/	5.71%
20 Average 1985-1994	12.34%	8.04%	4.30%
21 Average 1995-2004	10.69%	5.42%	5.27%
22 Difference	-1.65%	-2.62%	0.97%

Data from Quattro analysis:

Regression Output:

Constant		0.07505756
Std Err of Y Est		0.010037
R Squared		0.33844171
No. of Observations		20
Degrees of Freedom		18
X Coefficient(s)	-0.4039902	
Std Err of Coef.	0.13313	
	-3.03455	

Panel B: Determine How Risk premium varies with changes in interest rates
Using a Statistical Regression

Risk premium =	constant	- slope	x	10 Year Treasury rate
Risk premium =	0.0751	-0.40	x	10 Year Treasury rate
t-statistic for slope e/		-3.03		
R squared =	33.8%			

Panel C: Solve for current risk premium and equity cost:

Risk Premium = constant - slope x 10 yr Treasury rate

Risk premium = 7.51% - .40 x 5.47% f/ = 5.3%

Estimated cost of equity for water utilites sample = 10.8%

Estimated equity cost for San Jose Water $\boxed{11.2\%}$

forecast of 10 Yr Treasry 5.47%

0.40%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: Table 12.
d/ Annual average reported by the Federal Reserve.
e/ Slope significantly less than zero at 1% level.
f/ Source: Table 11.

12/14/05

San Jose Water Company

Table 15

Estimate of the Cost of Equity for Benchmark Water Utilites
Based on the Traditional Capital Asset Pricing Model

Cost of Equity = RF + Beta x MRP

	CAPM Estimate
Risk Free Rate[a/]	5.69%
Beta[b/]	0.74
Market Risk Premium[c/]	7.2%
Cost of Equity for Benchmark Water Utilities =	11.0%
Cost of Equity Estimate for San Jose =	11.4%

Notes and Sources:

a/ Source of average risk-free rate is Table 11.

b/ Source is Table 1.

c/ Source of market risk premium is the average long-horizon market risk premium reported by Ibbotson Associates in Table 9-1, SBBI, 2005 Yearbook.

12/14/05

0.40%

San Jose Water Company

Table 16

Analysis of Equity Costs and Risk Premiums Based on DCF Analyses
for the Value Line Industrial Composite: 1987 to 2005

	Study Date	Dividend Yield	Expected Growth	DCF Equity Cost	Long-term Treasury Lag 1 Mnth	Risk Premium	Line BR (Published)	to FERC br
1	2/87	3.00%	9.39%	12.39%	7.39%	5.00%	9.00%	9.39%
2	2/88	3.10%	9.93%	13.03%	8.83%	4.20%	9.50%	9.93%
3	7/88	3.50%	7.77%	11.27%	9.00%	2.27%	7.50%	7.77%
4	2/89	3.50%	7.77%	11.27%	8.93%	2.34%	7.50%	7.77%
5	2/90	3.20%	7.77%	10.97%	8.26%	2.71%	7.50%	7.77%
6	1/91	3.70%	9.93%	13.63%	8.24%	5.39%	9.50%	9.93%
7	2/92	2.80%	9.39%	12.19%	7.58%	4.61%	9.00%	9.39%
8	2/93	2.90%	8.31%	11.21%	7.34%	3.87%	8.00%	8.31%
9	2/94	3.00%	8.31%	11.31%	6.39%	4.92%	8.00%	8.31%
10	2/95	2.70%	9.93%	12.63%	7.97%	4.66%	9.50%	9.93%
11	3/96	2.70%	10.48%	13.18%	6.03%	7.15%	10.00%	10.48%
12	2/97	2.40%	12.13%	14.53%	6.91%	7.62%	11.50%	12.13%
13	1/98	1.50%	14.92%	16.42%	6.07%	10.35%	14.00%	14.92%
14	1/99	1.30%	16.05%	17.35%	5.36%	11.99%	15.00%	16.05%
15	2/00	0.80%	16.05%	16.85%	6.86%	9.99%	15.00%	16.05%
16	7/00	1.00%	14.92%	15.92%	6.28%	9.64%	14.00%	14.92%
17	2/01	1.20%	13.79%	14.99%	5.65%	9.34%	13.00%	13.79%
18	7/01	1.20%	12.13%	13.33%	5.82%	7.51%	11.50%	12.13%
19	1/02	1.20%	12.13%	13.33%	5.76%	7.57%	11.50%	12.13%
20	8/02	1.60%	12.68%	14.28%	5.51%	8.77%	12.00%	12.68%
21	1/03	1.60%	12.13%	13.73%	5.01%	8.72%	11.50%	12.13%
22	7/03	1.50%	11.57%	13.07%	4.34%	8.73%	11.00%	11.57%
23	3/04	1.60%	12.13%	13.73%	4.94%	8.79%	11.50%	12.13%
24	10/04	1.80%	11.57%	13.37%	4.89%	8.48%	11.00%	11.57%
25	4/05	1.90%	11.57%	13.47%	4.89%	8.58%	11.00%	11.57%
26	11/05	2.10%	12.68%	14.78%	4.74%	10.04%	12.00%	12.68%

Averages for:

All years (1987-2005)	7.0%
Last 15 years (1991-2005)	7.9%
Last 10 years (1996-2005)	9.0%
Last 5 years (2001-2005)	8.7%

Notes and Sources:
a/ Data obtained from *Value Line's* studies of the Industrial Composite.

12/14/05

San Jose Water Company 0.40%

Table 17

Summary Table: Estimated Cost of Equity for San Jose Water Company

	Estimated Equity Costs for Benchmark Utilities			Minimum Estimated Equity Costs for San Jose		
DCF analysis -- Table 10	10.5%	to	10.6%	10.9%	to	11.0%
Risk premium -- Table 12	10.4%	to	10.8%	10.8%	to	11.2%
Risk premium -- Table 13	10.8%	to	11.4%	11.2%	to	11.8%
Risk premium -- Table 14		10.8%			11.2%	
CAPM -- Table 15		11.0%			11.4%	
Summary						
Range of Equity Cost Estimates	10.4%		11.4%	10.8%		11.8%
Mid-point of Range		10.9%			11.3%	
Recommended ROE					11.2%	

12/14/05

October 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 650

Request:

Please include all additional material reflecting advisory material provided to PGE from Lehman Brothers.

Response:

Since March 2006, PGE received one additional report from Lehman Brothers September 18, 2006. It is included as Attachment 650-A

Attachment 650-A is confidential and subject to Protective Order No. 06-111. It is provided under separate cover.

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October 20, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 657

Request:

Referring to Exhibit 2108, is Dr. Zepp aware of long-term forecasts of stock market returns as provided by any analyst, academic or service in the USA markets? If yes, please provide a complete listing of all such analyses readily available to the Company. If not, does Dr. Zepp have additional information or studies to support his belief that the stock market will provide a return on equity, on average, a rate as high as 14.35 percent?

Response:

PGE objects to this response because it is overly broad and unduly burdensome. Dr. Zepp has not prepared an exhaustive study of all long-term forecasts of future potential market returns. Notwithstanding its objection, PGE responds as follows:

Dr. Zepp is aware that the information provided in PGE Exhibit 2108, combined with his forecast of the long-term Treasury rate of 5.35% indicates the expected ROE for the market falls in the range of 12.35% to 14.45%. Dr. Zepp is also aware the Ibbotson Associates report a potential future average market risk premium of 7.1%, which indicates a future market return of 12.45% and thus falls within the range.

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October 20, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 658

<u>Request:</u>

Please provide all support for the perpetual growth rate indicated in Dr. Zepp's Risk Premium Based on DCF Analyses, Exhibit 2108.

<u>Response:</u>

Please refer to PGE Exhibit 2108, footnotes (a) and (b).

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October 20, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 659

Request:

Referring to Exhibit 2108, what growth rate in the overall economy does Dr. Zepp believe are sustainable into perpetuity? Please provide any supporting documentation. Please reconcile this figure with PGE's forecasts of GDP growth, included in its workpapers.

Response:

Dr. Zepp did not estimate such a growth rate from the data provided in PGE Exhibit 2108 because it was not necessary for his testimony. In addition, Dr. Zepp did not rely upon such a growth rate in his cost of equity analysis.

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October 20, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 660

Request:

Referring to Exhibit 2108, does Dr. Zepp believe that growth rates can perpetually be greater than the growth in the overall economy?

Response:

Please see PGE Response to OPUC Data Request No. 659. In addition, PGE Exhibit 2108 presents results derived from Value Line data.

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October 20, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Revised Data Request
Dated October 6, 2006
Question No. 662

<u>**Request:**</u> ***(October 6, 2006)***

Referring to Exhibits 2105 and Exhibit 2106, does Dr. Zepp agree with the assumptions of growth in the first stage of his DCF models with regard to the growth rates actually anticipated for the sample of utility companies?

<u>**Revised:**</u> ***(October 11, 2006)***

Referring to Exhibits 2105 and Exhibit 2106, does Dr. Zepp believe that his assumptions of growth in the first stage of his DCF models are reasonable for purposes of estimating PGE's required return on equity? Please explain.

<u>*Response:*</u>

Please refer to PGE Exhibit 2100, pages 22-27. Mr. Morgan stated that the Commission should consider past growth rates when it determines DCF results. Dr. Zepp relied upon actual average annual changes in such growth for his analysis to show the DCF equity cost estimates that would result. Dr. Zepp did what Mr. Morgan stated should be done, but that Mr. Morgan did not do in his testimony. Dr. Zepp prepared rebuttal testimony showing Mr. Morgan's low DCF equity cost range does not include data Mr. Morgan said should be considered.

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October 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Revised Data Request
Dated October 6, 2006
Question No. 663

Request: ***(October 6, 2006)***

Please provide all current forecasts of interest rates available to the company for Treasury debt and corporate debt.

Revised: ***(October 11, 2006)***

Please provide the source data and documentation for the 7.2 percent "2007 Baa" rate identified at the bottom of PGE/2110 Zepp/1 and referenced at PGE/2100 Zepp/36, line 9. If the forecast is no longer 7.2 percent, please provide the updated figure.

Response:

Please see Attachment 663-A.

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UE 180
Attachment 663-A

Q2 2007 Interest Rate Forecasts

Exhibit 1923
Page 2 of 4

Second Quarter 2007

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term							Intermediate-Term				Long-Term				Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Woodworth Holdings	6.3 H	9.3 H	6.4 H	6.3 H	6.2 H	6.3 H	6.2 H	6.1 H	6.0 H	6.0	6.0 H	6.7	7.8	4.9	7.7 H	78.0	3.5	3.8 H	3.8 H
Barclays Capital	6.0	9.0	6.2	6.1	5.7	5.9	6.1	5.3	5.5	5.4	5.3	5.9	6.8	5.0	6.8	na	2.0	2.7	1.8
J.P. Morgan Chase	6.0	na	6.2	na	5.8	na	na	5.9 H	5.9	5.9	5.9	na	na	na	na	na	3.0	2.4	2.8
Wells Capital Management	5.9	8.9	5.9	5.8	5.7	5.7	5.8	5.8	5.7	5.4	5.6	6.5	7.4	4.9	6.9	na	2.5	2.6	2.3
Lehman Brothers	5.8	8.8	5.9	5.8	5.6	5.6	5.5	5.8	5.4	5.3	5.4	6.1	7.0	4.8	6.9	na	2.8	2.6	2.9
Action Economics	5.8	8.8	6.2	5.8	5.5	5.8	5.9	5.9	5.9	5.9	5.9	6.9	7.9 H	5.6	7.5	77.0	3.6	2.3	2.7
LaSalle Nat'l Bank	5.8	8.6	5.8	5.8	5.6	5.7	5.7	5.6	5.5	6.5 H	5.6	6.9 H	7.8	5.8 H	7.0	76.9	2.6	2.3	2.1
Banc of America Securities	5.8	8.8	5.9	na	5.8	6.1	6.0	5.7	5.7	5.7	5.8	6.6	7.4	na	7.3	na	2.9	2.5	3.0
RBS Greenwich Capital Econ.	5.7	8.7	5.8	5.8	5.8	5.6	5.5	5.5	5.4	5.4	5.5	6.3	7.2	5.0	7.0	80.0	3.1	2.3	2.7
Bank of Toyko-Mitsubishi UFJ	5.7	8.7	5.9	5.7	5.6	5.7	5.7	5.5	5.4	5.6	5.7	6.4	7.3	5.1	7.2	78.0	3.8	3.1	3.4
Bear Stearns & Co.	5.5	8.5	5.8	5.6	5.5	5.6	5.6	5.5	5.7	5.8	6.0 H	6.9	7.8	5.0	7.4	83.1	3.3	3.0	2.7
National City Corporation	5.5	8.5	5.8	5.6	5.3	5.5	5.5	5.7	5.7	5.7	5.8	6.5	7.4	6.5	7.1	76.2	3.0	1.9	1.9
ING Investment Mgt.	5.5	8.5	5.7	5.6	5.4	5.6	5.8	5.8	5.6	5.6	5.6	6.4	7.3	4.8	7.0	77.0	3.5	2.7	2.7
JPMorgan Private Client Services	5.5	8.5	5.7	5.4	5.3	5.4	5.4	5.3	5.2	5.2	5.2	5.8	6.7	5.2	6.8	80.6	2.8	2.9	2.7
Comerica Bank	5.5	8.5	5.7	5.5	5.4	5.5	5.5	5.4	5.4	5.4	5.5	6.2	7.1	4.8	7.0	78.3	3.0	2.2	2.1
Stone Harbor Investment Partners	5.5	8.5	5.7	5.6	5.0	5.2	5.2	4.9	5.0	5.0	5.1	5.8	6.6	na	6.5	77.0	2.9	1.8	2.4
Standard & Poor's Corp.	5.5	8.5	5.8	5.5	5.3	5.4	5.5	5.6	5.6	5.6	na	6.8	7.8	5.4	7.2	75.4	2.1	2.2	2.2
Briefing.com	5.4	8.4	5.6	5.4	5.3	5.4	5.4	5.3	5.3	5.3	5.4	6.2	7.4	5.0	6.8	na	2.9	2.4	2.3
Swiss Re	5.4	8.4	5.6	5.7	5.2	5.4	5.5	5.3	5.3	5.5	5.8	6.5	7.6	na	6.8	na	3.1	1.5	2.3
Argus Research	5.3	8.3	5.3	5.2	5.5	5.5	5.3	5.1	5.1	5.1	5.3	6.4	6.8	5.2	6.6	81.8	2.6	3.2	3.3
Nat'l Assn. of Realtors	5.3	8.3	5.6	5.5	5.1	5.2	5.3	5.3	5.3	5.3	5.4	6.1	7.0	5.3	7.1	na	3.3	1.8	2.2
Mesirow Financial	5.3	8.3	5.6	na	5.0	5.2	5.3	5.2	5.3	5.3	5.3	6.3	na	na	6.9	82.5	3.3	1.8	2.0
Loomis, Sayles & Company	5.3	8.3	5.5	5.3	5.1	5.3	5.2	4.8	4.8	4.8	4.8	6.0	6.9	4.3	6.4	78.8	3.2	1.9	2.0
Wachovia	5.3	8.3	5.4	5.4	5.0	5.2	5.3	5.3	5.3	5.4	5.5	6.2	7.1	4.8	7.0	75.9	2.8	2.8	2.9
Fannie Mae	5.3	8.3	na	na	5.1	5.2	5.2	5.2	5.2	5.3	5.3	6.2	7.3	5.2	6.8	na	3.0	1.8	2.2
Wayne Hummer Investments	5.2	8.2	5.4	5.5	5.1	5.2	5.3	5.0	5.1	5.2	5.3	6.2	7.0	4.9	6.8	80.7	2.7	2.4	2.4
Thredgold Economic Assoc.	5.2	8.2	5.4	5.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	6.1	7.0	4.8	6.7	80.0	3.0	2.2	2.5
State House Policy Office	5.2	8.2	5.4	5.2	5.2	5.3	5.4	5.4	5.5	5.7	5.8	6.6	7.5	5.3	7.4	80.2	2.1	2.0	2.2
UBS Warburg	5.1	na	5.3	na	na	na	na	4.2 L	4.2 L	4.3 L	4.5 L	na	na	na	na	na	2.2	2.1	2.3
Kellner Economic Advisers	5.1	8.1	5.3	5.6	5.3	5.4	5.6	5.6	5.7	5.7	5.7	6.7	7.8	5.4	7.2	86.0	1.0 L	3.6	3.3
J.W. Coons Advisors LLC	5.1	8.1	5.3	5.1	4.9	4.8	4.9	5.0	5.0	5.1	5.2	6.1	7.1	na	6.6	83.1	2.0	2.3	2.6
SunTrust Banks	5.0	8.0	5.5	5.1	4.9	5.1	5.1	5.2	5.3	5.8	5.6	6.6	7.7	5.3	7.0	88.2 H	3.0	2.6	3.2
DePrince & Associates	5.0	8.0	5.3	5.1	4.9	5.0	5.1	5.0	5.0	5.1	5.2	6.3	7.3	5.1	6.8	82.8	2.8	2.3	2.8
Deutsche Bank Securities, Inc.	5.0	8.0	5.3	na	5.1	na	na	5.1	5.2	5.3	5.4	na	na	na	na	na	2.6	1.9	2.0
Moody's Economy.com	5.0	8.0	5.3	5.0	5.0	5.0	5.2	5.3	5.1	5.1	5.7	6.6	7.2	na	6.7	na	2.7	2.8	2.1
Trusco Capital Management	5.0	8.0	5.3	5.0	4.8	5.1	5.2	5.3	5.5	5.4	5.6	6.5	6.7	4.9	7.1	81.0	2.5	2.1	2.0
Moody's Investors Service	5.0	8.0	5.3	5.1	4.9	5.1	5.0	5.0	5.0	5.0	5.1	5.8	6.7	4.7	6.6	82.4	5.1 H	2.4	2.7
Nomura Securities, Inc.	5.0	8.0	5.2	5.1	4.9	5.0	4.8	4.8	4.8	4.8	4.9	5.7	6.7	na	6.2	81.0	2.9	2.0	2.4
BMO Capital Markets	5.0	8.0	5.2	5.1	4.9	5.0	5.0	5.0	5.1	5.1	5.2	5.9	6.9	4.6	6.8	78.5	3.0	2.4	2.5
Scotiabank	5.0	8.0	5.1	5.1	4.9	4.9	4.9	5.0	5.2	5.3	5.4	6.4	7.3	5.3	6.9	77.3	2.5	2.1	2.1
Cycledata Corp.	5.0	8.0	5.1	5.1	4.9	5.0	5.0	5.0	5.0	5.0	5.2	6.0	6.9	4.8	6.6	83.0	2.5	2.4	3.0
Goldman Sachs	5.0	8.0	4.8	na	4.6	na	4.6	4.5	4.5	4.5	4.6	5.5	na	na	6.9	na	2.0	2.0	2.3
Georgia State University	5.0	8.0	na	na	4.9	5.0	5.0	5.1	5.2	5.4	5.4	6.5	7.4	na	7.0	na	2.7	1.7	2.2
Naroff Economic Advisors	5.0	8.0	5.0	5.0	5.0	5.1	5.1	5.3	5.3	5.5	5.7	6.4	7.3	5.2	6.9	73.5 L	3.0	2.2	2.4
ClearView Economics	4.9	7.9	5.2	4.9	4.8	5.0	4.9	4.9	4.8	4.9	5.0	5.7	6.6	4.5	6.5	78.0	3.1	2.2	3.5
Chmura Economics & Analytics	4.8	7.8	5.1	4.9	4.7	4.9	4.9	4.9	4.9	5.0	5.1	5.9	na	na	6.8	80.6	3.1	3.1	2.7
Prudential Equity Group LLC	4.5 L	7.5 L	4.5	4.5 L	4.5	4.5	4.6	4.7	4.7	4.8	4.9	5.8	6.8	5.1	6.3	77.0	2.7	1.3	2.4
The Northern Trust Company	4.5 L	7.5 L	4.5	na	4.1 L	na	4.1 L	4.4	4.7	4.9	4.9	5.8	na	4.4	6.4	na	2.8	2.0	2.3
U.S. Trust Company	4.5 L	7.5 L	4.4 L	4.5 L	4.4	4.4 L	4.8	4.4	4.3	4.6	4.7	5.4 L	6.3 L	4.1 L	6.2 L	82.0	2.3	2.0	2.3
Merrill Lynch Economics	4.5 L	na	4.5	na	4.4	na	na	4.3	4.6	4.7	4.9	na	na	na	na	na	2.2	1.2 L	0.4 L
August Consensus	**5.3**	**8.3**	**5.4**	**5.3**	**5.1**	**5.3**	**5.3**	**5.2**	**5.2**	**5.3**	**5.3**	**6.2**	**7.2**	**5.0**	**6.9**	**79.7**	**2.8**	**2.3**	**2.5**
Top 10 Avg.	5.8	8.7	6.0	5.8	5.7	5.7	5.7	5.7	5.7	5.8	5.8	6.7	7.7	5.4	7.3	83.4	3.5	2.9	3.1
Bottom 10 Avg.	4.8	7.8	4.8	4.9	4.6	4.9	4.7	4.6	4.6	4.7	4.8	5.7	6.6	4.6	6.4	76.3	2.0	1.7	1.6
July Consensus	5.2	8.2	5.4	5.3	5.1	5.2	5.3	5.2	5.2	5.3	5.4	6.3	7.2	5.0	6.9	78.9	2.9	2.3	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	1	1	8	6	11	8	11	11	11	12	11	12	9	9	11	11	14	6	10
Same	36	34	22	17	22	16	17	27	26	24	28	20	17	15	16	14	28	33	29
Up	13	12	18	17	16	20	18	12	13	14	11	14	16	12	19	8	10	11	11
Diffusion Index	62 %	62 %	60 %	64 %	65 %	64 %	58 %	51 %	52 %	52 %	50 %	52 %	58 %	54 %	59 %	45 %	48 %	55 %	51 %

Exhibit 1923
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OCT. 18. 2006 12:14PM UTILITY RESOURCES INC.

Second Quarter 2007

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Stone Harbor Investment Partners	6.0 H	9.0 H	6.2 H	6.1 H	5.7	5.7	5.7	5.8	5.6	5.5	5.5	6.2	7.1	na	7.0	80.0	3.9	2.5	3.1
Woodworth Holdings	6.0 H	9.0 H	6.1	6.1 H	5.7	5.9 H	5.9	5.8	5.7	5.7	5.7	6.4	7.3	4.8	7.3	78.5	3.5	3.8	3.8
Barclays Capital	6.0 H	9.0 H	6.2 H	6.1 H	5.7	5.9 H	6.1 H	5.3	5.3	5.3	5.2	5.9	6.7	5.0	6.8	na	2.5	2.9	1.6
J.P. Morgan Chase	6.0 H	na	6.2 H	na	5.9 H	na	na	5.9 H	5.8 H	5.9 H	5.8	na	na	na	na	na	3.0	2.4	2.9
LaSalle Nat'l Bank	5.8	8.8	5.9	5.9	5.8	5.7	5.7	5.8	5.5	5.5	5.8	6.9	7.6	5.2	7.0	77.0	2.8	2.3	2.1
Lehman Brothers	5.8	8.8	5.9	5.8	5.6	5.6	5.5	5.5	5.4	5.3	5.4	6.1	7.0	4.8	6.9	na	2.8	2.5	3.0
Wells Capital Management	5.8	8.8	5.8	5.7	5.6	5.6	5.5	5.5	5.4	5.3	5.4	6.3	7.2	4.8	6.9	na	2.5	2.8	3.0
Banc of America Securities	5.8	8.8	5.7	na	5.8	5.9 H	5.9	5.8	5.6	5.7	5.7	6.5	7.4	na	7.3	na	2.9	2.7	3.2
Bear Stearns & Co.	5.5	8.5	5.8	5.6	5.8	5.6	5.6	5.5	5.7	5.8	6.0	6.9	7.8	5.1	7.4 H	83.1	3.2	3.0	2.7
ING Investment Mgt.	5.5	8.5	5.7	5.6	5.4	5.6	5.6	5.6	5.8	5.8	5.6	6.4	7.3	4.8	7.0	77.0	3.5	2.8	2.7
Standard & Poor's Corp.	5.5	8.5	5.6	5.5	5.3	5.4	5.5	5.6	5.7	5.8	na	7.0 H	7.9 H	5.5 H	7.2	75.4	2.4	2.0	2.0
Briefing.com	5.5	8.5	5.6	5.5	5.4	5.4	5.3	5.3	5.2	5.2	5.3	6.2	7.2	4.9	6.8	na	2.9	2.4	2.4
JPMorgan Private Client Services	5.5	8.5	5.5	5.4	5.3	5.3	5.2	5.0	4.9	5.0	5.1	5.8	6.7	5.0	6.8	80.5	2.8	2.9	3.0
RBS Greenwich Capital Econ.	5.5	8.5	5.5	5.5	5.3	5.3	5.2	5.2	5.1	5.0	5.1	6.0	6.9	4.7	6.7	79.0	2.6	2.3	2.7
Argus Research	5.4	8.4	5.4	5.4	5.3	5.4	5.5	5.2	5.0	5.0	5.3	5.9	6.7	4.7	6.5	81.8	3.8	3.2 H	3.2
Swiss Re	5.4	8.4	5.6	5.7	5.2	5.3	5.4	5.4	5.4	5.4	5.8	6.2	7.1	na	6.8	na	3.1	1.4	2.2
Nat'l Assn. of Realtors	5.3	8.3	5.6	5.5	5.1	5.2	5.3	5.2	5.3	5.3	5.4	6.0	7.0	5.2	7.0	na	3.2	1.9	2.3
Comerica Bank	5.3	8.3	5.5	5.3	5.1	5.2	5.2	5.1	5.2	5.3	5.4	6.1	7.0	4.7	6.9	79.5	2.8	2.4	2.0
Action Economics	5.3	8.3	5.5	5.3	5.2	5.4	5.5	5.5	5.6	5.8	6.2 H	6.5	7.4	5.3	7.2	77.5	3.2	2.2	2.7
National City Corporation	5.3	8.3	5.5	5.3	5.0	5.2	5.3	5.5	5.5	5.8	5.7	6.3	7.2	5.4	6.9	75.4	2.9	2.1	2.0
Loomis, Sayles & Company	5.3	8.3	5.5	5.3	5.1	5.3	5.2	4.8	4.8	4.6	4.8	6.0	6.9	4.3	6.4	79.7	3.1	2.4	2.1
Mesirow Financial	5.3	8.3	5.4	5.3	5.2	5.2	5.2	5.2	5.2	5.1	5.1	6.2	na	na	6.5	81.0	2.9	2.3	2.5
J.W. Coons Advisors LLC	5.3	8.3	5.3	5.2	4.9	4.9	4.8	4.9	4.9	4.9	5.1	6.0	6.0 L	na	6.6	83.1	2.0	2.3	2.5
Fannie Mae	5.2	8.2	na	na	4.9	5.0	5.0	5.0	5.1	5.2	5.1	6.0	6.8	5.1	6.8	na	3.0	2.4	2.7
DePrince & Associates	5.2	8.2	5.5	5.3	5.1	5.2	5.2	5.1	4.9	5.0	5.1	6.2	7.2	5.0	6.7	82.3	2.8	2.3	2.8
State House Policy Office	5.2	8.2	5.3	5.2	5.1	5.2	5.2	5.2	5.2	5.4	5.5	6.3	7.1	5.0	7.0	80.3	1.8	2.5	2.1
ClearView Economics	5.1	8.1	5.3	5.1	5.0	5.1	5.0	4.8	4.8	4.8	5.0	6.7	6.6	4.6	6.5	78.0	2.3	2.2	3.5 H
Kellner Economic Advisers	5.1	8.1	5.3	5.6	5.3	5.4	5.8	5.6	5.7	5.0	5.4	6.7	7.6	5.1	7.0	82.0	0.5 L	3.1	3.3
PNC Financial Services Corp.	5.1	8.1	5.2	5.1	5.0	5.1	5.1	5.0	5.0	5.0	5.1	6.0	7.0	4.5	6.7	80.0	2.2	1.4	2.2
Trusco Capital Management	5.0	8.0	5.3	5.0	4.7	4.8	4.8	4.9	5.1	5.0	5.1	5.1 L	6.3	4.6	6.7	81.0	2.5	2.1	2.0
Moody's Investors Service	5.0	8.0	5.3	5.1	4.9	5.1	5.0	5.0	5.0	5.0	5.1	5.8	6.7	4.7	6.6	82.4	5.1 H	2.4	2.7
Wayne Hummer Investments	5.0	8.0	5.2	5.1	4.8	4.9	4.9	4.8	5.0	5.1	5.2	6.0	6.9	4.8	6.6	81.4	3.0	2.3	2.3
Thredgold Economic Assoc.	5.0	8.0	5.2	5.1	4.8	4.8	4.8	4.7	4.7	4.7	4.8	5.6	6.5	4.6	6.3	81.0	2.8	2.3	2.5
BMO Capital Markets	5.0	8.0	5.2	5.1	4.9	5.0	5.0	5.0	4.9	4.9	5.0	5.8	6.9	4.5	6.5	81.8	2.9	2.5	2.7
Nomura Securities, Inc.	5.0	8.0	5.1	5.1	4.8	5.0	4.7	4.7	4.7	4.7	4.9	5.8	6.6	na	6.2	81.0	2.9	2.4	2.4
Cyclodata Corp.	5.0	8.0	5.1	5.1	4.9	4.9	4.9	4.9	4.9	4.9	5.1	5.9	6.8	4.6	6.6	82.0	2.5	2.4	3.1
Deutsche Bank Securities, Inc.	5.0	8.0	5.1	na	5.1	na	na	4.8	4.9	5.0	5.2	na	na	na	na	na	2.6	1.9	2.0
SunTrust Banks	5.0	8.0	5.0	4.7	4.9	5.1	4.7	4.7	4.8	4.8	5.0	5.9	6.9	4.6	6.3	88.2 H	3.0	2.6	3.2
Wachovia	5.0	8.0	5.0	4.9	4.8	4.9	5.0	4.6	4.7	4.8	4.7	5.6	6.5	4.3	6.3	78.0	2.6	2.6	2.7
Goldman Sachs	5.0	8.0	4.8	na	4.4	na	4.5	4.5	4.5	4.5	4.5	6.8	na	na	6.9	na	2.0	2.3	2.3
Georgia State University	5.0	8.0	na	na	4.6	4.9	5.0	5.1	5.3	5.4	5.6	6.7	7.7	na	7.0	na	2.7	2.1	1.8
Chmura Economics & Analytics	5.0	8.0	5.3	5.1	4.9	5.1	5.1	5.0	5.0	5.0	5.1	5.9	na	na	6.6	75.4	3.5	3.1	2.7
Moody's Economy.com	4.8	7.8	5.0	4.8	5.0	5.0	5.1	5.0	5.0	5.0	5.2	6.4	7.0	na	6.6	na	2.5	2.9	2.1
UBS Warburg	4.8	7.8	4.9	na	4.5	na	na	4.1 L	4.2 L	4.2 L	4.4 L	na	na	na	na	na	2.3	2.1	2.2
Scotiabank	4.8	7.8	4.9	4.8	4.7	4.6	4.5	4.4	4.5	4.9	5.0	6.0	6.9	4.8	6.5	77.3	2.3	2.1	1.8
Naroff Economic Advisors	4.6	7.6	4.8	4.7	4.9	5.0	5.1	5.1	5.2	5.4	5.6	6.2	7.2	5.1	7.0	73.5 L	2.9	2.5	2.8
Merrill Lynch Economics	4.5 L	7.5 L	4.5	na	4.4	na	na	4.3	4.6	4.7	4.9	na	na	na	na	na	2.2	1.2 L	0.4 L
Prudential Equity Group LLC	4.5 L	7.5 L	4.5	4.5 L	4.5	4.5	4.8	4.7	4.7	4.8	4.9	5.8	6.6	5.1	6.3	77.0	2.7	1.3	2.4
The Northern Trust Company	4.5 L	7.5 L	4.5	na	4.1 L	na	4.1 L	4.4	5.0	5.2	4.9	5.8	na	4.4	6.4	na	2.7	2.0	2.3
U.S. Trust Company	4.5 L	7.5 L	4.4 L	4.5 L	4.4	4.4 L	4.6	4.4	4.3	4.6	4.7	5.4	6.3	4.1 L	6.2 L	81.0	2.1	2.0	2.2
September Consensus	**5.2**	**8.2**	**5.3**	**5.3**	**5.1**	**5.2**	**5.2**	**5.1**	**5.1**	**5.1**	**5.2**	**6.1**	**7.0**	**4.8**	**6.7**	**79.8**	**2.8**	**2.4**	**2.5**
Top 10 Avg.	5.8	8.7	5.9	5.7	5.6	5.6	5.7	5.6	5.6	5.6	5.7	6.7	7.5	5.2	7.1	82.8	3.6	2.9	3.2
Bottom 10 Avg.	4.7	7.7	4.7	4.8	4.5	4.8	4.6	4.5	4.6	4.7	4.7	5.6	6.5	4.4	6.3	76.4	2.0	1.7	1.9
August Consensus	5.3	8.3	5.4	5.3	5.1	5.3	5.3	5.2	5.2	5.3	5.3	6.2	7.2	5.0	6.9	78.7	2.8	2.3	2.5
Number of Forecasts Changed From A Month Ago:																			
Down	16	15	21	17	18	22	24	28	31	33	29	28	27	28	26	8	19	7	12
Same	27	25	20	14	23	18	17	17	13	13	13	13	11	8	15	13	24	25	24
Up	7	7	7	9	8	4	5	5	6	4	8	5	4	2	7	12	7	18	14
Diffusion Index	41 %	41 %	35 %	40 %	40 %	30 %	29 %	27 %	25 %	21 %	28 %	25 %	23 %	17 %	20 %	56 %	38 %	81 %	52 %

Exhibit 1923
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CERTIFICATE OF SERVICE

I certify that on November 2, 2006, I served the foregoing as set out in the attached cover letter upon all parties of record in this proceeding by delivering a copy by electronic mail and by mailing a copy by postage prepaid first class mail or by hand delivery/shuttle mail to the designated parties accepting paper service.

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