Oregon
Kate Brown, Governor

Public Utility Commission
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Mailing Address: PO Box 1088
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503-373-7394

August 11, 2016

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

**RE: Docket No. UG 305 – In the Matter of
CASCADE NATURAL GAS CORPORATION, Request for a General
Rate Revision.**

Enclosed for electronic filing is Staff Opening Testimony (Exhibit 100 – 1300), Certificate of Service and UG 305 Service List.

Exhibit 206 and Exhibit 403 (pages 5 and 6) are confidential. A copy of these confidential exhibits/pages were mailed today to parties who have signed Protective Order No. 16-141.

This voluminous filing of both confidential and non-confidential will be uploaded to Huddle by close of business today. The filing will be available to Parties who were assigned confidential access to Huddle.

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
(503) 378-5763
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/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
(503) 378-5763
kay.barnes@state.or.us

CERTIFICATE OF SERVICE

UG 305

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 11th day of August, 2016 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-5763

UG 305 – SERVICE LIST

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CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATION STATEMENT

NAME:	Marianne Gardner
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Master of Business Administration Oregon State University, Corvallis, Oregon Bachelor of Science in Accounting Montana State University, Bozeman, Montana CPA, Oregon
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UG 284, UG 287, UG 288, and UE 294.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Marianne Gardner, I am a Senior Revenue Requirement Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-sponsored adjustments and issues regarding Cascade Natural Gas's (Cascade or Company) filing in this docket, identified as UG 305. As such, I verify Cascade's proposed revenue requirement utilizing Staff's revenue requirement model. This model is also used to calculate Staff's modified revenue requirement after incorporating Staff's proposed adjustments to Cascade's revenue requirement.

Additionally, I provide background regarding specific issues I reviewed, my analysis, and my recommendations.

Q. Will other Staff submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to UG 305 is submitting separate testimony. In Part 1 of my testimony, I introduce the Staff witnesses and their respective assignments, and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 101	Witness Qualification Statement
Exhibit 102	Uncollectibles
Exhibit 103	Labor
Exhibit 104	Parvinen's Plant Addition
Exhibits 105	SIT, FIT and ADIT
Exhibit 106	Rate Case Costs
Exhibit 107	Other Revenue Taxes
Exhibit 108	Other Benefits
Exhibit 109	Interest Synchronization
Exhibit 110	Inflation/Escalation

Q. How is your testimony organized?

A. My testimony is organized as follows:

Part 1. Revenue Requirement 3
Part 2. Specific Issues 6

PART 1. REVENUE REQUIREMENT

Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.

A. I have provided a listing of rate topics in Table A.

Table A. Rate Case Topics

Exhibit No.	Issue Description	Staff Witness
100	Uncollectible accounts, Compensation, FTE, Amortization, Other taxes, Income taxes, Accumulated deferred income taxes, Working Capital, Prepaid Expenses, Inflation factor, Rate case costs	Gardner
200	Capital Structure/Cost of equity, Cost of LT Debt, Pension Asset Recovery	Muldoon
300	Sales & Transportation Revenues/Weather Normalization, Load Forecast, DSM, Miscellaneous operating revenues, LRIC/Marginal cost study, Conservation alliance plan and decoupling	St. Brown
400	Purchased Gas - City Gate Purchases, Other Gas Expense, Underground Storage Expense, Gas Storage, IRP	Colville
500	Distribution O&M expense, Rate spread and rate design, Atmospheric corrosion survey, Customer service	Gibbens
600	Customer accounting (Non-labor), Memberships, Dues, Donations, Meals and Entertainment, Materials and supplies (non-fuel), and Travel	Zarate
700	Customer Service & Informational, Sales Expenses (non-labor), Advertising and marketing, Promotional activities and concessions, Administrative and general expenses (Non-labor), Out of service plant, Utility plant in service, Utility plant additions, IT costs and rate base	Moore
800	Housekeeping Revisions to Tariffs	Shearer
900	Depreciation expense, Depreciation reserves	Peng
1000	Affiliated interest charges, Allocations and Multijuristictional Agreements	Kaufman
1100	Environmental Remediation Cost Recovery, Pipeline safety cost recovery	Johnson
1200	Public Purpose Cost Reallocation	Batmale
1300	Tariff filing verification, Rate spread/Rate design	Compton

Q. Please identify those issues for which Staff recommends a revenue requirement adjustment.

A. I have provided a listing in Table B below.

Table B							
			$000"s				
Company Filed General Rate Case Required Change to Revenue Requirement							$ 1,906
Opening Testimony Exhibit No.	Staff Witness	Issue No.	Proposed Staff Adjustments	Revenue	Expense	Rate Base	Revenue Requirement Effect
100	Gardner	1	Uncollectible Rate				(3)
100	Gardner	1	Uncollectibles		(118)		(121)
100	Gardner	2	Wages & Salaries		(229)	(59)	(242)
100	Gardner	3	MDU Cross-Charged Labor		(178)	(51)	(189)
100	Gardner	4	Amortization (placeholder)				-
100	Gardner	5	Accum. Deferred Income Tax (ADIT)			(4,094)	(437)
100	Gardner	8	Rate Case Costs		(56)		(58)
100	Gardner	9	Franchise Fee Rate		16		26
100	Gardner	10	Other Taxes (placeholder)				-
100	Gardner	11	Other Benefits		(18)		(18)
100	Gardner	12	Interest Synch.				13
100	Gardner	13	Inflation		(43)		(45)
200	Muldoon	3	LTD				(32)
300	St. Brown	1	Load Forecast Revenue	313			(313)
300	St. Brown	3	Other Revenue	11			(11)
400	Colville	1	Gas Storage in Rate Base			(38)	(4)
500	Gibbens	1	AC Survey		(12)		(13)
600	Zarate	1	Meals and Entertainment		(37)		(38)
600	Zarate	2	Memberships, Dues, Donations		(52)		(54)
600	Zarate	3	Travel		(94)		(97)
600	Zarate	4	Customer Accounts		(57)		(58)
600	Zarate	5	Material and Supplies			(62)	(7)
700	Moore	1	A&G		(16)		(16)
700	Moore	3	Plant			(3,329)	(355)
800	Shearer	2	Housekeeping -Tariffs				N/A
900	Peng	1	Reclass.**				-
900	Peng	2	Accumulated Depreciation			(390)	(42)
1000	Kaufman	1	Allocations & Affliliates		(724)		(746)
1000	Kaufman	1	Allocations & Affliliates	64			(64)
1100	Johnson	1	Env. Remediation Amort.*				N/A
1200	Batmale	1&2	CNG EE Programs & ETO *				N/A
1300	Compton	1	LRIC, Rate Spread & Rate Design *				N/A
Total Staff-Proposed Adjustments (Base Rates):				$ 388	$ (1,616)	$ (8,023)	$ (2,922)
Staff-Calculated Revenue Requirements Change (Base Rates):							$ (1,016)
**Company adjusted A&G rather than Depreciation Expense (spreadsheet error).							
* No adjustment to revenue requirement.							

PART 2. SPECIFIC ISSUES

Q. What areas of Cascade's filing are you primarily responsible for reviewing?

A. I reviewed the portions of the filing related to uncollectible expense, wages and salaries, incentives, workforce levels, amortization expense, other taxes, state income tax (SIT), federal income tax (FIT), accumulated deferred income taxes (ADIT), working capital allowance, inflation factor, director fees, and rate case costs. In order to gain additional insight, I reviewed the Company's responses to related Standard Data Requests (SDRs), issued approximately 75 data requests, and reviewed the Company's responses to my data requests.

Q. For each issue, please provide a summary of the Commission's historical treatment, the Company's filed proposal, Staff's analysis of the issue, and Staff's recommendation.

A. Below is a discussion of each issue:

ISSUE 1. UNCOLLECTIBLES

It is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the test year uncollectible expense for a utility's revenue requirement.[1] However, Commission Staff also examines

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[1] *See, e.g.*, Order Nos. 14-015 and 09-422 (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see* Order No. 05-871 and Order 15-412 (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average) and Order 15-412 (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

other evidence to determine whether this approach results in a reasonable forecasted test year result.

In this case, the Company includes $360,473 as uncollectible expense in its test year revenue requirement. According to Mr. Parvinen, the Company adjusted the uncollectible rate for the test year based on a three-year average (2013-2015) of actual write-offs.[2] However, the net write-off amounts of $369,764, $420,354, and $295,381 in Parvinen's uncollectibles adjustment workpaper[3] differ from the actual net write-off amounts provided by the Company in response to Staff DR No. 202(a) of $242,132, $303,729, and $169,224, respectively.[4]

Staff issued DR No. 316, requesting that the Company clarify the discrepancy. The Company explained the amounts provided in DR No. 202(a) are the actual net write-off amounts, whereas the amounts the Company used to adjust uncollectible expense for the test year in Parvinen's uncollectibles workpaper are not net write-off amounts (rather, they are write-off amounts that do not include any recovered amount).[5] Therefore, Staff proposes to recalculate the uncollectible rate using the three-year average of actual net write-offs provided in response to DR No. 202(a).

Additionally, the Company averaged total revenues for the uncollectible rate calculation. Total revenues include natural gas sales, gas transportation

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[2] UG 305/CNGC/200, Parvinen/5 at lines 3-7.
[3] Staff/102 at 1, Parvinen Workpapers Exhibits 201-206.xlsx, tab "Uncollectibles".
[4] Staff/102 at 2-5, CNG Response to Staff DR No. 202(a).
[5] Staff/103 at 6, CNG Response to Staff DR No. 316.

revenue, and other operating revenues. Consistent with Staff's UG 287 uncollectible adjustment, Staff proposes to average the natural gas sales for 2013, 2014, and 2015 to calculate the uncollectible rate and apply this rate to the test year natural gas sales for the test year uncollectible expense. Staff confirmed that the Oregon Total Revenue provided by the Company in OPUC DR No. 202(a) are not actually total revenues. Instead, the "Oregon Total Revenue" amount is "natural gas sales revenues." Staff confirmed the Company's misnomer by reviewing the Company's filed Results of Operation reports for 2013, 2014, and 2015 filed in docket RG 36.

Based on Staff's proposed changes, Staff calculates the test year uncollectible rate to be .3745 percent and the test year uncollectible expense to be $242,817.[6] Consequently, Staff recommends the Company's filed uncollectible revenue sensitive rate of .5329 percent be reduced to .3745 percent. This will in turn change the net to gross factor that is used for the revenue requirement calculation. Staff recommends that the uncollectible expense be reduced from the Company's filed test year amount of $360,473 to $242,817, which results in a decrease of $117,688 in uncollectible expense.

ISSUE 2. WORK FORCE LEVELS, SALARIES AND WAGES, AND INCENTIVES

The Commission typically uses Staff's three-year wage and salary model (W&S model or Staff's model) to estimate expenses for non-union wages and

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[6] Staff/102 at 7, Staff's uncollectible adjustment calculation.

salaries.[7] The increases in payroll from the historic base year should be tied to the rate of inflation using the All-Urban CPI.[8] I applied this model to the information the Company provided in its filing and responses to Staff's data requests. Also included in the model is union payroll. Rather than using All-Urban CPI, the Commission has ordered that union payroll increases be tied to negotiated wage increases as set forth in the negotiated union contract, unless evidence shows that the negotiated union contract was excessive.[9] Staff believes the contracted increases are reasonable. Therefore, consistent with past Commission practice, Staff adjusted union wage increases according to the most recent union contract.

As explained by Mr. Parvinen, the Company base year is 2015 actual Oregon booked amounts.[10] The Company proposed a series of adjustments to this base year culminating in the 2016 test year amounts. I have listed Cascade's modifications affecting workforce levels, salaries and wages, and incentives below. Each pertinent adjustment is assigned the letter ascribed in Mr. Parvinen's Exhibit 204, and shows the Company's proposed increase or (decrease) in labor expense.[11]

1. (f) "Annualizing Wage Rate Adjustment" ($25,017)
2. (h) "2016 Wage Adjustments" $193,869
3. (m) "Resource Planning Adjustment" $50,728

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[7] *See, e.g.*, Order No. 01-787.
[8] *See* Order 01-787 at 40; Order 99-697 at 43; Order 99-033 at 61; Order 95-322 at10.
[9] *See* Order 99-697 at 43.
[10] CNG/200, Parvinen/3 at 6-8.
[11] CNG/204, Parvinen/1 at (f), (h), (m).

Adjustments (f) and (h) are incorporated in Staff's W&S model. Staff's W&S adjustment, in this case, starts with 2013 amounts that are escalated based on the change in the all-urban CPI for 2013-2014, 2014-2015, and 2015-2016 to arrive at Staff's projected amount. This projected amount is compared to the Company's test year W&S and a sharing test is applied to calculate Staff's proposed adjustment. Actual 2013 base payroll and full-time equivalents (FTE) in the model are based on the Company's response to Staff DR No. 254.[12] The Company's response to Staff DR No. 254 for the 2016 year is the same as the 2015 base year and does not include the Company's labor adjustments (f), (h), and (m). For purposes of Staff's wage and salary model, Staff incorporated adjustments (f) and (h) into the 2015 base year salaries.[13]

Staff did not include adjustment (m) in the wage and salary model because in Docket LC 59, Staff recommended that Cascade evaluate its IRP staffing to ensure IRP activity schedules and OPUC IRP compliance requirements are met.[14] Cascade added two additional employees and allocated the Oregon jurisdiction 24.72 percent based on the three factor formula. During the next IRP review process, Staff assigned to the IRP docket will review the effectiveness of these two hires.[15] Therefore, Staff does not propose to disallow any portion of adjustment (m) at this time.

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[12] Staff/103 at 8, Company Response to Staff DR No. 254.
[13] Staff/100, Gardner Wage and Salary Model.xlsx
[14] *See* Order 16-054, Appendix A at 12.
[15] Staff/400, Colville/11.

Regarding incentives, Staff typically limits a portion of incentives according to Commission policy. Commission policy disallows 100 percent of officers' bonuses because they are based on increased earnings.[16] Also, it is Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders), and to disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[17]

Cascade did not explain or substantiate the amount of incentives in the 2016 test year in its testimony or workpapers. I reviewed the Company's response to Staff DR Nos. 368 and 369, describing the Company's incentive plan for officers and non-officers. However, in its response to Staff DR. No. 371, the Company confirmed that no incentive amounts were included in the 2015 base year or 2016 test year.[18] Rather, the incentives paid in 2015 were accrued as an expense in 2014 and no incentives were accrued for 2015 because the Company did not achieve its earnings targets for the 2015 base year. Therefore, I do not propose an incentive adjustment.

In summary, Staff's proposed wage and salary adjustment is broken down as a decrease to O&M expense and a decrease to Capital of $228,750 and

[16] *See* Order 99-033 at 62; Order 97-171 at 74-76.
[17] *See* Order 99-697 at 44-45; Order 99-033 at 62.
[18] Staff Exhibit/103 at 21, Company Response to Staff DR. No. 371. (UG 305/CNGC, Parvinen/Exhibit 201 is the Company Results of Operations (ROO) Summary Sheet. Column (1) is the 2015 base year results. Column (2) contains the Company's proposed adjustments to arrive at the adjusted 2016 test year in column (3)).

$59,192, respectively. The supporting calculations for this adjustment can be found in the electronic workpaper titled "UG 305 Gardner Wages and Salaries Adjustment.xlsx."

ISSUE 3. LABOR CROSS-CHARGES

Cascade is cross-charged by its parent company, MDU Resources Group, Inc. (MDUR), for MDU labor costs incurred in the course of providing services to Cascade. Cascade provided MDU's crossed-charged labor costs in its response to Staff DR No. 254, categorized as officer and non-officer cross-charges.[19] Staff did not include an FTE adjustment because the Company does not track FTE for labor cross-charged. Otherwise, Staff followed the same principles of the model to adjust cross-charged base wages, incentives, and over-time.

As noted above in Issue 2, the Company asserted there were no incentives included in the Company's Exhibit 201, ROO Summary Sheet. However, in Staff's review of the Company's 2015 ROO transaction detail provided by the Company,[20] Staff identified transactions categorized as "Bonuses and Commission" (Object Code 5130), which totaled $296,090. The explanatory fields for these transactions note that they were MDUR cross-charges. Based on my review of the Company's response to Staff DR Nos. 368 and 369 describing the Company's incentive plan, I recommend adjusting 100 percent of officers' incentives because they are based on financial

[19] *Id at 8.*
[20] The Company's original detail is included in Staff workpaper, "UG 305 Incentive Cross-Charges – OPUC-58(a) Revised.xlsx".

performance measures of earnings per share (EPS), return on investment capital (ROIC), and MDUR's three-year total shareholder return versus a proxy peer group return. [21]

Additionally, I recommend a partial disallowance of non-officer incentives. There are three components to non-officers' incentives with each comprising a third of the total incentive. According to Cascade, "The first component, [financial performance], is tied to earnings. If this target is reached then it is determined if the other goals were met to calculate total payout. If the minimum earnings goal is not met then there is no payment made even if the reduced spending and customer service goals were achieved." Based on this description, I recommend disallowing 75 percent of the financial performance incentive, 75 percent of the reduced spending incentive, and 50 percent of the incentive tied to customer service for non-officer incentives.[22]

My proposed adjustment is broken down as a decrease to O&M expense and a decrease to Capital of $177,555 and $50,664, respectively. The supporting calculations for this adjustment can be found in my electronic workpaper titled, "UG 305 Gardner Labor Cross-Charges Adjustment.xlsx."

ISSUE 4. AMORTIZATION EXPENSE AND ACCUMULATED AMORTIZATION

The Company did not include any narrative testimony regarding amortization in their initial filing. Parvinen's "2016 Plant Additions" exhibit

[21] *Id at 16-19.*
[22] See Order No. 99-697 at 44-45; Order No. 99-033 at 62.

includes intangible assets of $941,750.[23] The Company calculated the test year amortization adjustment using a 10 percent rate, resulting in $94,175 of 2016 of amortization expense for new additions and an increase to accumulated amortization of $47,088 ($94,175/2).[24] I verified with Ming Peng, OPUC Senior Economist, that the 10 percent rate and the accumulated amortization amount are correct.

As the Revenue Requirement Summary Witness, I will update the test year amortization expense and reserves to reflect adjustments sponsored by other Staff witnesses to intangible plant. Therefore, while I do not propose any adjustment at this time to amortization expense or to the reserve account, I may have an adjustment to the final revenue requirement contingent upon other Staff witnesses' discovery and analysis.

ISSUE 5. SIT, FIT and ADIT

The Company's proposal for the test year state and federal income tax expense is $1,439,825.[25] The incremental tax effect of the Company's adjustments to 2015 ROO based on the federal and Oregon statutory income tax rates of 35 percent and 7.6 percent, respectively, is $83,673. Cascade has based the revenue sensitive amount for state and federal income tax on these statutory rates.[26] The resulting conversion factor or net-to-gross factor is used to calculate the incremental revenue requirement. As confirmed in subsequent

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[23] UG 305/CNGC, Parvinen/Exhibit 205.
[24] Staff/104, Parvinen Workpapers Exhibits 201-206.xlsx, tab "2016 Plant Additions".
[25] CNGC/201, Parvinen/1 at line 17, column (3).
[26] CNG/200, Parvinen/4 at lines 15-21 and CNG/203, Parvinen/1.

data requests, the amount of income taxes included in the 2015 ROO are estimated taxes based on 2015 provisions.

Consistent with Internal Revenue Code (IRC) Sections 168(f)(2) and 168(i)(9), Normalization Rules for Public Utilities, the Commission requires that public utilities normalize federal income taxes for revenue requirement purposes. According to IRC Sec. 168(i)(9)(A):

> In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—
> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and
> (ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference." Also, ORS 757.269 (1) states "[s]ubject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operation of the utility." According to subsection (3), "During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes a part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon: (a) Whether the utility's affiliated group has a history of paying federal or state income

> taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation; (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or (c) Any other considerations the commission deems relevant to protect the public interest.

In addition to reviewing the Company's responses to Staff's Standard Data Requests, I issued additional data requests to ascertain whether the Company's normalized federal income taxes are consistent with Commission policy, and whether the amount of taxes included in this rate case are fair and reasonable. To this end, I reviewed the components and calculations of current taxes, deferred taxes, the related ADIT, and the Company's jurisdictional allocation between Oregon and Washington.

As part of my analysis, I reviewed the Company's calculations for the taxes included in the 2015 ROO, the filed Oregon Corporation Excise Tax Return, and Form 20 for years 2004 through 2014. I asked the Company to explain the differences in the Oregon state effective tax rate based on the Form 20 as compared to its filed ROO for the years 2012-2015.

I also requested information regarding bonus depreciation for the 2015 base year and the 2016 test year in Staff DR No. 272.[27] The Company response explained, "For tax purposes, Cascade is part of MDUR's consolidated tax return and as such the election to use Bonus Depreciation is made based on consolidated results." The Company further replies that the

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[27] Staff/105 at 2, Company Response to Staff DR No. 353 regarding SIT, FIT and ADIT.

MDUR tax department does not anticipate claiming bonus depreciation on either the 2015 or the 2016 tax returns.

In follow-up DR. No. 353, I asked for an explanation of the MDUR's tax department's business rationale or tax strategy to forgo bonus depreciation for 2015 and 2016. The Company explained:

> *The tax department along with management chose to forego the taking of bonus depreciation primarily because it was part of a tax consolidated group that is expected to be in a net operating loss carryforward position, which would have only been magnified by electing to take additional accelerated depreciation in the form of bonus depreciation.* MDU Resources, Inc. ("MDUR"), the consolidated group of which Cascade is a part, has forecasted net operating losses at the end of 2015 and 2016, before consideration of bonus depreciation in the amount of $226 million and $20 million, respectively. Taking bonus depreciation would double the losses for both years. Another business consideration is the expiration of various state income tax credits, such as $4 million of Oregon energy tax credits. [28]

In Staff's opinion, MDUR's decision to forgo or opt out of bonus depreciation for 2015 and 2016 is unreasonable, imprudent, and harms Cascade's customers. In essence, bonus depreciation is an interest free loan from the government to the taxpayer. The ability to increase tax depreciation by 50 percent of the asset's cost in 2015 and 2016 defers a company's tax liability and increases cash flow, which provides an enormous immediate benefit to a company. Further, if the company is a regulated utility, as part of normalization for rate making purposes, the regulated utility must reduce rate base by the

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[28] *Id at 3. (Emphasis added).*

associated deferred taxes. This in turn reduces the company's revenue requirement and utility customer rates as a result.

By forgoing bonus depreciation, MDUR fails to seize the opportunity to utilize "free" capital and instead either must increase its conventional borrowing or reduce its free cash flow to fund investment in utility plant. Ratepayers are negatively impacted because rates are increased for the new plant additions without the offset of deferred income taxes in rate base.

To review the Company's historical use of bonus depreciation, I asked whether MDUR had claimed bonus depreciation on its tax returns for the time periods and tax years listed in the table below. The column titled "Explanation" is the Company's response. As can be seen in the table, MDUR historically has opted to take the bonus depreciation deduction for each of the tax years the deduction was available, going back to 2008.[29]

Start date	End date	Tax Years	Explanation
Jan. 1, 2008	Sept. 8, 2010	1/1/2008 - 9/8/2010	Bonus Depreciation taken
Sept. 9, 2010	Dec. 31, 2011	9/1/2010 -	Bonus Depreciation taken
Jan. 1, 2012	Dec. 31, 2014	1/1/2012 -	Bonus Depreciation taken
Jan. 1, 2015	Dec. 31, 2016		No Bonus elected (see response to OPUC- 353)
Jan. 1, 2017	Dec. 31, 2017		No determination made

Further, in its response to Staff DR No. 353, the Company addresses the consolidated group's net operating loss carryforward position and the potential expiration of Oregon energy tax benefits, but never mentions the negative

[29] Staff/105 at 8,Company Response to Staff DR No. 357.

impact its decision will have on utility ratepayers. Nor does the Company discuss how MDUR's decision to opt out of bonus depreciation results in a larger rate base allowing MDUR to grow revenue. In my opinion, it is unreasonable for the consolidated group to benefit at the expense of utility ratepayers. Additionally, under 26 U.S. Code § 172 – Net operating loss deduction(b)(1)(A)(ii), the general rule is "a net operating loss for any taxable year shall be a net operating loss carryover to each of the 20 taxable years following the taxable year of the loss."[30] Hence, MDUR has the opportunity to carryover the net operating losses for a long period of time.

With regard to the Oregon Business Energy Tax Credit (BETC), in SDR No. 118, I requested a schedule of utility tax credits for the three most recent years preceding the test period.[31] Cascades' response to SDR No. 118 stated, "Cascade has no utility tax credits for the requested period." Subsequently, I spoke to with Cascade regulatory staff to clarify this statement. Cascade regulatory staff provided additional detail explaining that an affiliate, Future Source, had purchased the Oregon BETC's and none of the credits are allocated to the Oregon jurisdiction. Consequently, the Oregon jurisdiction receives no tax benefit. Staff intends to follow-up with a data request as confirmation.

Based on my analysis, I conclude that is unreasonable and imprudent for MDU to opt out of bonus depreciation for years 2015 and 2016; therefore, I

[30] https://www.law.cornell.edu/uscode/text/26/172 accessed 8/1/2016
[31] Staff/105 at 1, Company Response to Staff DR No. 118.

recommend adjusting 2015 and 2016 rate base by increasing ADIT. This proposed adjustment is based on the Company's response to Staff DR No. 356, which requested that the Company calculate the bonus depreciation tax impact as if the Company filed independent (standalone) tax returns for 2015 and 2016. My proposed adjustment is an increase to ADIT in rate base of $(4,094,231). The supporting calculations for this adjustment can be found in my electronic workpaper titled "UG 305 Gardner ADIT Adjustment.xlsx."

ISSUE 6. WORKING CAPITAL

The Company included $2,287,971 in its test year working capital allowance. This includes, FERC Accounts No. 154, Plant Material and Operating Supplies; No. 163, Store Expense Undistributed; No. 164.2, Liquefied Natural Gas Stored, and No. 165, Prepayments – Gas Storage. These accounts are considered material and supplies. The Commission typically authorizes utilities to include an allowance for material and supplies in rate base.[32]

Staff witness Kathy Zarate reviewed the amount included in rate base for the Plant Material and Operating Supplies account while Staff witness Erik Colville reviewed the amount included in rate base for gas storage in FERC Accounts Nos. 163, 164.2, and 165. Their conclusions can be found in their separate testimony.

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[32] *See, e.g.*, Order Nos. 77–394, (1977 WL 438034), Order No. 74–898 (1974 WL 391913).

ISSUE 7. DIRECTOR FEES

According to OAR 860-027-0016, "Directors' fees paid by an energy . . . utility to members of its board of directors, who are also paid as officers of the energy . . . utility, shall not be recognized as a charge to operating expenses in Oregon." In response to Staff SDR No. 62, Cascade verified that directors who are also officers of the Company did not receive director fees. Therefore, I do not propose an adjustment.

ISSUE 8. RATE CASE COSTS

In Staff DR Nos. 289 and 290,[33] I inquired about the rate case costs that Cascade included in the 2015 base year and the 2016 test year. In its response, Cascade provided the 2015 actual cost detail. In aggregate, 2015 rate case costs were $283,766.[34] In response to Staff DR No. 290(d), the Company explained that, while they do not expect the 2016 rate case costs to be the same as the 2015 base year costs, the 2015 base year costs are assumed to be representative of 2016. Therefore, consistent with the parties' testimony in support of the UG 287 stipulation, I recommend that the 2016 test year rate case costs of $287,171 (2015 base year $283,766 increased by the Company's inflation factor of 1.012[35]) be amortized over three years.[36] I also propose to include one third of the UG 287 rate case costs. A three-year amortization period allows a smoothing of rate case costs over a longer period

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[33] Staff/106 at 1-3, Company Response to Staff DR Nos. 289 and 290 regarding Rate Case Costs.
[34] *Id at 2.*
[35] Staff/106 at 5, Parvinen Workpapers Exhibits 201-206.xlsx, tab "Inflation".
[36] UG 287, Stipulation/3 at 19-20.

when rates may be in effect. My proposed adjustment results in a decrease in rate case expense of ($52,583).

ISSUE 9. REVENUE TAXES

Revenue taxes charged by Cascade to Oregon are described as Oregon Public Utility Commission regulatory fees, Oregon Department of Energy fees, and franchise fees.[37]

I reviewed the OPUC fee rate included in the Company's filed conversion factor[38] and found that it is the same as the annual fee rate of 0.275 percent authorized in Commission Order No. 16-067. So Staff does not propose any adjustment.

I also reviewed the Oregon Department of Energy Fees invoices for the 2015 and 2014 calendar years and the amount Cascade charged to expense for the 2015 base year. I am satisfied the correct amount of expense is recorded for the 2015 base year. Cascade inflated the 2016 test year for CPI by 0.012. I will propose an aggregate adjustment for inflation separately in Issue 11. Therefore, I do not propose a separate adjustment to Oregon Department of Energy Fees included in the test year. In Staff DR No. 262, I questioned the Company regarding the 0.01835 franchise fee included in the filed conversion factor. The Company responded that the franchise fee rate of 0.01835 was incorrect and should actually be 0.0231. I reviewed the

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[37] Staff/107 at 1, Other Revenues.
[38] UG 305/CNGC/203, Parvinen/1.

Company's workpaper included with its OPUC DR No. 262 response and propose to correct the rate to 0.0231 in Staff's revenue requirement model.

ISSUE 10. TAXES OTHER THAN INCOME

The category "Taxes Other than Income" includes payroll taxes, property taxes, and other miscellaneous taxes. I reviewed payroll taxes as part of the Wage and Salary adjustment and do not propose an additional adjustment besides what is proposed in Issue 2 above.

In reviewing property taxes, I analyzed annual tax amounts from the years 2010 through 2015, as well as those forecasted for 2016. I did not note any out of period expense. Property taxes for the 2015 base year are approximately $1,394,000, which the Company inflated by 1.12 percent to arrive at the test year property tax expense for the existing 2015 property. Also, based on my review, the 1.4689 property tax rate utilized by the Company to estimate the 2016 incremental property tax expense for their proposed 2016 plant additions appears to be reasonable.[39] I will adjust the inflation factor in Issue 13. Otherwise, based on the level of property the Company has proposed, I do not propose an adjustment.

Miscellaneous taxes are $7,773 of the total of $1,926,429 charged to the category "Taxes Other than Income" for 2015. I reviewed the transactional detail. The charges for miscellaneous taxes were primarily Oregon situs amounts for taxes levied by the Oregon Department of Transportation and the

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[39] Staff/104 at 1, Parvinen Workpapers Exhibits 201-206.xlsx, tab "2016 Plant Additions".

Oregon Department of Motor Vehicles. I did not find any exceptional expenses.

As the Revenue Requirement Summary Witness, I will update the test year property tax expense to reflect adjustments sponsored by other Staff witnesses to plant. Therefore, while I do not propose any adjustment at this time to property tax expense, I may have an adjustment to the final revenue requirement contingent upon other Staff witnesses' associated discovery and analysis.

ISSUE 11. OTHER BENEFITS

The Company has requested a total of $1,661,490 (2015 base year) before inflation, on an Oregon jurisdictional basis, for expenses relating to benefits.[40] This amount includes other benefits; medical, dental, and life insurance benefits; pension expense, post retirement expense, and 401-K expense; worker's compensation expense; and supplemental defined plan and contribution expense.

Benefit plan premiums are typically shared between the Company and the employees. The Company generally shares cost with the employees at a ratio of 80/20,[41] with the employer's premium cost being 80 percent and the employee's cost being the remaining 20 percent.

I reviewed the historical trend in the Company's Medical, Dental and Life Insurance expenses charged to cost code 5194 provided in the Company's

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[40] Staff/108 at 3, Other Benefits.
[41] *Id* at 14.

response to Staff DR No. 298 for the historical years 2012-2015 and the 2016 budget. [42] I also reviewed the health care benefit highlights and premiums for the years 2014 through 2016.[43] For a benchmark, I compared the Company costs to those published by the Kaiser Family Foundation. Staff usually relies on the Kaiser Family Foundation research for industry health benefit trends absent any compelling reason to rely more heavily on other evidence.

With regard to employer/employee sharing of costs, the 2015 Kaiser Family report, "Employer Health Benefits, 2015 Summary of Findings," states: "Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2014 and statistically similar to those reported in 2010." [44] Staff customarily proposes no adjustment to sharing between the Company and employees unless the sharing percentage is deemed unreasonable upon review. The Company's 80/20 sharing is reasonable and therefore I do not propose an adjustment.

For the remaining benefits, I reviewed the historical cost trend from 2012 through 2015, as well as the 2016 budgeted amounts provided in the Company's response to Staff SDR No. 63.[45] I noted anomalies in the trended costs and issued additional data requests to the Company. In the Cascade's

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[42] *Id.* at 16-17.
[43] *Id.* at 4-13.
[44] The Henry J. Kaiser Family Foundation, Employer Health Benefits, 2015 Summary of Findings, (July 27, 2016), http://kff.org/report-section/ehbs-2015-summary-of-findings/; Staff/108 at 20.
[45] Staff/108 at 1-3, Company Response to Staff DR No. 63.

response to Staff DR No. 373, the Company primarily points to market conditions and other external projections, such as discount rates, long-term rate of return and updated mortality tables, as causal to the fluctuations. I reviewed the Company's comments with Staff Witness, Matt Muldoon, and conclude that the Company's explanations are reasonable. I believe that the Company's proposal to forecast the 2016 test year based on the 2015 base year costs is acceptable except for costs in cost code 5192, "Other Benefits".

As described by the Company, code 5192 contains costs paid for actuarial services, investment consultants, and audit fees. In Staff's view, the Company has internal control of these types of expense. Therefore, I recommend substituting the Company's test year amount of $20,840 with the Company's 2016 budgeted amount of $3,181. This reduces the Company's test year expense by $(17,659).

ISSUE 12. INTEREST SYNCHRONIZATION

According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes to the regulated utility's cost of capital as initially filed in a general rate case. This is consistent with the treatment in Cascades' last general rate case, UG 287. The interest synchronization adjustment depends on Staff Witness Matt Muldoon's proposed adjustments to cost of capital (CoC) in this docket. Mr. Muldoon has recommended in his testimony an adjustment to the Company's filed cost of capital, of which the weighted cost of debt is a component. Because interest expense on long-term debt is tax deductible, Mr. Muldoon's proposed cost of long-term debt impacts income tax expense for ratemaking purposes. The cost of long-term debt proposed in CNG's direct testimony is 5.295 percent.[46] Mr. Muldoon's recommends a 5.250 percent cost of debt and a weighted cost of long-term debt of 2.678 percent.[47]

As the Revenue Requirement Summary witness, I recommend synchronizing the interest expense for the income tax calculation to reflect a weighted cost of debt of 2.678 percent. Based on the Company's test year rate base of $84,871,728 and weighted cost of long-term debt of 2.700 percent.[48] Staff's proposes to reduce interest expense by $18,672 = ($84,871,728 *(2.678% - 2.700)).

The amount is calculated on the base year as follows:

+ Net Rate Base

X Staff's Recommended (or Authorized) Weighted Cost of Debt

= Allowable Interest Deduction

- Company's Reported Interest Deduction

= Interest Coordination Adjustment

ISSUE 13. INFLATION FACTOR/ESCALATION

It is Staff policy to use the Consumer Price Index – All Urban Consumers for the U.S. as published by the State of Oregon Office of Economic Analysis for year over year escalation. The most recent release was June 3, 2013. According to Appendix A of this report, the percentage change for 2015 to

[46] UG 305/CNGC/200, Parvinen/9 at Table 1.
[47] UG 305/Staff, Muldoon/2 at Table 3.
[48] Staff/109, Parvinen Workpapers Exhibits 201-206.xlsx, tab "Capital Structure Calculation".

2016, is 1.0 percent.[49] The Company proposes to inflate the 2015 base year non-labor expenses for Production, Distribution, Customer Accounts, and A&G by 1.2 percent, resulting in an increase to the 2016 Test Year O&M expense of $90,228.[50] As provided in response to Staff's DR No. 291, the Company also used the CPI change for 2015 to 2016 from Appendix A. However, the Company used an earlier publication, March 2016.[51]

Staff proposes to use the most recently published CPI change of 1.0 percent. Additionally, Staff queried the Company regarding the source of the labor expenses the Company excluded from the 2015 base year. The company responded that they used system accrued wages.[52] Staff proposes to use the labor amounts derived from the Company's response to DR No. 58 revised because the detailed transactions provided in this response are the source for the summarized 2015 base year.[53] This increases the amount of labor excluded from the 2015 base year. Therefore, Staff recommends both a CPI factor of 1.0 percent and a reduction to the non-labor expenses, upon which the inflation factor is applied, of $955,974. This results in a decrease to the Company's inflation adjustment of $26,773 before excluding other Staff expense adjustments. After excluding other Staff reductions to expense of

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[49] Staff/110 at 1, Appendix A, June 2016.

[50] Staff/106 at 5, Parvinen Workpapers Exhibits 201-206.xlsx, tab "Inflation".

[51] Staff/110 at 10, Appendix A, March 2016.

[52] Staff/110 at 2.

[53] UG 305/CNGC/201 Parvinen/1 at column (1).

$1,573,563 Staff proposed inflation adjustment is a decrease of $42,509 to the Company's proposed inflation adjustment. The supporting calculations for this adjustment can be found in my electronic workpaper titled, "UG 305 Gardner Inflation Adjustment.xlsx" and "UG 305 Inflation – copy of OPUC-58(a) revised.xlsx."

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas Corporation
NORMALIZE UNCOLLECTIBLE EXPENSE
State of Oregon
UG 305

	Net Write Offs	
Calendar Year 2013		369,764
Calendar Year 2014		420,354
Calendar Year 2015		295,381
		1,085,499
	3 years of Net Write Offs: 2012 - 2014	1,085,499
Calendar Year 2013 Total Operating Revenue		65,973,538
Calendar Year 2014 Total Operating Revenue		70,092,488
Calendar Year 2015 Total Operating Revenue		67,650,226
		203,716,252
Uncollectible Expenses (Bad Debt Provision) for the 12 months ended 12/31/15		166,036
3 Year Average Net Write Off as a percentage of 2013-2015 Gross Revenues		0.533%
2015 Sales		67,650,226
	Proforma Expense	360,473
Adjustment to normalize Uncollectible Expenses		**194,437**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 202

Date prepared: 06/10/2016

Preparer: Tony Durado/Candice Tschauner/Mike Kingery

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 202

For each month of each year from 2012 through 2015, please provide on a total company, and a Cascade Natural Gas (CNG) Oregon share, basis:

a. The total actual net write-off related to uncollectible customer accounts, the related general business revenues and the uncollectible rate;
b. Energy assistance funds applied to customers' accounts (e.g., LIEAP and other public funds, outside agency funds, internal company funds, shareholder/customer voluntary funds, etc.);
c. Total amount of funds received for energy assistance. Please also identify the FERC account number(s), account title(s), and account description(s) where these funds were recorded, and the amount recorded in each account;
d. Total number of non-payment disconnections;
e. The monthly recorded FERC account 904 uncollectible amount;
f. The amount that was turned over to a collection agency;
g. The amount recovered by CNG through the use of a collection agency net of any third-party collection fees;
h. The collection agency's fees charged to and paid by CNG, and average percent of recoveries paid as fees; and
i. The net percent collected by the collection agency on the face value of the delinquent accounts turned over to the collection agency.

Response: **Please refer to OPUC-202 a&e.xlsx**
Please refer to OPUC-202 b&c.xlsx
Please refer to OPUC-202 d & f-i.xlsx

OPUC-202 a & e

Per	Amount
1 Total	1,280.71
2 Total	805.16
3 Total	(3,076.36)
4 Total	18,896.32
5 Total	18,435.42
6 Total	11,993.80
7 Total	29,459.46
8 Total	61,501.66
9 Total	29,706.39
10 Total	39,507.72
11 Total	16,350.70
12 Total	17,271.04
Grand Total	**242,132.02**

Oregon Total Net Write-off	**242,132.02**
Oregon Total Revenue	**61,777,271.99**
Uncollectible Rate	**0.39%**

OPUC-202 a & e

Per	Amount
1 Total	2,257.90
2 Total	(481.82)
3 Total	3,763.24
4 Total	13,769.11
5 Total	24,171.25
6 Total	38,927.32
7 Total	73,518.68
8 Total	55,155.31
9 Total	49,483.66
10 Total	23,478.04
11 Total	(6,332.03)
12 Total	26,017.91
Grand Total	**303,728.57**

Oregon Total Net Write-off	**303,728.57**
Oregon Total Revenue	**65,785,174.95**
Uncollectible Rate	**0.46%**

OPUC-202 a & e

Per	Amount
1 Total	3,267.88
2 Total	4,398.59
3 Total	(2,661.54)
4 Total	2,641.30
5 Total	20,729.94
6 Total	20,752.95
7 Total	22,880.06
8 Total	40,718.87
9 Total	23,450.77
10 Total	22,570.12
11 Total	10,808.03
12 Total	(333.40)
Grand Total	**169,223.57**

Oregon Total Net Write-off	**169,223.57**
Oregon Total Revenue	**63,397,033.37**
Uncollectible Rate	**0.27%**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 316

Date prepared: 6/28/16

Preparer: Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 316

Referring to the Company's response to Staff DR No. 202, specifically OPUC – 202 a&e.xlsx, , please explain why the net write-offs provided in (a.) for each of the years 2013, 2014, and 2015 are not the same as the net write-offs provided for the same years in the Company's response to Staff DR No. 213, specifically OPUC – 213.xlsx. Additionally, the Company's response in OPUC – 213.xlsx is materially different from the FERC 904 expense provided in response to Staff DR No. 202 (e.). For convenience, a table illustrating the differences is provided below. Please provide a narrative explanation or a correction to the amounts the Company provided if applicable.

Oregon	(1)	(2)	(3)	(4)
	Actual Net Write-offs [1]	FERC Acct 904 [2]	Net Write-offs [3]	Explanation
2013	$242,132	$261,624	$369,764	
2014	$303,729	$284,794	$420,354	
2015	$169,224	$166,036	$295,381	
[1] Response to OPUC - 202 (a.)				
[2] Response to OPUC - 202 (e.)				
[3] Response to OPUC -213 & Parvinen Workpapers Exhibits 201-206.xlsx				

Response:

(1) Is a calculation of net-write offs, which includes both write-off amounts and recovered amounts. FERC 144.
(2) FERC 904 is the amount booked as bad debt expense at year end. This is the amount we expect to be eventually written off.
(3) This amount only includes write off amounts and does not include any recovered amount. These figures are not net-write off amounts.

CNG UG 305
Test Year Ending December 31, 2016
Staff Uncollectible Adjustment

Source	Description/ Account No.			Staff Adjustment	
Data Response Attachment OPUC-202 a&e, 202a	3-year Average of Oregon Actual Net-Write Offs (Calendar Years 2013, 2014 and 2015)	a	1	$238,362	
Data Response Attachment OPUC-202 a&e, 202a	3-year Average of Oregon Related Revenues (Calendar years 2013, 2014 and 2015)	b	2	$63,653,160	
	3 year average bad debt rate	c		0.3745%	a/b
Parvinen Workpapers 203/Exhibit Support	2015 adjusted Uncollectibles	d		$360,473	f*e
Parvinen Workpapers 203/Exhibit Support	2015 Total Oregon Revenue	e		$67,650,226	
Parvinen Workpapers 203/Exhibit Support	2015 Base Business Uncollectible Rate	f		0.5329%	
Parvinen Workpapers Exhibits 201-206.xlsx, tab "Exhibit 201 - ROO Summary", line 1, col (3)	2016 Natural Gas Sales	g		$64,834,293	
	Staff proposed uncollectible rate (3 year average)	c		0.3745%	
		i		$ 242,785	g*c
	2016 Company 2016 test year Uncollectible expense	j		$ 360,473	
Staff Proposed Adjustment to Uncollectible Expense				$ (117,688)	i-j

Staff Supporting Sub-Schedule

1	$242,132
	$303,729
	$169,224
average of net write-offs	$238,362
2	$61,777,272
	$65,785,175
	$63,397,033
average of natural gas sales	$63,653,160

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 253

Date prepared: 6/27/16

Preparer: Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 253

253. Referring to the Company's response to Staff's SDR No. 92, Staff, as requested by the Company, is issuing a new data request listed as item "a." below. After discussion with the Company, Staff has restated SDR No. 92 here because the Company declined to supplement its response to SDR No. 92 by reporting the requested information of both O&M and Capitalized compensation by each employee classification and by each compensation type.

   a. Please update the response to SDR No. 92 and provide, for the projected 2016 test year, and for each of the historical calendar years 2012, 2013, 2014, and 2015, the actual compensation that the Company paid. Please report the compensation as illustrated in Table A below. Please note that SDR No. 92 requests the actual paid compensation for the historical years; in other words, the dollar amount requested is the whole amount paid, regardless of whether the compensation is capitalized (rate base) or classified as O&M in the Company's books.

   b. Referring to item "a." above, for years 2016, 2015, 2014, 2013, and 2012, please provide the cross-charges broken down between Officers and Non-Officers as illustrated in Table A below.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Table A (Company – Paid Compensation)

Year: Test Year - 2016	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers	N/A	$562,974.00	$0	$212,408.46	$775,382.46
Cross Charges-Non-officers	N/A	$4,350,668.90	$48,121.77	$799,915.60	$5,198,706.27
Total	N/A	$4,913,642.90	$48,121.77	$1,012,324.06	$5,974,088.73

Year: 2015	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers	N/A	$562,974.00	$0	$212,408.46	$775,382.46
Cross Charges-Non-officers	N/A	$4,350,668.90	$48,121.77	$799,915.60	$5,198,706.27
Total	N/A	$4,913,642.90	$48,121.77	$1,012,324.06	$5,974,088.73

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Year: 2014	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers	N/A	$550,478	$0	$474,091.28	$1,024,569.28
Cross Charges-Non-officers	N/A	$4,239,863.69	$45,919.82	$727,436.42	$5,013,219.93
Total	N/A	$4,790,341.69	$45,919.82	$1,201,527.70	$6,037,789.21

Year: 2013	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers	N/A	$538,848	$0	$108,557.44	$647,405.44
Cross Charges-Non-officers	N/A	$4,122,774,72	$57,208.24	$1,155,813.62	$5,335,796.58
Total	N/A	$4,661,622.72	$57,208.24	$1,264,371.06	$5,983,202.02

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Year: 2012	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers	N/A	$496,199	$0	$363,642.65	$859,841.65
Cross Charges-Non-officers	N/A	$4,603,714.36	$71,995.79	$612,425.89	$5,288,136.04
Total	N/A	$5,099,913.36	$71,995.79	$976,068.54	$6,147,977.69

Response:

For part (a) see revised Data Request #92, OPUC-92 revised.pdf

Part (b) (Table A above) includes all compensation paid and accrued for cross charged compensation.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 92

Date prepared: 6/23/16

Preparer: Kevin Conwell/Becky Mellinger

Contact: Pam Archer

Telephone: (509) 734-4591

92. For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year: 2016 (Projected)*		Projected Paid Cash Compensation			
Category	Total Company ❶ FTE	Base Wages or S	Overtime	Incentive or Bonus	Total
Officers	1	$200,890.00	$0	$80,356	$281,246
Exempt	111	$9,166,671	$0	$816,630	$9,983,301
Nonexempt	36	$1,843,257	$169,750	$192,591	$2,205,598
Union	190	$13,108,427	$1,875,426	$0	$14,983,853
Total	338	$24,319,245	$2,045,176	$1,089,577	$27,453,998
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Year: 2015		Actual Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	1	$204,180.97	0.00	$42,869.00	$247,049.97
Exempt	102	$8,998,942.97	0.00	$548,037.03	$9,546,979.30
Nonexempt	35	$1,858,640.06	$91,578.16	$99,922.55	$2,050,140.77
Union	179	$12,043,336.48	$3,049,299.34	$248,798.78	$15,341,434.60
Total	**317**	**$23,105,099.78**	**$3,140,877.50**	**$939,627.36**	**$27,185,604.64**
Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Year: 2014		Actual Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	1	$189,221.53	0.00	$97,637.00	$286,858.53
Exempt	103	$8,215,580.06	0.00	$724,521.99	$8,940,102.05
Nonexempt	34	$1,831,049.48	$99,417.70	$104,124.04	$2,034,591.22
Union	172	$11,358,342.54	$2,905,711.21	$110,303.97	$14,374,357.72
Total	**310**	**$21,594,193.61**	**$3,005,128.91**	**$1,036,587.00**	**$25,635,909.52**
Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Year: 2013		Actual Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers*	1	$175,479.98	$0.00	$43,755.00	$219,234.98
Exempt	97	$7,347,646.68	$0.00	$46,614.82	$7,394,261.50
Nonexempt	28	$1,222,993.79	$77,060.80	$12,896.00	$1,313,040.59
Union	166	$11,007,900.91	$2,848,084.16	$250.00	$13,856,235.07
Total	**292**	**$19,754,021.36**	**$2,925,144.96**	**$103,605.82**	**$22,782,772.14**
Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Year: 2012		Actual Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers*	1	$168,905.60	$.00	$8048.05	$176,953.65
Exempt	83	$6,524,777.83	$0.00	$395,509.34	$6,920,287.17
Nonexempt	23	$1,397,388.99	$96,507.36	$61,149.05	$1,555,045.40
Union	172	$10,610,611.15	$2,871,651.12	$29,675.95	$13,511,938.22
Total	**279**	**$18,701,683.57**	**$2,968,158.48**	**$494,392.39**	**$22,164,224.44**
Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

All amounts are for CNG employees only. No cross-charged amounts are included.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 254

Date prepared: 6/27/16

Preparer: Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 254

Referring to Staff's above DR No. 253, please provide the compensation data on an Oregon Jurisdictional basis for the 2016 projected test year and each of the historical calendar years 2012, 2013, 2014, and 2015 as illustrated in Table B below.

Table B (Oregon Jurisdiction – Paid Compensation)

Year: Test Year - 2016	Total Oregon FTE	Base Wages or Salaries	Overtime	Incentive or Bonns	Total
Officers	.25	$45,554.72	$0	$10,404.31	$59,959.03
Exempt	26	$2,171,788.85	$0	$133,035.53	$2,304,824.37
Nonexempt	9	$490,918.48	$24,883.91	$24,392.03	$540,194.41
Union	46	$3,093,364.51	$764,627.75	$62,336.45	$3,920,328.71
Cross-Charges Officers	N\A	$136,633.79	$0	$51,551.53	$188,185.32
Cross Charges-Non-officers	N\A	$1,055,907.36	$11,679.18	$194,139.50	$1,261,726.04
Total	N\A	$6,994,167.71	$801,190.84	$475,859.35	$8,271,217.90

Note: Cascade's test year is based on 2015 plus salary increases in the proposed wage and salary adjustment, the Supply Resource Planning adjustment, and the AC Survey adjustment.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Year: 2015	Total Oregon FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$45,554.72	$0	$10,404.31	$59,959.03
Exempt	26	$2,171,788.85	$0	$133,035.53	$2,304,824.37
Nonexempt	9	$490,918.48	$24,883.91	$24,392.03	$540,194.41
Union	46	$3,093,364.51	$764,627.75	$62,336.45	$3,920,328.71
Cross-Charges Officers	N/A	$136,633.79	$0	$51,551.53	$188,185.32
Cross Charges-Non-officers	N/A	$1,055,907.36	$11,679.18	$194,139.50	$1,261,726.04
Total	81.25	$6,994,167.71	$801,190.84	$475,859.35	$8,271,217.90

Year: 2014	Total Oregon FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$45,980.83	$0	$23,725.79	$69,706.62
Exempt	25	$1,961,262.61	$0	$176,269.32	$2,137,531.93
Nonexempt	8	$450,938.90	$26,859.13	$25,302.14	$503,100.17
Union	42	$2,828,316.08	$738,048.60	$21,326.73	$3,587,691.41
Cross-Charges Officers	N/A	$133,766.15	$0	$115,204.18	$248,970.33
Cross Charges-Non-officers	N/A	$1,030,286.87	$11,158.46	$176,767.06	$1,218,212.39
Total	75.25	$6,450,551.44	$776,066.19	$538,595.22	$7,765,212.85

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Year: 2013	Total Oregon FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$43,080.34	$0	$10,741.85	$53,822.19
Exempt	24	$1,762,089.45	$0	$8,708.55	$1,770,798.00
Nonexempt	7	$320,314.21	$23,792.12	$1,982.88	$346,089.21
Union	41	$2,737,634.64	$692,388.35	$0	$3,430,022.99
Cross-Charges Officers	N/A	$132,265.09	$0	$26,650.85	$158,915.94
Cross Charges-Non-officers	N/A	$1,012,163.21	$14,044.59	$283,752.28	$1,309,960.08
Total	72.25	$6,007,546.94	$730,225.06	$331,836.41	$7,069,608.41

Year: 2012	Total Oregon FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$41,432.54	$0	$1,974.19	$43,406.73
Exempt	20	$1,628,498.90	$0	$122,397.24	$1.750.896.14
Nonexempt	6	$355,935.32	$23,311.98	$16,818.12	$396,065.43
Union	42	$2,729,114.27	$654,847.46	$5,085.82	$3,389,047.55
Cross-Charges Officers	N/A	$121,717.61	$0	$89,201.54	$210,919.15
Cross Charges-Non-officers	N/A	$1,129,291.07	$17,660.53	$150,228.00	$1,297,179.60
Total	68.25	$6,005,989.71	$695,819.97	$385,704.91	$7,087,514.60

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Response: Compensation amounts for officers, exempt, non-exempt and union only include cash paid amounts. Amounts included for cross-charges officers and non-officers include both cash paid and accrued amounts.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 256

Date prepared: 6/27/16

Preparer: Becky Mellinger/Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 256

Referring to Staff's above DR No. 253, please provide the projected 2016 compensation and the 2012, 2013, 2014, and 2015 compensation on an accrual basis (GAAP) for both the Company and the Oregon Jurisdiction. Please format the data as illustrated in Table D and E below.

Table D (Company – Accrual Basis)

Year: Projected 2016 Test Year (2012-2015)	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers					
Cross Charges-Non-officers					
Total					

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Table E (Oregon Jurisdiction – Accrual Basis)

Year: Projected 2016 Test Year (2012-2015)	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Cross-Charges Officers					
Cross Charges-Non-officers					
Total					

Response:

As requested per OPUC staff our response to DR #256 only addresses incentive amounts budgeted in one year and paid in the next. There is no material difference between the amounts provided in DR #92 (cash paid compensation) and the full accrual amount for each year.

	2016	2015	2014	2013
Budgeted	1,061,486	1,274,075	1,136,670	941,589
Year End Accrual		-	689,122	747,218
Paid (in following Year)		-	680,138	897,511

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 368

Date prepared: 7/18/16

Preparer: Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 368

Referring to the Company's response, OPUC-98 AON Report.pdf, AON Hewitt observes on page 7 , "Bargained employees at CNGC do not participate in these [incentive] plans." If this is the case, please provide a narrative explaining why in the Company's response, OPUC-254.pdf, union incentives are included for each of the years 2014, 2015 and 2016.

Response:

The amounts included in OPUC-254.pdf for union employees and incentives are for any safety/wellness payments made. Union employees are eligible for these payments if granted and approved by the company. Safety/wellness payments are coded to the same object as regular incentive payments.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 369

Date prepared: 7/18/16

Preparer: Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 369

Referring to the Company's response, OPUC-254.pdf, for the incentives included in the table "Year 2015", please provide a breakdown of the incentive amount, by employee category, into incentives tied to Financial Performance, incentives tied to Reduced Spending, and incentives based on Customer Satisfaction as illustrated in the table below.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Year: 2015	Incentive or Bonus
Officers	
Financial Performance	
Reduced Spending	
Customer Service	
Total	$ 10,404.31
Exempt	
Financial Performance	
Reduced Spending	
Customer Service	
Total	$ 133,035.53
Nonexempt	
Financial Performance	
Reduced Spending	
Customer Service	
Total	$ 24,392.03
Union	
Financial Performance	
Reduced Spending	
Customer Service	
Total	$ 62,336.45
Cross-Charges Officers	
Financial Performance	
Reduced Spending	
Customer Service	
Total	$ 51,551.53
Cross-Charges Non-officers	
Financial Performance	
Reduced Spending	
Customer Service	
Total	$ 194,139.50

Response:

For exempt and non-exempt employees the breakdown of the incentive payments is 1/3 for each component. The first component is tied to earnings. If this target is reached then it is determined if the other goals were met to calculate total payout. If the minimum earnings goal is not met then there is no payment made even if the reduced spending and customer service goals were achieved.

Officer's incentive amounts are calculated differently as per the attached file OPUC-369 Officer Incentive Calculations.pdf

MDU Resources Group, Inc.
Executive Compensation Program Summary - EICP

Program	Performance Measures	How it Works
EICP (annual incentive)	EPS & ROIC	See below

- Each position has an EICP target (expressed as a % of base salary)
- The position's EICP target is a function of competitive practice and internal equity
- The EICP target is divided equally between EPS and ROIC
- EPS and ROIC are paid independently, according to the following scale:

EPS or ROIC Results vs. Goal		% of Target Paid
< 85%		0%
85%		25%
90%		50%
95%		75%
100%	*Target*	100%
103%		120%
106%		140%
109%		160%
112%		180%
115%		200%

- ROIC goals are increased each year until the business unit's (or MDUR's) ROIC goal is equal to or above its weighted average cost of capital
- After-tax payments of incentives above target are limited to 20% (after-tax) of the incremental earnings above plan. This limitation is measured at the major business unit level for business unit employees and at the corporate level for MDUR employees.

MDU Resources Group, Inc.
Executive Compensation Program Summary - Performance Shares

Program	Performance Measures	How it Works
Long-Term Performance Based Incentive (LTIP) a.k.a. "Performance Shares"	MDUR's 3 yr Total Shareholder Return (TSR) vs. the Proxy Peer Group	• Each position has an LTIP target (expressed as a % of base salary) • The position's LTIP target is a function of competitive practice and internal equity • In February, performance share grants are made to LTIP participants according to the following methodology: (Base Salary X LTIP target %) / Share Price where Share Price is the average closing price of MDUR's common stock for the first 22 calendar days of the month prior to the grant • The performance measurement period is 3 years; e.g., '05 - '07 • At the February meeting following a performance period, from 0% to 200% of the grant is paid, depending on MDUR's TSR results compared to the Proxy Peer Group. • The payment schedule is:

MDUR's Percentile Rank of TSR Compared to Proxy Peer Group		Payout %
Less than 40th		0%
40th		10%
50th	*Target*	100%
75th		150%
100th		200%

Results between percentile ranks are interpolated

• Dividend equivalents are credited according to the payout percentage.

MDU Resources Group, Inc.
Executive Compensation Program Summary - Base Salary

Program	Performance Measures	How it Works
Base Salary	Operating results and Performance Assessment factors	• A position is assigned to a salary class based on the competitive salary for the position and internal equity • The salary class midpoint approximates the competitive salaries of all positions in the salary grade • The executive's performance is assessed on operating / financial goals and the competencies delineated in our Performance Assessment program • Base salary increases are a function of the individual's performance and their current salary relative to their salary class midpoint

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 370

Date prepared: 7/26/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 370

Referring to Staff's above DR No. 369, for each incentive type, please provide a narrative explaining how each type benefits customers.

Response:

As stated is OPUC-369, there are three components to the incentive plan each providing benefits to customers.

The first component is overall earnings. Increasing earnings has a direct benefit on customers in two ways. If earnings are significantly improved earnings are shared with customers. However, anytime those earnings are improved means there is less reliance on customer funding. Less reliance on customer funding means less rate cases and/or less magnitude of increased rates.

The second component is reduced O&M expenditures. Much like the first component, reducing O&M has the impact of reducing the need of rate case or the magnitude of the rate case. These are measures a direct benefit to customers.

The third component is customer satisfaction. Each year customers are surveyed by JD Powers to determine customer's satisfaction with Cascade. Obviously customer satisfaction is a direct benefit to customers.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 371

Date prepared: 7/26/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 371

According to Staff Commission policy, in a rate case proceeding, Staff routinely disallows 100 percent of officer incentives, 75 percent of non-officer incentives related to cost savings and productivity, and 50 percent of non-officer incentives related to merit. Referring to the UG 305/CNGC, Parvinen/Exh 201, columns (1) and (3), please provide a narrative explaining whether any portion of the actual 2015 incentive amounts paid has been excluded from the incentive amounts included in columns (1) and (2). If so, please provide the amounts excluded and all underlying calculations, point to any testimony or data response that substantiates the amounts excluded, and provide the Company's rationale for excluding. If not, please explain why not.

Response:

Based on the benefits to customers described in OPUC-370, Cascade disagrees with apparent arbitrary disallowance described above. However, in this case there are no incentive amounts included in UG 305/CNGC, Parvinen/Exh 201. Incentive payouts paid in 2015 were accrued as operating expenses in 2014. Since the Company did not achieve its earnings targets or goals in 2015, no incentive was accrued for in 2015. Therefore, no payout was made in 2016 for 2015.

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas
Plant Additions Adjustments
Twelve Months Ended December 31, 2015
UG 305

	OR	WA	Combined	Depr Rate	Depr Exp	Dper Res	Tax Depr 0.05	Deferred Tax
3030-Misc. Intangible Plant	941,750	2,938,555	3,880,305	10.00	94,175.00	47,087.50		
3671-Transmission Mains	-	(284,392)	(284,392)	1.82	0.00	0.00		
3761-CNG Mains Steel	140,012	1,765,686	1,905,698	2.20	3,080.26	1,540.13		
3762-CNG Mains High Press Steel	1,537,002	13,417,359	14,954,361	1.25	19,212.52	9,606.26		
3763-CNG Mains Plastic	4,033,739	6,763,627	10,797,366	4.13	166,593.42	83,296.71		
3780-Meas & Reg Equip Gen	2,621,131	2,571,188	5,192,319	1.92	50,325.72	25,162.86		
3803-CNG Services Plastic	1,818,540	4,243,260	6,061,800	3.88	70,559.35	35,279.68		
3810-Gas Meters	1,084,336	3,383,469	4,467,805	2.27	24,614.43	12,307.22		
3830-Service Regulators	123,447	385,192	508,638	2.32	2,863.96	1,431.98		
3850-Ind. Meas. & Reg. Statio	226,964	918,287	1,145,252	2.18	4,947.82	2,473.91		
3901-CNG Structures & Improvement	7,848	66,870	74,719	1.24	97.32	48.66		
3913-CNG Servers and Workstation	127,611	398,185	525,796	16.24	20,723.96	10,361.98		
3915-CNG Office Furniture & Fixt	-	13,043	13,043	4.98	0.00	0.00		
3922-Transportation Equipmen	489,183	1,969,498	2,458,681	6.15	30,084.73	15,042.37		
3941-MDU/GPNG/CNG Tools, Shop & Gara	206,040	618,348	824,388	3.56	7,335.01	3,667.51		
3962-Power Operated Equipmen	250,445	622,439	872,884	5.18	12,973.08	6,486.54		
3972-CNG Comm Equip Telemeterin	65,925	205,706	271,631	0.13	85.70	42.85		
	13,673,972	**39,996,319**	**53,670,291**		**507,672**	**253,836**	683698.6	70,305

2015 Property Tax Rate	1.4689%		
Property Taxes	$200,857		
		Expense	
Additonal year of depreciation expense effect on accumulated depreciation		6,111,512	6,111,512
Total Accumulated Depreciation			6,365,348

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 118

Date prepared: 2/23/2016

Preparer: Becky Beach

Contact: Pam Archer

Telephone: (509) 734-4591

127. For the test year and the three most recent years preceding the test period, please provide a schedule of utility tax credits showing the amount generated in each year, the amount used each year, and the amount carried forward each year. In addition, please provide the year in which each carry-forward tax credit expires and provide the genesis of each tax credit.

     If available, please provide the requested information in MS Excel schedules with formulae intact.

Response: Cascade has no utility tax credits for the requested period.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 272

Date prepared: 6/22/16

Preparer: Becky Beach/Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 272

Referring to Exhibit No. 201, CNGC/201, Parvinen/1 at 21 and the Company's response to Staff DR No. 15, "OPUC-151 DR A166-167 (2011-2014) Lines 20-26.xlsx" at cell O25, please explain if the "Total Accumulated DFIT" amount includes a depreciation timing difference arising from bonus depreciation for each of the years 2014, 2015 and the 2016 test year. If not, please explain why not. If so, please explain how CNG incorporated bonus depreciation into the rate case.

Response:

For tax purposes, Cascade is part of MDUR's consolidated tax return and as such the election to use Bonus Depreciation is made based on consolidated results.

Bonus depreciation, in the amount of $16,319,761.95, was claimed in the 2014 tax year. No bonus depreciation was claimed for 2015 nor is it anticipated to be claimed is 2016 per MDUR Tax department.

Actual claimed bonus depreciation is incorporated in the rate case by the inclusion of Accumulated Deferred Income Tax. The deferred income tax includes the tax effect on the difference between book and tax depreciation expense, including bonus depreciation.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 353

Date prepared: 7/20/2016

Preparer: Donna Genora

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 353

Referring to the Company's response to Staff DR No. 272, please explain MDUR tax department's business rationale or tax strategy to forgo bonus depreciation for each of the years 2015 and 2016. In the response, please provide any analysis that informs the tax department's decision whether to claim or to forgo bonus depreciation for each of these years.

Response:

The tax department along with management chose to forego the taking of bonus depreciation primarily because it was part of a tax consolidated group that is expected to be in a net operating loss carryforward position, which would have only been magnified by electing to take additional accelerated depreciation in the form of bonus depreciation.

MDU Resources, Inc. ("MDUR"), the consolidated group of which Cascade is a part, has forecasted net operating losses at the end of 2015 and 2016, before consideration of bonus depreciation in the amount of $226 million and $20 million, respectively. Taking bonus depreciation would double the losses for both years. Another business consideration is the expiration of various state income tax credits, such as $4 million of Oregon energy tax credits.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 354

Date prepared: 7/15/2016

Preparer: Becky Beach

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 354

Referring to the 2014 tax year, please provide a narrative that explains the Company's allocation of the 2014 ADIT related to bonus depreciation to the Oregon jurisdiction. Please support the narrative with the actual calculation of the allocation to the Oregon jurisdiction rate base.

Response:

The ADIT is allocated to rate base using the JDE rate base ratio. For 2014, that ratio was 22.74% allocated to Oregon and 77.26% allocated to Washington.

The total ADIT for the year ending 12/31/2014 (at the 2014 tax return) was $99,624,026.52, Federal ADIT was $95,792,693.90 and Oregon State ADIT was $3,831,332.62. Of this amount, $6,950,528.53, Federal ADIT $6,656,963.88 and Oregon State ADIT $293,564.65, was related to asset that qualified for bonus depreciation.

The Federal ADIT is allocated using the rate base ratio above.
$6,656,963.88 x 22.74% = $1,513,793.59
The Oregon ADIT is allocated 100% to the state of Oregon. The total 2014 ADIT allocated to Oregon related to assets qualifying for bonus depreciation is
$1,513,793.59 + $293,564.65 = $1,807,358.24.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 355

Date prepared: 7/18/2016

Preparer: Becky Beach

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 355

Referring to Staff's DR No. 354 above, please explain whether the 2014 bonus depreciation claimed on the 2014 consolidated return was attributed in part to new capital additions included in the Oregon jurisdiction's rate base. In the response, please provide the total cost of Oregon situs and allocated new plant that qualified for bonus depreciation and provide the total cost of qualified new plant included on the 2014 consolidated tax return.

Response:

Federal tax depreciation included on the 2014 consolidated tax return includes bonus depreciation attributable to assets located and allocated to the State of Oregon. The total book basis additions attributable to Oregon (as reported on Cascade's 2014 Oregon FERC form 2) is $7,837,921.55, $7,232,706.47 with Oregon situs and $605,215.08 allocated to Oregon. (See attached spreadsheet for detail.) Using the book basis attributable to Oregon, the estimated tax basis, of assets attributable to Oregon, eligible for bonus depreciation is $6,919,339.01.

Bonus depreciation is not allocated based on situs, as taxable income is allocated using the single sales factor as prescribed by Oregon revenue code section 314.650 using a single sales factor. This affects the amount of Oregon current tax. All Oregon taxes are allocated 100% to Oregon.

Total cost of qualified new plant included on the 2014 consolidated tax return, as provided by MDUR Tax Department, was $359,807,742.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 356

Date prepared: 7/15/2016

Preparer: Becky Beach

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 356

If Cascade filed taxes on an independent (stand-alone) basis rather than on a consolidated basis, what bonus depreciation could Cascade claim in each of calendar years 2014 and 2015? What accounting entries specific to the application of bonus depreciation would occur in 2015 and 2016?

Response:

For the year ending 12/31/2014, Cascade claimed bonus depreciation in the amount of $16,319,761.95. If Cascade was to claim bonus depreciation in 2015, the amount of bonus depreciation claimed would be $21,622,502.61 per OPUC-273(b).

The effect of a bonus depreciation deduction on tax expense is a decrease in current tax expense, with an offsetting increase in deferred tax expense. It will also result in an increase in deferred tax liability adjustment to rate base. For 2015, the amounts would be a credit to current tax expense in the amount of $7,781,506.24, a credit to current tax payable in the amount of $7,781,506.24, a debit to deferred tax expense in the amount of $7,781,506.24, and a credit to deferred tax liability in the amount of $7,781,506.24. This amount is calculated below.

All figures are reflected on a system basis

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

	2015	2016	
Federal tax rate	35%	35%	A
Oregon tax rate	7.60%	7.60%	B
Oregon apportionment	20%	23%	C
Bonus Depreciaion	21,622,502.61	30,535,795.62	D
Oregon tax	328,662.04	533,765.71	D x B x C = E
Federal tax	7,452,844.20	10,500,710.47	(D - E) x A = F
Total tax	7,781,506.24	11,034,476.18	
Total tax additions	45,944,012.13	61,496,562.40	
Total bonus eligible additions	43,245,005.22	61,071,591.23	G
Estimated bonus depr	21,622,502.61	30,535,795.62	G x 50% = D
Accounting entries			
Current tax expense	(7,781,506.24)	(11,034,476.18)	
Current tax payable	7,781,506.24	11,034,476.18	
Deferred tax expense	7,781,506.24	11,034,476.18	
Deferred tax liability	(7,781,506.24)	(11,034,476.18)	

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 357

Date prepared: 7/21/2016

Preparer: Becky Beach

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 357

Bonus depreciation has been available for the periods as shown in the chart below under start date and end date.1 For each of the periods listed below, please list the tax years that bonus depreciation was claimed on the consolidated tax returns of MDU. If MDU did not claim bonus depreciation for any tax year bonus depreciation was available, please explain the MDU's decision or rationale to forgo bonus depreciation for that tax year.

Start date	End date	Tax Years	Explanation
Jan. 1, 2008	Sept. 8, 2010	1/1/2008 - 9/8/2010	Bonus Depreciation taken
Sept. 9, 2010	Dec. 31, 2011	9/1/2010 - 12/31/2011	Bonus Depreciation taken
Jan. 1, 2012	Dec. 31, 2014	1/1/2012 - 12/31/2014	Bonus Depreciation taken
Jan. 1, 2015	Dec. 31, 2016		No Bonus elected (see response to OPUC-353)
Jan. 1, 2017	Dec. 31, 2017		No determination made

Response:

1 http://www.bakertilly.com/insights/bonus-depreciation, accessed July 7, 2016.

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 289

Date prepared: 6/29/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 289

Please provide the amount of rate case costs included in the 2015 base year. Please provide all of the transactional data in an excel spreadsheet with all cells and formulae intact and include, at a minimum, the fields included in the list below.

CO
CO Desc.
BU
BU Desc.
OBJ
OBJ Desc
SUB
Internal Acct. Number
Internal Acct. Desc.
FERC Acct. Number
FERC Acct. Desc.
GL Date
Type
Type Desc.
Bt Type
Bt Type Desc
Vendor name
Amount
Oregon Situs
Oregon Allocation
Units
Explanation 1
Explanation 2
Payment date

Response:

See attached file entitled “OPUC-289.xlsx”

UG 305
Schedule of 2015 Rate Case Costs - provided by Company in response OPUC-289
(reformatted by Staff to facilitate printing to one page)

FERC ACCT	OBJ Code	GL Date		Oregon Situs	Oregon Allocated	Total Oregon Jurisdiction	Explanation 1	Explanation 2
9230	5222	5/8/2015	McDowell Rackner &	$24,442.50		$24,442.50		
9230	5222	6/12/2015	McDowell Rackner &	$3,759.75		$3,759.75	CNGC 2015 GRC	Legal Representation
9230	5222	6/24/2015	McDowell Rackner &	$2,047.50		$2,047.50	CNGC 2015 GRC	Legal Representation
9230	5222	9/17/2015	McDowell Rackner &	$976.50		$976.50	CNGC 2015 GRC	Legal Representation
9230	5222	9/28/2015	McDowell Rackner &	$27,370.25		$27,370.25	CNGC 2015 GRC	Legal Representation
9230	5222	11/3/2015	McDowell Rackner &	$29,558.67		$29,558.67	CNGC 2015 GRC	Legal Representation
9230	5222	12/2/2015	McDowell Rackner &	$11,909.25		$11,909.25	CNGC 2015 GRC	Legal Representation
9230	5222	12/16/2015	McDowell Rackner &	$1,285.00		$1,285.00	CNGC 2015 GRC	Legal Representation
9230	5221	1/28/2015	Black & Veatch	$30,395.92		$30,395.92	CNGC 2015 GRC	Legal Representation
9230	5221	2/23/2015	Black & Veatch	$35,926.79		$35,926.79	Oregon GRC	Cascade LRIC Study
9230	5221	3/19/2015	Black & Veatch	$40,042.56		$40,042.56	Oregon GRC	Cascade LRIC Study
9230	5221	4/10/2015	Black & Veatch	$48,869.94		$48,869.94	Oregon GRC	Cascade LRIC Study
9230	5221	5/15/2015	Black & Veatch	$4,912.43		$4,912.43	Oregon GRC	Cascade LRIC Study
9230	5221	6/25/2015	Black & Veatch	$3,412.50		$3,412.50	Oregon GRC	Cascade LRIC Study
9230	5221	7/13/2015	Black & Veatch	$5,150.00		$5,150.00	Oregon GRC	Cascade LRIC Study
9230	5221	8/19/2015	Black & Veatch	$4,725.00		$4,725.00	Oregon GRC	Cascade LRIC Study
9230	5221	2/11/2015	AUS Consulting		$6,067.50	$6,067.50	Oregon GRC	Cascade LRIC Study
9230	5221	5/8/2015	AUS Consulting		$1,822.06	$1,822.06	Depreciation Study	Oregon Rate Case
9230	5221	9/30/2015	AUS Consulting		$1,092.15	$1,092.15	Depreciation Study	Oregon Rate Case
				$274,784.56	$8,981.71	$283,766.27		

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 290

Date prepared: 6/29/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 290

Referring to Staff's above DR No. 289, please explain:

a. Whether any of the rate case cost amounts included in the 2015 base year are charges from MDU or any MDU affiliate. If so, please describe the type of services charged and highlight each transaction in yellow;

b. Whether any of the rate cost amounts included in the 2015 base year are amortized amounts. If so, please provide the amortization schedule(s) that support the amortized rate cost and the unamortized balance(s) as of 12/31/2015. Additionally, please highlight each transaction that is an amortized cost in blue.

c. Whether any of the costs classified as rate case costs are labor costs of CNGC employees. If so, please highlight each transaction that is a CNGC labor cost in green.

d. Please explain whether the rate case costs for the 2016 test year are exactly the same amount as the 2015 base year total rate case cost.

Response:

a. No charges are from MDU or MDUR.
b. 2015 base year amounts are those charges actually booked in 2015. There are no amortizations.
c. All rate costs are external consultants or legal representation. There is no CNGC employee labor costs included.
d. 2016 and 2015 rate case costs will not be the same. However, it is assumed that the 2015 rate case costs is representative of the expected 2016 rate case costs, therefore the company did not propose a rate case cost adjustment in this docket.

UG 305 Cascade Natural Gas
Staff Recommended Adjustment to 2016 Test Year Rate Case Costs

	2015 Actual Rate Case Costs	Inflation factor	Company 2016 Test Year Expense	Amortization 3 years	Staff Proposed Test Year Expense	Staff Proposed Adjustment
McDowell Rackner & Gibson PC	$ 101,349.42	1.012	$ 102,565.61	3	$ 34,188.54	$ (68,377.08)
Black & Veatch	$ 173,435.14	1.012	$ 175,516.36	3	$ 58,505.45	$ (117,010.91)
AUS Consulting	$ 8,981.71	1.012	$ 9,089.49	3	$ 3,029.83	$ (6,059.66)
	$ 283,766.27		$ 287,171.47	3	$ 95,723.82	$ (191,447.64)

Cascade Natural Gas
Inflation Factor
Twelve Months Ended December 31, 2015
UG 305

	Base Year Amounts		Base Year Wages	2016 Projected CPI	
Production	$108,233		$108,233	0.012	1298.799
Distribution	$5,639,690	2804393	$2,835,297	0.012	34023.5613
Customer Accounts	$1,709,474		$1,709,474	0.012	20513.6868
Customer Service	$0		$0	0.012	0
Administrative and General	$5,451,075	2585099	$2,865,976	0.012	34391.709
					90227.7561

2015 System Salary Wages	10,651,416.78	0.2427	2585098.85
2015 System Union Wages	11,554,979.00	0.2427	2804393.4

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas
Conversion Factor Calculation
Twelve Months Ended December 31, 2015
REVENUE SENSITIVE COSTS
UG 305

Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00533
Taxes Other - Franchise	0.01835
OPUC Fees	0.00275
Interest expense	
State Taxable Income	0.97357
State Income Tax	0.07401
Federal Taxable Income	0.89956
Federal Income Tax @ 35%	0.31485
Total Income Taxes	0.38886
Total Revenue Sensitive Costs	0.41529
Net-to-Gross Factor	**0.58471**

Combo-State & Federal Income Tax	
State	0.07600
Federal	0.35000
State and Federal Effective Tax Rate	0.3994

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 261

Date prepared: 6/17/16

Preparer: B Beach

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 261

Referring to UG 305/CNGC/201. Parvinen/1 at 1-3 and 6, please explain the relationship of each revenue type to revenue taxes. In the explanation, please identify the jurisdiction, e.g., city, state, etc., that levies a revenue tax, and for each jurisdiction identified, the amount levied, tax rate, and any tax filings and workpapers that support the 2015 base year amount of $2,877,481.

Response:
See attached files:
OPUC-261.xlsx
OPUC-261-A.pdf

Cascade Natural Gas
UG 305
OPUC - 261
Prepared by: B Beach

Revenue Tax	2015 Amount	Amount based on 2014 Revenue	Prior Year Adjustment	Amount based on 2015 Revenue paid in 2016	2014 Rate	2015 Rate	Income source	Taxing authority
Department of Energy Fee	68,341.60	78,734.00	(10,392.40)	78,297.00	0.1120%	0.1160%	Prior year Gross Operating Renveues	Oregon State Department of Energy
Gross Revenue Fee	175,231.24	175,231.24	-	186,038.12	0.2500%	0.2750%	Prior year Gross Operating Renveues	Oregon State PUC
Franchise Fee	2,633,907.72					Various	Current year Jurisdictional gas sales	Various Jurisdictions (see attached)
	2,877,480.56	253,965.24	(10,392.40)	264,335.12				

Oregon City Franchise Taxes (Summary)

City		FRAN Taxable Revenue	FRAN Tax Rate	FRAN Tax	
Athena	T057 Total	214,665.09	3.50%	7,513.25	
Baker City	T077 Total	2,859,688.48	5.00%	142,984.42	
Bend	T090 Total	24,944,016.64	5.00%	1,247,200.85	
Boardman	T100 Total	412,631.75	3.00%	12,378.95	
Hermiston	T358 Total	2,890,906.70	3.00%	86,727.21	
Huntington	T381 Total	59,554.30	5.00%	2,977.71	
Irrigon	T431 Total	86,327.87	3.00%	2,589.84	
La Pine	T514 Total	338,659.53	7.00%	23,706.17	
Madras	T543 Total	1,785,760.97	7.00%	125,003.27	
Metolius	T567 Total	48,935.60	3.00%	1,468.06	
Milton Freewater	T571 Total	303,006.85	8.00%	24,240.55	
Nyssa	T619 Total	435,329.73	3.00%	13,059.89	
Ontario	T657 Total	2,387,617.21	5.00%	132,082.55	Changed to 7% in October
Pendleton	T698 Total	4,174,970.20	7.00%	292,247.90	
Pilot Rock	T708 Total	378,449.41	8.00%	30,275.97	
Prineville	T719 Total	2,149,820.02	5.00%	107,491.01	
Redmond	T737 Total	6,181,436.60	5.00%	309,071.86	
Stanfield	T808 Total	159,529.90	3.00%	4,785.90	
Umatilla	T878 Total	843,817.50	3.00%	25,314.53	
Vale	T895 Total	353,480.30	3.00%	10,604.40	
Weston	T932 Total	192,205.94	3.00%	5,766.20	
		51,200,810.59		2,607,490.49	
Unbilled accrual		920,610.01		26,417.23	
		52,121,420.60		2,633,907.72	

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 262

Date prepared: 6/28/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 262

With regard to UG 305/CNGC/201, Parvinen/1, please provide a narrative description explaining how franchise fees are impacted by the Company's requested revenue requirement in this rate case.

Response:

Total franchise fees change as the revenue changes. Hence, the inclusion of a franchise fee component in the conversion factor calculation. However, it appears the franchise fee component included in the rate case has not been updated from a previous rate case. The correct rate should be 2.31% as shown in the response to OPUC-263.

The first 3% of a franchise fee is collected from all customers and any amount beyond 3% is collected only from customers living within the taxing authority boundary. Most of Cascade's service territory is within taxing authority, and most taxing authorities assess the full 3%. Most but not all, thus the rate to all customers is 2.31% not 3%.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 263

Date prepared: 6/21/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 263

With regard to UG 305/CNGC/203, Parvinen/1, please provide the actual franchise fee expenses for each of the years from 2005 through 2015 inclusive, and show the calculation of the current franchise fee rate of 1.835 percent.

Response:
See attached spreadsheet for 2005 to 2015 franchise fee expenses OPUC-263.xlsx

UG 305
OPUC-263
PBC

		Ledger Type	UO	UO	UO	UO	UO	UO
		Year	2015	2014	2013	2012	2011	2010
		Format	YTD	YTD	YTD	YTD	YTD	YTD
		Period	12	12	12	12	12	12
		Currency	***	***	***	***	***	***
		Company	00047	00047	00047	00047	00047	00047
		Business Unit	*	*	*	*	*	*
Object Account	Sub Account							
4009	*		(891,967.19)	960,436.41	(2,541,586.35)	1,447,264.45	567,091.04	864,134.02
4002	*		(62,505,066.18)	(66,745,611.36)	(59,235,685.64)	(65,337,797.21)	(76,964,572.04)	(74,744,149.25)
4890	*		(3,997,282.89)	(4,034,055.52)	(3,941,688.34)	(4,021,173.52)	(3,891,232.23)	(3,485,809.19)
4880	*		(185,988.33)	(193,624.08)	(169,572.64)	(202,346.98)	(333,196.97)	(237,000.82)
*	2488		0.00	0.00	110.47	1,522.35	57,192.72	160,174.38
4950	*		(39,827.92)	(48,891.15)	(26,633.44)	(17,401.94)	(6,218.95)	(34,305.75)
4930	*		(9,728.10)	(11,000.00)	(11,049.10)	(11,000.00)	(13,000.00)	(13,435.00)
4940	*		(24,915.60)	(24,264.01)	(22,682.01)	0.00	0.00	0.00
4891	*		4,550.30	4,521.76	(24,751.41)	8,916.87	(22,373.47)	(309,459.77)
		Operating Revenues (400)	(67,650,225.91)	(70,092,487.95)	(65,973,538.46)	(68,132,015.98)	(80,606,309.90)	(77,799,851.38)
4081	2442	OR Franchise Taxes	1,562,711.12	1,634,245.56	1,601,610.13	1,621,833.86	1,923,472.64	1,892,686.45
		OR Franchise Taxes	2.31%	2.33%	2.43%	2.38%	2.39%	2.43%

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 108

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 63

Date prepared: 02/24/2016

Preparer: Candice Tschauner

Contact: Pam Archer

Telephone: (509)734-4591

63. In the following table format, please provide medical benefit costs for the test year, historical base year, and the three years prior to the historical base year. Please also explain if the amounts reflected in the Company's response are before or after employer/employee sharing. For the test year estimates, please explain the assumptions relied upon (i.e. increased employees, specific escalation factor to premiums, etc) in arriving at the forecasted amounts.

	Test Year	Base Year	Base Year – 1	Base Year – 2	Base Year – 3
Medical					
Dental					
401(k)					
Group Life Insurance					
Retiree Life Insurance					
Long-Term Disability					
Other (*Please Label*)					
Total					

Response: Please see spreadsheet **OPUC-63.xlsx.**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 298

Date prepared: 07/01/2016

Preparer: Candice Maes

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 298

Referring to Staff's above DR No. 297 and Staff's attachment, UG 305 DR No. 298, please explain all year over year variances greater than $10,000 by object code for both the total Company and the Oregon jurisdiction. In the response, separate the variance change between volume and price. Examples of volume related drivers could be changes in workforce levels or number of employees participating. Examples of price drivers could be changes in plan type, insurance premiums, interest rates, etc. Please note that the numbers provided in Staff's attachment are from the Company's initial response to Staff SDR No. 63. Please update the tables as appropriate to be consistent with the Company's UG 305 filed testimony and exhibits.

Response: Please refer to file entitled "OPUC-298.xlsx" and response to OPUC-297.

CNG OPUC DR 63

TOTAL COMPANY

	2016	2015	2014	2013	2012	Variance by Dollar
5192 Other Benefits	13,616.01	81,548.60	187,158.19	37,588.31	54,975.05	(67,932.59)
5194 Medical/Dental & Life Insurance	3,208,487.79	3,017,395.29	2,808,428.22	2,276,096.20	2,207,277.56	191,092.50
5195 Pension	(82,320.98)	(106,803.73)	287,890.21	515,732.40	569,156.02	24,482.75
5196 Post Retirement	441,550.13	232,241.86	91,575.46	471,328.05	363,617.11	209,308.27
5197 401-K Plan	2,233,898.23	2,284,787.22	2,254,741.48	2,025,412.23	1,045,523.70	(50,888.99)
5199 Workers Compensation	205,572.08	236,735.98	228,012.89	280,677.55	267,186.11	(31,163.90)
5921 Supplemental Defined Plan & Contributi	454,878.37	672,603.62	444,772.38	(444,679.89)	79,052.96	(217,725.25)
	$ 6,475,681.63	**$ 6,418,508.84**	**$ 6,302,578.83**	**$ 5,162,154.85**	**$ 4,586,788.51**	**$ 57,172.79**

OREGON TOTAL

	2016	2015	2014	2013	2012	Variance by Dollar
5192 Other Benefits	3,181.11	20,592.86	45,381.08	8,954.47	14,661.66	(17,411.75)
5194 Medical/Dental & Life Insurance	812,207.32	784,319.21	717,623.89	564,825.30	575,205.01	27,888.11
5195 Pension	(22,269.76)	(28,263.38)	70,660.61	130,259.64	187,630.10	5,993.62
5196 Post Retirement	112,766.32	52,522.98	19,385.19	102,795.48	83,949.16	60,243.34
5197 401-K Plan	563,385.65	577,536.20	562,942.96	500,667.10	256,513.10	(14,150.55)
5199 Workers Compensation	59,323.69	91,541.07	69,227.76	87,347.07	105,339.37	(32,217.38)
5921 Supplemental Defined Plan & Contributi	110,535.36	163,240.94	108,079.70	(109,168.82)	19,391.67	(52,705.58)
	$ 1,639,129.69	**$ 1,661,489.88**	**$ 1,593,301.19**	**$ 1,285,680.24**	**$ 1,242,690.07**	**$ (22,360.19)**

Explanations

1.) Amounts reflected are after employer/employee sharing.
2.) Assumptions for Budget Year are Budgeted O&M Amounts.
3.) Medical and Dental variance will be a combination of negotiated policy increase and headcount.
4.) Pension, Post-retirement welfare, and SERP (5921) are calculated by acturials.
5.) 401K Plan varaince is tied to CNG earnings, and headcount of employees actively contributing to their plans.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 64

Date prepared: 02/04/2016

Preparer: Shannon Novakovich

Contact: Pam Archer

Telephone: (509)-734-4514

64. For each Medical (Health, Dental, and Vision) plan, please identify the premium for the Test Year, Base Year, and two calendar years prior to the Base Year. If the premium amounts vary by labor group, please provide the information for each labor group separately.

Response: Attached are monthly Employee/Employer premiums for years 2016, 2015 & 2014 Premium amounts do not vary between groups.

OPUC-64 Med Premiums

MDU RESOURCES

Benefits 2016

2016 Highlights

- Increase annual out-of-pocket maximum for both medical plans (Health Savings Account (HSA) and BlueCare PPO).
- Increase deductible and certain copays for PPO.
- Increase annual dental maximum.
- Increase vision frame/contact lens allowance.
- Employee Assistance Program provider changes from The Hartford to CHI St. Alexius Health.
- Decrease employee paid contributory life insurance premiums.

For the employees of MDU Utilities Group

Open Enrollment Dates: November 9-27, 2015

Enroll at http://eserve.mdu.com.

Medical Benefits

Health Savings Plan and Account (HSA)

The HSA Plan is a high-deductible plan that allows employees to establish a separate account to make pretax deferrals up to IRS limits of $3,350 (single) or $6,750 (family). If you are 55 or older, you can contribute an additional $1,000. **NEW!** The out-of-pocket maximum increased (see medical plan comparison chart). To contribute:

- You must elect a 2016 HSA contribution level; prior year elections do not carry over.
- You may not be covered under any non-high deductible health plan, including your spouse's flexible spending account or any part of Medicare.
- New HSA participants will receive a *Welcome Kit*, including account contract terms and debit card, by January 8, 2016.

Coverage	Employee Contribution (per month)	Company Contribution (per month)
Employee	$9	$364
Employee + Child	$16	$618
Employee + Children	$22	$761
Employee + Spouse	$46	$811
Family	$76	$1,096

BlueCard PPO Plan

The BlueCard PPO plan provides comprehensive coverage with a copay, deductible, and co-insurance structure. **NEW!** The annual deductible, out-of-pocket maximum, office visit copay, and emergency room copay increased (see medical plan comparison chart).

Coverage	Employee Contribution (per month)	Company Contribution (per month)
Employee	$83	$382
Employee + Child	$143	$647
Employee + Children	$178	$798
Employee + Spouse	$213	$856
Family	$292	$1,169

Opt-Out Feature

- If you elect to opt-out of the Company's medical insurance due to other available coverage, $100/month (taxable) will be included in your first paycheck each month.
- If you, your spouse, or your dependents are employees of the Company, the Opt-Out Feature is not available if anyone is covered by the Company medical plan.

Premiums are based on the total expected cost of the self-insured plans covered under the MDU Resources Group, Inc. Health and Welfare Benefit Program. The Company's practice is to share premium increases with the employee; however, the maximum aggregate medical increase to the employer contribution will not exceed 6% annually.

Dental Benefits

The Company offers a choice of three dental plans. These dental plans provide first-dollar coverage for routine oral examinations, cleanings, and certain X-rays, along with coverage for other services after meeting a deductible. The Dental with Orthodontia plan provides $1,500 lifetime maximum orthodontia benefit for children under age 19. These plans access the Delta Dental provider network.

NEW! The annual per person maximum benefit payable for all dental plans increased from $1,500 to $2,000. Sealants and preventive resin restorations will be considered preventive (100% paid with no deductible). Nitrous oxide and sedative temporary fillings will be paid if billed with respective service. Premiums are unchanged!

The two-year dental lock-in provision requires employees to maintain elected coverage for at least two years. Upgrades are allowed at open enrollment or at the time of a qualifying event, but restart the two-year lock-in requirement.

Dental Maintenance Plan

Coverage	Employee Contribution (per month)	Company Contribution (per month)
Employee	$6	$16
Employee + 1	$9	$29
Family	$17	$51

Dental

Coverage	Employee Contribution (per month)	Company Contribution (per month)
Employee	$14	$21
Employee + 1	$23	$42
Family	$40	$74

Dental with Orthodontia

Coverage	Employee Contribution (per month)	Company Contribution (per month)
Employee	$28	$21
Employee + 1	$43	$40
Family	$76	$69

Vision Benefits

The vision plan provides coverage for an exam, lenses, and frames, with applicable copays and allowance maximums. NEW! The frame/contact lens allowance increased from $120 to $150. The plan accesses the VSP provider network. Premiums are unchanged!

Coverage	Employee Contribution (per month)	Company Contribution (per month)
Employee	$10	$0
Employee + 1	$13	$0
Family	$22	$0

Other Benefits

Flexible Spending Account (FSA)

The FSA allows you to defer up to $2,500 to a Health Care Spending Account to use for eligible health care expenses, and/or up to $5,000 per household to a Dependent Care Spending Account for eligible dependent care expenses incurred while you are at work.

- Up to $500 of unused Health Care Spending Account funds from the current plan year will automatically rollover for use in the following plan year (no action is required). Any funds over $500 will be forfeited. The rollover amount does not count toward or reduce the annual $2,500 contribution maximum. Even if an election for the new plan year is not made, remaining funds will be carried over into the new plan year.
- If enrolled in the HSA Plan, the FSA Health Care Spending Account reimbursements are limited to dental and vision expenses until the HSA Plan deductible has been reached.
- When you elect the FSA Health Care Spending Account, you are enrolled in Crossover (automatic claims submission for payment). If you have dual coverage, an Opt-Out form should be completed to avoid duplicate payment. If you are covered under the HSA Plan, you are unable to have both an HSA debit card and be enrolled in Crossover.

Employee Assistance Program (EAP)

- NEW! The Employee Assistance Program provider has changed from The Hartford (Ability Assist) to CHI St. Alexius Health. Please see the enclosed brochure for services, contact information and additional details.

For the employees of: MDU Utilities Group

MDU RESOURCES GROUP INC

Benefits 2015

2015 Highlights

- No plan design changes for the HSA or Blue Card PPO medical plans.
- $250 HSA Funding in 2015.
- NEW! FSA Health Care Spending Account $500 rollover.

Enrollment Open November 10-28, 2014

Enroll at eserve.mdu.com

Medical Benefits

Health Savings Plan and Account (HSA)

The HSA Plan is a high-deductible plan that allows employees to establish a separate account to make pretax deferrals up to IRS limits of $3,350 (single) or $6,650 (family). If you are 55 or older, you can contribute an additional $1,000. To contribute:

- You must elect a 2015 HSA contribution level; prior year elections do not carry over.
- You may not be covered under any non-high deductible health plan, including your spouse's flexible spending account or any part of Medicare.
- New HSA participants will receive a *Welcome Kit*, including account contract terms and debit card, by January 10, 2015.

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$4.16	$347
Employee + Child	$6.92	$589
Employee + Children	$9.60	$726
Employee + Spouse	$20.31	$774
Family	$38.26	$1,046

BlueCard PPO Plan

The BlueCard PPO plan provides comprehensive coverage with a copay, deductible, and co-insurance structure.

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$36.46	$364
Employee + Child	$63.23	$617
Employee + Children	$78.46	$761
Employee + Spouse	$94.15	$816
Family	$129.31	$1,116

Opt-Out Feature

- If you elect to opt-out of the Company's medical insurance due to other available coverage, $100/month (taxable) will be included in your first paycheck each month.
- If you, your spouse, or your dependents are employees of the Company, the Opt-Out Feature is not available if anyone is covered by the Company medical plan.

Premiums are based on the total expected cost of the self-insured plans covered under the MDU Resources Group, Inc. Health and Welfare Benefit Program. The Company's practice is to share premium increases with the employee; however, the maximum aggregate medical increase to the employer contribution will not exceed 8% annually.

Dental Benefits

The Company offers a choice of three dental plans. These dental plans provide first-dollar coverage for routine oral examinations, cleanings, and certain X-rays, along with coverage for other services after meeting a deductible. The Dental with Orthodontia plan provides $1,500 lifetime maximum orthodontia benefit for children under age 19. These plans access the Delta Dental provider network.

The two-year dental lock-in provision requires employees to maintain elected coverage for at least two years. Upgrades are allowed at open enrollment or at the time of a qualifying event, but restart the two-year lock-in requirement.

Dental Maintenance Plan

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	[illegible]	$16
Employee + 1	$4.15	$29
Family	$7.86	$50

Dental

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$6.46	$24
Employee + 1	$10.62	$41
Family	$16.46	$73

Dental with Orthodontia

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$10.62	$21
Employee + 1	$19.85	$39
Family	$35.08	[illegible]

Vision Benefits

The vision plan provides coverage for an exam, lenses and frames, with applicable copays and allowance maximums. The plan accesses the VSP provider network.

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$4.62	$0
Employee + 1	$6.00	$0
Family	$10.15	$0

Other Benefits

Flexible Spending Account (FSA)

The FSA allows you to defer up to $2,500 to a Health Care Spending Account to use for eligible health care expenses, and/or up to $5,000 per household to a Dependent Care Spending Account for eligible dependent care expenses incurred while you are at work.

- **NEW!** Any unused Health Care Spending Account funds from the current plan year account – up to $500 – will automatically rollover for use in the following plan year (no action is required). Any funds over $500 will be forfeited. The rollover amount does not count toward or reduce the annual $2,500 contribution maximum. Even if an election for the new plan year is not made, remaining funds will be carried over into the new plan year.
- If enrolled in the HSA Plan, the FSA Health Care Spending Account reimbursements are limited to dental and vision expenses until the HSA Plan deductible has been reached.
- When you elect the FSA Health Care Spending Account, you are enrolled in Crossover (automatic claims submission for payment). If you have dual coverage, an Opt-Out form should be completed to avoid duplicate payment. If you are covered under the HSA Plan, you are not able to have an HSA debit card and be enrolled in Crossover.

2014 MONTHLY PREMIUMS

MDU Utilities Group

Medical, Dental, and Vision

	Employee Contribution		Company Contribution	Full Premium
	Monthly	Pay Period (26)	Monthly	Monthly
Health Savings Account (HSA) Plan				
Employee	$8	$3.69	$330	$338
Employee + Child	$15	$6.92	$594	$609
Employee + Children	$19	$8.77	$691	$710
Employee + Spouse	$35	$16.15	$736	$771
Family	$67	$30.92	$995	$1,062
BlueCard PPO				
Employee	$76	$35.08	$346	$422
Employee + Child	$137	$63.23	$622	$759
Employee + Children	$162	$74.77	$724	$886
Employee + Spouse	$191	$88.15	$770	$961
Family	$264	$121.85	$1,060	$1,324
Dental Maintenance Plan				
Employee	$5	$2.31	$16	$21
Employee + 1	$9	$4.15	$29	$38
Family	$17	$7.85	$50	$67
Dental				
Employee	$14	$6.46	$21	$35
Employee + 1	$23	$10.62	$41	$64
Family	$40	$18.46	$73	$113
Dental with Orthodontia				
Employee	$23	$10.62	$21	$44
Employee + 1	$43	$19.85	$39	$82
Family	$76	$35.08	$68	$144
Vision				
Employee	$10	$4.62	$0	$10
Employee + 1	$13	$6.00	$0	$13
Family	$22	$10.15	$0	$22

The premiums above are based on the total expected cost of the self-insured plans covered under the MDU Resources Group, Inc. Health and Welfare Benefit Program. The Company's practice is to share premium increases with the employee; however, the maximum aggregate medical increase to the employer contribution will not exceed 5% annually.

Life Insurance

Age As of January 1, 2014	Life Insurance: Monthly Rate per $1,000 of Coverage	Life Insurance: Pay Period Rate per $1,000 of Coverage
	Employee/Spouse:	
Under 30	$0.08	$0.037
30-34	$0.09	$0.042
35-39	$0.12	$0.055
40-44	$0.17	$0.078
45-49	$0.30	$0.138
50-54	$0.46	$0.212
55-59	$0.77	$0.355
60-64	$1.00	$0.462
65-69	$1.96	$0.905
70+	$3.25	$1.500
	Child(ren):	
	$ 5,000	$.30
	$10,000	$.60

Voluntary AD&D Insurance

Coverage Amount	Monthly Premium	Pay Period Premium
$25,000	$0.63	$0.291
$50,000	$1.25	$0.577
$100,000	$2.50	$1.154
$150,000	$3.75	$1.731
$200,000	$5.00	$2.308

MDU Resources Group, Inc. expects to continue these benefit plans indefinitely; however, it reserves the right to amend or terminate these plans at any time for any reason to comply with any federal or state laws governing welfare benefits, the requirements of the Internal Revenue Code or ERISA.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 65

Date prepared: 02/04/2016

Preparer: Shannon Novakovich

Contact: Pam Archer

Telephone: (509)-734-4514

65. Please provide the current employer / employee contribution for each labor group (non-represented, and each union group) for medical (health, dental, and vision) plans (i.e. 90/10, 85/15, 80/20, etc.). Is the Company anticipating any change to these percentages for the Test Year? Please explain.

Response:

For test year 2016, the following is the employer/employee contribntion schedule:

Medical – Upon satisfying annual dednctible amounts, the contribution is 80% employer and 20% employee.

Dental – Upon satisfying annual deductible, the contribution is 80% or 50% employer and 20% or 50% employee. This percentage amount follows the percentage of treatment cost, up to a maximum fee per procedure.

Vision – Upon satisfying vision copays, the following coverage is available to those who elect vision benefits:

- **Prescription Glasses - $25 copay**
- **Lenses – Once every calendar year**
- **Frame – Once every other calendar year ($150 allowance on frames or 20% off the frame allowance)**

All Cascade Natural Gas Corp. employees have the same health and wellness package/benefits regardless of bargained or non-bargained status. Benefits are negotiated and coordinated through MDU Resources located in Bismark, ND.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 297

Date prepared: 7/1/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 297

Referring to the Company's response to Staff SDR No. 63, OPUC-63.xls, please explain whether the years 2016 and 2015 listed under the Oregon Totals agree with the 2016 Test Year Adjusted Total and 2015 Base Year as presented in UG 305/CNGC/201, Parvinen/1 at columns (1) and (3). In the response, please confirm that the 2016 and 2015 Oregon Total amounts from the Company's response to SDR No. 63 are contained in the summarized amounts provided in Parvinen Exhibit 201. If not, please explain and revise the response to SDR No. 63 so that the Oregon jurisdictional amounts for 2015 and 2016 are consistent with the Company's UG 305 Exhibit 201.

Response:

The amounts included in SDR No. 63 for 2016 are not included in UG 305/CNGC/201. The 2015 amounts are the Base Year amounts included in UG 305/CNGC/201. As such the base year amounts are increase by the inflation factor adjustment.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 298

Date prepared: 07/01/2016

Preparer: Candice Maes

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 298

Referring to Staff's above DR No. 297 and Staff's attachment, UG 305 DR No. 298, please explain all year over year variances greater than $10,000 by object code for both the total Company and the Oregon jurisdiction. In the response, separate the variance change between volume and price. Examples of volume related drivers could be changes in workforce levels or number of employees participating. Examples of price drivers could be changes in plan type, insurance premiums, interest rates, etc. Please note that the numbers provided in Staff's attachment are from the Company's initial response to Staff SDR No. 63. Please update the tables as appropriate to be consistent with the Company's UG 305 filed testimony and exhibits.

Response: Please refer to file entitled "OPUC-298.xlsx" and response to OPUC-297.

CNG OPUC DR 63

TOTAL COMPANY

	2016	2015	2014	2013	2012
5192 Other Benefits	13,616.01	81,548.60	187,158.19	37,588.31	54,975.05
5194 Medical/Dental & Life Insurance	3,208,487.79	3,017,395.29	2,808,428.22	2,276,096.20	2,207,277.56
5195 Pension	(82,320.98)	(106,803.73)	287,890.21	515,732.40	569,156.02
5196 Post Retirement	441,550.13	232,241.86	91,575.46	471,328.05	363,617.11
5197 401-K Plan	2,233,898.23	2,284,787.22	2,254,741.48	2,025,412.23	1,045,523.70
5199 Workers Compensation	205,572.08	236,735.98	228,012.89	280,677.55	267,186.11
5921 Supplemental Defined Plan & Contributi	454,878.37	672,603.62	444,772.38	(444,679.89)	79,052.96
	$ 6,475,681.63	**$ 6,418,508.84**	**$ 6,302,578.83**	**$ 5,162,154.85**	**$ 4,586,788.51**

OREGON TOTAL

	2016	2015	2014	2013	2012
5192 Other Benefits	3,181.11	20,592.86	45,381.08	8,954.47	14,661.66
5194 Medical/Dental & Life Insurance	812,207.32	784,319.21	717,623.89	564,825.30	575,205.01
5195 Pension	(22,269.76)	(28,263.38)	70,660.61	130,259.64	187,630.10
5196 Post Retirement	112,766.32	52,522.98	19,385.19	102,795.48	83,949.16
5197 401-K Plan	563,385.65	577,536.20	562,942.96	500,667.10	256,513.10
5199 Workers Compensation	59,323.69	91,541.07	69,227.76	87,347.07	105,339.37
5921 Supplemental Defined Plan & Contributi	110,535.36	163,240.94	108,079.70	(109,168.82)	19,391.67
	$ 1,639,129.69	**$ 1,661,489.88**	**$ 1,593,301.19**	**$ 1,285,680.24**	**$ 1,242,690.07**

Explanations
1.) Amounts reflected are after employer/employee sharing.
2.) Assumptions for Budget Year are Budgeted O&M Amounts.
3.) Medical and Dental variance will be a combination of negotiated policy increase and headcount.
4.) Pension, Post-retirement welfare, and SERP (5921) are calculated by acturials.
5.) 401K Plan varaince is tied to CNG earnings, and headcount of employees actively contributing to their plans.

Cascade Natural Gas
Inflation Factor
Twelve Months Ended December 31, 2015
UG 305

	Base Year Amounts	Base Year Wages		2016 Projected CPI	
Production	$108,233		$108,233	0.012	1298.799
Distribution	$5,639,690	2804393	$2,835,297	0.012	34023.5613
Customer Accounts	$1,709,474		$1,709,474	0.012	20513.6868
Customer Service	$0		$0	0.012	0
Administrative and General	$5,451,075	2585099	$2,865,976	0.012	34391.709
					90227.7561

2015 System Salary Wages	10,651,416.78	0.2427	2585098.85
2015 System Union Wages	11,554,979.00	0.2427	2804393.4

UG 305
Staff Analysis
Other Benefits

		OREGON TOTAL			
		2016 Budget[1]	2016 Test Year	Inflation Factor[2]	2015 Base Year[1]
5192	Other Benefits	3,181.11	20,839.97	0.012	20,592.86
5194	Medical/Dental & Life Insurance	812,207.32	793,731.04	0.012	784,319.21
5195	Pension	(22,269.76)	(28,602.54)	0.012	(28,263.38)
5196	Post Retirement	112,766.32	53,153.26	0.012	52,522.98
5197	401-K Plan	563,385.65	584,466.63	0.012	577,536.20
5199	Workers Compensation	59,323.69	92,639.56	0.012	91,541.07
5921	Supplemental Defined Plan & Contribution	110,535.36	165,199.83	0.012	163,240.94
		$ 1,639,129.69	**$ 1,681,427.76**		**$ 1,661,489.88**

[1] Exhibit
[2] Exhibit

Year over Year Variance

		2016 Test Year	2016 Budget	2016 Test Year Vs. 2016 Budget
5192	Other Benefits	20,839.97	3,181.11	17,658.86
5194	Medical/Dental & Life Insurance	793,731.04	812,207.32	(18,476.28)
5195	Pension	(28,602.54)	(22,269.76)	(6,332.78)
5196	Post Retirement	53,153.26	112,766.32	(59,613.06)
5197	401-K Plan	584,466.63	563,385.65	21,080.98
5199	Workers Compensation	92,639.56	59,323.69	33,315.87
5921	Supplemental Defined Plan & Contribution	165,199.83	110,535.36	54,664.47
		$ 1,681,427.76	**$ 1,639,129.69**	**$ 42,298.07**

		2016 Test Year	2015 Base Year	2016 Test Year Vs. 2015 Base Year
5192	Other Benefits	20,839.97	20,592.86	247.11
5194	Medical/Dental & Life Insurance	793,731.04	784,319.21	9,411.83
5195	Pension	(28,602.54)	(28,263.38)	(339.16)
5196	Post Retirement	53,153.26	52,522.98	630.28
5197	401-K Plan	584,466.63	577,536.20	6,930.43
5199	Workers Compensation	92,639.56	91,541.07	1,098.49
5921	Supplemental Defined Plan & Contribution	165,199.83	163,240.94	1,958.89
		$ 1,681,427.76	**$ 1,661,489.88**	**$ 19,937.88**

2015 Kaiser Family Foundation
Employer Health Benefits Report
2015 Summary of Findings[3]

	2015	
	Ave. Family Plan	
Employee Contribution	$ 4,955	22%
Employer Contribution	$ 17,545	78%
Total Premium	$ 22,500	100%
	Ave. Single Plan	
Employee Contribution	$ 2,713	25%
Employer Contribution	$ 8,167	75%
Total Premium	$ 10,880	100%

[3] Exhibit

THE KAISER FAMILY FOUNDATION -AND- HEALTH RESEARCH & EDUCATIONAL TRUST

Employer Health Benefits

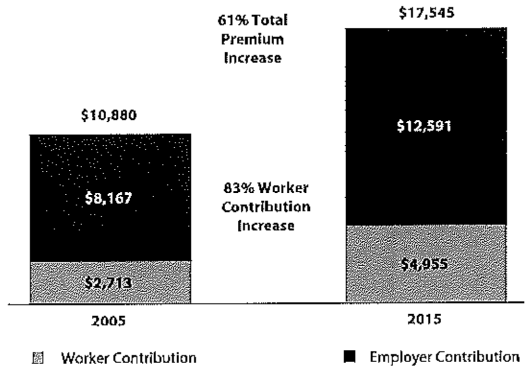
2015 Summary of Findings

Employer-sponsored insurance covers over half of the non-elderly population, 147 million people in total.[1] To provide current information about employer-sponsored health benefits, the Kaiser Family Foundation (Kaiser) and the Health Research & Educational Trust (HRET) conduct an annual survey of private and nonfederal public employers with three or more workers. This is the seventeenth Kaiser/HRET survey and reflects employer-sponsored health benefits in 2015.

The key findings from the survey, conducted from January through June 2015, include a modest increase (4%) in the average premiums for both single and family coverage in the past year. The average annual single coverage premium is $6,251 and the average family coverage premium is $17,545. The percentage of firms that offer health benefits to at least some of their employees (57%) and the percentage of workers covered at those firms (63%) are statistically unchanged from 2014. Relatively small percentages of employers with 50 or more full-time equivalent employees reported switching full-time employees to part time status (4%), changing part-time workers to full-time workers (10%), reducing the number of full-time employees they intended to hire (5%) or increasing waiting periods (2%) in response to the employer shared responsibility provision which took effect for some firms this year. Employers continue to be inrerested in programs addressing the health and behaviors of their employees, such as health risk assessments, biometric screenings, and health promotion and wellness programs. Meaningful numbers of employers which offer one of these screening programs now offer incentives to employees who complete them; 31% of large firms offering health benefits provide an incentive to complete a health risk assessment and 28% provide an incentive to complete a biometric screening. A majority of large employers (200 or more workers) (53%) have analyzed their health benefits to see if they would be subject to the high-cost plan tax when it takes effect in 2018, with some already making changes to their benefit plans in response to the tax.

EXHIBIT A

Exhibit A: Average Annual Health Insurance Premiums and Worker Contributions for Family Coverage, 2005–2015



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2005–2015.

HEALTH INSURANCE PREMIUMS AND WORKER CONTRIBUTIONS

In 2015, the average annual premiums for employer-sponsored health insurance are $6,251 for single coverage and $17,545 for family coverage (Exhibit A). Each rose 4% over the 2014 average premiums. During the same period, workers' wages increased 1.9% and inflation declined by 0.2%.[2] Premiums for family coverage increased 27% during the last five years, the same rate they grew between 2005 and 2010 but significantly less than they did between 2000 to 2005 (69%) (Exhibir B).

Average premiums for high-deductible health plans with a savings option (HDHP/SOs) are lower than the overall average for all plan types for both single and family coverage (Exhibit C), at $5,567 and $15,970, respectively. The average premium for family coverage is lower for covered workers in small firms (3-199 workers) than for workers in large firms (200 or more workers) ($16,625 vs. $17,938).

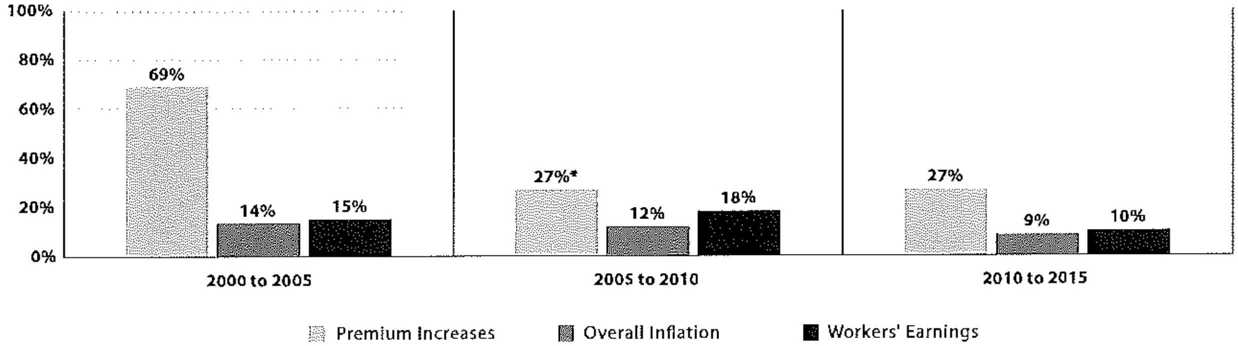
As a result of differences in benefits, cost sharing, covered populations, and geographical location, premiums vary significantly around the averages for both single and family coverage. Eighteen percent of covered workers are in plans with an annual roral premium for family coverage of at least $21,054 (120% or more of the average family premium), and 22% of covered workers are in plans where the family premium is less than $14,036 (less than 80% of the average family premium). The distribution is similar around the average for single coverage premiums (Exhibit D).

Employers generally require thar workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2014 and statistically similar ro those reported in 2010. Workers in small firms contribute a lower average percentage for single coverage compared to workers in large firms (15% vs. 19%), but they contribute a higher average percentage for family coverage (36% vs. 26%). Workers in firms with a higher percentage of lower-wage workers (at leasr 35% of workers earn $23,000 a year or less) contribute higher percentages of the premium for family coverage (41% vs. 28%) than workers in firms with a smaller share of lower-wage workers.

As with total premiums, the share of the premium contribured by workers varies considerably. For single coverage, 61% of

EXHIBIT B

Average Premium Increases for Covered Workers with Family Coverage, 2000-2015



* Premium change is statistically different from previous period shown (p<.05).

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2000-2015. Bureau of Labor Statistics, Consumer Price Index, U.S. City Average of Annual Inflation (April to April), 2000-2015; Bureau of Labor Statistics, Seasonally Adjusted Data from the Current Employment Statistics Survey, 2000-2015 (April to April).

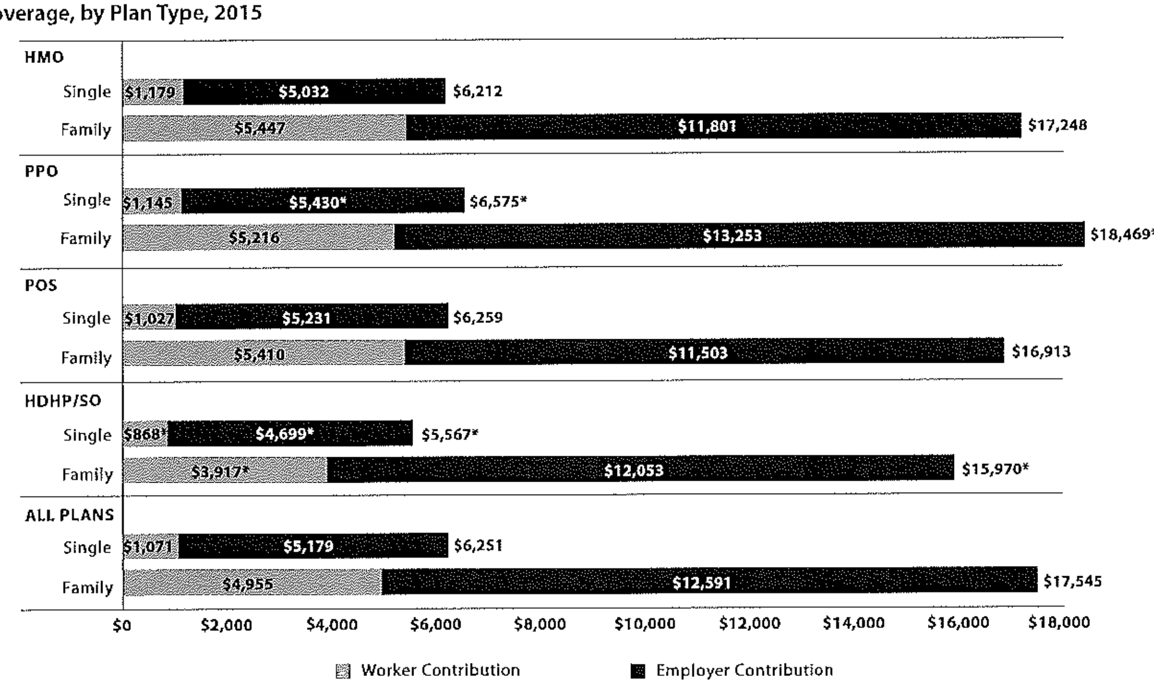
covered workers are in plans that require them to make a contribution of less than or equal to a quarter of the total premium, 2% are in plans that require more than half of the premium, and 16% are in plans that require no contribution at all. For family coverage, 44% of covered workers are in plans that require them to make a contribution of less than or equal to a quarter of the total premium and 15% are in plans that require more than half of the premium, while only 6% are in plans that require no contribution at all (Exhibit E).

Employers use different strategies to structure their employer contributions; 45% of small employers offering health benefits indicated that they contribute the same dollar amount for family coverage as single coverage, 34% contributed a larger dollar amount for family than single coverage, and 18% used some other approach.

Looking at the dollar amounts that workers contribute, the average annual premium contributions in 2015 are $1,071 for single coverage and $4,955 for family coverage. Covered workers' average dollar contribution to family coverage has increased 83% since 2005 and 24% since 2010 (Exhibit A). Workers in small firms have lower average contributions for single coverage than workers in large firms ($899 vs. $1,146), but higher average contributions for family coverage ($5,904 vs. $4,549). Workers in firms with a higher percentage of lower-wage workers have higher average contributions for family coverage ($6,382 vs. $4,829) than workers

EXHIBIT C

Average Annual Firm and Worker Premium Contributions and Total Premiums for Covered Workers for Single and Family Coverage, by Plan Type, 2015

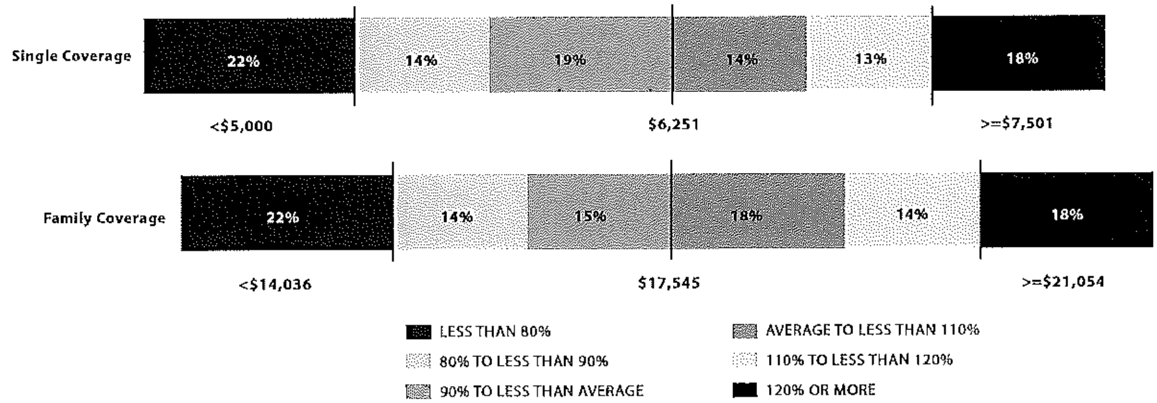


* Estimate is statistically different from All Plans estimate by coverage type (p<.05).

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2015.

EXHIBIT D

Distribution of Annual Premiums for Single and Family Coverage Relative to the Average Annual Single or Family Premium, 2015



NOTE: The average annual premium is $6,251 for single coverage and $17,545 for family coverage. The premium distribution is relative to the average single or family premium. For example, $5,000 is 80% of the average single premium, $5,625 is 90% of the average single premium, $6,876 is 110% of the average single premium, and $7,501 is 120% of the average single premium. The same break points relative to the average are used for the distribution for family coverage.

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2015.

in firms with lower percentages of lower-wage workers.

PLAN ENROLLMENT

PPO plans remain the most common plan type, enrolling 52% of covered workers in 2015, although a smaller percentage than 2014. Twenty-four percent of covered workers are enrolled in a high-deductible plan with a savings options (HDHP/SO), 14% in an HMO, 10% in a POS plan, and 1% in a conventional (also known as an indemnity) plan (Exhibit F). Enrollment distribution varies by firm size; for example, PPOs are relatively more popular for covered workers at large firms than small firms (56% vs. 41%) and POS plans are relatively more popular among small firms than large firms (19% vs. 6%).

Almost a quarter (24%) of covered workers are enrolled in HDHP/SOs in 2015; enrollment in these plans has increased over time from 13% of covered workers in 2010. In 2015, 7% of firms offering health benefits offered a high-deductible health plan with a health reimbursement arrangement (HDHP/HRA), and 20% offered a health savings (HSA) qualified HDHP.

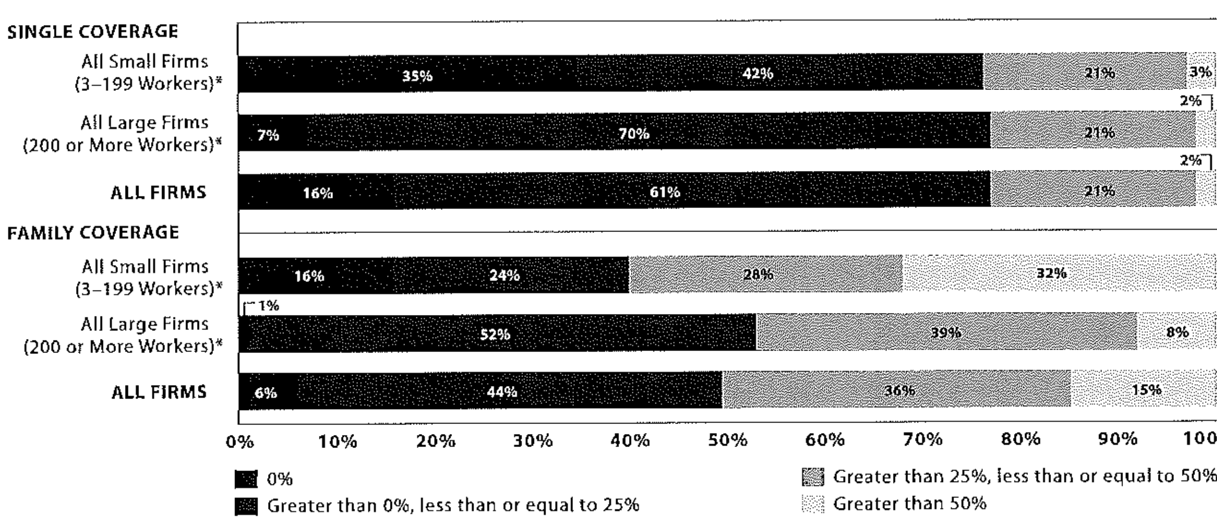
EMPLOYEE COST SHARING

Most covered workers face additional out-of-pocket costs when they use health care services. Eighty-one percent of covered workers have a general annual deductible for single coverage that must be met before most services are paid for by the plan. Even workers without a general annual deductible often face other types of cost sharing when they use services, such as copayments or coinsurance for office visits and hospitalizations.

Among covered workers with a general annual deductible, the average deductible

EXHIBIT E

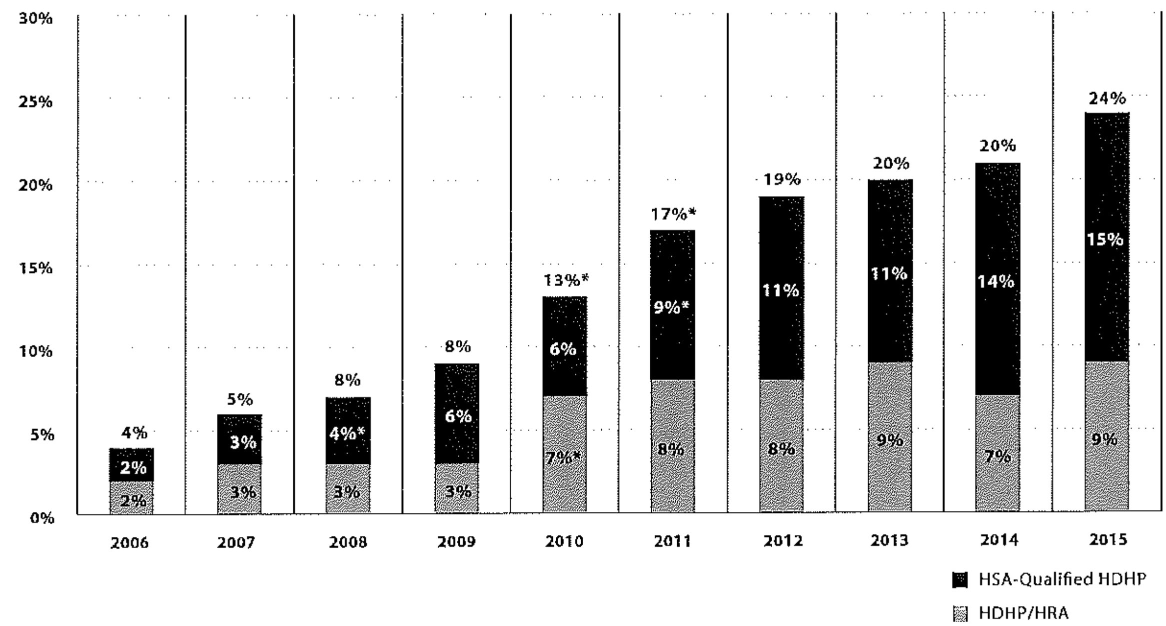
Distribution of Percentage of Premium Paid by Covered Workers for Single and Family Coverage, by Firm Size, 2015



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2015.

EXHIBIT F

Percentage of Covered Workers Enrolled in an HDHP/HRA or HSA-Qualified HDHP, 2006-2015



*Estimate is statistically different from estimate for the previous year shown (p<.05).

NOTE: Covered Workers enrolled in an HDHP/SO are enrolled in either an HDHP/HRA or a HSA-Qualified HDHP. For more information see the Survey Methodology Section. The percentages of covered workers enrolled in an HDHP/SO may not equal the sum of HDHP/HRA and HSA-Qualified HDHP enrollment estimates due to rounding.

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2006-2015.

amount for single coverage is $1,318. The average annual deductible is similar to last year ($1,217), but has increased from $917 in 2010. Deductibles differ by firm size; for workers in plans with a deductible, the average deductible for single coverage is $1,836 in small firms, compared to $1,105 for workers in large firms. Sixty-three percent of covered workers in small firms are in a plan with a deductible of at least $1,000 for single coverage compared to 39% in large firms; a similar pattern exists for those in plans with a deductible of at least $2,000 (36% for small firms vs. 12% for large firms) (Exhibit G).

Looking at the increase in deductible amounts over time does not capture the full impact for workers because the share of covered workers in plans with a general annual deductible also has increased significantly, from 55% in 2006 to 70% in 2010 to 81% in 2015. If we look at the change in deductible amounts for all covered workers (assigning a zero value to workers in plans with no deductible), we can look at the impact of both trends together. Using this approach, the average deductible for all covered workers in 2015 is $1,077, up 67% from $646 in 2010 and 255% from $303 in 2006.

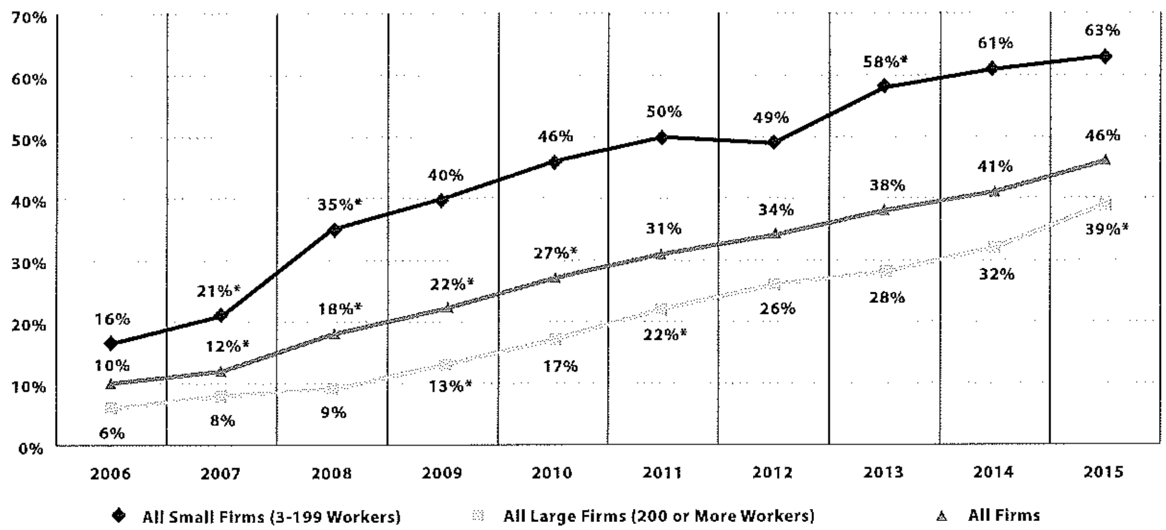
A large majority of workers also have to pay a portion of the cost of physician office visits. Almost 68% of covered workers pay a copayment (a fixed dollar amount) for office visits with a primary care or specialist physician, in addition to any general annual deductible their plan may have. Smaller shares of workers pay coinsurance (a percentage of the covered amount) for primary care office visits (23%) or specialty care visits (24%). For in-network office visits, covered workers with a copayment pay an average of $24 for primary care and $37 for specialty care. For covered workers with coinsurance, the average coinsurance for office visits is 18% for primary and 19% for specialty care. While the survey collects information only on in-network cost sharing, it is generally understood that out-of-network cost sharing is higher.

Virtually all (99%) of covered workers are enrolled in a plan that covers some prescription drugs. Cost sharing for filling a prescription usually varies with the type of drug – for example, whether it is a generic, brand-name, or specialty drug – and whether the drug is considered preferred or not on the plan's formulary. These factors result in each drug being assigned to a tier that represents a different level, or type, of cost sharing. Eighty-one percent of covered workers are in plans with three or more tiers of cost sharing. Twenty-three percent of covered workers are enrolled in a plan with four or more cost sharing tiers compared to 13% in 2010. Copayments are the most common form of cost sharing for tiers one through three. Among workers with plans with three or more tiers, the average copayments in these plans are $11 for first tier drugs, $31 for second tier drugs, $54 for third tier drugs, and $93 for fourth tier drugs. HDHP/SOs have a somewhat different cost sharing pattern for prescription drugs than other plan types; just 61% of covered workers are enrolled in a plan with three or more tiers of cost sharing, 12% are in plans that pay the full cost of prescriptions once the plan deductible is met, and 22% are in a plan with the same cost sharing for all prescription drugs.

Most covered workers with drug coverage are enrolled in a plan which covers specialty drugs such as biologics (94%). Large employers have used a variety of strategies for containing the cost of specialty drugs including utilization management programs (31%), step therapies where enrollees must first try

EXHIBIT G

Percentage of Covered Workers Enrolled in a Plan with a General Annual Deductible of $1,000 or More for Single Coverage, By Firm Size, 2006-2015



* Estimate is statistically different from estimate for the previous year shown (p<.05).

NOTE: These estimates include workers enrolled in HDHP/SO and other plan types. Average general annual health plan deductibles for PPOs, POS plans, and HDHP/SOs are for in-network services.

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2006-2015.

alternatives (30%) and tight limits on the number of units administered at a single time (25%).

Twelve percent of covered workers enrolled in a plan with prescription drug coverage are enrolled in a plan with a separate annual drug deductible that applies only to prescription drugs. Among these workers, the average separate annual deductible for prescription drug coverage is $231. Five percent of covered workers are enrolled in a plan with an annual deductible for prescription drug coverage of $500 or more.

Most workers also face additional cost sharing for a hospital admission or an outpatient surgery episode. After any general annual deductible is met, 65% of covered workers have a coinsurance and 14% have a copayment for hospital admissions. Lower percentages have per day (per diem) payments (4%), a separate hospital deductible (2%), or both copayments and coinsurance (11%). The average coinsurance rate for hospital admissions is 19%. The average copayment is $308 per hospital admission, the average per diem charge is $281, and the average separate annual hospital deductible is $1,006. The cost sharing provisions for outpatient surgery are similar to those for hospital admissions, as most covered workers have either coinsurance (67%) or copayments (15%). For covered workers with cost sharing, for each outpatient surgery episode, the average coinsurance is 19% and the average copayment is $181.

Almost all (98%) of covered workers are in plans with an out-of-pocket maximum for single coverage, significantly more than the 88% in 2013. While almost all workers have an out-of-pocket limit, the actual dollar limits differ considerably. For example, among covered workers in plans that have an out-of-pocket maximum for single coverage, 13% are in plans with an annual out-of-pocket maximum of $6,000 or more, and 9% are in plans with an out-of-pocket maximum of less than $1,500.

AVAILABILITY OF EMPLOYER-SPONSORED COVERAGE

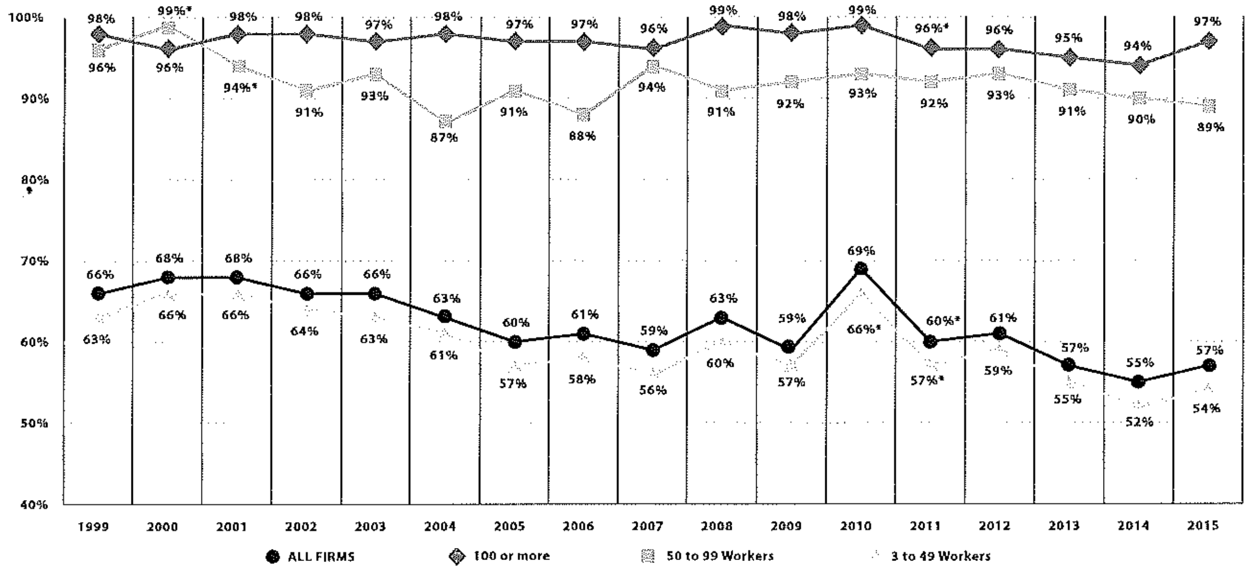
Fifty-seven percent of firms offer health benefits to their workers, statistically unchanged from 55% last year and 60% in 2005 (Exhibit H). The likelihood of offering health benefits differs significantly by size of firm, with only 47% of employers with 3 to 9 workers offering coverage, but virtually all employers with 1,000 or more workers offering coverage to at least some of their employees. Ninety percent of workers are in a firm that offers health benefits to at least some of its employees, similar to 2014 (90%).

Even in firms that offer health benefits, not all workers are covered. Some workers are not eligible to enroll as a result of waiting periods or minimum work-hour rules. Other workers do not enroll in coverage offered to them because of the cost of coverage or because they are covered through a spouse. Among firms that offer coverage, an average of 79% of workers are eligible for the health benefits offered by their employer. Of those eligible, 79% take up their employer's coverage, resulting in 63% of workers in offering firms having coverage through their employer. Among both firms that offer and those that do not offer health benefits, 56% of workers are covered by health plans offered by their employer, similar to 2014 (55%).

Beginning in 2015, employers with at least 100 full-time equivalent employees (FTEs) must offer health benefits to their full-time workers that meet minimum standards for value and affordability or pay a penalty. The requirement applies to employers with 50 or more FTEs beginning in 2016. Of firms reporting at least 100 FTEs (or, if they did not know FTEs, of firms with at least 100 employees), 96% report that they offer one health plan that would meet these

EXHIBIT H

Percentage of Firms Offering Health Benefits, by Firm Size, 1999-2015



*Estimate is statistically different from estimate for the previous year shown (p<.05).

NOTE: Estimates presented in this exhibit are based on the sample of both firms that completed the entire survey and those that answered just one question. For more information see the Survey Methods Section

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 1999-2015.

requirements, two percent did not and three percent reported "don't know." Five percent of these firms reported that this year they offered more comprehensive benefits to some workers who previously were only offered a limited benefit plan. Twenty-one percent reported that they extended eligibility to groups of workers not previously eligible because of the employer shared responsibility provision.

We asked firms reporting 50 or more FTEs (or, if they did not know how many FTEs, firms with at least 50 employees) about changes to their workforce in response to the employer requirement. Four percent reported that they changed some job classifications from full-time to part-time so employees would not be eligible for health benefits while 10% reported changing some job classifications from part-time to full-time so that they would become eligible. Four percent also reported reducing the number of full-time employees that they intended to hire because of the cost of health benefits.

RETIREE COVERAGE

Twenty-three percent of large firms that offer health benefits in 2015 also offer retiree health benefits, similar to the percentage in 2014 (25%). Among large firms that offer retiree health benefits, 92% offer health benefits to early retitees (workers retiring before age 65), 73% offer health benefits to Medicare-age retirees, and 2% offer a plan that covers only prescription drugs. Employers offering retiree benefits report interest in new ways of delivering them. Among large firms offering retiree benefits, seven percent offer them through a private exchange and 26% are considering changing the way they offer retiree coverage because of the new health insurance exchanges established by the ACA.

WELLNESS, HEALTH RISK ASSESSMENTS AND BIOMETRIC SCREENINGS

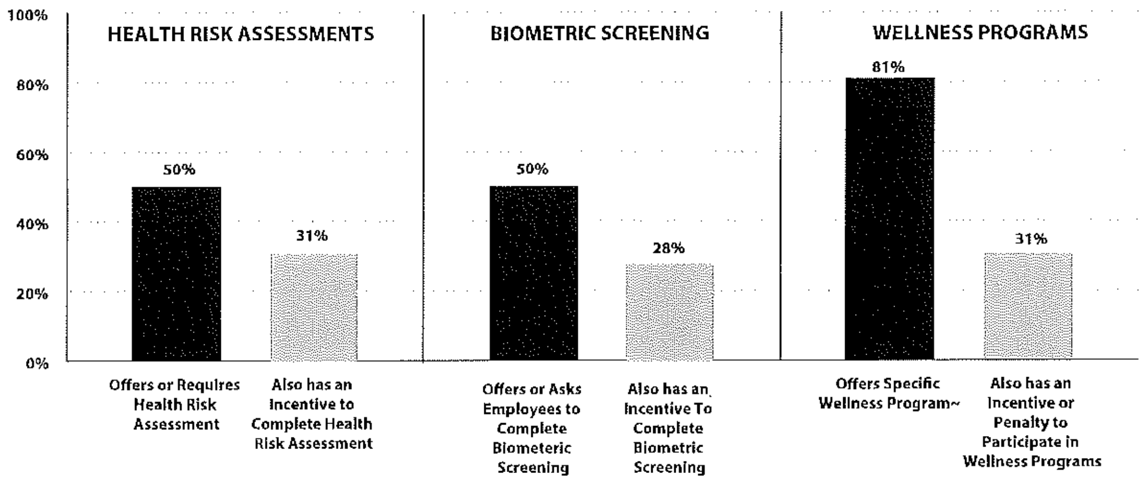
Health Risk Assessment. Employers continue to offer programs that encourage employees to identify health issues and to manage chronic conditions. A majority of larger employers now offer health screening programs including health risk assessments, which are questionnaires asking employees about lifestyle, stress or physical health, and in-person examinations such as biometric screenings. Some employers have incentive programs that reward or penalize employees for a range of activities including participating in wellness programs or meeting biometric outcomes.

Fifty percent of large employers offering health benefits provide employees with an opportunity or require employees to complete a health risk assessment. A health risk assessment includes questions about medical history, health status, and lifestyle, and is designed to identify the health risks of the person being assessed. Large firms are more likely than small firms to offer an opportunity or require employees to complete a health risk assessment (50% vs. 18%). Among firms with a health risk assessment, 62% of large firms report that they provide incentives to employees that complete the assessment. There is significant variation in the percentage of employees that complete a health risk assessment among firms; 27% of large firms with a health risk assessment report that more than three-quarters of employees complete the screening while 41% report that a quarter or less complete it.

Biometric Screening. Fifty percent of large firms and 13% of small firms offering health benefits ask or offer employee the opportunity to complete a biometric screening. Biometric screening is a health examination that measures an employee's risk factors such as body weight, cholesterol, blood pressure, stress, and nutrition. Among large firms

EXHIBIT I

Among Large Firms (200 or more workers) Offering Health Benefits, Percentage of Firms Offering Incentives for Various Wellness and Health Promotion Activities, 2015



~ Firms which offer either "Programs to Help Employees Stop Smoking", "Programs to Help Employees Lose Weight", or "Other Lifestyle or Behavioral Coaching"

SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2015.

with biometric screening programs, 56% offer employees incentives to complete a biometric screening. Among firms with a biometric screening program and an incentive to complete it, 20% have a reward or penalty for meeting specified biometric outcomes such as achieving a target body mass index (BMI) or cholesterol level. The maximum financial value for meeting biometric outcomes ranges considerably across these firms: 16% have a maximum annual incentive of $150 or less and 28% have a maximum annual incentive of more than $1,000.

Wellness Programs. Many employers offer wellness or health promotion programs to improve their employees' health. Eighty-one percent of large employers and 49% of small employers offer employees programs to help them stop smoking, lose weight, or make other lifestyle or behavioral changes. Of firms offering health benefits and a wellness program, 38% of latge firms and 15% of small firms offer employees a financial incentive to participate in or complete a wellness program. Among large firms with an incentive to participate in or complete a wellness program, 27% believe that incentives are "very effective" at encouraging employees to participate (Exhibit I).

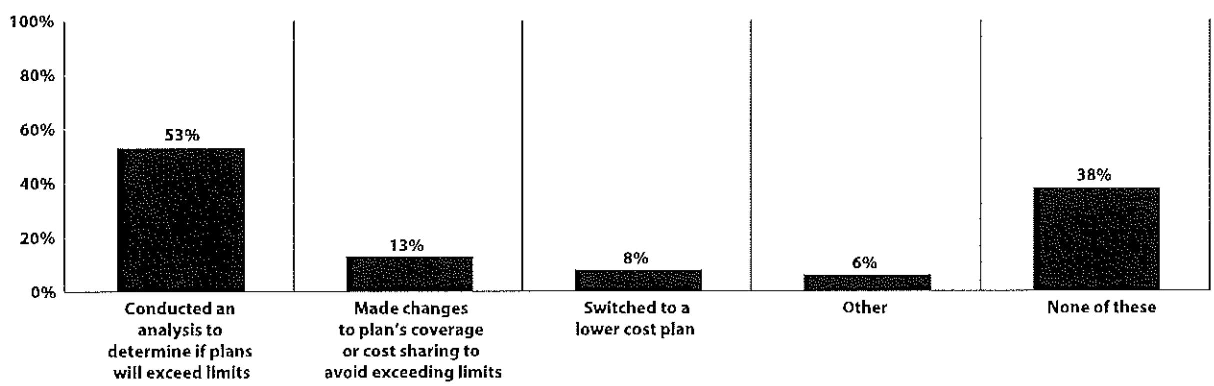
Disease management programs. Disease management programs try to improve the health and reduce the costs for enrollees with chronic conditions. Thitty-rwo percent of small employers and 68% of large employers offer disease management programs. Among firms with disease management programs, eight percent of large fitms and 24% of firms with 5,000 or more workers offer a financial incentive to employees who participate.

PROVIDER NETWORKS

High Performance or Tiered Networks. Seventeen percent of employers offering health benefits have high perfotmance or tiered networks in their largest health plan. These programs identify providers that are mote efficient ot have higher quality care, and may provide financial or other

EXHIBIT J

Among Large Firms (200 or more Workers) Offering Health Benefits, Percentage of Firms Who Have Taken Various Actions in Anticipation of the Excise Tax on High Cost Plans, by Firm Size, 2015



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2015.

incentives for enrollees to use the selected providers. Firms with 1,000-4,999 workers employees are more likely to have a largest plan that includes a high performance or tiered network (33%) than firms in other size categories.

Narrow Networks. Some employers limit their provider networks to reduce the cost of the plan. Nine percent of employers reported that their plan eliminated hospitals or a health system to reduce cost and seven percent offer a plan considered a narrow network plan. These plans typically have a provider network more limited than the standard HMO network.

Telemedicine. Telemedicine includes exchanging heath information electronically, including through smart phones or webcasts in order to improve a patient's health. The largest health plan at 27% of large firms (200 or more workers) offering health benefits covers telemedicine.

OTHER TOPICS

Pre-Tax Premium Contributions. Thirty-seven percent of small firms and 90% of large firms have a plan under section 125 of the Internal Revenue Service Code (sometimes called a premium-only plan) to allow employees to use pre-tax dollars to pay for a share of health insurance premiums.

Flexible Spending Accounts. Seventeen percent of small firms and 74% of large firms offer employees the option of contributing to a flexible spending account (FSA). FSAs permit employees to make pre-tax contributions that may be used during the year to pay for eligible medical expenses. The Affordable Care Act put some additional limits on FSAs, including capping the amount that could be contributed in a year ($2,550 in 2015) and limits on the use of FSA dollars for non-prescribed over the counter medications and premiums.[3] Three percent of firms not offering health benefits offered an FSA in 2015.

Waiting Periods and Enrollment. With exceptions for orientation periods and variable hour employees, the ACA limits waiting periods to no more than 90 days for all group health plans.[4] The average waiting period for covered workers who face a waiting period decreased from 2.1 months in 2014 to 2 months in 2015. The provision of the Affordable Care Act requiring employers with 200 or more full-time employees to automatically enroll eligible new full-time employees in one of the firm's health plans after any waiting period has not yet taken effect. In 2015, 13% of large employers (200 or more workers) and 42% of small employers automatically enroll eligible employees.

Self-Funding. Seventeen percent of covered workers at small firms and 83% of covered workers at large firms are enrolled in plans that are either partially or completely self-funded. Overall, 63% of covered workers are enrolled in a plan that is either partially or completely self-funded, 60 percent of whom are covered by additional insurance against high claims, sometimes known as stop loss coverage. The percentage of covered workers at both small and large firms in self-funded plans is similar to the percentage reported in 2010.

Private Exchanges. Private exchanges are arrangements created by consultants, brokers or insurers that allow employers to offer their employees a choice of different benefit options, often from different insurers. While these arrangements are fairly new, 17% of firms with more than 50 employees offering health benefits say they are considering offering benefits through a private exchange. Twenty-two percent of employers with 5,000 or more employees are considering this option. Enrollment to this point has been modest: 2% of covered workers in firms with more than 50 employees are enrolled in a private exchange.

Professional Employment Organization. Some firms provide for health and other benefits by entering into a co-employment relationship with a Professional Employer Organization (PEO). Under this arrangement, the firm manages the day-to-day responsibilities of employees but the PEO hires the employees and acts as the employer for insurance, benefits, and other administrative purposes. Five percent of employers offering health benefits with between three and 499 workers offer coverage through a PEO.

Grandfathered Health Plans. The ACA exempts "grandfathered" health plans from a number of its provisions, such as the requirements to cover preventive benefits without cost sharing or the new rules for small employers' premiums ratings and benefits. An employer-sponsored health plan can be grandfathered if it covered a worker when the ACA became law (March 23, 2010) and if the plan has not made significant changes that reduce benefits or increase employee costs.[5] Thirty-five percent of firms offering health benefits offer at least one grandfathered health plan in 2015. Twenty-five percent of covered workers are enrolled in a grandfathered health plan in 2015.

EXCISE TAX ON HIGH-COST HEALTH PLANS

Beginning in 2018, employer health plans will be will be subject to an excise tax of 40% on the amount by which their cost exceeds specified thresholds ($10,200 for single coverage and $27,000 for family coverage in 2018).[6] The tax is calculated with respect to each employee based on the combinations of health benefits received by that employee, including the employer and employee share of health plan premiums (or premium equivalents for self-funded plans), FSA contributions, and employer contributions to health savings accounts and health reimbursement arrangement contributions. Fifty-three percent of large firms (200 or more workers) offering health benefits have conducted an analysis to determine if they will exceed the 2018 thresholds, with 19% of these firms saying that their largest health plan would exceed the 2018 threshold. A small percentage of large employers offering health benefits report that they already have made changes to their plans' coverage or cost-sharing requirements (13%) or switched to a lower cost plan (8%) in response to the anticipated tax (Exhibit J).

CONCLUSION

The continuing implementation of the ACA has brought about a number of changes for employer-based coverage, ranging from benefits changes (such as the requirement to cover certain preventive care without cost sharing or have an out-of-pocket limit) to the requirement for larger employers to offer coverage to their full-time workers or face financial penalties. Even with these new requirements, most market fundamentals have stayed consistent with prior trends, suggesting that the implementation has not caused significant disruption for most market participants. Premiums for single and family coverage increased by 4% in 2015, continuing a fairly long period (2005 to 2015) where annual premium growth has averaged about 5%. The percentage of employers offering coverage (57%) is similar to recent years,[7] as is the percentage of workers in offering firms covered by their own employer (63%). The offer and coverage rates have been declining very gradually since we have been doing the survey, with the current values generally below those we saw prior to 2005.

The stability we have seen over the last several yeats does not mean that no changes are occurring. Employers continue to focus on wellness and health promotion and extend their programs to assess health risk; here programs that collect personal health information and provide financial incentives for employees to undertake health programs or meet biometric targets have the potential to significantly alter how people with employer-based coverage interact with their health plan. Employers, particularly large employers, continue to show intetest in private exchanges, although enrollment ro date is not very large. If these exchanges succeed, they have the potential to move some of the decision-making about benefits away from employers, which could transform how employees and employers interact over benefits.

While the ACA has not transformed the market, changes are occurring and more are likely to come. Some employers report that they have modified job classifications in reaction to the employer requirement to offer benefits, with more reporting that they increased the number of jobs with full-time status than decreasing it. Additionally, five percent of large firms (200 or more workers) employers reported that they intend to reduce the number of full-time employees that they intend to hire because of the cost of providing health care benefits. Employers also are considering the potential impacts thar the high-cost plan tax may have on their health benefits, with small percentages already taking action to lower plan costs. Over a longer period, the high-cost plan tax has the potential to cause significant changes in employer-sponsored coverage as employers and workers look for ways to keep cost increases to inflation far below the even moderate premium increases we have seen in recent years.

Whether the period of moderate premium growth will continue as the economy improves is one the biggest questions facing the employer market. Higher costs tend to follow improvements in economic growth,[8] and recent increases in spending for health services will put upward pressure on premiums.[9] At the same time, concerns about the high-cost plan tax will have employers and insurers looking for savings. These competing pressures may well lead to plan changes such as tighter networks, stricter management and higher cost sharing as employers and insurers struggle to contain these higher costs.

METHODOLOGY

The Kaiser Family Foundation/Health Research & Educational Trust 2015 Annual Employer Health Benefits Survey (Kaiser/HRET) reports findings from a telephone survey of 1,997 randomly selected public and private employers with three or more workers. Researchers at the Health Research & Educational Trust, NORC at the University of Chicago, and the Kaiser Family Foundation designed and analyzed the survey. National Research, LLC conducted the fieldwork between January and June 2015. In 2015, the overall response rate is 42%, which includes firms that offer and do not offer health benefits. Among firms that offer health benefits, the survey's response rate is also 41%.

We asked all firms with which we made phone contact, even if the firm declined to participate in the survey: "Does your company offer a health insurance program as a benefit to any of your employees?" A total of 3,191 firms responded to this question (including the 1,997 who responded to the full survey and 1,194 who responded to this one question). Their responses are included in our estimates of the percentage of firms offering health coverage. The response rate for this question is 67%.

Since firms are selected randomly, it is possible to extrapolate from the sample to national, regional, industry, and firm size estimates using statistical weights. In calculating weights, we first determine the basic weight, then apply a nonresponse adjustment, and finally apply a posr-stratification adjustment. We use the U.S. Census Bureau's Statistics of U.S. Businesses as the basis for the stratification and the post-stratification adjustment for firms in the private sector, and we use the Census of Governments as the basis for post-stratification for firms in the public sector. Some numbers in the report's exhibits do not sum up to totals because of rounding effects, and, in a few cases, numbers from distribution exhibits referenced in the text may not add due to rounding effects. Unless otherwise noted, differences referred to in the text and exhibits use the 0.05 confidence level as the threshold for significance.

For more information on the survey methodology, please visit the Methodology section at http://ehbs.kff.org/.

The Kaiser Family Foundation, a leader in health policy analysis, health journalism and communication, is dedicated to filling the need for trusted, independent information on the major health issues facing our nation and its people. The Foundation is a non-profit private operating foundation based in Menlo Park, California.

The Health Research & Educational Trust (HRET) is a private, not-for-profit organization involved in research, education, and demonstration programs addressing health management and policy issues. Founded in 1944, HRET, an affiliate of the American Hospital Association, collaborates with health care, government, academic, business, and community organizations across the United States to conduct research and disseminate findings that help shape the future of health care.

[1] Majerol, Melissa, Newkirk, Vann and Garfield, Rachel. "The uninsured: A primer—key facts about health insurance on the eve of coverage expansions." Kaiser Commission on Medicaid and the Uninsured. Dec 2014. http://kff.org/uninsured/report/the-uninsured-a-primer/ See supplemental tables - Table 1: 268.9 million non-elderly people, 54.6% of whom are covered by ESI.

[2] Kaiser/HRET surveys use the April-to-April time period, as do the sources in this and the following note. The inflation numbers are not seasonally adjusted. Bureau of Labor Statistics. Consumer Price Index - All Urban Consumers: Department of Labor; 2015. [cited 2015 September 2] http://data.bls.gov/timeseries/CUUR0000SA0?output_view=pct_1mth. Wage data are from the Bureau of Labor Statistics and based on the change in total average hourly earnings of production and nonsupervisory employees. Employment, hours, and earnings from the Current Employment Statistics survey: Department of Labor; 2015 [cited 2015 September 2]. http://data.bls.gov/timeseries/CES0500000008

[3] "Application of Market Reform and other Provisions of the Affordable Care Act to HRAs, Health FSAs, and Certain other Employer Healthcare Arrangements." Notice 2013-54. Internal Revenue Service. http://www.irs.gov/pub/irs-drop/n-13-54.pdf

[4] Federal Register. Volume 79, No 36, February 24, 2014. http://webapps.dol.gov/FederalRegister/HtmlDisplay.aspx?DocId=27369&Month=2&Year=2014

[5] Federal Register. Vol. 75, No 221, November 17, 2010, http://www.gpo.gov/fdsys/pkg/FR-2010-11-17/pdf/2010-28861.pdf.

[6] Claxton, Gary & Levitt, Larry. "How Many Employers Could be Affected by the Cadillac Plan Tax?" Kaiser Family Foundation. Apr 2015. http://kff.org/health-reform/issue-brief/how-many-employers-could-be-affected-by-the-cadillac-plan-tax/

[7] The 2015 offer rate is significantly lower than the 69% of firms which indicated that they offered benefits in 2010. The increase in the 2010 estimate was primarily driven by a 12 percentage point increase in firms with between 3 and 9 employees offering coverage. Given the number of small firms in the country, statistics weighted by the number of employers tend to be volatile - for more information see the survey design section.

[8] "Assessing the Effects of the Economy on the Recent Slowdown in Health Spending." Kaiser Family Foundation. Apr 2013. http://kff.org/health-costs/issue-brief/assessing-the-effects-of-the-economy-on-the-recent-slowdown-in-health-spending-2/

[9] "How has health spending changed over time?" Peterson-Kaiser Health System Tracker. June 2015. http://www.healthsystemtracker.org/chart-collection/how-has-health-spending-changed-over-time/?slide=1

THE HENRY J. KAISER FAMILY FOUNDATION

-AND-

HRET HEALTH RESEARCH & EDUCATIONAL TRUST

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Filling the need for trusted information on national health issues, the Kaiser Family Foundation is a nonprofit organization based in Menlo Park, California.

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The full report of survey findings (#8775) is available on the Kaiser Family Foundation's website at www.kff.org. This summary (#8776) is also available at www.kff.org.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 263

Date prepared: 6/21/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 263

With regard to UG 305/CNGC/203, Parvinen/1, please provide the actual franchise fee expenses for each of the years from 2005 through 2015 inclusive, and show the calculation of the current franchise fee rate of 1.835 percent.

Response:
See attached spreadsheet for 2005 to 2015 franchise fee expenses OPUC-263.xlsx

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 265

Date prepared: 6/23/16

Preparer: Donna Genora

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 265

Please provide a narrative explaining MDU's allocation policy regarding the allocation of revenues, expenses, tax benefits, deferred taxes, etc. that arise from an underlying plant asset to the various companies and/or jurisdictions. In the response, include a discussion regarding the allocation treatment of bonus depreciation and property tax expense to the Oregon Jurisdiction.

Response:
We do not allocation revenues, expense, deferred taxes and tax benefits between separate operating companies with the exception of our income tax sharing arrangement where we allocate income tax liabilities and benefits among the member Group, as explained below. Specifically, bonus depreciation and property taxes are considered when calculating separate company income tax payable by Federal and state jurisdictions. Asset domicile is used when calculating state apportionment factors such as revenue, plant, rent and wages.

MDU files a consolidated Federal income tax return under section 1501 and the Federal tax liability of the Group is determined under Code Section 1502 and the Regulations thereunder by consolidating the income, expenses, gains, losses and credits of all of the members of the group.

State income taxes for the Group are allocated among the members based upon the amount of each member's separate return liability in each state, after reduction for the amount of consolidated state income tax savings considered to be allocated to such member.

Column (j), entitled "Public Purpose Cost Reallocation" removes from expenses the portion of costs provided to the Energy Trust of Oregon (ETO) as part of the Company's general expenses. During 2015, additional funds were provided to the ETO in an amount not less than $500,000 per year consistent with the Commission's order in docket UG 167.[3] The recovery mechanism changed as a result of docket UG 287 to collect all ETO funds in the Public Purpose Charge (PPC). The booked expense therefore needs to be removed. This adjustment increases net income by $304,297.

Column (k), entitled "2016 Plant Additions" provides the Company's budgeted level of capital additions expected to go into service during 2016. The majority of the projected investments are non-revenue producing. The Company will update this projection later in the case to reflect actual costs and more up-to-date estimates. The net income effect of the rate base additions, for depreciation expense and property taxes, is a decrease of $425,543. The rate base impact is an increase of $7,238,320.

Column (l), entitled "Inflation Factor Adj" shows the impact of applying a consumer price index (CPI) inflation factor to non-labor related expenses. The net income effect is a decrease of $54,191.

Column (m), entitled "Resource Planning Adjustment" reflects additions to labor expenses for employees that will be added in 2016. The Company is anticipating a net gain of two additional positions in 2016 on a system basis. These two positions are added in response to the Commission's recommendation in Order No. 16-054 issued in docket LC 59 that the

[3] *In the Matter of Cascade Natural Gas Corporation Request for Authorization to Establish a Decoupling Mechanism and Approval of Tariff Sheets No. 30 and No. 30-A*, Docket UG 167, Order No. 06-191 at 3 (Apr. 19, 2006).

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 373

Date prepared: 07/26/2016

Preparer: Sam Brown/Carmen Glasser

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 373

Referring to the table below included in OPUC-298.xlsx, please:

a. Provide a narrative explaining the sharp increase in Medical/Dental & Life Insurance cost between the years 2013 and 2014;

b. Provide a narrative explaining the types of costs that are included in Other Benefits;

c. Provide a narrative explaining the variability in cost levels between years for each of the expense types Pension, Post Retirement, and Supplemental Defined Plan & Contribution. In the response, please describe in detail price determinants or cost drivers causal to the swings in expense levels;

d. Provide copies of both the 2015 and 2016 plan related to Supplemental Defined Plan and Contribution; and,

e. Explain the sharp increase in the 401-K Plan costs between the years 2012 and 2013.

		OREGON TOTAL					
		2016	2015	2014	2013	2012	Variance by Dollar
5192	Other Benefits	3,181	20,593	45,381	8,954	14,662	(17,412)
5194	Medical/Dental & Life Insurance	812,207	784,319	717,624	564,825	575,205	27,888
5195	Pension	(22,270)	(28,263)	70,661	130,260	187,630	5,994
5196	Post						

CASCADE NATURAL GAS CORPORATION
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	Retirement	112,766	52,523	19,385	102,795	83,949	60,243
5197	401-K Plan	563,386	577,536	562,943	500,667	256,513	(14,151)
5199	Workers Compensation	59,324	91,541	69,228	87,347	105,339	(32,217)
5921	Supplemental Defined Plan & Contribution	110,535	163,241	108,080	(109,169)	19,392	(52,706)
		1,639,130	**1,661,490**	**1,593,301**	**1,285,680**	**1,242,690**	**(22,360)**

Response:

a.) Medical/Dental and Life Insurance
The 2014 Medical/Dental and Life Insurance pension expense increased as a result of higher than anticipated medical claims. When claims exceed funded premiums, the Company is required to make up the difference based on the Company's contracts within the plan.

b.) Other Benefits include consulting costs including actuarial and investment consultants, audit fees, and miscellaneous communication costs.

c.) Pension
The 2013 pension expense decreased from 2012 due to a benefit freeze in 2012. The 2014 pension expense decreased from 2013 due to higher return on assets in 2013 and higher discount rates than in 2013. The 2015 pension expense decreased from 2014 due to a higher than expected contribution receivable applied to the 2014 plan year. The 2016 pension expense increased due to low asset returns in 2015 and a lower long-term rate of return.

Postretirement
The 2013 postretirement expense increased due to a decrease in the amortization of prior service credit bases. The 2014 postretirement expense decreased due to higher return on assets in 2013 and higher discount rates than in 2013. The 2015 postretirement expense increased due to lower discount rates and updated mortality tables and projection scales that reflected greater life expectancies. 2016 postretirement expense increased due to low asset returns in 2015 and a lower long-term rate of return.

SERP
The 2013 SERP expense decreased due to lower expected distributions to participants. The 2014 and 2015 SERP expense increased due to market fluctuations. The 2016 SERP expense decreased due to higher discount rates.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
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d.) See separately attached reports OPUC-373 (d).pdf.

e.) 401(k) costs increased in 2013 as the result of the implementation of an age-weighted retirement contribution due to freezing the pension plan for certain employees covered by the collective bargaining agreement. This contribution ranges from 5% - 11.5% of eligible plan compensation, depending on the age of the employee as of December 31, 2012.

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 109

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade
Captial Structure Calculation
UG 305
Twelve Months Ended December 31, 2015

COST OF CAPITAL - Company	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	51.00%	5.295%	2.700%
Preferred Stock	0.00%	0.000%	0.000%
Common Equity	49.00%	9.400%	4.606%
Total	100.00%		**7.306%**

CASE: UG 305
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 110

Exhibits in Support
Of Opening Testimony

August 11, 2016

Jun 2016 - Other Economic Indicators

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	15,020.6	15,354.6	15,583.3	15,961.7	16,348.9	16,687.2	17,157.7	17,622.6	18,050.9	18,489.7	18,932.5	19,387.1
% Ch	1.6	2.2	1.5	2.4	2.4	2.1	2.8	2.7	2.4	2.4	2.4	2.4
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	103.3	105.2	106.9	108.7	109.8	111.4	113.6	115.9	118.3	120.8	123.3	125.9
% Ch	2.1	1.8	1.6	1.6	1.0	1.5	2.0	2.1	2.0	2.1	2.1	2.1
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	104.1	106.1	107.6	109.1	109.4	110.4	112.2	114.5	116.9	119.4	121.9	124.6
% Ch	2.5	1.9	1.4	1.4	0.3	0.9	1.6	2.0	2.1	2.1	2.2	2.1
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	224.6	229.8	235.5	241.2	244.2	247.9	252.9	258.6	264.4	270.3	276.8	283.3
% Ch	2.9	2.3	2.5	2.4	1.2	1.5	2.0	2.3	2.2	2.3	2.4	2.3
U.S.	224.9	229.6	233.0	236.7	237.0	239.4	244.8	251.0	257.5	264.1	270.9	277.7
% Ch	3.1	2.1	1.5	1.6	0.1	1.0	2.2	2.6	2.6	2.6	2.6	2.5
Oregon Average Wage												
Rate (Thous $)	45.2	46.5	47.3	48.9	50.4	52.2	54.3	56.6	59.0	61.4	63.9	66.5
% Ch	3.2	3.0	1.6	3.2	3.2	3.5	4.0	4.3	4.2	4.1	4.1	4.1
U.S. Average Wage												
Wage Rate (Thous $)	50.3	51.7	52.2	53.8	55.2	56.6	58.8	61.1	63.4	65.8	68.5	71.2
% Ch	2.8	2.7	1.0	3.2	2.5	2.7	3.8	3.9	3.8	3.9	4.1	4.0
Housing Indicators												
FHFA Oregon Housing Price Index												
1980 Q1=100	347.4	346.0	370.9	403.7	441.7	482.6	520.8	544.3	563.9	583.1	602.7	622.3
% Ch	(6.9)	(0.4)	7.2	8.8	9.4	9.3	7.9	4.5	3.6	3.4	3.4	3.3
FHFA National Housing Price Index												
1980 Q1=100	312.3	312.0	324.9	346.2	370.8	382.6	394.2	403.5	412.9	424.4	436.9	453.5
% Ch	(3.7)	(0.1)	4.1	6.6	7.1	3.2	3.0	2.4	2.3	2.8	3.0	3.8
Housing Starts												
Oregon (Thous)	8.0	10.8	14.2	15.6	16.0	18.8	21.4	22.9	23.1	23.8	24.2	24.2
% Ch	5.3	35.5	31.5	9.3	2.6	17.9	13.4	7.3	1.0	2.9	1.5	0.2
U.S. (Millions)	0.6	0.8	0.9	1.0	1.1	1.2	1.4	1.5	1.5	1.6	1.6	1.7
% Ch	4.5	28.1	18.4	7.8	10.7	8.3	15.7	8.1	3.1	4.2	1.2	1.3
Other Indicators												
Unemployment Rate (%)												
Oregon	9.4	8.8	7.8	7.0	5.8	4.9	5.1	5.3	5.4	5.4	5.4	5.5
Point Change	(1.1)	(0.7)	(1.0)	(0.8)	(1.2)	(0.8)	0.2	0.2	0.0	0.1	0.0	0.0
U.S.	8.9	8.1	7.4	6.2	5.3	4.8	4.7	4.7	4.9	4.9	4.9	4.8
Point Change	(0.7)	(0.9)	(0.7)	(1.2)	(0.9)	(0.4)	(0.2)	0.0	0.2	0.0	(0.1)	(0.1)
Industrial Production Index												
U.S, 2002 = 100	97.3	100.0	101.9	104.9	105.2	104.4	107.3	111.0	113.9	117.0	120.0	122.8
% Ch	2.9	2.8	1.9	2.9	0.3	(0.8)	2.8	3.4	2.6	2.8	2.5	2.4
Prime Rate (Percent)	3.3	3.3	3.3	3.3	3.3	3.6	4.4	5.4	6.0	6.0	6.0	6.0
% Ch	0.0	0.0	0.0	0.0	0.3	11.8	21.1	22.7	10.9	0.0	0.0	0.0
Population (Millions)												
Oregon	3.86	3.89	3.93	3.97	4.02	4.07	4.12	4.17	4.22	4.27	4.31	4.36
% Ch	0.6	0.7	0.9	1.1	1.3	1.3	1.2	1.2	1.2	1.1	1.1	1.1
U.S.	312.5	314.8	317.1	319.5	321.9	324.5	327.1	329.8	332.4	335.0	337.6	340.2
% Ch	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Timber Harvest (Mil Bd Ft)												
Oregon	3,649.0	3,749.0	4,199.0	4,126.0	4,200.0	5,339.9	5,342.1	5,187.4	5,083.9	5,008.5	4,941.5	4,916.4
% Ch	13.1	2.7	12.0	(1.7)	1.8	27.1	0.0	(2.9)	(2.0)	(1.5)	(1.3)	(0.5)

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 291

Date prepared: 6/21/16

Preparer: Michael Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 291

Referring to UG 305/CNGC/200, Parvinen/7 at 16-17 and Parvinen workpapers Exhibits 201 - 206.xls, tab "Inflation Factor", please:

a. Provide a source document that supports the 2016 projected CPI factor of 0.012.

b. Explain whether the 2015 base year wages of $2,804,393, union wages, and $2,585,099, salary wages, removed from the 2015 base year amounts in tab "Inflation Factor" are the same as the 2015 wages and salaries amounts for union wages and salary wages provided by the Company in a response to any UG 305 Staff SDRs or DRs requesting 2015 wages and salaries amounts. If so, please provide the Company response(s). If not, please explain why not. For clarification, the table from tab, "Inflation Factor' is inserted below.

	Base Year Amounts	Base Year Wages	Adjusted Amounts
Production	$108,233		$108,233
Distribution	$5,639,690	$2,804,393	$2,835,297
Customer Accounts	$1,709,474		$1,709,474
Customer Service	$0		$0
Administrative and General	$5,451,075	$2,585,099	$2,865,976
	$12,908,472	$5,389,492	$7,518,980

Response:

a) Please see OPUC-291 Economic forecast Detail.pdf
b) No. The figures in the table above are derived from the "2016 Wage Adjustment" which uses system accrued wages. Other data responses have been provided from various payroll records trying to meet the needs of specific data requests.

APPENDIX A: ECONOMIC FORECAST DETAIL

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Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 4th quarter 2015
(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,797.0	3.0	1,791.0	2.5	5.9	0.3	3.1
Total Private	1,492.7	3.1	1,487.1	2.6	5.6	0.4	3.3
Mining and Logging	7.6	4.3	7.8	5.4	(0.1)	(1.9)	(1.1)
Construction	83.9	7.3	82.8	3.2	1.1	1.3	4.2
Manufacturing	186.7	1.0	186.4	0.5	0.2	0.1	2.7
Durable Goods	130.6	0.4	130.6	0.3	0.0	0.0	2.1
Wood Product	22.8	5.0	22.8	3.1	(0.1)	(0.3)	3.0
Metals and Machinery	36.9	0.4	37.0	0.7	(0.1)	(0.3)	1.8
Computer and Electronic Product	37.4	(1.2)	37.2	(0.6)	0.2	0.6	1.8
Transportation Equipment	12.5	(3.0)	12.5	(5.5)	0.0	0.2	3.8
Other Durable Goods	20.9	0.7	21.0	1.6	(0.1)	(0.2)	1.3
Nondurable Goods	56.1	2.5	55.9	0.9	0.2	0.4	4.1
Food	28.0	1.0	28.1	0.4	(0.1)	(0.2)	2.4
Other Nondurable Goods	28.1	4.0	27.8	1.5	0.3	1.0	5.9
Trade, Transportation & Utilities	337.0	1.4	338.3	2.1	(1.3)	(0.4)	2.3
Retail Trade	204.1	1.6	204.6	2.6	(0.5)	(0.2)	2.8
Wholesale Trade	73.9	0.8	74.2	1.2	(0.3)	(0.4)	1.4
Transportation, Warehousing & Utilities	59.0	1.3	59.5	1.5	(0.5)	(0.9)	1.9
Information	33.9	1.6	33.4	2.3	0.5	1.5	5.3
Financial Activities	94.7	3.3	94.0	2.5	0.7	0.8	2.2
Professional & Business Services	231.9	5.2	230.7	4.2	1.3	0.5	3.6
Educational & Health Services	262.2	3.8	260.0	2.5	2.1	0.8	4.2
Educational Services	36.1	5.3	35.1	0.8	0.9	2.6	3.9
Health Services	226.1	3.5	224.9	2.8	1.2	0.5	4.2
Leisure and Hospitality	193.6	3.1	193.3	3.7	0.3	0.2	4.3
Other Services	61.2	3.2	60.5	1.8	0.8	1.3	2.8
Government	304.3	2.7	303.9	2.2	0.3	0.1	2.4
Federal	27.8	0.7	27.9	(0.4)	(0.1)	(0.5)	0.4
State	87.2	(1.8)	88.7	2.1	(1.5)	(1.7)	2.0
State Education	33.5	5.1	32.6	(3.1)	0.9	2.8	2.5
Local	189.3	5.1	187.3	2.6	2.0	1.1	2.9
Local Education	97.9	3.1	97.3	2.9	0.6	0.6	2.7

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2015:4	2016:1	2016:2	2016:3	2016:4	2014	2015	2016	2017	2018	2019
Personal Income ($ billions)											
Nominal Personal Income	176.6	178.9	181.6	184.4	187.5	163.7	173.1	183.1	195.3	207.9	219.7
% change	5.5	5.3	6.0	6.4	6.9	5.7	5.8	5.8	6.7	6.5	5.7
Real Personal Income (base year=2005)	160.9	163.1	164.9	166.3	168.2	150.0	158.2	165.7	173.3	180.6	187.0
% change	5.4	5.7	4.4	3.5	4.6	4.2	5.4	4.7	4.6	4.2	3.5
Nominal Wages and Salaries	92.7	94.4	96.0	97.7	99.5	85.1	90.4	96.9	104.0	110.9	117.0
% change	7.4	7.5	6.9	7.3	7.7	6.1	6.3	7.1	7.3	6.6	5.5
Other Indicators											
Per Capita Income ($1,000)	43.7	44.2	44.7	45.2	45.8	41.2	43.0	45.0	47.4	49.9	52.1
% change	4.3	4.1	4.7	4.8	5.7	4.5	4.4	4.5	5.4	5.2	4.5
Average Wage rate ($1,000)	51.0	51.6	52.1	52.7	53.3	48.9	50.3	52.4	54.8	57.2	59.6
% change	4.3	4.1	4.4	4.4	4.7	3.3	2.9	4.2	4.6	4.5	4.1
Population (Millions)	4.0	4.1	4.1	4.1	4.1	3.97	4.02	4.07	4.12	4.17	4.22
% change	1.2	1.1	1.3	1.5	1.1	1.1	1.3	1.3	1.2	1.2	1.2
Housing Starts (Thousands)	18.5	17.1	17.6	18.1	19.3	15.6	15.9	18.0	21.1	22.7	23.1
% change	70.0	(27.6)	12.2	13.3	26.8	9.3	2.0	13.4	17.2	7.4	1.8
Unemployment Rate	5.8	5.7	5.6	5.6	5.5	7.0	5.8	5.6	5.4	5.6	5.6
Point Change	(0.3)	(0.1)	(0.1)	0.0	(0.1)	(0.8)	(1.2)	(0.2)	(0.2)	0.1	0.0
Employment (Thousands)											
Total Nonfarm	1,797.0	1,810.5	1,820.8	1,832.7	1,845.3	1,721.4	1,778.7	1,827.3	1,874.6	1,912.6	1,937.8
% change	3.0	3.0	2.3	2.6	2.8	2.8	3.3	2.7	2.6	2.0	1.3
Private Nonfarm	1,492.7	1,503.3	1,512.2	1,523.0	1,534.4	1,427.5	1,477.3	1,518.2	1,560.9	1,594.7	1,616.0
% change	3.1	2.9	2.4	2.9	3.0	3.0	3.5	2.8	2.8	2.2	1.3
Construction	83.9	84.9	85.5	86.1	87.0	80.1	82.7	85.9	88.2	89.7	90.2
% change	7.3	5.0	2.9	2.9	4.2	8.0	3.2	3.9	2.7	1.6	0.6
Manufacturing	186.7	187.4	187.6	187.8	188.4	179.4	185.7	187.8	189.9	192.0	193.2
% change	1.0	1.5	0.5	0.4	1.3	2.5	3.6	1.1	1.1	1.1	0.6
Durable Manufacturing	130.6	131.0	131.1	131.1	131.5	126.1	130.1	131.2	132.6	134.2	134.7
% change	0.4	1.2	0.5	(0.0)	1.1	2.3	3.2	0.8	1.1	1.2	0.4
Wood Product Manufacturing	22.8	22.9	22.8	22.9	23.0	22.0	22.5	22.9	23.2	23.6	23.5
% change	5.0	1.3	(0.1)	1.2	1.2	4.0	2.4	1.7	1.1	2.1	(0.6)
High Tech Manufacturing	37.4	37.5	37.4	37.1	37.2	36.5	37.5	37.3	37.6	37.9	37.8
% change	(1.2)	0.6	(0.9)	(2.9)	1.1	(0.4)	2.7	(0.4)	0.7	0.8	(0.3)
Transportation Equipment	12.5	12.5	12.6	12.6	12.7	11.5	12.4	12.6	12.8	13.0	13.0
% change	(3.0)	1.4	1.6	1.3	1.9	5.7	8.4	1.4	1.7	1.7	(0.1)
Nondurable Manufacturing	56.1	56.4	56.5	56.7	56.9	53.3	55.6	56.6	57.3	57.8	58.5
% change	2.5	2.2	0.5	1.3	1.8	2.9	4.4	1.8	1.2	0.8	1.3
Private nonmanufacturing	1,306.0	1,315.9	1,324.6	1,335.2	1,346.0	1,248.1	1,291.6	1,330.4	1,371.0	1,402.7	1,422.8
% change	3.4	3.1	2.7	3.2	3.3	3.1	3.5	3.0	3.0	2.3	1.4
Retail Trade	204.1	205.7	206.8	208.2	209.5	196.3	202.6	207.6	212.7	216.7	220.1
% change	1.6	3.2	2.2	2.6	2.7	2.4	3.2	2.5	2.5	1.9	1.6
Wholesale Trade	73.9	74.5	74.9	75.4	76.1	72.4	73.5	75.2	77.1	78.0	78.8
% change	0.8	3.4	2.1	2.7	3.7	1.3	1.4	2.4	2.4	1.2	1.0
Information	33.9	34.0	34.2	34.4	34.6	32.1	33.3	34.3	35.1	35.8	36.6
% change	1.6	1.2	2.3	2.3	2.3	(0.4)	3.7	2.9	2.3	2.1	2.2
Professional and Business Services	231.9	235.1	236.7	239.6	242.8	219.7	228.9	238.6	252.6	265.7	270.3
% change	5.2	5.6	2.8	5.0	5.3	4.9	4.2	4.2	5.9	5.2	1.7
Health Services	226.1	227.5	228.8	230.1	231.2	213.9	222.8	229.4	233.7	237.9	241.6
% change	3.5	2.5	2.4	2.3	1.9	2.5	4.2	2.9	1.9	1.8	1.6
Leisure and Hospitality	193.6	195.2	197.3	199.4	201.1	182.9	191.3	198.3	204.6	208.0	211.5
% change	3.1	3.4	4.4	4.3	3.5	3.6	4.6	3.6	3.2	1.7	1.7
Government	304.3	307.2	308.6	309.7	310.9	293.9	301.4	309.1	313.7	317.9	321.8
% change	2.7	3.9	1.8	1.5	1.5	1.8	2.5	2.6	1.5	1.3	1.2

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2015:4	2016:1	2016:2	2016:3	2016:4	2014	2015	2016	2017	2018	2019
			Personal Income ($ billions)								
Nominal Personal Income	176.6	178.9	181.6	184.4	187.5	163.7	173.1	183.1	195.3	207.9	219.7
% change	(0.2)	(0.5)	(0.5)	(0.7)	(0.8)	0.0	0.0	(0.6)	(1.0)	(0.9)	(0.9)
Real Personal Income (base year=2005)	160.9	163.1	164.9	166.3	168.2	150.0	158.2	165.7	173.3	180.6	187.0
% change	(0.4)	(0.0)	0.0	(0.4)	(0.5)	0.0	(0.0)	(0.2)	(0.6)	(0.5)	(0.5)
Nominal Wages and Salaries	92.7	94.4	96.0	97.7	99.5	85.1	90.4	96.9	104.0	110.9	117.0
% change	0.4	0.3	0.1	(0.1)	(0.1)	0.0	0.3	0.1	(0.1)	(0.0)	(0.0)
			Other Indicators								
Per Capita Income ($1,000)	43.7	44.2	44.7	45.2	45.8	41.2	43.0	45.0	47.4	49.9	52.1
% change	(0.2)	(0.5)	(0.5)	(0.7)	(0.8)	0.0	0.0	(0.6)	(1.0)	(0.9)	(0.9)
Average Wage rate ($1,000)	51.0	51.6	52.1	52.7	53.3	48.9	50.3	52.4	54.8	57.2	59.6
% change	0.1	(0.1)	(0.1)	(0.2)	(0.1)	(0.0)	0.2	(0.1)	(0.0)	0.0	0.1
Population (Millions)	4.04	4.05	4.06	4.1	4.1	3.97	4.02	4.07	4.12	4.17	4.22
% change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Housing Starts (Thousands)	18.5	17.1	17.6	18.1	19.3	15.6	15.9	18.0	21.1	22.7	23.1
% change	2.9	(7.8)	(6.8)	(5.2)	(5.1)	(0.1)	1.1	(6.2)	(2.1)	(0.5)	0.1
Unemployment Rate	5.8	5.7	5.6	5.6	5.5	7.0	5.8	5.6	5.4	5.6	5.6
Point Change	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	0.0	(0.0)	(0.2)	0.0	0.0	0.0
			Employment (Thousands)								
Total Nonfarm	1,797.0	1,810.5	1,820.8	1,832.7	1,845.3	1,721.4	1,778.7	1,827.3	1,874.6	1,912.6	1,937.8
% change	0.3	0.4	0.3	0.1	0.0	0.0	0.2	0.2	(0.1)	(0.1)	(0.1)
Private Nonfarm	1,492.7	1,503.3	1,512.2	1,523.0	1,534.4	1,427.5	1,477.3	1,518.2	1,560.9	1,594.7	1,616.0
% change	0.4	0.3	0.2	0.0	(0.1)	0.0	0.2	0.1	(0.2)	(0.2)	(0.2)
Construction	83.9	84.9	85.5	86.1	87.0	80.1	82.7	85.9	88.2	89.7	90.2
% change	1.3	1.5	0.9	0.6	0.9	0.0	0.4	1.0	0.5	0.5	0.5
Manufacturing	186.7	187.4	187.6	187.8	188.4	179.4	185.7	187.8	189.9	192.0	193.2
% change	0.1	0.2	0.2	(0.0)	(0.1)	0.0	0.0	0.1	(0.3)	(0.3)	(0.3)
Durable Manufacturing	130.6	131.0	131.1	131.1	131.5	126.1	130.1	131.2	132.6	134.2	134.7
% change	0.0	0.1	0.1	(0.2)	(0.4)	(0.0)	(0.0)	(0.1)	(0.7)	(0.5)	(0.4)
Wood Product Manufacturing	22.8	22.9	22.8	22.9	23.0	22.0	22.5	22.9	23.2	23.6	23.5
% change	(0.3)	(0.2)	(0.1)	(0.6)	(0.7)	(0.0)	(0.3)	(0.4)	(1.4)	(1.3)	(0.7)
High Tech Manufacturing	37.4	37.5	37.4	37.1	37.2	36.5	37.5	37.3	37.6	37.9	37.8
% change	0.6	1.0	1.0	0.5	0.0	0.0	0.3	0.6	(0.0)	1.3	1.3
Transportation Equipment	12.5	12.5	12.6	12.6	12.7	11.5	12.4	12.6	12.8	13.0	13.0
% change	0.2	(0.4)	0.6	0.4	0.6	(0.0)	(0.1)	0.3	1.1	1.5	2.2
Nondurable Manufacturing	56.1	56.4	56.5	56.7	56.9	53.3	55.6	56.6	57.3	57.8	58.5
% change	0.4	0.6	0.5	0.6	0.7	0.0	0.1	0.6	0.7	0.2	(0.2)
Private nonmanufacturing	1,306.0	1,315.9	1,324.6	1,335.2	1,346.0	1,248.1	1,291.6	1,330.4	1,371.0	1,402.7	1,422.8
% change	0.4	0.3	0.2	0.0	(0.1)	0.0	0.2	0.1	(0.2)	(0.2)	(0.2)
Retail Trade	204.1	205.7	206.8	208.2	209.5	196.3	202.6	207.6	212.7	216.7	220.1
% change	(0.2)	(0.1)	(0.4)	(0.5)	(0.6)	0.0	(0.0)	(0.4)	(0.7)	(1.2)	(1.2)
Wholesale Trade	73.9	74.5	74.9	75.4	76.1	72.4	73.5	75.2	77.1	78.0	78.8
% change	(0.4)	(0.1)	0.1	0.2	0.2	(0.0)	(0.2)	0.1	0.2	(0.2)	(0.1)
Information	33.9	34.0	34.2	34.4	34.6	32.1	33.3	34.3	35.1	35.8	36.6
% change	1.5	1.2	1.3	1.3	1.3	(0.0)	1.0	1.3	1.0	0.7	1.1
Professional and Business Services	231.9	235.1	236.7	239.6	242.8	219.7	228.9	238.6	252.6	265.7	270.3
% change	0.5	0.8	0.2	(0.2)	(0.5)	0.0	0.3	0.0	(0.5)	0.0	0.2
Health Services	226.1	227.5	228.8	230.1	231.2	213.9	222.8	229.4	233.7	237.9	241.6
% change	0.5	0.5	0.6	0.4	0.3	(0.0)	0.2	0.5	0.2	0.7	0.9
Leisure and Hospitality	193.6	195.2	197.3	199.4	201.1	182.9	191.3	198.3	204.6	208.0	211.5
% change	0.2	(0.2)	(0.2)	(0.3)	(0.7)	0.0	0.1	(0.4)	(0.8)	(1.1)	(1.2)
Government	304.3	307.2	308.6	309.7	310.9	293.9	301.4	309.1	313.7	317.9	321.8
% change	0.1	0.6	0.6	0.6	0.6	(0.0)	0.0	0.6	0.6	0.6	0.5

Table A.4 – Annual Economic Forecast

Mar 2016 - Personal Income

(Billions of Current Dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Personal Income*												
Oregon	145.1	152.4	154.9	163.7	173.1	183.1	195.3	207.9	219.7	231.5	243.0	254.7
% Ch	5.6	5.0	1.6	5.7	5.8	5.8	6.7	6.5	5.7	5.4	4.9	4.8
U.S.	13,254.5	13,915.1	14,068.4	14,694.2	15,359.7	15,998.1	16,825.4	17,707.3	18,590.8	19,505.3	20,424.1	21,374.7
% Ch	6.2	5.0	1.1	4.4	4.5	4.2	5.2	5.2	5.0	4.9	4.7	4.7
Wage and Salary												
Oregon	74.0	77.2	80.1	85.1	90.4	96.9	104.0	110.9	117.0	123.2	129.2	135.5
% Ch	4.3	4.2	3.9	6.1	6.3	7.1	7.3	6.6	5.5	5.3	4.9	4.8
U.S.	6,633.2	6,930.3	7,114.4	7,477.8	7,839.8	8,220.0	8,656.2	9,101.4	9,549.6	10,022.7	10,500.8	10,989.8
% Ch	4.0	4.5	2.7	5.1	4.8	4.8	5.3	5.1	4.9	5.0	4.8	4.7
Other Labor Income												
Oregon	18.2	19.7	20.1	19.8	20.6	21.7	23.0	24.3	25.7	27.0	28.2	29.5
% Ch	2.4	8.5	2.0	(1.6)	3.9	5.4	6.1	5.9	5.6	5.1	4.5	4.4
U.S.	1,142.0	1,165.3	1,197.8	1,224.0	1,264.3	1,313.8	1,374.6	1,427.2	1,481.1	1,535.3	1,588.3	1,643.0
% Ch	2.5	2.0	2.8	2.2	3.3	3.9	4.6	3.8	3.8	3.7	3.5	3.4
Nonfarm Proprietor's Income												
Oregon	10.1	10.7	11.1	11.8	12.3	13.2	14.1	15.0	15.8	16.7	17.6	18.5
% Ch	3.2	6.0	3.3	5.9	5.0	6.5	7.3	6.0	5.6	5.7	5.4	5.1
U.S.	1,068.1	1,179.8	1,196.3	1,268.5	1,327.4	1,382.2	1,456.4	1,514.8	1,574.4	1,651.8	1,730.9	1,812.5
% Ch	8.2	10.5	1.4	6.0	4.6	4.1	5.4	4.0	3.9	4.9	4.8	4.7
Dividend, Interest and Rent												
Oregon	27.9	30.3	30.1	31.4	32.7	34.1	36.5	39.3	42.0	44.4	46.8	48.8
% Ch	10.7	8.5	(0.4)	4.2	4.1	4.4	6.9	7.7	6.7	5.8	5.3	4.4
U.S.	2,399.2	2,649.1	2,623.8	2,728.4	2,839.8	2,909.6	3,067.2	3,291.4	3,498.4	3,680.4	3,850.7	4,024.4
% Ch	12.0	10.4	(1.0)	4.0	4.1	2.5	5.4	7.3	6.3	5.2	4.6	4.5
Transfer Payments												
Oregon	29.7	29.7	30.8	33.5	35.8	37.6	39.4	41.5	43.7	45.9	48.1	50.7
% Ch	1.5	(0.0)	3.7	8.8	6.9	4.8	4.9	5.3	5.2	5.1	4.9	5.3
U.S.	2,274.3	2,329.2	2,406.1	2,538.3	2,645.9	2,772.3	2,888.5	3,018.7	3,176.8	3,349.8	3,522.5	3,708.2
% Ch	1.7	2.4	3.3	5.5	4.2	4.8	4.2	4.5	5.2	5.4	5.2	5.3
Contributions for Social Security												
Oregon	11.6	12.1	14.2	14.9	15.7	16.9	18.1	19.3	20.4	21.6	22.8	24.0
% Ch	(7.5)	4.8	16.9	5.4	5.4	7.3	7.1	6.5	6.2	5.8	5.6	5.1
U.S.	423.9	437.2	579.4	611.8	637.1	666.3	703.0	742.1	785.5	829.5	874.3	920.6
% Ch	(17.6)	3.1	32.5	5.6	4.1	4.6	5.5	5.6	5.8	5.6	5.4	5.3
Residence Adjustment												
Oregon	(3.4)	(3.6)	(3.6)	(3.6)	(3.8)	(3.9)	(4.1)	(4.2)	(4.3)	(4.4)	(4.4)	(4.5)
% Ch	9.3	4.7	0.6	0.0	5.6	3.1	3.4	2.8	2.0	2.1	2.0	1.8
Farm Proprietor's Income												
Oregon	0.1	0.5	0.4	0.7	0.8	0.5	0.4	0.4	0.3	0.3	0.3	0.2
% Ch	(416.4)	269.3	(24.7)	86.0	13.6	(29.7)	(16.9)	(12.8)	(13.5)	(9.9)	(3.4)	(15.6)
Per Capita Income (Thousands of $)												
Oregon	37.6	39.2	39.4	41.2	43.0	45.0	47.4	49.9	52.1	54.3	56.3	58.4
% Ch	5.1	4.3	0.7	4.5	4.4	4.5	5.4	5.2	4.5	4.2	3.8	3.6
U.S.	42.4	44.2	44.4	46.0	47.7	49.3	51.4	53.7	55.9	58.2	60.5	62.8
% Ch	5.4	4.2	0.4	3.7	3.7	3.3	4.3	4.4	4.2	4.1	3.9	3.9

* Personal Income includes all classes of income minus Contributions for Social Security

Mar 2016 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Nonfarm												
Oregon	1,619.8	1,640.0	1,674.1	1,721.4	1,778.7	1,827.3	1,874.6	1,912.6	1,937.8	1,960.4	1,977.5	1,997.1
% Ch	1.1	1.2	2.1	2.8	3.3	2.7	2.6	2.0	1.3	1.2	0.9	1.0
U.S.	131.8	134.1	136.4	139.0	141.9	144.3	146.2	147.9	149.4	151.0	152.2	153.3
% Ch	1.2	1.7	1.7	1.9	2.1	1.7	1.3	1.2	1.0	1.1	0.8	0.7
Private Nonfarm												
Oregon	1,324.8	1,349.0	1,385.3	1,427.5	1,477.3	1,518.2	1,560.9	1,594.7	1,616.0	1,633.3	1,648.3	1,664.3
% Ch	1.8	1.8	2.7	3.0	3.5	2.8	2.8	2.2	1.3	1.1	0.9	1.0
U.S.	109.8	112.2	114.5	117.2	120.0	122.3	124.0	125.5	126.8	128.1	129.3	130.3
% Ch	1.8	2.2	2.1	2.3	2.4	1.9	1.4	1.2	1.1	1.0	0.9	0.8
Mining and Logging												
Oregon	7.0	7.2	7.6	7.7	7.7	7.8	8.0	8.2	8.2	8.3	8.4	8.4
% Ch	4.6	3.2	4.8	2.0	(0.2)	1.6	2.6	1.7	0.8	0.7	0.9	0.7
U.S.	0.8	0.8	0.9	0.9	0.8	0.7	0.8	0.8	0.8	0.8	0.9	0.9
% Ch	11.8	7.6	1.8	3.8	(6.6)	(11.1)	2.4	4.3	3.2	2.8	2.7	2.8
Construction												
Oregon	68.6	69.9	74.1	80.1	82.7	85.9	88.2	89.7	90.2	90.7	91.3	92.3
% Ch	1.4	1.8	6.1	8.0	3.2	3.9	2.7	1.6	0.6	0.5	0.7	1.2
U.S.	5.5	5.6	5.9	6.1	6.4	6.8	7.1	7.4	7.6	7.8	7.9	8.0
% Ch	0.2	2.1	3.7	4.8	4.2	5.6	5.1	3.6	2.9	2.5	2.0	1.7
Manufacturing												
Oregon	168.1	171.9	175.0	179.4	185.7	187.8	189.9	192.0	193.2	194.5	196.5	198.1
% Ch	2.6	2.2	1.8	2.5	3.6	1.1	1.1	1.1	0.6	0.7	1.0	0.8
U.S.	11.7	11.9	12.0	12.2	12.3	12.3	12.4	12.5	12.6	12.7	12.8	12.9
% Ch	1.7	1.7	0.8	1.4	1.1	(0.1)	0.9	0.9	1.0	0.8	0.7	0.2
Durable Manufacturing												
Oregon	118.6	121.6	123.2	126.1	130.1	131.2	132.6	134.2	134.7	135.3	136.6	137.7
% Ch	3.2	2.5	1.3	2.3	3.2	0.8	1.1	1.2	0.4	0.4	1.0	0.8
U.S.	7.3	7.5	7.5	7.7	7.8	7.8	7.8	7.9	8.0	8.1	8.2	8.2
% Ch	2.9	2.7	1.0	1.8	1.4	(0.4)	1.1	1.3	1.0	0.8	1.0	0.4
Wood Products												
Oregon	19.3	19.8	21.1	22.0	22.5	22.9	23.2	23.6	23.5	23.5	23.9	24.2
% Ch	(3.7)	2.6	7.0	4.0	2.4	1.7	1.1	2.1	(0.6)	(0.0)	1.6	1.5
U.S.	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
% Ch	(1.5)	0.7	4.2	5.3	2.1	4.9	7.7	6.2	2.8	3.5	3.1	2.2
Metal and Machinery												
Oregon	33.3	34.7	35.4	35.9	36.9	37.3	37.6	38.0	38.4	39.0	39.7	40.1
% Ch	6.9	4.2	2.0	1.5	2.5	1.1	1.0	1.0	1.2	1.5	1.7	1.2
U.S.	2.8	2.9	2.9	3.0	3.0	2.9	2.9	3.0	3.0	3.1	3.1	3.2
% Ch	5.7	4.2	0.7	1.8	0.1	(2.6)	0.3	1.3	2.2	1.7	1.9	1.6
Computer and Electronic Products												
Oregon	36.4	37.0	36.6	36.5	37.5	37.3	37.6	37.9	37.8	37.7	37.8	37.9
% Ch	4.1	1.6	(1.0)	(0.4)	2.7	(0.4)	0.7	0.8	(0.3)	(0.1)	0.0	0.4
U.S.	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2
% Ch	0.8	(1.3)	(2.2)	(1.4)	0.5	0.5	3.6	2.6	1.1	0.8	0.7	0.8
Transportation Equipment												
Oregon	10.7	11.1	10.9	11.5	12.4	12.6	12.8	13.0	13.0	12.9	12.9	12.8
% Ch	5.2	3.4	(2.3)	5.7	8.4	1.4	1.7	1.7	(0.1)	(1.3)	0.3	(1.0)
U.S.	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.5
% Ch	3.6	5.8	3.3	3.6	3.1	0.7	(0.1)	(1.0)	(1.6)	(1.0)	(0.8)	(2.9)
Other Durables												
Oregon	18.9	19.1	19.2	20.2	20.9	21.1	21.4	21.6	21.9	22.2	22.4	22.7
% Ch	1.6	1.0	0.8	5.4	3.1	1.0	1.3	1.3	1.4	1.0	1.1	1.2
U.S.	2.0	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.3	2.3	2.4
% Ch	0.0	0.7	1.6	2.3	2.3	1.3	2.8	2.2	0.9	1.0	1.2	0.8
Nondurable Manufacturing												
Oregon	49.5	50.3	51.8	53.3	55.6	56.6	57.3	57.8	58.5	59.2	59.9	60.4
% Ch	1.2	1.5	3.0	2.9	4.4	1.8	1.2	0.8	1.3	1.2	1.0	0.9
U.S.	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7
% Ch	(0.3)	0.1	0.3	0.7	0.7	0.4	0.4	0.3	0.9	0.6	0.2	(0.3)
Food Manufacturing												
Oregon	24.2	24.8	25.9	26.9	27.9	28.3	28.9	29.1	29.6	29.9	30.2	30.5
% Ch	1.8	2.4	4.3	4.0	3.6	1.6	1.8	0.9	1.4	1.2	1.0	1.0
U.S.	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7
% Ch	0.5	0.7	0.3	0.5	0.8	1.2	2.2	1.4	1.9	1.8	1.6	1.2
Other Nondurable												
Oregon	25.3	25.4	25.9	26.3	27.7	28.3	28.5	28.6	29.0	29.3	29.6	29.9
% Ch	0.7	0.5	1.7	1.8	5.3	2.0	0.6	0.7	1.2	1.1	1.1	0.8
U.S.	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
% Ch	(0.6)	(0.2)	0.3	0.8	0.5	(0.3)	(0.3)	0.2	0.5	(0.2)	(0.7)	(1.1)
Trade, Transportation, and Utilities												
Oregon	305.9	310.0	318.0	325.6	334.9	342.5	351.3	357.8	363.0	366.6	369.2	371.2
% Ch	1.2	1.3	2.6	2.4	2.9	2.3	2.6	1.8	1.5	1.0	0.7	0.6
U.S.	25.1	25.5	25.9	26.4	26.9	27.3	27.5	27.7	27.8	27.8	27.9	27.8
% Ch	1.7	1.6	1.5	2.0	2.0	1.4	0.8	0.6	0.4	0.2	0.1	(0.1)

Mar 2016 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Retail Trade												
Oregon	184.8	187.1	191.6	196.3	202.6	207.6	212.7	216.7	220.1	222.2	224.0	225.7
% Ch	0.9	1.2	2.4	2.4	3.2	2.5	2.5	1.9	1.6	1.0	0.8	0.8
U.S.	14.7	14.8	15.1	15.4	15.7	15.9	15.9	15.8	15.8	15.8	15.7	15.7
% Ch	1.5	1.1	1.6	1.9	2.0	1.4	(0.2)	(0.3)	(0.1)	(0.1)	(0.2)	(0.4)
Wholesale Trade												
Oregon	67.7	68.8	71.5	72.4	73.5	75.2	77.1	78.0	78.8	79.7	80.2	80.5
% Ch	1.0	1.6	3.9	1.3	1.4	2.4	2.4	1.2	1.0	1.1	0.7	0.4
U.S.	5.5	5.7	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.3	6.4	6.4
% Ch	1.7	2.2	1.2	1.6	1.5	1.4	1.7	1.5	1.3	1.0	0.7	0.6
Transportation and Warehousing, and Utilities												
Oregon	53.4	54.1	54.9	56.9	58.8	59.7	61.6	63.1	64.2	64.8	64.9	65.0
% Ch	2.3	1.3	1.5	3.6	3.4	1.4	3.2	2.4	1.8	0.9	0.3	0.0
U.S.	4.9	5.0	5.0	5.2	5.3	5.4	5.6	5.7	5.7	5.8	5.8	5.8
% Ch	2.3	2.3	1.6	2.8	2.8	1.4	2.8	2.2	0.8	0.5	0.2	0.1
Information												
Oregon	31.7	32.1	32.3	32.1	33.3	34.3	35.1	35.8	36.6	36.9	37.2	37.5
% Ch	(0.1)	1.5	0.4	(0.4)	3.7	2.9	2.3	2.1	2.2	0.8	0.7	0.7
U.S.	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.1
% Ch	(1.3)	0.1	1.2	1.3	1.8	0.9	0.1	1.3	1.8	1.2	2.2	1.9
Financial Activities												
Oregon	91.7	90.5	91.6	92.4	93.8	96.1	97.9	98.5	98.7	99.0	99.1	99.2
% Ch	(1.6)	(1.3)	1.2	0.9	1.6	2.5	1.8	0.6	0.2	0.3	0.1	0.1
U.S.	7.7	7.8	7.9	8.0	8.1	8.2	8.1	8.0	8.0	7.9	8.0	8.0
% Ch	0.0	1.1	1.3	1.2	1.9	0.9	(1.0)	(1.3)	(0.8)	(0.1)	0.2	0.2
Professional and Business Services												
Oregon	195.2	202.1	209.4	219.7	228.9	238.6	252.6	265.7	270.3	275.5	279.7	284.8
% Ch	3.5	3.6	3.6	4.9	4.2	4.2	5.9	5.2	1.7	1.9	1.5	1.8
U.S.	17.3	17.9	18.5	19.1	19.7	20.4	21.1	21.6	22.0	22.6	23.0	23.5
% Ch	3.6	3.5	3.3	3.1	3.4	3.2	3.6	2.5	1.8	2.4	2.0	2.2
Education and Health Services												
Oregon	234.2	237.8	242.7	248.5	258.4	265.2	269.9	274.5	278.6	282.0	285.3	289.1
% Ch	2.3	1.6	2.0	2.4	4.0	2.6	1.8	1.7	1.5	1.2	1.2	1.3
U.S.	20.2	20.7	21.1	21.5	22.1	22.7	22.9	23.2	23.5	23.8	24.0	24.2
% Ch	1.7	2.3	1.9	1.8	2.7	2.7	1.2	1.2	1.4	1.0	1.0	0.9
Educational Services												
Oregon	32.9	33.6	34.1	34.6	35.6	35.8	36.1	36.6	37.0	37.4	37.6	37.9
% Ch	3.4	2.0	1.5	1.6	2.7	0.5	1.1	1.3	1.1	1.0	0.6	0.8
U.S.	3.3	3.3	3.4	3.4	3.5	3.5	3.4	3.4	3.4	3.3	3.3	3.2
% Ch	3.1	2.8	0.4	1.9	1.4	0.2	(1.9)	(0.5)	(0.7)	(1.0)	(1.3)	(2.0)
Health Care and Social Assistance												
Oregon	201.2	204.3	208.6	213.9	222.8	229.4	233.7	237.9	241.6	244.6	247.7	251.2
% Ch	2.1	1.5	2.1	2.5	4.2	2.9	1.9	1.8	1.6	1.2	1.3	1.4
U.S.	17.0	17.4	17.7	18.1	18.6	19.2	19.5	19.8	20.2	20.4	20.7	21.0
% Ch	1.5	2.2	2.2	1.8	3.0	3.2	1.8	1.4	1.8	1.4	1.3	1.3
Leisure and Hospitality												
Oregon	165.6	170.1	176.6	182.9	191.3	198.3	204.6	208.0	211.5	213.6	215.0	216.3
% Ch	2.0	2.7	3.8	3.6	4.6	3.6	3.2	1.7	1.7	1.0	0.6	0.6
U.S.	13.4	13.8	14.3	14.7	15.2	15.5	15.6	15.9	16.0	16.2	16.3	16.4
% Ch	2.4	3.2	3.5	3.2	3.0	2.0	1.1	1.4	1.2	0.9	0.9	0.5
Other Services												
Oregon	56.8	57.3	58.0	59.1	60.5	61.8	63.3	64.6	65.6	66.1	66.7	67.3
% Ch	0.4	0.9	1.2	1.8	2.5	2.1	2.4	2.1	1.5	0.9	0.8	0.9
U.S.	5.4	5.4	5.5	5.6	5.6	5.7	5.6	5.6	5.5	5.5	5.5	5.5
% Ch	0.6	1.3	1.0	1.6	1.2	0.3	(1.3)	(0.3)	(0.4)	(0.2)	(0.2)	(0.4)
Government												
Oregon	295.0	291.0	288.8	293.9	301.4	309.1	313.7	317.9	321.8	327.1	329.2	332.9
% Ch	(1.6)	(1.4)	(0.7)	1.8	2.5	2.6	1.5	1.3	1.2	1.7	0.6	1.1
U.S.	22.1	21.9	21.8	21.9	21.9	22.0	22.2	22.4	22.6	22.9	22.8	23.0
% Ch	(1.8)	(0.8)	(0.3)	0.0	0.4	0.4	0.6	1.1	0.9	1.2	(0.2)	0.5
Federal Government												
Oregon	28.8	28.1	27.5	27.4	27.7	27.8	27.7	27.5	27.3	28.9	27.3	27.2
% Ch	(5.7)	(2.5)	(1.9)	(0.3)	1.0	0.4	(0.6)	(0.5)	(0.6)	5.6	(5.5)	(0.3)
U.S.	2.9	2.8	2.8	2.7	2.7	2.7	2.7	2.6	2.6	2.7	2.6	2.6
% Ch	(3.9)	(1.3)	(1.8)	(1.6)	0.3	(0.5)	(1.5)	(1.5)	(1.3)	4.9	(5.6)	(0.6)
State Government, Oregon												
State Total	80.6	80.1	81.0	84.1	87.4	89.0	90.7	92.1	93.3	94.3	95.2	96.1
% Ch	1.0	(0.6)	1.2	3.7	3.9	1.9	1.9	1.6	1.3	1.1	1.0	1.0
State Education	31.1	31.8	32.0	32.5	33.1	33.1	33.2	33.4	33.6	33.7	33.9	34.0
% Ch	4.6	2.1	0.7	1.4	1.9	(0.0)	0.5	0.5	0.5	0.5	0.5	0.3
Local Government, Oregon												
Local Total	185.6	182.8	180.3	182.4	186.3	192.3	195.4	198.3	201.2	204.0	206.7	209.5
% Ch	(2.1)	(1.5)	(1.4)	1.2	2.1	3.2	1.6	1.5	1.5	1.4	1.3	1.4
Local Education	97.0	95.1	93.6	94.6	96.6	99.7	101.7	103.3	104.5	105.7	106.9	108.2
% Ch	(3.3)	(1.9)	(1.6)	1.1	2.1	3.3	2.0	1.5	1.2	1.1	1.2	1.2

Mar 2016 - Other Economic Indicators

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	15,020.6	15,354.6	15,583.3	15,961.7	16,346.8	16,780.6	17,274.5	17,728.6	18,160.0	18,600.2	19,001.4	19,410.7
% Ch	1.6	2.2	1.5	2.4	2.4	2.7	2.9	2.6	2.4	2.4	2.2	2.2
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	103.3	105.2	106.9	108.7	109.8	111.7	113.9	116.2	118.6	121.1	123.7	126.3
% Ch	2.1	1.8	1.6	1.6	1.0	1.7	1.9	2.0	2.0	2.1	2.2	2.2
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	104.1	106.1	107.6	109.1	109.4	110.5	112.7	115.1	117.5	120.0	122.6	125.4
% Ch	2.5	1.9	1.4	1.4	0.3	1.0	2.0	2.1	2.1	2.1	2.2	2.3
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	224.6	229.8	235.5	241.2	243.2	246.6	252.4	258.6	264.5	270.5	277.1	283.9
% Ch	2.9	2.3	2.5	2.4	0.8	1.4	2.4	2.4	2.3	2.3	2.4	2.5
U.S.	224.9	229.6	233.0	236.7	237.0	239.9	246.0	252.6	259.1	265.5	272.4	279.8
% Ch	3.1	2.1	1.5	1.6	0.1	1.2	2.6	2.7	2.5	2.5	2.6	2.7
Oregon Average Wage												
Rate (Thous $)	45.2	46.5	47.3	48.9	50.3	52.4	54.8	57.2	59.6	62.0	64.5	66.9
% Ch	3.2	3.0	1.6	3.3	2.9	4.2	4.6	4.5	4.1	4.1	4.0	3.8
U.S. Average Wage												
Wage Rate (Thous $)	50.3	51.7	52.2	53.8	55.2	57.0	59.2	61.5	63.9	66.4	69.0	71.7
% Ch	2.8	2.7	0.9	3.1	2.7	3.1	4.0	3.9	3.8	3.9	4.0	3.9
Housing Indicators												
FHFA Oregon Housing Price Index												
1980 Q1=100	347.6	346.2	371.2	404.4	440.8	471.9	491.8	509.1	526.2	543.7	561.9	579.8
% Ch	(6.9)	(0.4)	7.2	8.9	9.0	7.0	4.2	3.5	3.4	3.3	3.3	3.2
FHFA National Housing Price Index												
1980 Q1=100	312.3	312.0	324.9	346.2	370.8	382.6	394.2	403.5	412.9	424.4	436.9	453.5
% Ch	(3.7)	(0.1)	4.1	6.6	7.1	3.2	3.0	2.4	2.3	2.8	3.0	3.8
Housing Starts												
Oregon (Thous)	8.0	10.8	14.3	15.6	15.9	18.0	21.1	22.7	23.1	23.5	23.8	23.6
% Ch	5.3	35.5	31.5	9.3	2.0	13.4	17.2	7.4	1.8	1.8	1.1	(0.6)
U.S. (Millions)	0.6	0.8	0.9	1.0	1.1	1.3	1.4	1.5	1.6	1.6	1.6	1.6
% Ch	4.5	28.1	18.4	7.8	10.9	14.0	12.2	6.3	3.3	2.5	0.5	0.2
Other Indicators												
Unemployment Rate (%)												
Oregon	9.4	8.8	7.8	7.0	5.8	5.6	5.4	5.6	5.6	5.5	5.4	5.5
Point Change	(1.1)	(0.7)	(1.0)	(0.8)	(1.2)	(0.2)	(0.2)	0.1	0.0	(0.2)	(0.0)	0.0
U.S.	8.9	8.1	7.4	6.2	5.3	4.9	4.9	4.9	5.0	5.0	5.0	5.1
Point Change	(0.7)	(0.9)	(0.7)	(1.2)	(0.9)	(0.4)	(0.1)	0.0	0.1	(0.0)	0.0	0.1
Industrial Production Index												
U.S, 2002 = 100	97.2	100.0	101.9	105.7	107.1	107.8	111.0	114.3	117.3	120.5	123.1	125.6
% Ch	3.0	2.8	1.9	3.7	1.3	0.6	3.0	2.9	2.6	2.8	2.1	2.0
Prime Rate (Percent)	3.3	3.3	3.3	3.3	3.3	3.9	4.9	5.9	6.3	6.3	6.3	6.3
% Ch	0.0	0.0	0.0	0.0	0.3	20.0	25.6	20.2	5.9	0.0	0.0	0.0
Population (Millions)												
Oregon	3.86	3.89	3.93	3.97	4.02	4.07	4.12	4.17	4.22	4.27	4.31	4.36
% Ch	0.6	0.7	0.9	1.1	1.3	1.3	1.2	1.2	1.2	1.1	1.1	1.1
U.S.	312.5	314.8	317.1	319.5	321.9	324.5	327.1	329.8	332.4	335.0	337.6	340.2
% Ch	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Timber Harvest (Mil Bd Ft)												
Oregon	3,649.0	3,749.0	4,199.0	4,126.0	4,200.0	4,838.1	4,843.5	4,823.1	4,824.3	4,816.3	4,799.4	4,809.3
% Ch	13.1	2.7	12.0	(1.7)	1.8	15.2	0.1	(0.4)	0.0	(0.2)	(0.4)	0.2

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is: 201 High Street, Suite 100, Salem, OR 97301-3612.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I am responsible for Cost of Capital (CoC) issues in this docket:

1. Capital Structure,
2. Cost of Common Equity, also known as Return on Equity (ROE),
3. Cost of Long-Term (LT) Debt, and
4. Overall Rate of Return (ROR).

I also examine a separate topic:

5. Employee Pensions & Benefits (See Staff/100 for Medical Elements) addressing rates of return and pension asset recovery.

Q. What is your CoC recommendation?

A. I recommend a Cascade Natural Gas Corp. (CNG, Cascade or Company) 49 percent equity capital structure, ROE of 9.40 percent, and a 5.25 percent Cost of LT Debt. This translates to an overall ROR of 7.284 percent.

Q. Did you prepare tables showing current, Cascade-proposed and Staff recommended overall CoC?

A. Yes, the following three tables provide that information.

Table 1

CNG Current Authorized (UG 287 Order No. 15-412)			CNG
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	49.00%	5.30%	2.597%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	51.00%	9.55%	4.871%
	100.00%		**7.468%**

Table 2

CNG Requested – UG 305		CNG Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**51.00%**	**5.295%**	2.704%	**-0.157%**
Preferred Stock	0.00%		0.000%	
Common Stock	**49.00%**	**9.400%**	4.606%	
	100.00%		**7.310%**	

Table 3

Staff Summary – UG 305		Staff Recommendation		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**51.00%**	**5.250%**	2.678%	**-0.183%**
Preferred Stock	0.00%		0.000%	
Common Stock	**49.00%**	**9.400%**	4.606%	
	100.00%		**7.284%**	

Q. Cascade filed for: 1) 49 percent Common Equity (Equity) / 51 percent LT Debt Capital Structure, 2) 9.40 percent ROE, and 3) an Overall Rate of Return of 7.310 percent, and a 5.295 percent Cost of LT Debt. Does your analysis support these proposals?[1]

[1] Please note that the Company has no outstanding preferred stock. See Cascade's Executive Summary/3 at 9.

A. I recommend the same Capital Structure and ROE as proposed by the Company. I calculate a lower Cost of LT Debt of 5.250.

Q. How long has Staff been analyzing issues related to Cascade's CoC?

A. Staff has been performing analysis for several months beginning prior to Cascade's filing because Staff was aware of Cascade's intent to file.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1 – Capital Structure	4
Issue 2 – COST of COMMON EQUITY (ROE)	6
Peer Screen	11~~11~~10
Sensitivity analysis	12
Growth Rates	13
Check of Reasonableness	23~~23~~22
Equity Flotation Costs	23~~23~~22
Outboard Adjustments of Modeling Results	24~~24~~23
Traction with Investors	24~~24~~23
Table 4 – Staff Hamada Adjusted ROE Estimates	26~~26~~25
Issue 3 – Cost of LT Debt	27~~27~~26
Debt Maturity Profile	28~~28~~27
Issue 4 – Overall Rate of Return (ROR)	28~~28~~27
Issue 5 – Pensions	29~~29~~28

Q. Did you prepare other exhibits in support of your opening testimony?

A. Yes. I prepared the following other exhibits:

Staff/202 .... Staff Peer Screening
Staff/203 .... Staff Three Stage DCF Modeling
Staff/204 .... Staff Synthetic Forward Curve TIPS Analysis
Staff/205 .... Staff Historical GDP Analysis with BEA Data
Staff/206 .... **CONFIDENTIAL** Cost of LT Debt Table
Staff/207 .... Value Line (VL) Gas and Water Utility Industry Profiles
Staff/208 .... Other Growth Resources
Staff/209 ....Financial Market Snapshot
Staff/210 .... Pension Tables

WHAT IS NEW IN THIS RATE CASE

Q. What is new in this rate case that explains Staff's recommendation to reduce Cascade's ROE to 9.40 percent from the 9.55 percent ROE of Commission Order No. 15-412, entered December 28, 2015 in Docket No. UG 287?

A. A broad consensus of federal government agencies, economists and referent experts now project substantially lower long-term growth in U.S. GDP. Officials no longer see rates going as high as projected in 2015 and it taking a longer time to get to that lower endpoint. Notably, projections of long-term growth rates by a broad consensus of U.S. Government, academic, business and analytic referent sources for U.S. gross domestic product (GDP) was lowered further in spring of 2016. The U.S. Federal Reserve's now sees 2.2 percent as the upper expected GDP growth in the long-run.[2]

Paired with another broad consensus that growth in U.S. gas sales will be less than the rate of GDP growth, trends are consistent with Staff's proposed reduction to ROE compared to that of the prior rate case.

Q. Has there been a gas utility general rate case recently litigated before the Commission that helps to frame this discussion?

A. Yes. In Order No. 16-109 entered March 15, 2016, and supplementing Order No. 17-076, the Commission decided that a 9.40 percent ROE was just

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[2] See Revisiting GDP Growth Projections by Fernando M. Martin of the Federal Reserve Bank of St. Louis (FRED) released March 4, 2016.

and reasonable for Avista Corp. This was a litigated rather than settled rate case.

Q. Were the GDP growth rates described in Staff's discussion here, then prevalent for the Avista general rate case described above?

A. Yes. Given the short time since the Avista rate case decision, the White House's budget and certain other referent sources shown in Exhibit Staff/208 continue to project growth rates that Staff used in the Avista rate case.

Q. At this time, do Cascade and Avista have like financial risk and operational risk?

A. Yes. Both have comparable access to like rated capital. Each utility's Oregon operations now also have like operational and corporate risk.

Q. Does Staff suggest that the litigated 9.40 percent ROE of Commission Order No. 16-109 in Docket No. UG 288 provides an informative benchmark for this Cascade general rate case?

A. Yes. Staff suggests that the Commission's 9.40 percent decision in Order No. 16-109 in a recent litigated like case provides a good check on Staff's recommendation of 9.40 percent ROE in this case.

ISSUE 1 – CAPITAL STRUCTURE

Q. Why is a Capital Structure of 49 percent equity reasonable?

A. This Capital Structure is the average of the Cascade-provided Equity for the test year and the two prior years.

Q. What else supports your recommendation for 49 percent equity and 51 percent LT Debt capital structure?

A. I have two other reasons for supporting my recommended capital structure:

1. This capital structure is within the range that optimizes the Company's financial performance balanced against the risk of leverage.
2. This capital structure excludes elements not historically considered LT Debt by the Commission. My recommended LT Debt portion of the capital structure excludes short term debt with maturities less than one year and imputed debt from the Company's contracts, consistent with ORS 757.415(3).

Q. Does a 49 percent Equity Capital Structure represent a fact-based actual Capital Structure rather than one assumed or targeted?

A. Yes.

ISSUE 2 – COST OF COMMON EQUITY / RETURN ON EQUITY (ROE)

Q. Describe the analysis underlying Staff's ROE recommendation.

A. I rely on two different multistage DCF models,[3] applied using a cohort group of peer utilities, to estimate the expected return on common equity required by Company investors. I compare the results of my DCF analysis with national historical gas utilities' authorized ROE values as a check on the reasonableness of my ROE estimates. I also varied peer groups and input parameters to test the reasonableness of my modeling.

Q. What is a DCF model?

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[3] *See* Order No. 01-777, at page 2 in Docket No. UE 115, Commission discussion of multistage versus single-stage DCF models.

A. A DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation. The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.[4] A DCF model has three primary components: a current stock price, an expected dividend, and an expected growth rate in dividends.[5]

Cascade is wholly owned by MDU and hence is not publicly traded. Staff infers the required ROE by applying its three-stage DCF models to a comparable sample of gas utilities similar to Cascade in risk profile and operations.

Q Describe the two different multi-stage DCF models that you used.

A. The first is a conventional three-stage Discounted Dividend Model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (Model X). The second is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (Model Y).

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per share to be received in the years 2016 through 2020, annual rates of dividend

4 Order No. 01-777 at 26.

5 Order No. 07-015 at 32.

growth from 2021 through 2025, and a long-term growth rate applicable to dividends through 2045.

The three stages of the models are: 1) 2016-2020, where I use Value Line's forecasts of dividends per share for each company; 2) 2021-2025, wherein the rate of dividend growth converges from the average rate over the 2016-2020 period to the growth rate in of the third stage; which is, 3) 2026-2045. Model X includes a terminal value calculation, in which I assume dividends per share grown indefinitely at the rate of growth in Stage 3 ("growing in perpetuity"). In contrast, Model Y terminates in a sale of stock wherein the price is determined by my escalated price/earnings (P/E) ratio.

Q. Why did you use five years for Stages One and Two, and about 20 years for Stage Three?

A. I presume a 30-year horizon is relevant for investors. This is consistent with long-standing Staff practice, including in the most recent NW Natural general rate case, Docket No. UG 221 and the most recent Avista general rate case, Docket No. UG 288.[6] This time frame allows for investor consideration of30-year U.S. Treasury Long Bond and other alternate investment opportunities. I use five years for Stage One as that is the timeframe for which Value Line (VL) estimates of future dividends are available. It is important to note that VL does not project estimates beyond five years into the future at any given time.

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[6] UG221 Staff/1300, Storm/64.

I use five years for Stage Two because that is a reasonable length of time for each individual company's Stage One dividend growth rate to converge to the Stage Three growth rate, which is representative of all gas utilities. I discuss the mechanics of this convergence below. I use about 20 years for Stage Three, corresponding to forward projections from federal sources, and calculate a terminal valuation for the sale of each company's stock in 2045.

Q. How do you address dividend timing?

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values[7] produced with each set of calculations for each peer utility. This approach more closely replicates the "real world" quarterly receipt of dividends by investors; i.e., it takes into account the time value of money.

Q. How do the models account for differences in peer capital structures?

A. Each model employs the Hamada equation to calculate an adjustment for differences in capital structure between each peer utility and the Company-proposed and Staff-supported capital structure for Cascade.[8]

Q. What price do you use for each peer utility's stock?

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7 The technical term for each of these estimates is the "internal rate of return," or IRR.

8 Staff describes this adjustment in recent cost of capital testimony. See, as an example, Staff's description in Docket No. UE 233 Staff/800, Storm/54-57.

A. I use the average of closing prices for each utility from the first trading day in March, April, and May of 2016.

Q. Did you review the impact of using prices from any other day of these months?

A. No.

Q. How do Staff's two DCF models differ?

A. Model X uses the calculation of a growing perpetuity as part of the terminal valuation in 2045. This is a common approach in multistage DCF models.

Model Y uses the current price-earnings (P/E) ratio[9] multiplied by the estimated earnings per share (EPS) in 2045, which establishes the stock's "selling price" in 2045 for terminal valuation. I estimate the 2045 EPS analogously with methods used to estimate the 2045 dividend in both models; i.e., based on VL estimates to which multiple growth rates are sequentially applied.

Q. What is the purpose of Model Y?

A. Model Y recognizes that most companies have estimates of future EPS and future dividends growing at different rates. Utilizing EPS that grows on a separate trajectory than dividends is the foundation for an alternative means of terminal valuation. In this way, Model X provides a check on Model Y and vice-versa.

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9 "Current" in this context means the price obtained, as previously described, divided by Value Line's estimated 2016 earnings per share (EPS); i.e., it is a forward P/E, not an historical P/E.

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate Cascade's ROE?

A. I used companies that meet the following criteria as peer utilities to the regulated gas utility activities of Cascade Natural Gas Corp.:

1. Covered by VL as a gas utility;
2. Forecasted by VL to have positive dividend growth;
3. S&P LT issuer credit rating greater than or equal to BBB–, or Moody's issuer credit rating greater than or equal to Baa3;
4. No decline in annual dividend in last five years based on SNL;
5. 70 percent or greater regulated assets *per* SEC filings;
6. Less than 56 percent LT Debt in VL capital structure; and
7. No recent or imminent merger and acquisition activity.

Q. Why do you eliminate potential peer utilities that are not forecasted to have positive dividend growth?

A. There is evidence that investors find common stock of dividend-cutting utilities less attractive. For example, the FPL Group's Florida Power and Light and Niagara Mohawk Power Corporation stock prices declined sharply after dividend cuts.[10] Similarly, in November 2012, Exelon's common stock fell 6 percent immediately after Exelon publicly stated that it was considering cutting its dividend to fund stock buy backs and resource acquisitions.[11]

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[10] *The New York Times* article, "Niagara Mohawk Stock Dives after Dividend Suspension", published January 25, 1996.

[11] See Crain's Chicago Business article, "Exelon Shares Slump as It Mulls Cutting Dividend" of November 1, 2012 regarding the impacts of CEO Chris Crane's floated idea of cutting the Exelon dividend. Both institutional and individual investors started rapidly selling as the Company explained quickly that the press had misunderstood Exelon's intent to possibly cut dividends six months from then.

Q. There appears to be one difference from Staff's recent peer screening criteria, which is the peer company must have at least 70 percent of its assets subject to regulation, rather than the previously-used 80 percent threshold. Why do you make this change, and how do you assess the impact of the change?

A. Recent merger and acquisition (M&A) activity has reduced the number of pure play gas utilities that are highly regulated like Cascade. Staff's analysis also includes a sensitivity peer set with 80 percent of assets regulated, given that is Staff's preferred approach when data is available.

Q. What cohort of companies resulted from your screens?

A. Please see Staff/202 Muldoon/1-2 for detailed Staff screens and also for a table that shows the list of peer utilities obtained by Staff screens.

SENSITIVITY ANALYSIS

Q. Did Staff apply Models X and Y using a peer group that consists of all Value Line tracked publicly traded gas utilities?

A. Yes. Staff included it as a sensitivity case because this group is regularly used as a peer group by gas utilities seeking general rate increases.[12] In addition to the 80 percent regulated sensitivity peer group and the all gas utilities followed by VL peer group, I have a third sensitivity peer group, which adds investor owned water companies to Staff's recommended peer group.

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[12] As an example, see the Avista general rate case filing in Docket No. UG 284.

Q. Why do you include publicly traded U.S. water utilities in your sensitivity analysis?

A. Water utilities screened by the same criteria as gas utilities may offer a larger pool of potential peers at some point in the future. As earlier mentioned acquisitions like that of AGL by Southern Co. and Piedmont by Duke remove from consideration utilities that closely resemble Cascade from an investor perspective.

Q. Does the running of these sensitivities replace or modify Staff's primary screening methods?

A. No. However, the results of my sensitivity analyses inform the Commission and provide a check of reasonableness for recommendations herein.

GROWTH RATES

Q. What is the most important element of discounted dividend or DCF models when used to estimate investors' required ROE?

A. The estimated rate of growth of future dividends (aka the long-term growth rate).

Q. What is the trend on investor expectation for growth rates?

A. Investors are seeing a broad consensus of referent sources projecting lower than historical GDP growth rates in both the short- and long-term.

Q. What long-term growth rates do you use in the two DCF models? [13]

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[13] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods

A. I used three different growth rates, each based on a different methodology or source. The three growth rates are shown in Figure 1 below.

The first growth rate shown in Figure 1 is a weighted average of long-term growth rate estimates from different sources. 50 percent of the weighted average is calculated from estimates of long-term Gross Domestic Product (GDP) by the EIA, OMB, the White House 2017 Budget, and the CBO, with each receiving one-quarter of the 50 percent weight.[14] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2015,[15] to which I apply the most recent Federal Reserve (FED) Treasury Inflation Protected Securities (TIPS) inflation forecast.

The second growth rate is derived from U.S. Bureau of Economic Analysis data. This presumes that the economy is just going through a divergent lower growth moment and will soon return to long-run growth trends.

The third growth rate is that which the top 10 percent of referent persons polled project on average. Indiana University's Kelley School of Business

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and, to a limited extent, their conceptual underpinnings in Docket No. UE 233 Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

[14] The EIA is the Energy Information Administration within the U.S. Department of Energy, OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings. See, e.g., Docket No. UE 233 Exhibit Staff/800, Storm/50 line 4 through Storm/51 line 3.

[15] Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, e.g., Docket No. UE 233 Exhibit Staff/800, Storm/46, line 15 through Storm/50 line 3.

uses this as a top likely growth rate or ceiling for its forward-looking economic projections. This matches the Top 10 value published by Blue Chip and shown in Figure 1.

Figure 1

UG 305 Staff Growth Summary

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	Real Rate	TIPS Inflation Forecast	Nominal Rate	Weight	Weighted Rate
EIA	2.20%	1.70%	3.94%	12.50%	0.49%
OMB - 10 Year GDP Projection	2.00%		4.10%	12.50%	0.51%
White House 2017 Budget	2.30%		4.30%	12.50%	0.54%
CBO Projections			4.20%	12.50%	0.53%
Historical 1980 Q1 – 2016 Q1	2.81%	1.70%	4.56%	50.0%	2.28%
Composite				100%	4.35%
BEA Avg. Nominal Historical 1980 Q1 – 2016 Q1			5.34%		5.34%
Indiana U – Kelley 2018-35 Ctr Econometric Research	2.90%	2.12%	5.08%	100.0%	5.08%
Blue Chip* – Top 10% 2019 Values	2.90%	2.12%	5.08%	100.0%	5.08%

Note: Kelley School of Business ceiling projection matches Top 10 Blue Chip[16]

Q. **Have you entirely refreshed and updated your source data regarding growth rates since the last general rate case before the Commission?**

A. Yes. Source information for growth inputs is provided in Staff Exhibits 204, 205 and 208.

Q. **Do these growth rates from government sources and referent business leaders continue to reflect the substantial drop in expectations of long-term GDP occurring in second quarter of 2015?**

A. Yes.

16 The Blue Chip Consensus forecast is a summary of a number of private forecasts. See www,whitehouse.gov/administration/eop/Economic-Projections-and-the-Budget-Outlook/ for a discussion of how the Blue Chip Consensus and federal expectations vary.

Q. Are there many material trends in the various growth inputs since the Company last filed a rate case in March 2015 in Docket No. UG 287?

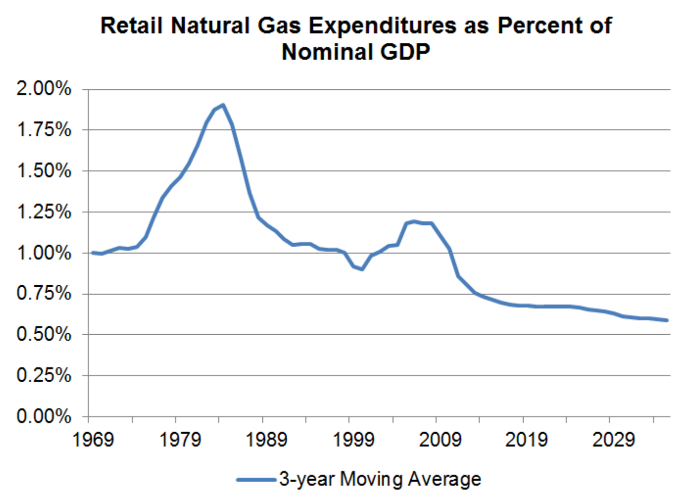
A. Yes, at this time, even formerly exuberant business and academic referent leaders no longer project that long-term US GDP Growth will come back up to historical trends. While the White House retained its Spring 2015 projections, the CBO dropped its long-run year over year GDP growth from 4.3 percent to 4.1 percent. The historic real GDP trend dropped 6 basis points. There are a number of key drivers:

1. The U.S. Social Security Administration (SSA) projects lower population growth and no delayed productivity surge following the 2008 great recession.
2. TIPS implied inflation is down to 1.7 percent from 2.12 percent. This is consistent with central banks seeing inflation below two percent targets.
3. The Federal Reserve Bank of St. Louis (FRED) notes a decline in labor force participation rates.
4. Moody's and the Wall Street Journal (WSJ) observe lower U.S. productivity growth, which grew at an average annual rate of 2.2 percent since WW II. This has averaged only 0.5 percent over the last five years.
5. The WSJ also has reported on a variety of other potential contributing factors. These include a lower business investment and less research and development spending since 2009, as well as a mismatch between skills needed and education of graduates entering the American workforce. In the article, "Maker Measures" of June 8, 2016, the WSJ

pulls data from U.S. Bureau of Economic Analysis, Bureau of Economic Analysis, Bureau of Labor Statistics via FRED Economic Data, and Bureau of Labor Statistics to suggest that some of the problems can be summed up as fewer hands with sluggish output amidst reduced global demand.

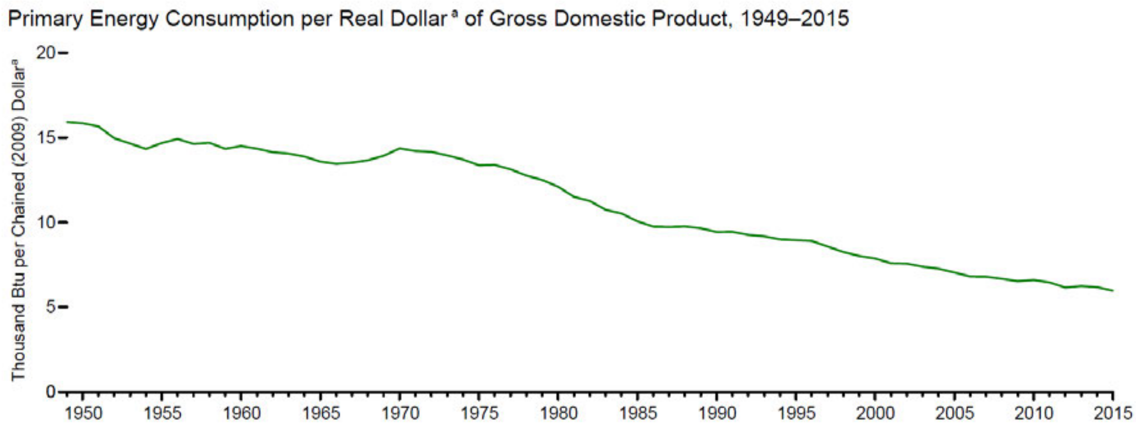
In aggregate, these and other drivers narrowed expectations, and lowered highest expected GDP growth.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for gas utilities?



A. Yes. Based on information from the U.S. Energy Information Administration (EIA), gas use per dollar of GDP has been declining for years and EIA expects the decline to continue.[17]

[17] Historical retail expenditures result from retail prices in the EIA's Annual Energy Review's Table 6.8 and quantities in Table 6.5. Estimated future retail expenditures are based on EIA's Annual Energy Outlook's (early release) "Natural Gas Supply, Disposition, and Prices." Historical GDP is from the U.S. Bureau of Economic Analysis.



Q. Given the EIA's outlook for the industry illustrated above, do you use an annual rate of long-term growth less than that estimated for GDP?

A. I do not. Arguably, the EIA outlook supports a lower annual growth rate. But, Staff uses the GDP growth rate as conservative ceiling value. As Professor Aswath Demodaran, Professor of Finance at the NY University's Stern School of Business reminds us in his classic text "Investment Valuation", long-term growth of a target security will be less than the economy in which it operates, but there is no guarantee that a given company will not grow more slowly. Therefore, one can view my recommendations as upper limits of reasonable expectations.

Q. What are the results of your multistage DCF models?

A. Please see Exhibit Staff/203 for a summary followed by modeling detail.

Q. Your modeling focuses on Value Line Gas Utility peers, why does this group best reflect Cascade's Oregon operations?

A. According to SNL Financial LLC (SNL) and its affiliate Regulatory Research Associates (RRA), Cascade operations are primarily that of a local gas distribution company.[18]

Q. Is there any other information in RRA's June 10, 2016, report on MDU Resources Group, Inc. (MDU) of interest to the Commission?

A. In its recent analysis of MDU, RRA highlights: "After fully exiting its troubled oil and gas exploration and production, or E&P, segment in April 2016, MDU Resources Group looks forward to a new, lower-risk operating profile, banking heavily on its regulated utility operations … MDU shares gained 25% between April 5, the day before the announcement that the last of its E&P segment assets were sold, and June 9." This finding is consistent with Staff's position that Cascade is less risky than MDU as a whole.

While we estimate Cascade's cost of equity as if it were a stand-alone company, the news regarding MDU could impact the cost of future Cascade debt as rating agencies take into account the parent's debt rating while also looking at the level of protections a Commission has established to wall-off any risk of the parent from impacting subsidiaries.

Q. What trend does SNL show for Average Authorized gas ROE's in general rate case decisions?

A. RRA "Major Rate Case Decisions" shows a downward trend, which is displayed in Figure 2. Gas ROEs continue to fall in general rate cases and

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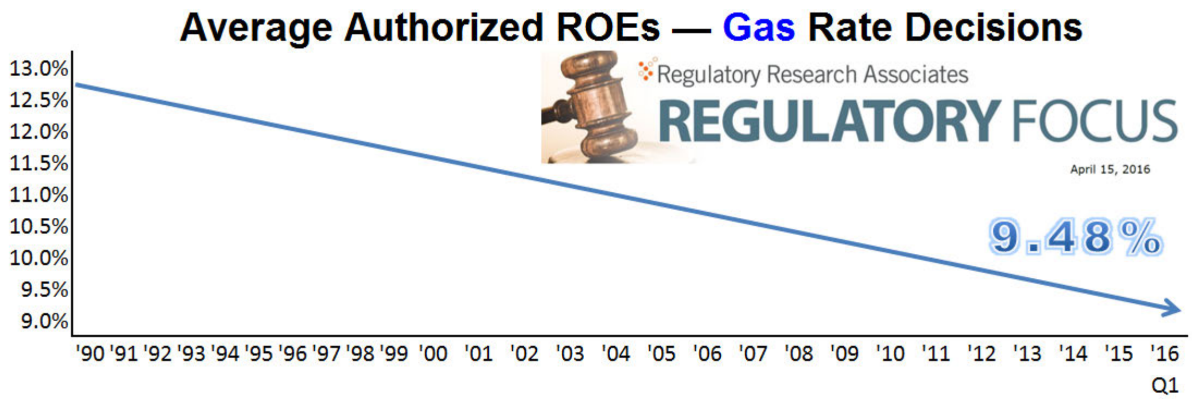
[18] RRA is now part of S&P Market Intelligence, please see: https://www.snl.com/InteractiveX/article.aspx?ID=36795604 for more information.

were on average 9.48 percent for the first quarter of 2016. This national average is eight basis points higher than my recommendation.

Figure 2[19]



Q. What is your recommended ROE inclusive of flotation costs?

A. I recommend a preliminary range for consideration of 7.56 percent to 9.41 percent. I refine that to a best fit range of 8.97 percent to 9.41 percent with a midpoint of 9.19 percent.

Q. What is the Company's requested ROE?

A. Cascade requested an authorized ROE of 9.40 percent.

Q. What is your assessment of the Company's proposed ROE?

A. Cascade's proposed ROE of 9.40 percent is supportable and consistent with mainstream growth estimates utilized in Staff's modeling.

Q. The Commission's decision regarding a just and reasonable point value for ROE may hinge on growth rates. Did your analysis include the construction of a synthetic forward curve using UST TIPS break even points?

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19 Staff Accessed SNL Rate Case Statistics at https://www.snl.com/interactivex/file.aspx?ID=33875815&KeyFileFormat=PDF

A. Yes. My forward curve is provided in Exhibit Staff/204, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of diminished future inflation.

Q. Did Staff examine a historical GDP growth trend?

A. Yes, Staff extracted and ran a regression on 1980 through 2016 Q1 data from U.S. Bureau of Economic Analysis (BEA) to generate the annual real historical GDP growth rate shown in Table 5. Staff's recommended range of ROEs includes values presuming GDP growth over the next thirty years would look like that of the past 30 years?

Q. Does Staff show this analysis in its exhibits?

A. Yes. Exhibit Staff/805 shows Staff's analysis in support of this finding.

Q. What changes does Staff see in modeling inputs for recent general rate cases?

A. Federal estimates of GDP growth whether short-, medium-, or long-term remain down from two years ago, and are continuing lower. Federal estimates of population growth over all three time frames are also down. And no bounce following the economic downturn of 2008 has occurred. The general financial news is that despite global uncertainty, the U.S. economy continues to advance, but slower than historical trends. However, myriad shocks and overall fragility in underlying fundamentals merit continued caution.

CHECK OF REASONABLENESS

Q. What control modeling does Staff perform to corroborate recommendations?

A. I examined multiple peer groups and growth rates to validate my recommendations. Model X and Model Y have similar results generating a range of reasonable ROEs of 7.56 percent to 9.41 percent as shown on Staff/203 Muldoon/1. Please see page 10 of this testimony for a description of these models. As earlier discussed, the Company's requested ROE of 9.4 percent falls within this range of reasonable ROEs.

EQUITY FLOTATION COSTS

Q. Has Staff included an upward adjustment to ROE to account for equity flotation costs?

A. Yes. Staff includes 12.5 bps addressing long-term equity flotation costs in its recommended range of reasonable ROE's.

Q. Why do you address equity flotation costs when Cascade is not floating new public stock offerings right now?

A. My 12.5 bps upward adjustment is a durable modifier reflecting aggregate overall long-term cost to float new equity into perpetuity.

Q. Your flotation cost is higher than requested by various utility-retained third party CoC analysts in recent rate cases, why is that?

A. My higher flotation value reflects costs incurred by Commission jurisdictional utilities. My recommendations capture aggregate capitalization and issuance size as well as credit ratings of utilities that would present a general rate case before the Commission. In contrast utility-retained external analysts tend to use generic tables from texts like Dr. Roger Morin's "New Regulatory Finance". Such tables include larger and differently situated utilities with different size equity flotations and different cost bases than the utilities the Commission regulates.

OUTBOARD ADJUSTMENTS OF MODELING RESULTS

Q. Why is application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at Cascade's target capital structure reasonable?

A. Staff usually employs the Hamada Equation. As earlier discussed, Staff's screening criteria already identify peers that have very close capital structure to the Company. Use of the Hamada adjusted results helps insure that Staff has captured all material risk in its analysis.

TRACTION WITH INVESTORS

Q. What assurance does the Commission have that your viewpoint has any practical traction with investors, financial managers and analysts?

A. Warren Buffett defines intrinsic value as: "the discounted value of the cash that can be taken out of a business during its remaining life."[20] For an investor without control of the business, the value of a stock is the discounted value of the cash flows that are realized while that stock is held (dividends),

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[20] See Warren Buffett's discussions in the 2012 Berkshire Hathaway, Inc., New York Stock Exchange (NYSE) ticker symbol (BRK) annual reports regarding intrinsic BRK value.

plus the discounted proceeds from any sale of the stock.[21] This approach is dispassionate, is the standard in Oregon, and constructively informs decision making.

Q. Please recap your thinking.

A. Staff's criteria used to develop its proxy group reflects objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, and exposure to company specific factors. As a result, investors are likely to regard this group as having risks and prospects comparable to the Company.

Q. Summarize the role of DCF modeling?

A. Staff's three-stage DCF models replicate market valuation that sets the price investors are willing to pay for a share of the Company's stock. By estimating the present value of the future cash flows investors expect to receive from the stock as dividends and capital gains, Staff estimates investors' required rate of return. This allows the Commission to back into the range of discount rates or cost of equity sophisticated investors implicitly used in bidding the stock up to that target price.

Q. Please provide a table summarizing your ROE analysis and estimates.

A. Table 4 below shows Staff ROE estimates.

[21] "Ruminations on Risk" by Michael Mauboussin and Alexander Schay, US Investment Strategy, Valuation Strategy, August 3, 2001. That publication is supported in part by Credit Suisse and First Boston.

TABLE 4 – STAFF'S HAMADA ADJUSTED ROE ESTIMATES

Range of Modeled Results		7.56%	**to**	9.41%	**ROE**
Best Fit Range of Reasonable ROEs		**8.97%**	**to**	**9.41%**	**ROE**
(Best fit is Staff's Hamada adjusted screened gas utilities that have most similar characteristics to CNG regulated gas operations in Oregon)					
Midpoint of Best Fit Modeling Results			**9.19%**	**ROE**	
(Staff's informed judgement excludes some of the lower range of modeling results depicted above)					
Staff Point ROE Recommendation:			**9.4%**	**ROE**	

Q. How do rating agency assessments in Staff Exhibit 208 inform results?

A. Rating agency assessments are consistent with the upper end of Staff's range of reasonable ROE's.

Q. Does Staff's recommended ROE meet appropriate legal and policy standards?

A. Yes. The ROE that I recommend meets the U.S. Supreme Court cases *Hope Natural Gas*[22] (*Hope*) and *Bluefield* Waterworks[23] (*Bluefield*) standards, as well as the requirements of Oregon Revised Statue (ORS) 756.040. My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" – and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[24]

22 *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

23 *Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-693 (1923).

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

ISSUE 3 – COST OF LT DEBT

Q. What is the basis for Staff's recommendation for 5.25 percent Cost of LT Debt?

A. Staff researched Cascade's debt using Bloomberg resources. Staff also built and analyzed its usual spreadsheets to analyze this data. Please see Confidential Exhibit Staff/206, Muldoon/1. Staff's analysis supports Staff's conclusion that 5.25 percent Cost of LT Debt is a conservative and reasonable estimate. Cascade has reviewed Staff's supporting spreadsheet of outstanding and planned long-term debt, and Staff's work incorporates the Company's review.

Q. Did the Company overstate issuance costs, fail to address the current portion of LT Debt, or misstate the timing, amounts, maturity or coupon rates for planned debt issuances?

A. No. Cascade was conservative in its review of LT Debt. Exhibit Staff/806 adds more detail to the Company's filing and makes several relatively small clarifications as described further in the confidential exhibit. Cascade has reviewed and agrees with Staff's analysis on this subject reflected in the response to DR 274.

Q. Are there discrepancies between the Company's corrected position and Staff's spreadsheet findings regarding Cost of LT Debt?

A. No. Both Staff and Company support a 5.25 percent Cost of LT Debt in lieu of the Company's filing value of 5.295 percent.

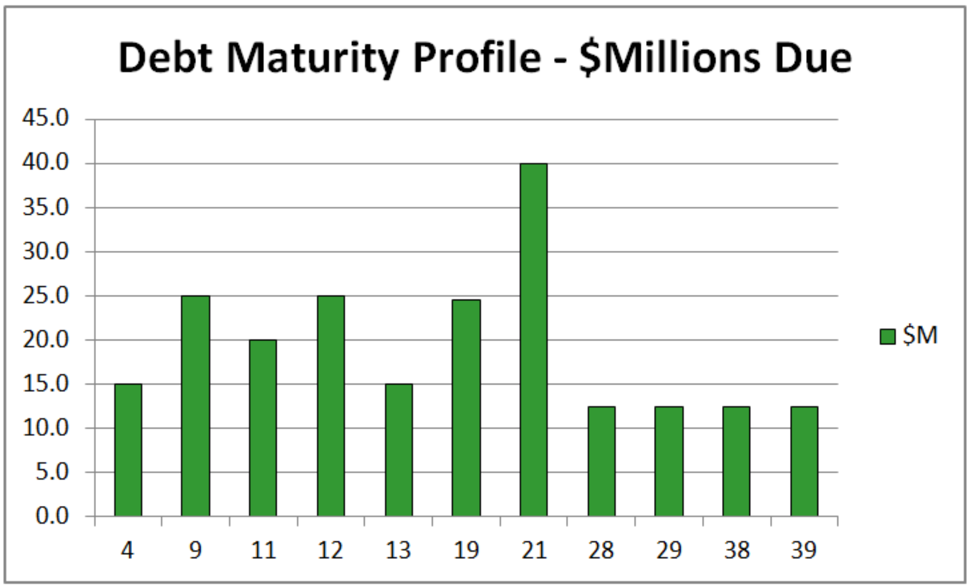
DEBT MATURITY PROFILE

Q. Has Staff reviewed the Company's debt maturities?

A. Yes. Staff has prepared Figure 4 below showing the Company's debt maturity profile. Staff makes no adjustment to the Company's maturities.

Figure 4

Years	$M
4	15.0
9	25.0
11	20.0
12	25.0
13	15.0
19	24.5
21	40.0
28	12.5
29	12.5
38	12.5
39	12.5



Q. Need the Commission wait for any updates to resolve Cost of LT Debt?

A. No, the Commission can review my confidential LT Debt table and additional information therein. This material provides the information for the Commission to make an informed decision regarding Cost of LT Debt, without having to wait for more detail about planned issuances.

ISSUE 4 – OVERALL RATE OF RETURN (ROR)

Q. In summary, are Staff's modeling results supportive of 49 percent Equity / 51 percent LT Debt Capital Structure, 9.40 percent ROE and 5.25 percent Cost of LT Debt?

A. Yes. In reviewing pension costs as part of this general rate case, Staff analyzed these two inputs, reviewed them for reasonableness, and verified calculations, but makes recommends no changes to the EROA or discount rate and makes no adjustment to associated costs.

Q. And you agree with the Company, as expressed in the Company's response to Confidential DR 274, that these CoC findings are reasonably represented by a revised ROR of 7.284 percent?

A. Yes.

Q. Does that conclude your opening testimony regarding Cost of Capital?

A. Yes.

ISSUE 5 – PENSIONS

Q. Please provide some background of how pension costs are recovered in rates.

A. The Commission addressed rate recovery of pension costs in Order No. 15-226. In that order, the Commission explained that a "defined benefit" pension is an employer-sponsored retirement plan through which employees accrue benefits and receive specified payments after they retire. The payments made under pension plans are guaranteed and an employer must keep the plan funded with cash contributions or investments to meet this obligation.

Employers must use FAS 87 accounting standards for financial reporting of pension costs. FAS 87 requires employers to recognize the cost of their pension plans during the working years of the employees that will receive the pension benefits during retirement. Because FAS 87 expense is based on an accrual, not cash basis, the amount of pension costs recorded is generally different than the actual amount of annual contributions made. Over the life of the plan, however, total contributions are expected to equal total FAS 87 expense (as well as FAS 88 expense related to pension plan termination).

The FAS 87 expense, which can be positive or negative, is calculated based on four components:

- Service cost – the value of the benefits earned, or accrued during the current year based on the applicable benefit formula for each participant.
- Interest cost – the interest on the pension plan liability (projected benefit obligation) for the year. This amount increases pension cost and represents the time value of money on the benefit obligation.
- Expected return on assets (EROA) – the expected return on assets for the year, which if positive will reduce pension cost. The difference between the actual return on assets and the expected return on assets represents an actuarial gain or loss that will be recognized in future pension cost.
- Amortizations of unrecognized costs – the change in liability due to plan changes, changes in actuarial assumptions used to value plan liabilities, differences between past differences between expected and actual asset returns, and other unrecognized gains and losses.

Employers use actuaries to determine the amounts to contribute to the plans. Contribution levels are designed to meet specified targets, which are typically guided by federal minimum funding requirements based on the value of plan assets and the projected future obligation. Employers are generally required to annually fund the amount of benefits being earned for the year plus a portion of any unfunded liability. Cascade, like other utilities in Oregon, obtains rate recovery of its pension contributions through an annual FAS expense forecast in a test year period.

Q. What is Cascade's annual FAS expense forecast for the test year?

A. Cascade uses a 2015 base year to calculate a Plan Fair Value of $72,376,574, and interest cost of $3,540,170 that is based on a 7.0 percent EROA and 3.70 percent discount rate (aka interest cost). Tables 1 and 2 in Exhibit Staff/210 show Cascade's EROA and Discount Rates, in comparison to those of other jurisdictional utilities.

Q. Does Staff have concerns regarding projections or escalations in Cascade's pension assumptions and calculations?

A. No. Staff does not recommend any adjustments to Cascade's test-year pension related cost estimates. Cascade does not escalate its 2015 base-year costs to produce its test-year forecast.

Q. Does Staff have concerns regarding Cascade's low 7.0 percent EROA?

A. No. Cascade's EROA has held relatively steady at 7.0 percent for three years. And, Cascade uses a discount rate that is lower than other utilities in Oregon, which must be considered in conjunction with EROA. The drop from 4.56 percent to 3.72 percent on the discount rate reflects less overall pressure on the Company's pension obligations.

Q. Please discuss trends in EROA in general.

A. Large retirement systems such as the California Public Employees' Retirement System (CalPERS) project lower than historic returns on its pension fund. Cascade's EROA reflects this trend.

Q. About what is Cascade's funding level for its pensions?

A. Cascade has trended at about 80 percent funding of its pension obligations.

Q. Is there some fluctuation around this trend?

A. Yes, Cascade's contributions two years ago brought its funding level up above 84 percent. There is some lumpiness around a long-term trend of 80 percent funding levels.[25] In the actuarial report provided by the Company on page 8, in response to DR 82, a clarification is provided that Cascade's plan may not be considered "at risk" while 80 percent funded. Cascade continues to satisfy this metric.

Q. Does Staff's review of post-retirement benefits under FAS 106 lead to mirrored conclusions to Staff's review of Cascade's Pensions under FAS 87?

A. Yes. Please also see Staff/100 Gardner testimony regarding post-retirement medical costs.

Q. Do certain Commission decisions lend clarity to Staff's review process?

A. Yes. Please note that Commission Order No. 15-226 in Docket No. UM 1633 reaffirmed the current pension cost recovery method for use in setting rates. Forecasted FAS 87 expense is used for rate making, and net prepaid pension assets are not allowed in rate base.

Q. Some companies seek to de-risk pension plan portfolios by reducing exposure to common equity returns and concentrating exposure to fixed income returns, creating an investment mix that cannot meet

[25] See the Company's response to DR 59 for values discussed here.

future pension needs without cash infusion from rate payers. Does that concern arise in this rate case?

A. No.

Q. Some pension funds such as that of PG&E's $11 billion pension plan and the $45 billion Massachusetts Pension Reserves Investment Management Board have shifted more heavily toward global equities to avoid high current U.S. equity price / earnings (P/E) ratios. Is that a key factor explaining the discount rate in this general rate case?

A. No. In general, the low discount rate discussed above is driven in large part by historically low interest rates over much of the last decade.

Q. How would recent central bank actions impair a historical 8.0 percent rate-of-return assumption?

A. Consider that in 1979 the US experienced 11.2% annual inflation, and the U.S. Federal Reserve set year-end interest rates at 15.25 percent. Expecting to achieve an 8.0 percent rate of return with fixed income would have been reasonable in 1979. However, current 10- and 30-year UST are now yielding only about 1.7 percent and 2.5 percent respectively. So an equal mix of 10- and 30- year UST would now yield almost 600 basis points (bps) less than a historical target return set in 1979. Therefore, equity is an integral component for a current pension investment mix.

Q. Has the Fed lowered expectations of future UST yields?

A. Yes, as shown in Staff/209 Muldoon/18, Fed Chief Yellen acknowledges that current and forward looking normal expectations could be lower than in the past. The Fed now expects to both raise rates more slowly and reach a lower stable equilibrium rate than it expected a year ago,

Q. In summary, do Cascade's pension and post-retirement benefit elements in this rate case fall within a range of reasonableness benchmarked against other jurisdictional utilities, such that no adjustment is needed?

A. That is correct, Cascade's pension EROA and discount rate are reasonable. No adjustment is currently required.

Q. Is Staff's conclusion consistent with the Company's third-party actuary?

A. Yes, the Company's assumptions and actuarial report is signed by Mark B. Magnus, actuary of New York Life Retirement Plan Services of Westwood, MA.

Q. Does Staff have any recommendation for the improvement of the Company's actuarial and other pension and post-retirement benefit reporting?

A. Yes, Staff would like to see the Company's actuarial report discount rates also clearly show assumptions of A) the underlying real interest rate and B) the inflation rate.

CONCLUSION

Q. You suggest only minor adjustments in this general rate case, yet you recommend that the Commission accept most of the cost of capital and pension values of the Company as filed.

A. Yes. On these particular issues, Staff's review and analysis shows that the Company has tried to factually represent its position without embellishment. The corrections to long-term debt and to overall ROR, made by Staff and verified by the Company, remedy oversights.

Q. Is the record complete and robust, despite lack of adversarial positions among Staff, the Company and stakeholders?

A. Yes**.**

Q. Does that conclude your opening testimony?

A. Yes

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

August 11, 2016

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Utility Program Energy – Rates Finance and Audit Division
ADDRESS:	201 High Street, Suite 100 Salem, OR 97301-3612.
EDUCATION:	In 1981, I received a Bachelors of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on Cost of Capital. I have worked on Cost of Capital in the following general rate case dockets: AVA UG 186; UG 201, UG 246, and UG 284 current; NWN UG 221; PAC UE 246, and UE 263; PGE UE 262, UE 283, and UE 294 current. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Staff Peer Screening

Exhibits in Support
of Opening Testimony

August 11, 2016

Staff Exhibit 202 – Staff Peer Screening

Is provided in electronic format for

Exhibit 202 and Exhibit 203

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Staff Three Stage DCF Modeling

Exhibits in Support
of Opening Testimony

August 11, 2016

Staff Exhibit 203 – Staff Three Stage DCF Modeling

Is provided in electronic format for

Exhibit 202 and Exhibit 203

Acronyms and Abbreviations Used

CIK	SEC Central Index Key
EDGAR	SEC Electronic Data Gathering, Analysis and Retrieval System
EEI	Edison Electric Institute
EIN	IRS Employer Identification Number
IRS	U.S. Internal Revenue Service
SEC	U.S. Securities and Exchange Commission
SIC	Standard Industrial Code
SNL	SNL Financial, LC – A financial Information gathering firm
U.S.	United States of America
VL	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C	CCC	C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC				CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

Utility Continuity Screen

Natural Gas — CNG UG 305

Sensitivities:
1 VL Gas Utilities (80% Regulated)
2 All VL Gas Utilities except UGI (Propane)
3 VL Gas and Water Utilities (2/3 Regulated)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
#	Abbreviated Utility	UG 287 Staff	UG 305 Staff	VL Corporate Name Gas Utility	NYS, NSDQ Ticker	SNL Key	IRS EIN	SEC File	VL Region	VL 5/2/2016 Beta	Yahoo Fin. 5/3/2016 Beta	Yahoo Fin. 5/3/2016 Mkt Cap $ Billions	VL 5/2/2015 Mkt Cap $ Billions	Gas or Water U. w VL Beta < 1 5/2/2016	VL ID No.	SNL or VL No Div Declines 5 years	Either / Or: S&P Local LT 5/3/2016 Rating ≥ BBB-	Either / Or: Moody's Local LT 5/3/2016 Rating ≥ Baa3	Last 10-K ≥ 2/3 U.S. Regulated Revenues	VL 2016 LT Debt < 56% of Capital	VL 2019-2021 LT Debt % of Capital
-	Cascade	No	No	Cascade Natural Gas Corp.	MDU	4057112	91-0599090	1-7196	West	N/A	N/A	N/A	N/A	-	N/A	Pass	BBB+	none	100%	N/A	N/A
1	AGL	No	No	AGL Resources, Inc.	GAS	4057108	58-2210952	1-14174	East	0.60	-0.37	7.95	7.80	Yes	785	Pass	BBB+	W Jan 2015	*	48.0%	47.0%
2	Atmos	No	No	Atmos Energy Corp.	ATO	4057157	75-1743247	1-10042	Central	0.80	0.36	7.46	7.20	Yes	802	Pass	A-	A2	59%	45.0%	45.0%
3	Laclede (Spire)	No	No	Spire, Inc. — Formerly: The Laclede Group, Inc.	SR / LG	4002506	74-2976504	1-16681	Central	0.70	0.28	2.77	2.80	Yes	5203	Pass	A-	A3	84%	54.5%	51.5%
4	New Jersey	No	No	New Jersey Resources Corp.	NJR	4057128	22-2376465	1-8359	East	0.80	0.92	2.43	2.90	Yes	6359	Pass	A	Aa2	25%	43.5%	41.0%
5	NiSource	No	No	NiSource Inc.	NI	4057051	35-2108964	1-16189	East	0.85	0.35	7.36	7.00	Yes	6188	Fail	BBB+	Ba1	50%	60.0%	60.0%
6	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	4057132	93-0256722	1-15973	West	0.65	0.44	1.44	1.40	Yes	6490	Pass	A+	A3	96%	44.5%	43.5%
7	Piedmont	Yes	No	Piedmont Natural Gas Company, Inc.	PNY	4057136	56-0556998	1-6196	East	0.75	1.10	4.86	4.80	Yes	7094	Pass	A	A2	93%	50.0%	49.5%
8	South Jersey	No	No	South Jersey Industries, Inc.	SJI	4057145	22-1901645	1-6364	East	0.85	0.68	2.01	2.80	Yes	8281	Pass	BBB+	A2	50%	49.0%	47.5%
9	Southwest Gas	No	Yes	Southwest Gas Corporation	SWX	4041957	88-0085720	1-7850	West	0.80	0.56	3.14	2.50	Yes	8314	Pass	BBB+	A3	67%	49.5%	48.5%
10	UGI	No	No	UGI Corporation (Propane Focus / VL)	UGI	4057537	23-2668356	1-11071	East	0.95	0.71	6.89	6.20	Yes	9166	Pass	None	A2	13%	54.5%	48.5%
11	WGL	No	No	WGL Holdings, Inc.	WGL	4007261	52-2210912	1-16163	East	0.80	0.56	3.43	3.40	Yes	9668	Pass	A+	A3	49%	42.5%	48.0%
12	American States	No	Sensitivity	American States Water Company	AWR	N/A	95-4676679	1-14431	Water	0.75	0.40	1.53	1.40	Yes	8288	Pass	A+	W Jan 2005	73%	42.0%	57.0%
13	American Water	Sensitivity	Sensitivity	American Water Works Company, Inc.	AWK	N/A	51-0063696	1-34028	Water	0.70	0.23	13.13	12.30	Yes	98442	Pass	A	A3	89%	55.0%	55.0%
14	Aqua America	No	No	Aqua America, Inc.	WTR	N/A	23-1702594	1-6659	Water	0.75	0.55	5.71	5.60	Yes	7056	Pass	None	A3	98%	51.0%	52.0%
15	CA Water	No	Sensitivity	California Water Service Group	CWT	N/A	77-0448994	1-13883	Water	0.75	0.67	1.37	1.30	Yes	1574	Pass	A+	Withdrawn	97%	44.5%	42.0%
16	CT Water	No	No	Connecticut Water Service, Inc.	CTWS	N/A	06-0739839	0-8084	Water	0.60	0.16	0.53	0.50	Yes	2274	Pass	A	Withdrawn	94%	45.0%	47.5%
17	Consol Water	No	No	Consolidated Water Co. Ltd.	CWCO	N/A	98-0619652	0-25248	Water	0.85	0.73	0.21	0.18	Yes	9991	Pass	None	Withdrawn	36%	0.0%	0.0%
18	Middlesex Water	Sensitivity	Sensitivity	Middlesex Water Co.	MSEX	N/A	22-1114430	0-422	Water	0.70	0.55	0.60	0.50	Yes	5950	Pass	A	Withdrawn	88%	39.0%	40.0%
19	SJW	No	No	SJW Corp.	SJW	N/A	77-0066628	1-8966	Water	0.75	0.24	0.70	0.75	Yes	7824	Pass	None	Withdrawn	96%	50.5%	51.5%
20	York Water	Sensitivity	Sensitivity	York Water Company (The)	YORW	N/A	23-1242500	1-34245	Water	0.70	0.59	0.37	0.38	Yes	16182	Pass	A-	Withdrawn	100%	45.0%	47.0%
	TOTAL PEERS	2	2					Gas Utility	AVG:	0.78								W Indicates Withdrawn			
		5	7						STDV:	0.10											
		w Sensitivities	w Sensitivities					H_2O Utility	AVG:	0.73											

Utility Conti

Natural Gas

CNG UG 305

Sensitivities: 1, 2, 3

1	2	3	4	23	24	25	26	27	28	
#	Abbreviated Utility	UG 287 Staff	UG 305 Staff	VL 2016 Common Equity % of Capital	VL Preferred Stock of Capital	VL Div. Growth Rate > 0%	No M&A Activity in Last 4 Years	Bloomberg M&A Under 11% of Mkt Cap	M&A Activity Activity in Last 5 Years	#
-	Cascade	No	No	N/A	N/A	N/A	N/A	N/A	N/A	-
1	AGL	No	No	52.0%	0.0%	Pass	Fail	Fail	*Acquired Nicor Dec. 2011. **Purchase of Co. by Southern Co to close in second half of 2016.**	1
2	Atmos	No	No	55.0%	0.0%	Pass	Pass	7%		2
3	Laclede (Spire)	No	No	45.5%	0.0%	Pass	Fail	Fail	***Acquired Missouri Gas** $975M Sep **2013, and Alabama Gas** Sept **2014** **Changed Name to "Spire" Apr. 28, 2016.**	3
4	New Jersey	No	No	56.5%	0.0%	Pass	Pass	0%		4
5	NiSource	No	No	40.0%	0.0%	Fail	Fail	Fail	*** Spinoff of Columbia Pipeline Gas Group – Balance Sheet in Flux / VL. 2016 Ops will vary widely / VL & SNL**	5
6	Northwest Natural	Yes	Yes	55.5%	0.0%	Pass	Pass	0%		6
7	Piedmont	Yes	No	50.0%	0.0%	Pass	Fail	Fail	* Acquired privatized service to Fort Bragg, NC per Oct. 2013. **Purchase of Co. by Duke to Close in 2016**	7
8	South Jersey	No	No	51.0%	0.0%	Pass	Pass	0%		8
9	Southwest Gas	No	Yes	50.5%	0.0%	Pass	Pass	0%		9
10	UGI	No	No	45.5%	0.0%	Pass	Fail	Fail	*** Acquired Energy Transfer Partners** Jan **2012** and **Heritage Propane** Jan **2013 – Very Heavy Propane Position**	10
11	WGL	No	No	56.0%	1.5%	Pass	Pass	0%		11
12	American States	No	Sensitivity	58.0%	0.0%	Pass	Pass	0%	Sold Chapparal City Water of AZ June 2011	12
13	American Water	Sensitivity	Sensitivity	44.9%	0.1%	Pass	Pass	N/A	Acquired Mt. Ebo Sewage	13
14	Aqua America	No	No	49.0%	0.0%	Pass	Fail	Fail	*** Acquired AquaSource July 2013 and North Maine Utilities July 2015 – 300 Purchases in last 2 decades / VL.**	14
15	CA Water	No	Sensitivity	55.5%	0.0%	Pass	Pass	0%	Acquired Rio Grande Corp and West HI Utilities Sep 2008	15
16	CT Water	No	No	54.9%	0.1%	Pass	Fail	Fail	*** Purchased Maine Water** in Jan **2012,** and **Biddeford & Saco** in Maine in Dec. **2012.**	16
17	Consol Water	No	No	99.9%	0.1%	Fail	Pass	0%	**Unclear Earnings Results** for Foreign Operations beyond those serving San Diego and Tijuana / VL	17
18	Middlesex Water	Sensitivity	Sensitivity	60.9%	0.1%	Pass	Pass	0%		18
19	SJW	No	No	49.5%	0.0%	Pass	Fail	ACQ	Acquired Bexar Metropolitan Water Dist. – Large 1-time 2014 profits.	19
20	York Water	Sensitivity	Sensitivity	55.0%	0.0%	Pass	Pass	0%		20
	TOTAL PEERS	2	2							
		5 w Sensitivities	7 w Sensitivities							

CNG - Gas Peer Dividends

UG 305

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
	#	Abbreviated Utility	UG 288 Staff	UG 305 Staff	Ticker	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2011 Yr	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2012 Yr	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Yr	2011-13 Average	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2012-14 Average	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr
1	1	AGL	No	No	GAS	0.45	0.45	0.45	0.55	1.90	0.36	0.46	0.46	0.46	1.74	0.47	0.47	0.47	0.47	1.88	1.84	0.49	0.49	0.49	0.49	1.96	1.86	0.51	0.51	0.51	0.51	2.04
2	2	Atmos	No	No	ATO	0.34	0.34	0.34	0.345	1.37	0.345	0.345	0.345	0.35	1.39	0.35	0.35	0.35	0.37	1.42	1.39	0.37	0.37	0.37	0.39	1.50	1.44	0.39	0.39	0.39	0.42	1.59
3	3	Laclede (Spire)	No	No	SR / LG	0.405	0.405	0.405	0.405	1.62	0.415	0.415	0.415	0.415	1.66	0.425	0.425	0.425	0.425	1.70	1.66	0.44	0.44	0.44	0.44	1.76	1.71	0.46	0.46	0.46	0.46	1.84
4	4	New Jersey	No	No	NJR	0.18	0.18	0.18	0.18	0.72	0.19	0.19	0.19	0.40	0.97	0.00	0.20	0.20	0.20	0.60	0.76	0.21	0.21	0.21	0.23	0.86	0.81	0.23	0.23	0.23	0.24	0.93
5	5	NiSource	No	No	NI	0.23	0.23	0.23	0.23	0.92	0.23	0.23	0.24	0.24	0.94	0.24	0.24	0.25	0.25	0.98	0.95	0.25	0.25	0.26	0.26	1.02	0.98	0.26	0.26	0.155	0.155	0.83
6	6	Northwest Natural	Yes	Yes	NWN	0.435	0.435	0.435	0.445	1.75	0.445	0.445	0.445	0.455	1.79	0.455	0.455	0.455	0.46	1.83	1.79	0.46	0.46	0.46	0.465	1.85	1.82	0.465	0.465	0.465	0.4675	1.86
7	7	Piedmont	Yes	No	PNY	0.28	0.29	0.29	0.29	1.15	0.29	0.30	0.30	0.60	1.49	0.00	0.31	0.31	0.31	0.93	1.19	0.31	0.32	0.32	0.32	1.27	1.23	0.32	0.33	0.33	0.33	1.31
8	8	South Jersey	No	No	SJI	0.00	0.183	0.183	0.3840	0.75	0.00	0.202	0.202	0.423	0.83	0.00	0.222	0.222	0.458	0.90	0.83	0.00	0.237	0.237	0.488	0.96	0.90	0.00	0.251	0.251	0.515	1.02
9	9	Southwest Gas	No	Yes	SWX	0.25	0.265	0.265	0.265	1.05	0.265	0.295	0.295	0.295	1.15	0.295	0.33	0.33	0.33	1.29	1.16	0.33	0.365	0.365	0.365	1.43	1.29	0.365	0.405	0.405	0.405	1.58
10	11	WGL	No	No	WGL	0.378	0.39	0.39	0.39	1.55	0.39	0.40	0.40	0.40	1.59	0.40	0.42	0.42	0.42	1.66	1.60	0.42	0.44	0.44	0.44	1.74	1.66	0.44	0.463	0.463	0.463	1.83
11	12	American States	No	Sensitivity	AWR					0.55	0.14	0.14	0.1775	0.1775	0.64	0.1775	0.1775	0.2025	0.2025	0.76	0.65	0.2025	0.2025	0.213	0.213	0.83	0.74	0.213	0.213	0.224	0.224	0.87
12	13	American Water	Sensitivity	Sensitivity	AWK	0.22	0.23	0.23	0.23	0.91	0.23	0.23	0.25	0.50	1.21	0.00	0.28	0.28	0.28	0.84	0.99	0.28	0.31	0.31	0.31	1.21	1.09	0.31	0.34	0.34	0.34	1.33
13	15	CA Water	No	Sensitivity	CWT	0.154	0.154	0.154	0.15	0.62	0.1575	0.1575	0.1575	0.1575	0.63	0.16	0.16	0.16	0.16	0.64	0.63	0.1625	0.1625	0.1625	0.1625	0.65	0.64	0.1675	0.1675	0.1675	0.1675	0.67
14	18	Middlesex Water	Sensitivity	Sensitivity	MSEX	0.183	0.183	0.183	0.185	0.73	0.185	0.185	0.185	0.1875	0.74	0.1875	0.1875	0.1875	0.19	0.75	0.74	0.19	0.19	0.19	0.1925	0.76	0.75	0.1925	0.1925	0.1925	0.19875	0.78
15	20	York Water	Sensitivity	Sensitivity	YORW	0.131	0.131	0.131	0.131	0.52	0.134	0.134	0.134	0.134	0.54	0.14	0.138	0.138	0.138	0.55	0.54	0.1431	0.1431	0.1431	0.1431	0.57	0.55	0.1495	0.1495	0.1495	0.1555	0.60
		TOTAL	2	2																												
			5	7																												
			w Sensitivities	w Sensitivities																												

Note: Staff modifies Historic Values for NJR to Reflect 2/1 Split, consistent w Value Line and Yahoo Finance.

CNG - Gas Peer EPS

Value Line Estimated EPS

Value Line Estimated Near Future Earnings per Shar

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
	#	Abbreviated Utility	UG 288 AVA	UG 288 AVA	Ticker	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Yr	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr	2013-15 Average	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2016 Yr	2014-16 Average	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2017 Yr
1	1	AGL	No	No	GAS	1.31	0.41	0.24	0.68	2.64	2.81	0.48	0.19	1.24	4.72	1.62	0.35	0.09	0.89	2.95	3.44	1.75	0.35	0.15	1.05	3.30	3.66	1.80	0.40	0.2	1.20	3.60
2	2	Atmos	No	No	ATO	0.85	1.23	0.36	0.08	2.52	0.95	1.38	0.45	0.23	3.01	0.96	1.35	0.55	0.23	3.09	2.87	1.00	1.42	0.57	0.26	3.25	3.12	1.06	1.47	0.62	0.3	3.45
3	3	Laclede (Spire)	No	No	SR / LG	1.14	1.34	0.25	(0.30)	2.43	1.09	1.59	0.33	(0.35)	2.66	1.09	2.18	0.32	(0.43)	3.16	2.75	1.08	2.25	0.35	(0.28)	3.40	3.07	1.20	2.30	0.35	(0.25)	3.60
4	4	New Jersey	No	No	NJR	0.43	0.82	0.12	(0.01)	1.36	0.47	1.81	0.05	(0.23)	2.10	0.65	1.16	0.03	(0.06)	1.78	1.75	0.58	1.13	0.01	(0.12)	1.60	1.83	0.63	1.18	0.06	(0.07)	1.80
5	5	NiSource	No	No	NI	0.69	0.23	0.16	0.49	1.57	0.85	0.25	0.10	0.49	1.69	0.61	(0.23)	0.05	0.20	0.63	1.30	0.50	0.10	0.05	0.35	1.00	1.11	0.55	0.10	0.05	0.40	1.10
6	6	Northwest Natural	Yes	Yes	NWN	1.40	0.08	(0.31)	1.07	2.24	1.40	0.04	(0.32)	1.04	2.16	1.04	0.08	(0.24)	1.08	1.96	2.12	1.20	0.10	(0.20)	1.10	2.20	2.11	1.25	0.15	(0.20)	1.15	2.35
7	7	Piedmont	Yes	No	PNY	1.18	0.74	(0.03)	(0.11)	1.78	1.26	0.80	(0.09)	(0.13)	1.84	1.18	0.84	(0.10)	(0.18)	1.74	1.79	1.23	0.89	(0.05)	(0.12)	1.95	1.84	1.24	0.90	(0.04)	(0.10)	2.00
8	8	South Jersey	No	No	SJI	0.76	0.16	(0.02)	0.62	1.52	1.01	0.15	(0.05)	0.47	1.58	0.86	0.03	(0.07)	0.66	1.48	1.53	0.90	0.05	0.00	0.65	1.60	1.55	0.95	0.08	0.02	0.70	1.75
9	9	Southwest Gas	No	Yes	SWX	1.73	0.22	(0.06)	1.22	3.11	1.51	0.21	0.04	1.25	3.01	1.53	0.10	(0.10)	1.38	2.91	3.01	1.60	0.20	0.00	1.40	3.20	3.04	1.70	0.25	0.05	1.50	3.50
10	11	WGL	No	No	WGL	1.14	1.75	(0.03)	(0.55)	2.31	0.99	1.84	0.02	(0.17)	2.68	1.16	2.02	0.22	(0.23)	3.17	2.72	1.18	2.00	0.21	(0.24)	3.15	3.00	1.20	2.01	0.22	(0.23)	3.20
11	12	American States	No	Sensitivity	AWR	0.35	0.43	0.53	0.30	1.61	0.28	0.39	0.54	0.36	1.57	0.32	0.41	0.56	0.31	1.60	1.59	0.31	0.47	0.59	0.33	1.70	1.62	0.35	0.50	0.60	0.35	1.80
12	13	American Water	Sensitivity	Sensitivity	AWK	0.32	0.57	0.84	0.33	2.06	0.39	0.62	0.86	0.52	2.39	0.44	0.68	0.96	0.56	2.64	2.36	0.46	0.74	1.03	0.57	2.80	2.61	0.53	0.77	1.10	0.65	3.05
13	15	CA Water	No	Sensitivity	CWT	0.01	0.28	0.61	0.12	1.02	(0.11)	0.36	0.70	0.24	1.19	0.03	0.21	0.52	0.18	0.94	1.05	0.03	0.22	0.60	0.20	1.05	1.06	0.05	0.35	0.65	0.30	1.35
14	18	Middlesex Water	Sensitivity	Sensitivity	MSEX	0.20	0.28	0.36	0.19	1.03	0.20	0.29	0.42	0.22	1.13	0.22	0.31	0.41	0.28	1.22	1.13	0.23	0.33	0.45	0.29	1.30	1.22	0.25	0.34	0.46	0.30	1.35
15	20	York Water	Sensitivity	Sensitivity	YORW	0.17	0.18	0.19	0.21	0.75	0.16	0.22	0.23	0.28	0.89	0.20	0.22	0.28	0.27	0.97	0.87	0.20	0.26	0.28	0.26	1.00	0.95	0.22	0.27	0.30	0.29	1.08
		TOTAL	2	2																												
			5	7																												
			w Sensitivities	w Sensitivities																												

Note: Staff modifies Historic Values for NJR to Reflect 2/1 Split, consistent w Value Line and Yahoo Finance.

CNG - Gas Peer Dividends

UG 305

Value Line Estimated Near Future Dividends in Blue

	1	2	3	4	5	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
	#	Abbreviated Utility	UG 288 Staff	UG 305 Staff	Ticker	2013-15 Average	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2016 Yr	2014-16 Average	2017 Yr	2018 Yr	2019 Yr	2020 Yr	2021 Yr	VL Avg. 2019 - 21 / Yr	Div Growth 2019-21 vs. 2013-15	#	
1	1	AGL	No	No	GAS	1.96	0.53	0.53	0.53	0.53	2.12	2.04	2.16	2.24	2.32	2.40	2.48	2.40	4.3%	1	1
2	2	Atmos	No	No	ATO	1.50	0.42	0.42	0.42	0.42	1.68	1.59	1.80	1.91	2.03	2.15	2.27	2.15	7.0%	2	2
3	3	Laclede (Spire)	No	No	SR / LG	1.77	0.49	0.49	0.49	0.49	1.96	1.85	1.96	2.04	2.12	2.20	2.28	2.20	4.3%	3	3
4	4	New Jersey	No	No	NJR	0.80	0.24	0.24	0.24	0.24	0.96	0.92	0.98	0.99	1.01	1.02	1.03	1.02	3.9%	4	4
5	5	NiSource	No	No	NI	0.94	0.155	0.155	0.165	0.165	0.64	0.83	0.68	0.72	0.76	0.80	0.84	0.80	-3.3%	5	5
6	6	Northwest Natural	Yes	Yes	NWN	1.84	0.4675	0.4675	0.4675	0.4675	1.87	1.86	1.91	1.96	2.00	2.05	2.10	2.05	2.0%	6	6
7	7	Piedmont	Yes	No	PNY	1.17	0.33	0.34	0.34	0.34	1.35	1.31	1.39	1.43	1.47	1.51	1.55	1.51	3.5%	7	7
8	8	South Jersey	No	No	SJI	0.96	0.00	0.27	0.27	0.54	1.08	1.02	1.15	1.23	1.31	1.40	1.49	1.40	7.7%	8	8
9	9	Southwest Gas	No	Yes	SWX	1.43	0.405	0.45	0.47	0.47	1.80	1.60	1.92	2.04	2.17	2.30	2.43	2.30	10.2%	9	9
10	11	WGL	No	No	WGL	1.74	0.463	0.4875	0.4875	0.4875	1.93	1.83	1.95	1.98	2.00	2.03	2.06	2.03	3.4%	11	10
11	12	American States	No	Sensitivity	AWR	0.82	0.224	0.232	0.232	0.232	0.92	0.88	0.97	1.06	1.15	1.25	1.35	1.25	9.1%	12	11
12	13	American Water	Sensitivity	Sensitivity	AWK	1.13	0.34	0.37	0.37	0.37	1.45	1.33	1.57	1.72	1.88	2.05	2.22	2.05	11.2%	13	12
13	15	CA Water	No	Sensitivity	CWT	0.65	0.1725	0.1725	0.1725	0.1725	0.69	0.67	0.71	0.79	0.89	0.99	1.09	0.99	7.5%	15	13
14	18	Middlesex Water	Sensitivity	Sensitivity	MSEX	0.76	0.19875	0.2025	0.2025	0.2025	0.81	0.78	0.84	0.86	0.89	0.91	0.93	0.91	3.2%	18	14
15	20	York Water	Sensitivity	Sensitivity	YORW	0.58	0.1555	0.1555	0.1555	0.161	0.63	0.60	0.66	0.72	0.78	0.85	0.92	0.85	7.4%	20	15
		TOTAL	2	2														Staff Gas 2/3 Regulated	6.1%	Mean	
			5	7														(Sensitivity 1) Staff Gas 80% Regulated	2.0%		
			w Sensitivities	w Sensitivities														(Sensitivity 2) All VL Gas Except UGI	4.3%		
																		(Sensitivity 3) Gas 2/3 Regulated w Water	7.2%		

CNG - Gas Peer EPS

e in Blue

	1	2	3	4	5	33	34	35	36	37	38	39		
	#	Abbreviated Utility	UG 288 AVA	UG 288 AVA	Ticker	2015-17 Average	2018 Yr	2019 Yr	2020 Yr	2021 Yr	VL Avg 2019 - 21 / Yr	EPS Growth 2019-21 vs. 2013-15	#	
1	1	AGL	No	No	GAS	3.45	3.92	4.27	4.65	5.03	4.65	5.2%	1	1
2	2	Atmos	No	No	ATO	3.19	3.62	3.81	4.00	4.19	4.00	5.7%	2	2
3	3	Laclede (Spire)	No	No	SR / LG	3.25	3.79	3.99	4.20	4.41	4.20	7.3%	3	3
4	4	New Jersey	No	No	NJR	1.72	1.83	1.87	1.90	1.93	1.90	1.4%	4	4
5	5	NiSource	No	No	NI	1.13	1.19	1.29	1.40	1.51	1.40	1.3%	5	5
6	6	Northwest Natural	Yes	Yes	NWN	2.22	2.59	2.86	3.15	3.44	3.15	6.8%	6	6
7	7	Piedmont	Yes	No	PNY	1.91	2.06	2.13	2.20	2.27	2.20	3.5%	7	7
8	8	South Jersey	No	No	SJI	1.63	1.89	2.04	2.20	2.36	2.20	6.3%	8	8
9	9	Southwest Gas	No	Yes	SWX	3.24	3.89	4.32	4.80	5.28	4.80	8.1%	9	9
10	11	WGL	No	No	WGL	3.02	3.31	3.43	3.55	3.67	3.55	4.5%	11	10
11	12	American States	No	Sensitivity	AWR	1.70	1.94	2.09	2.25	2.41	2.25	5.9%	12	11
12	13	American Water	Sensitivity	Sensitivity	AWK	2.74	3.27	3.50	3.75	4.00	3.75	8.0%	13	12
13	15	CA Water	No	Sensitivity	CWT	1.15	1.43	1.51	1.60	1.69	1.60	7.3%	15	13
14	18	Middlesex Water	Sensitivity	Sensitivity	MSEX	1.26	1.37	1.38	1.40	1.42	1.40	3.7%	18	14
15	20	York Water	Sensitivity	Sensitivity	YORW	0.98	1.13	1.19	1.25	1.31	1.25	6.2%	20	15
		TOTAL	2	2							Staff Gas 2/3 Regulated	7.5%	Mean	
			5	7							(Sensitivity 1) Staff Gas 80% Regulated	6.8%		
			w Sensitivities	w Sensitivities							(Sensitivity 2) All VL Gas Except UGI	5.0%		
											(Sensitivity 3) Gas 2/3 Regulated w Water	6.6%		

CNG GRC
UG 305 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	12	13	14	15	16	17	#	18	19		
						Yahoo Finance $ Stock Closing Price 1st Trading Day of Month																	
	#	Abbreviated Utility	UG 288 Staff	UG 305 Staff	Ticker	March 3/1/2016	April 4/1/2016	May 5/2/2016	3-Day Avg $ Stock Price	Div Yield at Recent Price	VL 2016 Return on Common Equity		VL 2016 Cap Structure % Long Term Debt	% Common Equity	VL Beta	2016 VL Tax Rate	Hamada Unlevered Beta	Relevered Beta Equity at 49.0%		Equity Risk Premium	Hamada Adjustment Equity At 49.0%	#	
1	1	AGL	No	No	GAS	65.14	65.86	66.14	65.71	3.1%	10.0%		48.0	52.0	0.60	37.5%	0.38	0.63		4.20%	0.12%	1	1
2	2	Atmos	No	No	ATO	74.26	72.55	73.59	73.47	2.2%	10.5%		45.0	55.0	0.80	38.5%	0.53	0.87		4.20%	0.31%	2	2
3	3	Laclede (Spire)	No	No	SR / LG	67.75	63.66	64.70	65.37	2.8%	9.0%		54.5	45.5	0.70	28.0%	0.38	0.66		4.20%	-0.18%	3	3
4	4	New Jersey	No	No	NJR	36.43	35.68	36.52	36.21	2.6%	12.0%		43.5	56.5	0.80	32.0%	0.53	0.90		4.20%	0.41%	4	4
5	5	NiSource	No	No	NI	23.56	22.71	23.60	23.29	3.6%	8.0%		60.0	40.0	0.85	37.0%	0.44	0.72		4.20%	-0.53%	5	5
6	6	Northwest Natural	Yes	Yes	NWN	53.85	51.54	56.77	54.05	3.4%	7.5%		44.5	55.5	0.65	40.0%	0.44	0.71		4.20%	0.26%	6	6
7	7	Piedmont	Yes	No	PNY	59.83	59.80	59.98	59.87	2.2%	10.5%		50.0	50.0	0.75	25.0%	0.43	0.76		4.20%	0.06%	7	7
8	8	South Jersey	No	No	SJI	28.45	27.91	27.60	27.99	3.6%	10.5%		49.0	51.0	0.85	22.0%	0.49	0.88		4.20%	0.13%	8	8
9	9	Southwest Gas	No	Yes	SWX	65.85	64.91	67.76	66.17	2.4%	9.0%		49.5	50.5	0.80	35.0%	0.49	0.82		4.20%	0.08%	9	9
10	11	WGL	No	No	WGL	72.37	67.89	68.65	69.64	2.6%	12.0%		42.5	57.5	0.80	39.0%	0.55	0.90		4.20%	0.43%	10	10
11	12	American States	No	Sensitivity	AWR	39.36	41.69	40.70	40.58	2.2%	12.5%		42.0	58.0	0.75	38.0%	0.52	0.85		4.20%	0.43%	12	11
12	13	American Water	Sensitivity	Sensitivity	AWK	68.93	72.76	74.29	71.99	1.8%	9.5%		55.0	45.0	0.70	38.5%	0.40	0.66		4.20%	-0.19%	13	12
13	15	CA Water	No	Sensitivity	CWT	26.72	27.93	28.74	27.80	2.4%	7.5%		44.5	55.5	0.75	32.0%	0.49	0.83		4.20%	0.33%	15	13
14	18	Middlesex Water	Sensitivity	Sensitivity	MSEX	30.85	36.58	38.32	35.25	2.2%	10.0%		39.0	61.0	0.70	35.0%	0.49	0.83		4.20%	0.54%	18	14
15	20	York Water	Sensitivity	Sensitivity	YORW	30.52	29.65	29.38	29.85	2.0%	11.5%		45.0	55.0	0.70	28.5%	0.44	0.77		4.20%	0.30%	20	15
		TOTAL	2	2																Staff Gas 2/3 Regulated	0.17%	Mean	
			5	7			26.39	26.33												(Sensitivity 1) Staff Gas 80% Regulated	0.26%		
			w Sensitivities	w Sensitivities																(Sensitivity 2) All VL Gas Except UGI	0.11%		
																				(Sensitivity 3) Gas 2/3 Regulated w Water	0.25%		

SJI 2/1 Stock Split in May 2015 is addressed by doubling the May and June share prices.

Dividend Yield = (Annual Dividends per Share) / Price per Share

5.08% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows Staff UG 305 Model X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	#	Abbreviated Utility	Control	Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage 2016	2017	2018	2019	2020	Transition Stage 2021	2022	2023	2024	2025
1	1	AGL	Yes	No	8.0%	44.8%	0.00	(65.71)	2.12	2.16	2.24	2.32	2.40	2.48	2.59	2.71	2.83	2.95
2	2	Atmos	Yes	No	7.6%	50.5%	0.00	(73.47)	1.68	1.80	1.91	2.03	2.15	2.27	2.44	2.61	2.79	2.98
3	3	Laclede (Spire)	Yes	No	7.8%	47.6%	0.00	(65.37)	1.96	1.96	2.04	2.12	2.20	2.28	2.39	2.49	2.60	2.71
4	4	New Jersey	Yes	No	7.3%	54.2%	0.00	(36.21)	0.96	0.98	0.99	1.01	1.02	1.03	1.08	1.12	1.16	1.21
5	5	NiSource	Yes	No	7.2%	53.2%	(0.00)	(23.29)	0.64	0.68	0.72	0.76	0.80	0.84	0.81	0.78	0.76	0.73
6	6	Northwest Natural	Yes	Yes	7.9%	45.3%	0.00	(54.05)	1.87	1.91	1.96	2.00	2.05	2.10	2.14	2.19	2.23	2.28
7	7	Piedmont	Yes	No	7.0%	58.1%	0.00	(59.87)	1.35	1.39	1.43	1.47	1.51	1.55	1.61	1.67	1.72	1.79
8	8	South Jersey	Yes	No	9.5%	31.1%	0.00	(27.99)	1.08	1.15	1.23	1.31	1.40	1.49	1.61	1.73	1.87	2.01
9	9	Southwest Gas	Yes	Yes	8.4%	42.2%	0.00	(66.17)	1.80	1.92	2.04	2.17	2.30	2.43	2.69	2.96	3.26	3.57
#	11	WGL	Yes	No	7.3%	53.4%	(0.00)	(69.64)	1.93	1.95	1.98	2.00	2.03	2.06	2.13	2.20	2.28	2.36
#	12	American States	No	Sensitivity	8.0%	46.9%	0.00	(40.58)	0.92	0.97	1.06	1.15	1.25	1.35	1.48	1.61	1.76	1.91
#	13	American Water	No	Sensitivity	7.9%	48.1%	0.00	(71.99)	1.45	1.57	1.72	1.88	2.05	2.22	2.48	2.75	3.05	3.37
#	15	CA Water	No	Sensitivity	8.3%	42.9%	0.00	(27.80)	0.69	0.71	0.79	0.89	0.99	1.09	1.18	1.27	1.36	1.46
#	18	Middlesex Water	No	Sensitivity	7.0%	57.5%	(0.00)	(35.25)	0.81	0.84	0.86	0.89	0.91	0.93	0.97	1.00	1.03	1.06
#	20	York Water	No	Sensitivity	7.6%	50.8%	0.00	(29.85)	0.63	0.66	0.72	0.78	0.85	0.92	0.99	1.06	1.14	1.22

1	2	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40		
#	Abbreviated Utility	Final Stage 2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2044 Terminal Value	2045 Div	2045 Perpetuity	#	
1	AGL	3.10	3.26	3.43	3.60	3.78	3.98	4.18	4.39	4.61	4.85	5.10	5.35	5.63	5.91	6.21	6.53	6.86	7.21	7.57	295.32	7.96	287.36	1	1
2	Atmos	3.13	3.29	3.46	3.64	3.82	4.02	4.22	4.43	4.66	4.90	5.14	5.41	5.68	5.97	6.27	6.59	6.93	7.28	7.65	337.68	8.04	329.64	2	2
3	Laclede (Spire)	2.85	3.00	3.15	3.31	3.48	3.65	3.84	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.71	6.00	6.30	6.62	6.96	293.56	7.31	286.24	3	3
4	New Jersey	1.27	1.34	1.40	1.48	1.55	1.63	1.71	1.80	1.89	1.99	2.09	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	160.59	3.26	157.33	4	4
5	NiSource	0.77	0.80	0.84	0.89	0.93	0.98	1.03	1.08	1.14	1.20	1.26	1.32	1.39	1.46	1.53	1.61	1.69	1.78	1.87	99.62	1.96	97.66	5	5
6	Northwest Natural	2.39	2.52	2.64	2.78	2.92	3.07	3.22	3.39	3.56	3.74	3.93	4.13	4.34	4.56	4.79	5.03	5.29	5.56	5.84	237.42	6.14	231.29	6	6
7	Piedmont	1.88	1.97	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.15	4.36	4.58	265.88	4.81	261.07	7	7
8	South Jersey	2.11	2.21	2.33	2.44	2.57	2.70	2.84	2.98	3.13	3.29	3.46	3.63	3.82	4.01	4.22	4.43	4.66	4.89	5.14	133.31	5.40	127.90	8	8
9	Southwest Gas	3.75	3.94	4.14	4.35	4.58	4.81	5.05	5.31	5.58	5.86	6.16	6.47	6.80	7.15	7.51	7.89	8.29	8.71	9.16	314.01	9.62	304.39	9	9
11	WGL	2.48	2.60	2.74	2.88	3.02	3.17	3.34	3.51	3.68	3.87	4.07	4.27	4.49	4.72	4.96	5.21	5.48	5.75	6.05	307.74	6.35	301.39	11	10
12	American States	2.01	2.11	2.22	2.33	2.45	2.57	2.70	2.84	2.98	3.14	3.29	3.46	3.64	3.82	4.02	4.22	4.44	4.66	4.90	191.13	5.15	185.98	12	11
13	American Water	3.55	3.73	3.92	4.11	4.32	4.54	4.77	5.02	5.27	5.54	5.82	6.12	6.43	6.75	7.10	7.46	7.83	8.23	8.65	342.88	9.09	333.79	13	12
15	CA Water	1.54	1.62	1.70	1.79	1.88	1.97	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.76	131.56	3.95	127.61	15	13
18	Middlesex Water	1.12	1.17	1.23	1.30	1.36	1.43	1.51	1.58	1.66	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.60	2.73	156.32	2.87	153.46	18	14
20	York Water	1.29	1.35	1.42	1.49	1.57	1.65	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.58	2.71	2.84	2.99	3.14	138.41	3.30	135.12	20	15

	Control	Staff	Mean IRR	Mean % of NPV_{DIV}	Mean NPV @ IRR	
TOTALS	10	2				
		7	8.13%	43.72%	0.00%	Staff Gas 2/3 Regulated
		w Sensitivities	7.87%	45.27%	0.00%	(Sensitivity 1) Staff Gas 80% Regulated
			7.79%	48.03%	-0.07%	(Sensitivity 2) All VL Gas Except UGI
			7.89%	47.68%	-0.02%	(Sensitivity 3) Gas 2/3 Regulated w Water

B.O.Y. Cash Flows Staff UG 305 Model X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	#	Abbreviated Utility	Control	Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage 2016	2017	2018	2019	2020	Transition Stage 2021	2022	2023	2024	2025
1	1	AGL	Yes	No	8.1%	43.2%	0.00	(65.71)	2.16	2.24	2.32	2.40	2.48	2.59	2.71	2.83	2.95	3.10
2	2	Atmos	Yes	No	7.8%	48.5%	0.00	(73.47)	1.80	1.91	2.03	2.15	2.27	2.44	2.61	2.79	2.98	3.13
3	3	Laclede (Spire)	Yes	No	7.9%	46.1%	0.00	(65.37)	1.96	2.04	2.12	2.20	2.28	2.39	2.49	2.60	2.71	2.85
4	4	New Jersey	Yes	No	7.4%	52.1%	0.00	(36.21)	0.98	0.99	1.01	1.02	1.03	1.08	1.12	1.16	1.21	1.27
5	5	NiSource	Yes	No	7.3%	52.1%	(0.00)	(23.29)	0.68	0.72	0.76	0.80	0.84	0.81	0.78	0.76	0.73	0.77
6	6	Northwest Natural	Yes	Yes	8.0%	44.0%	0.00	(54.05)	1.91	1.96	2.00	2.05	2.10	2.14	2.19	2.23	2.28	2.39
7	7	Piedmont	Yes	No	7.1%	56.8%	(0.00)	(59.87)	1.39	1.43	1.47	1.51	1.55	1.61	1.67	1.72	1.79	1.88
8	8	South Jersey	Yes	No	9.8%	29.0%	0.00	(27.99)	1.15	1.23	1.31	1.40	1.49	1.61	1.73	1.87	2.01	2.11
9	9	Southwest Gas	Yes	Yes	8.6%	40.0%	0.00	(66.17)	1.92	2.04	2.17	2.30	2.43	2.69	2.96	3.26	3.57	3.75
#	11	WGL	Yes	No	7.4%	52.2%	0.00	(69.64)	1.95	1.98	2.00	2.03	2.06	2.13	2.20	2.28	2.36	2.48
#	12	American States	No	Sensitivity	8.1%	44.7%	0.00	(40.58)	0.97	1.06	1.15	1.25	1.35	1.48	1.61	1.76	1.91	2.01
#	13	American Water	No	Sensitivity	8.1%	45.8%	0.00	(71.99)	1.57	1.72	1.88	2.05	2.22	2.48	2.75	3.05	3.37	3.55
#	15	CA Water	No	Sensitivity	8.5%	40.6%	0.00	(27.80)	0.71	0.79	0.89	0.99	1.09	1.18	1.27	1.36	1.46	1.54
#	18	Middlesex Water	No	Sensitivity	7.1%	56.2%	(0.00)	(35.25)	0.84	0.86	0.89	0.91	0.93	0.97	1.00	1.03	1.06	1.12
#	20	York Water	No	Sensitivity	7.8%	48.8%	0.00	(29.85)	0.66	0.72	0.78	0.85	0.92	0.99	1.06	1.14	1.22	1.29

1	2	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40		
#	Abbreviated Utility	Final Stage 2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2044 Terminal Value	2045 Div	2045 Perpetuity	#	
1	AGL	3.26	3.43	3.60	3.78	3.98	4.18	4.39	4.61	4.85	5.10	5.35	5.63	5.91	6.21	6.53	6.86	7.21	7.57	7.96	296.48	8.36	288.12	1	1
2	Atmos	3.29	3.46	3.64	3.82	4.02	4.22	4.43	4.66	4.90	5.14	5.41	5.68	5.97	6.27	6.59	6.93	7.28	7.65	8.04	337.42	8.44	328.97	2	2
3	Laclede (Spire)	3.00	3.15	3.31	3.48	3.65	3.84	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.71	6.00	6.30	6.62	6.96	7.31	294.70	7.69	287.01	3	3
4	New Jersey	1.34	1.40	1.48	1.55	1.63	1.71	1.80	1.89	1.99	2.09	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	161.39	3.43	157.96	4	4
5	NiSource	0.80	0.84	0.89	0.93	0.98	1.03	1.08	1.14	1.20	1.26	1.32	1.39	1.46	1.53	1.61	1.69	1.78	1.87	1.96	100.13	2.06	98.06	5	5
6	Northwest Natural	2.52	2.64	2.78	2.92	3.07	3.22	3.39	3.56	3.74	3.93	4.13	4.34	4.56	4.79	5.03	5.29	5.56	5.84	6.14	238.97	6.45	232.52	6	6
7	Piedmont	1.97	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.15	4.36	4.58	4.81	266.78	5.05	261.73	7	7
8	South Jersey	2.21	2.33	2.44	2.57	2.70	2.84	2.98	3.13	3.29	3.46	3.63	3.82	4.01	4.22	4.43	4.66	4.89	5.14	5.40	133.05	5.68	127.37	8	8
9	Southwest Gas	3.94	4.14	4.35	4.58	4.81	5.05	5.31	5.58	5.86	6.16	6.47	6.80	7.15	7.51	7.89	8.29	8.71	9.16	9.62	313.25	10.11	303.14	9	9
11	WGL	2.60	2.74	2.88	3.02	3.17	3.34	3.51	3.68	3.87	4.07	4.27	4.49	4.72	4.96	5.21	5.48	5.75	6.05	6.35	309.46	6.68	302.78	11	10
12	American States	2.11	2.22	2.33	2.45	2.57	2.70	2.84	2.98	3.14	3.29	3.46	3.64	3.82	4.02	4.22	4.44	4.66	4.90	5.15	190.54	5.41	185.14	12	11
13	American Water	3.73	3.92	4.11	4.32	4.54	4.77	5.02	5.27	5.54	5.82	6.12	6.43	6.75	7.10	7.46	7.83	8.23	8.65	9.09	341.36	9.55	331.80	13	12
15	CA Water	1.62	1.70	1.79	1.88	1.97	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.76	3.95	131.03	4.15	126.89	15	13
18	Middlesex Water	1.17	1.23	1.30	1.36	1.43	1.51	1.58	1.66	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.60	2.73	2.87	156.86	3.01	153.85	18	14
20	York Water	1.35	1.42	1.49	1.57	1.65	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.58	2.71	2.84	2.99	3.14	3.30	138.12	3.47	134.65	20	15

	Control	Staff	Mean IRR	Mean % of NPV_{DIV}	Mean NPV @ IRR	
TOTALS	10	2				
		7	8.29%	41.99%	0.00%	Staff Gas 2/3 Regulated
		w Sensitivities	7.99%	43.99%	0.00%	(Sensitivity 1) Staff Gas 80% Regulated
			7.93%	23.20%	-0.02%	(Sensitivity 2) All VL Gas Except UGI
			8.04%	45.73%	-0.01%	(Sensitivity 3) Gas 2/3 Regulated w Water

Average B.O.Y. & E.O.Y. Cash Flows Model X

	1	2	3	4	5	6	7	8	9
	#	Abbreviated Utility	Control	Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2016 - 2020 Dividend Growth Rates EOY	BOY	Average
1	1	AGL	Yes	No	8.1%	44.0%	3.1%	3.5%	3.3%
2	2	Atmos	Yes	No	7.7%	49.5%	6.4%	6.0%	6.2%
3	3	Laclede (Spire)	Yes	No	7.8%	46.9%	2.9%	3.9%	3.4%
4	4	New Jersey	Yes	No	7.3%	53.2%	1.5%	1.3%	1.4%
5	5	NiSource	Yes	No	7.2%	52.6%	5.7%	5.5%	5.6%
6	6	Northwest Natural	Yes	Yes	7.9%	44.6%	2.3%	2.4%	2.3%
7	7	Piedmont	Yes	No	7.1%	57.4%	2.8%	2.8%	2.8%
8	8	South Jersey	Yes	No	9.6%	30.1%	6.7%	6.7%	6.7%
9	9	Southwest Gas	Yes	Yes	8.5%	41.1%	6.4%	6.1%	6.3%
#	11	WGL	Yes	No	7.3%	52.8%	1.3%	1.3%	1.3%
#	12	American States	No	Sensitivity	8.1%	45.8%	8.0%	8.6%	8.3%
#	13	American Water	No	Sensitivity	8.0%	46.9%	9.0%	9.1%	9.1%
#	15	CA Water	No	Sensitivity	8.4%	41.7%	9.4%	11.4%	10.4%
#	18	Middlesex Water	No	Sensitivity	7.1%	56.9%	3.1%	2.7%	2.9%
#	20	York Water	No	Sensitivity	7.7%	49.8%	7.9%	8.6%	8.3%

	Control	Staff	Mean Average IRR	Mean % of NPV_{DIV}	Mean EOY	
TOTALS	10	2				
		7	8.21%	42.86%	4.30%	Staff Gas 2/3 Regulated
		w Sensitivities	7.93%	44.63%	2.35%	(Sensitivity 1) Staff Gas 80% Regulated
			7.86%	47.22%	3.94%	(Sensitivity 2) All VL Gas Except UGI
			7.96%	46.70%	6.79%	(Sensitivity 3) Gas 2/3 Regulated w Water

5.34%	Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal V **EPS Growth**

E.O.Y. Cash Flows

Staff UG 305 Model Y

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41		
						Terminal Value as			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2044					
	#	Abbreviated Utility	Control	Staff	IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage					Final Stage																				Terminal Value	2045 Div	2045 Sale	2046	#	
1	1	AGL	Yes	No	8.6%	48.0%	0.00	(65.71)	2.12	2.16	2.24	2.32	2.40	2.48	2.60	2.71	2.83	2.96	3.11	3.28	3.45	3.64	3.83	4.04	4.25	4.48	4.72	4.97	5.24	5.52	5.81	6.12	6.45	6.79	7.16	7.54	7.94	375.23	8.37	366.87		1	1
				e					3.30	3.60	3.92	4.27	4.65	5.03	5.30	5.58	5.87	6.18	6.51	6.86	7.22	7.61	8.01	8.44	8.89	9.37	9.87	10.40	10.95	11.54	12.15	12.80	13.48	14.20	14.96	15.76	16.60		17.49		18.42		
2	2	Atmos	Yes	No	7.8%	51.1%	0.00	(73.47)	1.68	1.80	1.91	2.03	2.15	2.27	2.44	2.61	2.79	2.98	3.14	3.31	3.49	3.68	3.87	4.08	4.30	4.53	4.77	5.02	5.29	5.57	5.87	6.18	6.51	6.86	7.23	7.61	8.02	362.10	8.45	353.65		2	2
				e					3.25	3.45	3.62	3.81	4.00	4.19	4.44	4.70	4.97	5.25	5.53	5.82	6.13	6.46	6.81	7.17	7.55	7.96	8.38	8.83	9.30	9.80	10.32	10.87	11.45	12.06	12.71	13.38	14.10		14.85		15.64		
3	3	Laclede (Spire)	Yes	No	8.2%	49.6%	0.00	(65.37)	1.96	1.96	2.04	2.12	2.20	2.28	2.39	2.49	2.60	2.72	2.86	3.01	3.17	3.34	3.52	3.71	3.91	4.12	4.34	4.57	4.81	5.07	5.34	5.63	5.93	6.24	6.58	6.93	7.30	343.74	7.69	336.05		3	3
				e					3.40	3.60	3.79	3.99	4.20	4.41	4.74	5.10	5.47	5.86	6.18	6.50	6.85	7.22	7.60	8.01	8.44	8.89	9.36	9.86	10.39	10.94	11.53	12.14	12.79	13.48	14.19	14.95	15.75		16.59		17.48		
4	4	New Jersey	Yes	No	7.0%	51.9%	0.00	(36.21)	0.96	0.98	0.99	1.01	1.02	1.03	1.08	1.12	1.16	1.21	1.28	1.34	1.41	1.49	1.57	1.65	1.74	1.84	1.93	2.04	2.15	2.26	2.38	2.51	2.64	2.78	2.93	3.09	3.25	141.80	3.43	138.37		4	4
				e					1.60	1.80	1.83	1.87	1.90	1.93	1.96	1.99	2.02	2.05	2.16	2.28	2.40	2.52	2.66	2.80	2.95	3.11	3.28	3.45	3.63	3.83	4.03	4.25	4.47	4.71	4.97	5.23	5.51		5.80		6.11		
5	5	NiSource	Yes	No	7.5%	54.6%	0.00	(23.29)	0.64	0.68	0.72	0.76	0.80	0.84	0.81	0.78	0.76	0.73	0.77	0.81	0.85	0.90	0.94	0.99	1.05	1.10	1.16	1.22	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	112.54	2.06	110.47		5	5
				e					1.00	1.10	1.19	1.29	1.40	1.51	1.53	1.55	1.57	1.59	1.68	1.77	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.68	2.82	2.97	3.13	3.30	3.47	3.66	3.85	4.06	4.27		4.50		4.74		
6	6	Northwest Natural	Yes	Yes	8.8%	50.0%	(0.00)	(54.05)	1.87	1.91	1.96	2.00	2.05	2.10	2.14	2.19	2.23	2.28	2.40	2.53	2.66	2.81	2.96	3.11	3.28	3.45	3.64	3.83	4.04	4.25	4.48	4.72	4.97	5.24	5.52	5.81	6.12	335.81	6.45	329.36		6	6
				e					2.20	2.35	2.59	2.86	3.15	3.44	3.69	3.94	4.21	4.50	4.74	4.99	5.26	5.54	5.83	6.14	6.47	6.82	7.18	7.56	7.97	8.39	8.84	9.31	9.81	10.34	10.89	11.47	12.08		12.73		13.41		
7	7	Piedmont	Yes	No	6.8%	56.4%	0.00	(59.87)	1.35	1.39	1.43	1.47	1.51	1.55	1.61	1.67	1.72	1.79	1.88	1.98	2.09	2.20	2.32	2.44	2.57	2.71	2.85	3.00	3.16	3.33	3.51	3.70	3.90	4.11	4.32	4.56	4.80	244.67	5.05	239.61		7	7
				e					1.95	2.00	2.06	2.13	2.20	2.27	2.35	2.44	2.53	2.62	2.76	2.90	3.06	3.22	3.40	3.58	3.77	3.97	4.18	4.40	4.64	4.89	5.15	5.42	5.71	6.02	6.34	6.68	7.03		7.41		7.80		
8	8	South Jersey	Yes	No	10.0%	33.7%	0.00	(27.99)	1.08	1.15	1.23	1.31	1.40	1.49	1.61	1.73	1.87	2.01	2.11	2.23	2.35	2.47	2.60	2.74	2.89	3.04	3.20	3.38	3.56	3.75	3.95	4.16	4.38	4.61	4.86	5.12	5.39	163.34	5.68	157.66		8	8
				e					1.60	1.75	1.89	2.04	2.20	2.36	2.52	2.68	2.85	3.02	3.18	3.35	3.53	3.72	3.92	4.13	4.35	4.58	4.83	5.09	5.36	5.64	5.95	6.26	6.60	6.95	7.32	7.71	8.12		8.56		9.01		
9	9	Southwest Gas	Yes	Yes	9.3%	47.5%	0.00	(66.17)	1.80	1.92	2.04	2.17	2.30	2.43	2.69	2.96	3.26	3.57	3.77	3.97	4.18	4.40	4.64	4.88	5.15	5.42	5.71	6.01	6.34	6.67	7.03	7.41	7.80	8.22	8.66	9.12	9.61	454.94	10.12	444.82		9	9
				e					3.20	3.50	3.89	4.32	4.80	5.28	5.72	6.19	6.69	7.21	7.60	8.01	8.43	8.88	9.36	9.86	10.38	10.94	11.52	12.14	12.79	13.47	14.19	14.95	15.74	16.58	17.47	18.40	19.39		20.42		21.51		
10	11	WGL	Yes	No	7.2%	52.5%	0.00	(69.64)	1.93	1.95	1.98	2.00	2.03	2.06	2.13	2.20	2.28	2.36	2.48	2.62	2.76	2.90	3.06	3.22	3.40	3.58	3.77	3.97	4.18	4.40	4.64	4.89	5.15	5.42	5.71	6.02	6.34	296.88	6.68	290.20		11	10
				e					3.15	3.20	3.31	3.43	3.55	3.67	3.84	4.02	4.21	4.40	4.64	4.89	5.15	5.42	5.71	6.02	6.34	6.68	7.03	7.41	7.80	8.22	8.66	9.12	9.61	10.12	10.66	11.23	11.83		12.46		13.13		
11	12	American States	No	Sensitivity	8.4%	48.8%	0.00	(40.58)	0.92	0.97	1.06	1.15	1.25	1.35	1.48	1.61	1.76	1.91	2.01	2.12	2.23	2.35	2.48	2.61	2.75	2.90	3.05	3.22	3.39	3.57	3.76	3.96	4.17	4.40	4.63	4.88	5.14	222.24	5.41	216.82		12	11
									1.70	1.80	1.94	2.09	2.25	2.41	2.56	2.71	2.88	3.05	3.21	3.38	3.56	3.75	3.95	4.16	4.38	4.62	4.87	5.12	5.40	5.69	5.99	6.31	6.65	7.00	7.38	7.77	8.19		8.62		9.08		
12	13	American Water	No	Sensitivity	8.5%	51.1%	0.00	(71.99)	1.45	1.57	1.72	1.88	2.05	2.22	2.48	2.76	3.05	3.38	3.56	3.75	3.95	4.16	4.38	4.62	4.86	5.12	5.39	5.68	5.99	6.31	6.64	7.00	7.37	7.76	8.18	8.62	9.08	427.21	9.56	417.65		13	12
				e					2.80	3.05	3.27	3.50	3.75	4.00	4.33	4.68	5.05	5.45	5.74	6.05	6.37	6.71	7.07	7.44	7.84	8.26	8.70	9.17	9.65	10.17	10.71	11.29	11.89	12.52	13.19	13.90	14.64		15.42		16.24		
13	15	CA Water	No	Sensitivity	9.1%	47.5%	0.00	(27.80)	0.69	0.71	0.79	0.89	0.99	1.09	1.18	1.27	1.37	1.47	1.54	1.63	1.71	1.80	1.90	2.00	2.11	2.22	2.34	2.47	2.60	2.74	2.88	3.04	3.20	3.37	3.55	3.74	3.94	181.00	4.15	176.85		15	13
				e					1.05	1.35	1.43	1.51	1.60	1.69	1.82	1.95	2.09	2.24	2.36	2.49	2.62	2.76	2.91	3.06	3.22	3.40	3.58	3.77	3.97	4.18	4.41	4.64	4.89	5.15	5.43	5.71	6.02		6.34		6.68		
14	18	Middlesex Water	No	Sensitivity	6.7%	55.1%	0.00	(35.25)	0.81	0.84	0.86	0.89	0.91	0.93	0.97	1.00	1.03	1.06	1.12	1.18	1.24	1.31	1.38	1.45	1.53	1.61	1.70	1.79	1.89	1.99	2.09	2.21	2.32	2.45	2.58	2.72	2.86	135.98	3.01	132.97		18	14
				e					1.30	1.35	1.37	1.38	1.40	1.42	1.47	1.53	1.59	1.64	1.73	1.82	1.92	2.03	2.13	2.25	2.37	2.49	2.63	2.77	2.91	3.07	3.23	3.41	3.59	3.78	3.98	4.20	4.42		4.66		4.90		
15	20	York Water	No	Sensitivity	7.9%	51.8%	0.00	(29.85)	0.63	0.66	0.72	0.78	0.85	0.92	0.99	1.06	1.14	1.23	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.67	2.82	2.97	3.13	3.29	152.37	3.47	148.90		20	15
				e					1.00	1.08	1.13	1.19	1.25	1.31	1.39	1.48	1.58	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.67	2.81	2.96	3.12	3.29	3.47	3.65	3.85	4.05	4.27	4.50		4.74		4.99		

TOTALS	10	2	Mean			
		7	9.04%	48.77%	0.00%	Staff Gas 2/3 Regulated
		w Sensitivities	8.76%	49.99%	0.00%	(Sensitivity 1) Staff Gas 80% Regulated
			8.12%	49.52%	0.00%	(Sensitivity 2) All VL Gas Except UGI
			8.39%	50.26%	0.00%	(Sensitivity 3) Gas 2/3 Regulated w Water

B.O.Y. Cash Flows   Staff   Model Y EPS Growth

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
						Terminal Value as			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	#	Abbreviated Utility	AVA	Staff	IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage				
1	1	AGL	Yes	No	8.7%	46.4%	0.00	(65.71)	2.16	2.24	2.32	2.40	2.48	2.60	2.71	2.83	2.96	3.11
				e					3.30	3.60	3.92	4.27	4.65	5.03	5.30	5.58	5.87	6.18
2	2	Atmos	Yes	No	8.0%	49.1%	0.00	(73.47)	1.80	1.91	2.03	2.15	2.27	2.44	2.61	2.79	2.98	3.14
				e					3.25	3.45	3.62	3.81	4.00	4.19	4.44	4.70	4.97	5.25
3	3	Laclede (Spire)	Yes	No	8.3%	48.0%	0.00	(65.37)	1.96	2.04	2.12	2.20	2.28	2.39	2.49	2.60	2.72	2.86
				e					3.40	3.60	3.79	3.99	4.20	4.41	4.74	5.10	5.47	5.86
4	4	New Jersey	Yes	No	7.1%	50.5%	0.00	(36.21)	0.98	0.99	1.01	1.02	1.03	1.08	1.12	1.16	1.21	1.28
				e					1.60	1.80	1.83	1.87	1.90	1.93	1.96	1.99	2.02	2.05
5	5	NiSource	Yes	No	7.6%	53.3%	0.00	(23.29)	0.68	0.72	0.76	0.80	0.84	0.81	0.78	0.76	0.73	0.77
				e					1.00	1.10	1.19	1.29	1.40	1.51	1.53	1.55	1.57	1.59
6	6	Northwest Natural	Yes	Yes	8.9%	48.6%	(0.00)	(54.05)	1.91	1.96	2.00	2.05	2.10	2.14	2.19	2.23	2.28	2.40
				e					2.20	2.35	2.59	2.86	3.15	3.44	3.69	3.94	4.21	4.50
7	7	Piedmont	Yes	No	6.9%	55.0%	0.00	(59.87)	1.39	1.43	1.47	1.51	1.55	1.61	1.67	1.72	1.79	1.88
				e					1.95	2.00	2.06	2.13	2.20	2.27	2.35	2.44	2.53	2.62
8	8	South Jersey	Yes	No	10.2%	31.6%	0.00	(27.99)	1.15	1.23	1.31	1.40	1.49	1.61	1.73	1.87	2.01	2.11
				e					1.60	1.75	1.89	2.04	2.20	2.36	2.52	2.68	2.85	3.02
9	9	Southwest Gas	Yes	Yes	9.5%	45.4%	0.00	(66.17)	1.92	2.04	2.17	2.30	2.43	2.69	2.96	3.26	3.57	3.77
				e					3.20	3.50	3.89	4.32	4.80	5.28	5.72	6.19	6.69	7.21
10	11	WGL	Yes	No	7.3%	51.1%	0.00	(69.64)	1.95	1.98	2.00	2.03	2.06	2.13	2.20	2.28	2.36	2.48
				e					3.15	3.20	3.31	3.43	3.55	3.67	3.84	4.02	4.21	4.40
11	12	American States	No	Sensitivity	8.6%	46.7%	0.00	(40.58)	0.97	1.06	1.15	1.25	1.35	1.48	1.61	1.76	1.91	2.01
									1.70	1.80	1.94	2.09	2.25	2.41	2.56	2.71	2.88	3.05
12	13	American Water	No	Sensitivity	8.7%	48.8%	0.00	(71.99)	1.57	1.72	1.88	2.05	2.22	2.48	2.76	3.05	3.38	3.56
				e					2.80	3.05	3.27	3.50	3.75	4.00	4.33	4.68	5.05	5.45
13	15	CA Water	No	Sensitivity	9.3%	45.2%	0.00	(27.80)	0.71	0.79	0.89	0.99	1.09	1.18	1.27	1.37	1.47	1.54
				e					1.05	1.35	1.43	1.51	1.60	1.69	1.82	1.95	2.09	2.24
14	18	Middlesex Water	No	Sensitivity	6.8%	53.6%	0.00	(35.25)	0.84	0.86	0.89	0.91	0.93	0.97	1.00	1.03	1.06	1.12
				e					1.30	1.35	1.37	1.38	1.40	1.42	1.47	1.53	1.59	1.64
15	20	York Water	No	Sensitivity	8.1%	49.8%	0.00	(29.85)	0.66	0.72	0.78	0.85	0.92	0.99	1.06	1.14	1.23	1.29
				e					1.00	1.08	1.13	1.19	1.25	1.31	1.39	1.48	1.58	1.67
		TOTALS	10	2	Mean													
				7	9.18%	47.00%	0.00%	Staff Gas 2/3 Regulated										
				w Sensitivities	8.87%	48.63%	0.00%	(Sensitivity 1) Staff Gas 80% Regulated										
					8.25%	47.90%	0.00%	(Sensitivity 2) All VL Gas Except UGI										
					8.54%	48.30%	0.00%	(Sensitivity 3) Gas 2/3 Regulated w Water										

2	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41		
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2044					
Abbreviated Utility	Final Stage																			Terminal Value	2045 Div	2045 Sale	2046	#	
AGL	3.28	3.45	3.64	3.83	4.04	4.25	4.48	4.72	4.97	5.24	5.52	5.81	6.12	6.45	6.79	7.16	7.54	7.94	8.37	375.68	8.81	366.87		1	1
	6.51	6.86	7.22	7.61	8.01	8.44	8.89	9.37	9.87	10.40	10.95	11.54	12.15	12.80	13.48	14.20	14.96	15.76	16.60		17.49		18.42		
Atmos	3.31	3.49	3.68	3.87	4.08	4.30	4.53	4.77	5.02	5.29	5.57	5.87	6.18	6.51	6.86	7.23	7.61	8.02	8.45	362.55	8.90	353.65		2	2
	5.53	5.82	6.13	6.46	6.81	7.17	7.55	7.96	8.38	8.83	9.30	9.80	10.32	10.87	11.45	12.06	12.71	13.38	14.10		14.85		15.64		
Laclede (Spire)	3.01	3.17	3.34	3.52	3.71	3.91	4.12	4.34	4.57	4.81	5.07	5.34	5.63	5.93	6.24	6.58	6.93	7.30	7.69	344.15	8.10	336.05		3	3
	6.18	6.50	6.85	7.22	7.60	8.01	8.44	8.89	9.36	9.86	10.39	10.94	11.53	12.14	12.79	13.48	14.19	14.95	15.75		16.59		17.48		
New Jersey	1.34	1.41	1.49	1.57	1.65	1.74	1.84	1.93	2.04	2.15	2.26	2.38	2.51	2.64	2.78	2.93	3.09	3.25	3.43	141.98	3.61	138.37		4	4
	2.16	2.28	2.40	2.52	2.66	2.80	2.95	3.11	3.28	3.45	3.63	3.83	4.03	4.25	4.47	4.71	4.97	5.23	5.51		5.80		6.11		
NiSource	0.81	0.85	0.90	0.94	0.99	1.05	1.10	1.16	1.22	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	112.65	2.17	110.47		5	5
	1.68	1.77	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.68	2.82	2.97	3.13	3.30	3.47	3.66	3.85	4.06	4.27		4.50		4.74		
Northwest Natural	2.53	2.66	2.81	2.96	3.11	3.28	3.45	3.64	3.83	4.04	4.25	4.48	4.72	4.97	5.24	5.52	5.81	6.12	6.45	336.16	6.79	329.36		6	6
	4.74	4.99	5.26	5.54	5.83	6.14	6.47	6.82	7.18	7.56	7.97	8.39	8.84	9.31	9.81	10.34	10.89	11.47	12.08		12.73		13.41		
Piedmont	1.98	2.09	2.20	2.32	2.44	2.57	2.71	2.85	3.00	3.16	3.33	3.51	3.70	3.90	4.11	4.32	4.56	4.80	5.05	244.94	5.32	239.61		7	7
	2.76	2.90	3.06	3.22	3.40	3.58	3.77	3.97	4.18	4.40	4.64	4.89	5.15	5.42	5.71	6.02	6.34	6.68	7.03		7.41		7.80		
South Jersey	2.23	2.35	2.47	2.60	2.74	2.89	3.04	3.20	3.38	3.56	3.75	3.95	4.16	4.38	4.61	4.86	5.12	5.39	5.68	163.65	5.98	157.66		8	8
	3.18	3.35	3.53	3.72	3.92	4.13	4.35	4.58	4.83	5.09	5.36	5.64	5.95	6.26	6.60	6.95	7.32	7.71	8.12		8.56		9.01		
Southwest Gas	3.97	4.18	4.40	4.64	4.88	5.15	5.42	5.71	6.01	6.34	6.67	7.03	7.41	7.80	8.22	8.66	9.12	9.61	10.12	455.48	10.66	444.82		9	9
	7.60	8.01	8.43	8.88	9.36	9.86	10.38	10.94	11.52	12.14	12.79	13.47	14.19	14.95	15.74	16.58	17.47	18.40	19.39		20.42		21.51		
WGL	2.62	2.76	2.90	3.06	3.22	3.40	3.58	3.77	3.97	4.18	4.40	4.64	4.89	5.15	5.42	5.71	6.02	6.34	6.68	297.24	7.03	290.20		11	10
	4.64	4.89	5.15	5.42	5.71	6.02	6.34	6.68	7.03	7.41	7.80	8.22	8.66	9.12	9.61	10.12	10.66	11.23	11.83		12.46		13.13		
American States	2.12	2.23	2.35	2.48	2.61	2.75	2.90	3.05	3.22	3.39	3.57	3.76	3.96	4.17	4.40	4.63	4.88	5.14	5.41	222.53	5.70	216.82		12	11
	3.21	3.38	3.56	3.75	3.95	4.16	4.38	4.62	4.87	5.12	5.40	5.69	5.99	6.31	6.65	7.00	7.38	7.77	8.19		8.62		9.08		
American Water	3.75	3.95	4.16	4.38	4.62	4.86	5.12	5.39	5.68	5.99	6.31	6.64	7.00	7.37	7.76	8.18	8.62	9.08	9.56	427.72	10.07	417.65		13	12
	5.74	6.05	6.37	6.71	7.07	7.44	7.84	8.26	8.70	9.17	9.65	10.17	10.71	11.29	11.89	12.52	13.19	13.90	14.64		15.42		16.24		
CA Water	1.63	1.71	1.80	1.90	2.00	2.11	2.22	2.34	2.47	2.60	2.74	2.88	3.04	3.20	3.37	3.55	3.74	3.94	4.15	181.22	4.37	176.85		15	13
	2.36	2.49	2.62	2.76	2.91	3.06	3.22	3.40	3.58	3.77	3.97	4.18	4.41	4.64	4.89	5.15	5.43	5.71	6.02		6.34		6.68		
Middlesex Water	1.18	1.24	1.31	1.38	1.45	1.53	1.61	1.70	1.79	1.89	1.99	2.09	2.21	2.32	2.45	2.58	2.72	2.86	3.01	136.14	3.17	132.97		18	14
	1.73	1.82	1.92	2.03	2.13	2.25	2.37	2.49	2.63	2.77	2.91	3.07	3.23	3.41	3.59	3.78	3.98	4.20	4.42		4.66		4.90		
York Water	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.67	2.82	2.97	3.13	3.29	3.47	152.55	3.65	148.90		20	15
	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.67	2.81	2.96	3.12	3.29	3.47	3.65	3.85	4.05	4.27	4.50		4.74		4.99		

Average B.O.Y. & E.O.Y. Cash Flows   Model Y EPS Growth

	1	2	3	4	5	6	7	8	9
						Terminal Value as	Average 2016 - 2020 Dividend Growth Rates		
	#	Abbreviated Utility	AVA	Staff	Average IRR	% of NPV_{DIV}	EOY	BOY	Average
1	1	AGL	Yes	No	8.7%	47.2%	3.1%	3.5%	3.3%
2	2	Atmos	Yes	No	7.9%	50.1%	6.4%	6.0%	6.2%
3	3	Laclede (Spire)	Yes	No	8.2%	48.8%	2.9%	3.9%	3.4%
4	4	New Jersey	Yes	No	7.0%	51.2%	1.5%	1.3%	1.4%
5	5	NiSource	Yes	No	7.6%	53.9%	5.7%	5.5%	5.6%
6	6	Northwest Natural	Yes	Yes	8.8%	49.3%	2.3%	2.4%	2.3%
7	7	Piedmont	Yes	No	6.9%	55.7%	2.8%	2.8%	2.8%
8	8	South Jersey	Yes	No	10.1%	32.7%	6.7%	6.7%	6.7%
9	9	Southwest Gas	Yes	Yes	9.4%	46.5%	6.4%	6.1%	6.3%
10	11	WGL	Yes	No	7.3%	51.8%	1.3%	1.3%	1.3%
11	12	American States	No	Sensitivity	8.5%	47.8%	8.0%	8.6%	8.3%
12	13	American Water	No	Sensitivity	8.6%	49.9%	9.0%	9.1%	9.1%
13	15	CA Water	No	Sensitivity	9.2%	46.3%	9.4%	11.4%	10.4%
14	18	Middlesex Water	No	Sensitivity	6.8%	54.3%	3.1%	2.7%	2.9%
15	20	York Water	No	Sensitivity	8.0%	50.8%	7.9%	8.6%	8.3%
		TOTALS	10	2	Mean				
				7	9.11%	47.88%	4.30%	Staff Gas 2/3 Regulated	
				w Sensitivities	8.81%	49.31%	2.35%	(Sensitivity 1) Staff Gas 80% Regulated	
					8.19%	48.71%	3.94%	(Sensitivity 2) All VL Gas Except UGI	
					8.46%	49.28%	6.79%	(Sensitivity 3) Gas 2/3 Regulated w Water	

UG 305 Staff ROE Summary

OMB White House Nominal GDP Growth Yr/Yr 4.3% Unchanged from UG 287 (Last CNG GRC)
CBO Nominal GDP Growth Yr/Yr 4.1% Down from 4.3%

TIPS Implied Inflation 1.70% Down from 2.12%
Historical Real GDP 2.81% Down from 2.87%

CBO: 4.2% Nominal GDP Down from 4.55%
EIA Placeholder 2.2% Down from 2.4% Real GDP

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates

Component	Real Rate	TIPS Inflation Forecast	Nominal Rate	Weight	Weighted Rate
EIA	2.20%	1.70%	3.94%	12.50%	0.49%
OMB - 10 Year GDP Projection		2.00%	4.10%	12.50%	0.51%
White House 2017 Budget		2.30%	4.30%	12.50%	0.54%
CBO Projections			4.20%	12.50%	0.53%
Historical 1980 Q1 – 2016 Q1	2.81%	1.70%	4.56%	50.0%	2.28%
Composite				100%	4.35%
BEA Avg. Nominal Historical 1980 Q1 – 2016 Q1			5.34%		5.34%
Indiana U – Kelley 2018-35 Ctr Econometric Research	2.90%	2.12%	5.08%	100.0%	5.08%
Blue Chip* – Top 10% 2019 Values	2.90%	2.12%	5.08%	100.0%	5.08%
Blue Chip – Average	2.40%	2.12%	4.57%	100.0%	4.57%
Blue Chip – Bottom 10%	1.90%	2.12%	4.06%	100.0%	4.06%

Stage 3 – Other Long-Term Annual Dividend & EPS Growth Rates Considered

Component	Real Rate	TIPS Inflation Forecast	Nominal Rate	Weight	Weighted Rate
Blue Chip* – Top 10% 2021-2025 Values	2.70%	2.12%	4.88%	100.0%	4.88%
Blue Chip – Average	2.30%	2.12%	4.47%	100.0%	4.47%
Blue Chip – Bottom 10%	2.00%	2.12%	4.16%	100.0%	4.16%
Blue Chip* – Top 10% 2021-2025 Values	Nominal		5.00%	100.0%	5.00%
Blue Chip – Average			4.40%	100.0%	4.40%
Blue Chip – Bottom 10%			3.90%	100.0%	3.90%

Change Drivers:

A. Historical GDP rose 6 bps after inclusion of creative works, etc. back to 1929.
B. Global expectation of inflation dropped, except in certain emerging market nations.
C. No delayed productivity surge followed the 2008 downturn.
D. US birth rates declined sharply from pre-2008, while imigration reform remains controversial.
E. Global stresses and low inflation delay Fed raising of interest rates.
F. Global investor flight to safety/quality continues.

Effect: Narrowing expectations and lower highest expected GDP growth

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity

X	Composite Growth	4.35%	Top-10 LT Blue Chip Growth	5.08%	Nominal Historical Growth	5.34%
Staff 70% Regulated VL Gas	7.92%		8.21%		8.67%	
Sensitivity 80% Regulated	7.64%		7.93%		8.78%	
Sensitivity All VL Gas - UGI	7.56%		7.86%		8.36%	
Sensitivity w Water	7.67%		7.96%		8.45%	

Hamada Adjustments to Right →

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)

X	Composite Growth	4.35%	Top-10 LT Blue Chip Growth	5.08%	Nominal Historical Growth	5.34%
Staff Gas Peers	8.09%		8.38%		8.84%	
Sensitivity w AGL	7.90%		8.19%		9.04%	
Sensitivity w Water	7.67%		7.97%		8.47%	
Sensitivity w AGL & Water	7.92%		8.21%		8.70%	

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale

Y	Composite Growth	4.35%	Top-10 LT Blue Chip Growth	5.08%	Nominal Historical Growth	5.34%
Staff Gas Peers	8.86%		9.07%		9.11%	
Sensitivity w AGL	9.05%		9.26%		8.81%	
Sensitivity w Water	8.34%		8.55%		8.19%	
Sensitivity w AGL & Water	8.49%		8.70%		8.46%	

Hamada Adjustments to Right →

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)

Y	Composite Growth	4.35%	Top-10 LT Blue Chip Growth	5.08%	Nominal Historical Growth	5.34%
Staff Gas Peers	9.03%		9.24%		9.28%	
Sensitivity w AGL	9.31%		9.52%		9.07%	
Sensitivity w Water	8.45%		8.66%		8.30%	
Sensitivity w AGL & Water	8.74%		8.95%		8.71%	

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : 12.5 bps

Range of Modeled Results 7.56% to 9.41% ROE

Best Fit Range of Reasonable ROEs 8.97% to 9.41% ROE

(Best fit is Staff's Hamada adjusted screened gas utilities that have most similar characteristics to CNG regulated gas operations in Oregon)

Midpoint of Best Fit Modeling Results 9.19% ROE

(Staff's informed judgement excludes some of the lower range of modeling results depicted above)

Staff Point ROE Recommendation: 9.4% ROE

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 204

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support of Opening Testimony

August 11, 2016

Staff Exhibit 204 – Staff Synthetic Forward Curve TIPS Analysis

Is provided in electronic format.

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Staff Historical GDP Analysis with BEA Data

Exhibits in Support
of Opening Testimony

August 11, 2016

Staff Exhibit 205 – Staff Historical GDP Analysis with BEA Data

Is provided in electronic format.

Bureau of Economic Analysis (BEA)

Current-Dollar and "Real" Gross Domestic Product (GDP)

Staff Accessed May 13, 2016

Annual

http://www.bea.gov/national/index.htm

Yr	GDP in billions of current dollars	GDP in billions of chained 2009 dollars
1929	104.6	1,056.6
1930	92.2	966.7
1931	77.4	904.8
1932	59.5	788.2
1933	57.2	778.3
1934	66.8	862.2
1935	74.3	939.0
1936	84.9	1,060.5
1937	93.0	1,114.6
1938	87.4	1,077.7
1939	93.5	1,163.6
1940	102.9	1,266.1
1941	129.4	1,490.3
1942	166.0	1,771.8
1943	203.1	2,073.7
1944	224.6	2,239.4
1945	228.2	2,217.8
1946	227.8	1,960.9
1947	249.9	1,939.4
1948	274.8	2,020.0
1949	272.8	2,008.9
1950	300.2	2,184.0
1951	347.3	2,360.0
1952	367.7	2,456.1
1953	389.7	2,571.4
1954	391.1	2,556.9
1955	426.2	2,739.0
1956	450.1	2,797.4
1957	474.9	2,856.3
1958	482.0	2,835.3
1959	522.5	3,031.0
1960	543.3	3,108.7
1961	563.3	3,188.1
1962	605.1	3,383.1
1963	638.6	3,530.4
1964	685.8	3,734.0
1965	743.7	3,976.7
1966	815.0	4,238.9
1967	861.7	4,355.2
1968	942.5	4,569.0
1969	1,019.9	4,712.5
1970	1,075.9	4,722.0
1971	1,167.8	4,877.6
1972	1,282.4	5,134.3
1973	1,428.5	5,424.1
1974	1,548.8	5,396.0
1975	1,688.9	5,385.4
1976	1,877.6	5,675.4
1977	2,086.0	5,937.0
1978	2,356.6	6,267.2
1979	2,632.1	6,466.2
1980	2,862.5	6,450.4
1981	3,211.0	6,617.7
1982	3,345.0	6,491.3
1983	3,638.1	6,792.0
1984	4,040.7	7,285.0
1985	4,346.7	7,593.8
1986	4,590.2	7,860.5
1987	4,870.2	8,132.6
1988	5,252.6	8,474.5
1989	5,657.7	8,786.4
1990	5,979.6	8,955.0
1991	6,174.0	8,948.4
1992	6,539.3	9,266.6
1993	6,878.7	9,521.0
1994	7,308.8	9,905.4
1995	7,664.1	10,174.8
1996	8,100.2	10,561.0
1997	8,608.5	11,034.9
1998	9,089.2	11,525.9
1999	9,660.6	12,065.9
2000	10,284.8	12,559.7
2001	10,621.8	12,682.2
2002	10,977.5	12,908.8
2003	11,510.7	13,271.1
2004	12,274.9	13,773.5
2005	13,093.7	14,234.2
2006	13,855.9	14,613.8
2007	14,477.6	14,873.7
2008	14,718.6	14,830.4
2009	14,418.7	14,418.7
2010	14,964.4	14,783.8
2011	15,517.9	15,020.6
2012	16,155.3	15,354.6
2013	16,663.2	15,583.3
2014	17,348.1	15,961.7
2015	17,947.0	16,348.9

Quarterly

(Seasonally adjusted annual rates)

1980 through 2016 Q1

Average 5.34% Nominal

Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#	Average	2.61%	Real
1947q1	243.1	1,934.5	1	1	8.783381	1980
1947q2	246.3	1,932.3	2	2	8.762896	
1947q3	250.1	1,930.3	3	3	8.761378	
1947q4	260.3	1,960.7	4	4	8.779742	
1948q1	266.2	1,989.5	5	5	8.800219	1981
1948q2	272.9	2,021.9	6	6	8.792899	
1948q3	279.5	2,033.2	7	7	8.804310	
1948q4	280.7	2,035.3	8	8	8.792565	
1949q1	275.4	2,007.5	9	9	8.775704	1982
1949q2	271.7	2,000.8	10	10	8.781125	
1949q3	273.3	2,022.8	11	11	8.777525	
1949q4	271.0	2,004.7	12	12	8.778495	
1950q1	281.2	2,084.6	13	13	8.791516	1983
1950q2	290.7	2,147.6	14	14	8.814078	
1950q3	308.5	2,230.4	15	15	8.833463	
1950q4	320.3	2,273.4	16	16	8.853880	
1951q1	336.4	2,304.5	17	17	8.873552	1984
1951q2	344.5	2,344.5	18	18	8.890961	
1951q3	351.8	2,392.8	19	19	8.900753	
1951q4	356.6	2,398.1	20	20	8.908695	
1952q1	360.2	2,423.5	21	21	8.918583	1985
1952q2	361.4	2,428.5	22	22	8.927699	
1952q3	368.1	2,446.1	23	23	8.943140	
1952q4	381.2	2,526.4	24	24	8.950611	
1953q1	388.5	2,573.4	25	25	8.959838	1986
1953q2	392.3	2,593.5	26	26	8.964414	
1953q3	391.7	2,578.9	27	27	8.974441	
1953q4	386.5	2,539.8	28	28	8.979606	
1954q1	385.9	2,528.0	29	29	8.986572	1987
1954q2	386.7	2,530.7	30	30	8.997729	
1954q3	391.6	2,559.4	31	31	9.006754	
1954q4	400.3	2,609.3	32	32	9.023131	
1955q1	413.8	2,683.8	33	33	9.028735	1988
1955q2	422.2	2,727.5	34	34	9.041863	
1955q3	430.9	2,764.1	35	35	9.047621	
1955q4	437.8	2,780.8	36	36	9.060784	
1956q1	440.5	2,770.0	37	37	9.070814	1989
1956q2	446.8	2,792.9	38	38	9.078647	
1956q3	452.0	2,790.6	39	39	9.086080	
1956q4	461.3	2,836.2	40	40	9.088195	
1957q1	470.6	2,854.5	41	41	9.099085	1990
1957q2	472.8	2,848.2	42	42	9.102944	
1957q3	480.3	2,875.9	43	43	9.103189	
1957q4	475.7	2,846.4	44	44	9.094638	
1958q1	468.4	2,772.7	45	45	9.089934	1991
1958q2	472.8	2,790.9	46	46	9.097664	
1958q3	486.7	2,855.5	47	47	9.102454	
1958q4	500.4	2,922.3	48	48	9.106800	
1959q1	511.1	2,976.6	49	49	9.118554	1992
1959q2	524.2	3,049.0	50	50	9.129510	
1959q3	525.2	3,043.1	51	51	9.139188	
1959q4	529.3	3,055.1	52	52	9.149156	
1960q1	543.3	3,123.2	53	53	9.151026	1993
1960q2	542.7	3,111.3	54	54	9.156950	
1960q3	546.0	3,119.1	55	55	9.161812	
1960q4	541.1	3,081.3	56	56	9.175076	
1961q1	545.9	3,102.3	57	57	9.184838	1994
1961q2	557.4	3,159.9	58	58	9.198409	
1961q3	568.2	3,212.6	59	59	9.204292	
1961q4	581.6	3,277.7	60	60	9.215577	
1962q1	595.2	3,336.8	61	61	9.218993	1995
1962q2	602.6	3,372.7	62	62	9.222476	
1962q3	609.6	3,404.8	63	63	9.231005	
1962q4	613.1	3,418.0	64	64	9.238072	
1963q1	622.7	3,456.1	65	65	9.244616	1996
1963q2	631.8	3,501.1	66	66	9.261927	
1963q3	645.0	3,569.5	67	67	9.271134	
1963q4	654.8	3,595.0	68	68	9.281647	
1964q1	671.1	3,672.7	69	69	9.289235	1997
1964q2	680.8	3,716.4	70	70	9.304213	
1964q3	692.8	3,766.9	71	71	9.316860	
1964q4	698.4	3,780.2	72	72	9.324588	
1965q1	719.2	3,873.5	73	73	9.334432	1998
1965q2	732.4	3,926.4	74	74	9.344084	
1965q3	750.2	4,006.2	75	75	9.357087	
1965q4	773.1	4,100.6	76	76	9.373369	
1966q1	797.3	4,201.9	77	77	9.381323	1999
1966q2	807.2	4,219.1	78	78	9.389532	
1966q3	820.8	4,249.2	79	79	9.402043	
1966q4	834.9	4,285.6	80	80	9.419247	
1967q1	846.0	4,324.9	81	81	9.422148	2000
1967q2	851.1	4,328.7	82	82	9.440857	
1967q3	866.6	4,366.1	83	83	9.442063	
1967q4	883.2	4,401.2	84	84	9.447726	
1968q1	911.1	4,490.6	85	85	9.444883	2001
1968q2	936.3	4,566.4	86	86	9.450168	
1968q3	952.3	4,599.3	87	87	9.447000	
1968q4	970.1	4,619.8	88	88	9.449775	
1969q1	995.4	4,691.6	89	89	9.458941	2002
1969q2	1,011.4	4,706.7	90	90	9.464440	
1969q3	1,032.0	4,736.1	91	91	9.469299	
1969q4	1,040.7	4,715.5	92	92	9.469932	
1970q1	1,053.5	4,707.1	93	93	9.475102	2003
1970q2	1,070.1	4,715.4	94	94	9.484337	
1970q3	1,088.5	4,757.2	95	95	9.500948	
1970q4	1,091.5	4,708.3	96	96	9.512569	
1971q1	1,137.8	4,834.3	97	97	9.518303	2004
1971q2	1,159.4	4,861.9	98	98	9.525604	
1971q3	1,180.3	4,900.0	99	99	9.534653	
1971q4	1,193.6	4,914.3	100	100	9.543263	
1972q1	1,233.8	5,002.4	101	101	9.553866	2005
1972q2	1,270.1	5,118.3	102	102	9.559073	
1972q3	1,293.8	5,165.4	103	103	9.567441	
1972q4	1,332.0	5,251.2	104	104	9.573135	
1973q1	1,380.7	5,380.5	105	105	9.585078	2006
1973q2	1,417.6	5,441.5	106	106	9.588064	
1973q3	1,436.8	5,411.9	107	107	9.588955	
1973q4	1,479.1	5,462.4	108	108	9.596752	
1974q1	1,494.7	5,417.0	109	109	9.597370	2007
1974q2	1,534.2	5,431.3	110	110	9.604994	
1974q3	1,563.4	5,378.7	111	111	9.611697	
1974q4	1,603.0	5,357.2	112	112	9.615259	
1975q1	1,619.6	5,292.4	113	113	9.608412	2008
1975q2	1,656.4	5,333.2	114	114	9.613362	
1975q3	1,713.8	5,421.4	115	115	9.608553	
1975q4	1,765.9	5,494.4	116	116	9.587200	
1976q1	1,824.5	5,618.5	117	117	9.573246	2009
1976q2	1,856.9	5,661.0	118	118	9.571895	
1976q3	1,890.5	5,689.8	119	119	9.575157	
1976q4	1,938.4	5,732.5	120	120	9.584789	
1977q1	1,992.5	5,799.2	121	121	9.589106	2010
1977q2	2,060.2	5,913.0	122	122	9.598720	
1977q3	2,122.4	6,017.6	123	123	9.605452	
1977q4	2,168.7	6,018.2	124	124	9.611731	
1978q1	2,208.7	6,039.2	125	125	9.607861	2011
1978q2	2,336.6	6,274.0	126	126	9.615112	
1978q3	2,398.9	6,335.3	127	127	9.617211	
1978q4	2,482.2	6,420.3	128	128	9.628412	
1979q1	2,531.6	6,433.0	129	129	9.635020	2012
1979q2	2,595.9	6,440.8	130	130	9.639678	
1979q3	2,670.4	6,487.1	131	131	9.640875	
1979q4	2,730.7	6,503.9	132	132	9.641103	
1980q1	**2,796.5**	**6,524.9**	133	133	9.645830	2013
1980q2	2,799.9	6,392.6	134	134	9.648608	
1980q3	2,860.0	6,382.9	135	135	9.655949	
1980q4	2,993.5	6,501.2	136	136	9.665326	
1981q1	3,131.8	6,635.7	137	137	9.663001	2014
1981q2	3,167.3	6,587.3	138	138	9.674169	
1981q3	3,261.2	6,662.9	139	139	9.684635	
1981q4	3,283.5	6,585.1	140	140	9.689762	
1982q1	3,273.8	6,475.0	141	141	9.691364	2015
1982q2	3,331.3	6,510.2	142	142	9.700980	
1982q3	3,367.1	6,486.8	143	143	9.705890	
1982q4	3,407.8	6,493.1	144	144	9.709332	

OLS Regression

Annualized Real LN GPD Q

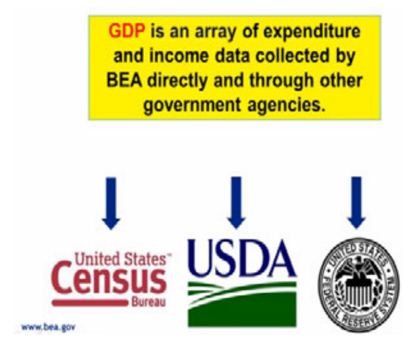
2.81%

Regression Statistics	
Multiple R	0.987417266
R Square	0.974992857
Adjusted F	0.974817982
Standard I	0.046957988
Observatic	145

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regressio	1	12.29397577	12.29397577	5575.3662	1.9522E-116
Residual	143	0.315322521	0.002205053		
Total	144	12.60929829			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.788180644	0.007839813	1120.968099	6.83E-284	8.772683746	8.803677542	8.772683746	8.803677542
X Variable	**0.006956569**	9.31662E-05	74.66837497	1.95E-116	0.006772409	0.00714073	0.006772409	0.00714073



Note July 31, 2013, 14th Comprehensive Significant Revision:
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

1983q1	3,480.3	6,578.2	**145**
1983q2	3,583.8	6,728.3	**146**
1983q3	3,692.3	6,860.0	**147**
1983q4	3,796.1	7,001.5	**148**
1984q1	3,912.8	7,140.6	**149**
1984q2	4,015.0	7,266.0	**150**
1984q3	4,087.4	7,337.5	**151**
1984q4	4,147.6	7,396.0	**152**
1985q1	4,237.0	7,469.5	**153**
1985q2	4,302.3	7,537.9	**154**
1985q3	4,394.6	7,655.2	**155**
1985q4	4,453.1	7,712.6	**156**
1986q1	4,516.3	7,784.1	**157**
1986q2	4,555.2	7,819.8	**158**
1986q3	4,619.6	7,898.6	**159**
1986q4	4,669.4	7,939.5	**160**
1987q1	4,736.2	7,995.0	**161**
1987q2	4,821.5	8,084.7	**162**
1987q3	4,900.5	8,158.0	**163**
1987q4	5,022.7	8,292.7	**164**
1988q1	5,090.6	8,339.3	**165**
1988q2	5,207.7	8,449.5	**166**
1988q3	5,299.5	8,498.3	**167**
1988q4	5,412.7	8,610.9	**168**
1989q1	5,527.4	8,697.7	**169**
1989q2	5,628.4	8,766.1	**170**
1989q3	5,711.6	8,831.5	**171**
1989q4	5,763.4	8,850.2	**172**
1990q1	5,890.8	8,947.1	**173**
1990q2	5,974.7	8,981.7	**174**
1990q3	6,029.5	8,983.9	**175**
1990q4	6,023.3	8,907.4	**176**
1991q1	6,054.9	8,865.6	**177**
1991q2	6,143.6	8,934.4	**178**
1991q3	6,218.4	8,977.3	**179**
1991q4	6,279.3	9,016.4	**180**
1992q1	6,380.8	9,123.0	**181**
1992q2	6,492.3	9,223.5	**182**
1992q3	6,586.5	9,313.2	**183**
1992q4	6,697.6	9,406.5	**184**
1993q1	6,748.2	9,424.1	**185**
1993q2	6,829.6	9,480.1	**186**
1993q3	6,904.2	9,526.3	**187**
1993q4	7,032.8	9,653.5	**188**
1994q1	7,136.3	9,748.2	**189**
1994q2	7,269.8	9,881.4	**190**
1994q3	7,352.3	9,939.7	**191**
1994q4	7,476.7	10,052.5	**192**
1995q1	7,545.3	10,086.9	**193**
1995q2	7,604.9	10,122.1	**194**
1995q3	7,706.5	10,208.8	**195**
1995q4	7,799.5	10,281.2	**196**
1996q1	7,893.1	10,348.7	**197**
1996q2	8,061.5	10,529.4	**198**
1996q3	8,159.0	10,626.8	**199**
1996q4	8,287.1	10,739.1	**200**
1997q1	8,402.1	10,820.9	**201**
1997q2	8,551.9	10,984.2	**202**
1997q3	8,691.8	11,124.0	**203**
1997q4	8,788.3	11,210.3	**204**
1998q1	8,889.7	11,321.2	**205**
1998q2	8,994.7	11,431.0	**206**
1998q3	9,146.5	11,580.6	**207**
1998q4	9,325.7	11,770.7	**208**
1999q1	9,447.1	11,864.7	**209**
1999q2	9,557.0	11,962.5	**210**
1999q3	9,712.3	12,113.1	**211**
1999q4	9,926.1	12,323.3	**212**
2000q1	10,031.0	12,359.1	**213**
2000q2	10,278.3	12,592.5	**214**
2000q3	10,357.4	12,607.7	**215**
2000q4	10,472.3	12,679.3	**216**
2001q1	10,508.1	12,643.3	**217**
2001q2	10,638.4	12,710.3	**218**
2001q3	10,639.5	12,670.1	**219**
2001q4	10,701.3	12,705.3	**220**
2002q1	10,834.4	12,822.3	**221**
2002q2	10,934.8	12,893.0	**222**
2002q3	11,037.1	12,955.8	**223**
2002q4	11,103.8	12,964.0	**224**
2003q1	11,230.1	13,031.2	**225**
2003q2	11,370.7	13,152.1	**226**
2003q3	11,625.1	13,372.4	**227**
2003q4	11,816.8	13,528.7	**228**
2004q1	11,988.4	13,606.5	**229**
2004q2	12,181.4	13,706.2	**230**
2004q3	12,367.7	13,830.8	**231**
2004q4	12,562.2	13,950.4	**232**
2005q1	12,813.7	14,099.1	**233**
2005q2	12,974.1	14,172.7	**234**
2005q3	13,205.4	14,291.8	**235**
2005q4	13,381.6	14,373.4	**236**
2006q1	13,648.9	14,546.1	**237**
2006q2	13,799.8	14,589.6	**238**
2006q3	13,908.5	14,602.6	**239**
2006q4	14,066.4	14,716.9	**240**
2007q1	14,233.2	14,726.0	**241**
2007q2	14,422.3	14,838.7	**242**
2007q3	14,569.7	14,938.5	**243**
2007q4	14,685.3	14,991.8	**244**
2008q1	14,668.4	14,889.5	**245**
2008q2	14,813.0	14,963.4	**246**
2008q3	14,843.0	14,891.6	**247**
2008q4	14,549.9	14,577.0	**248**
2009q1	14,383.9	14,375.0	**249**
2009q2	14,340.4	14,355.6	**250**
2009q3	14,384.1	14,402.5	**251**
2009q4	14,566.5	14,541.9	**252**
2010q1	14,681.1	14,604.8	**253**
2010q2	14,888.6	14,745.9	**254**
2010q3	15,057.7	14,845.5	**255**
2010q4	15,230.2	14,939.0	**256**
2011q1	15,238.4	14,881.3	**257**
2011q2	15,460.9	14,989.6	**258**
2011q3	15,587.1	15,021.1	**259**
2011q4	15,785.3	15,190.3	**260**
2012q1	15,973.9	15,291.0	**261**
2012q2	16,121.9	15,362.4	**262**
2012q3	16,227.9	15,380.8	**263**
2012q4	16,297.3	15,384.3	**264**
2013q1	16,440.7	15,457.2	**265**
2013q2	16,526.8	15,500.2	**266**
2013q3	16,727.5	15,614.4	**267**
2013q4	16,957.6	15,761.5	**268**
2014q1	16,984.3	15,724.9	**269**
2014q2	17,270.0	15,901.5	**270**
2014q3	17,522.1	16,068.8	**271**
2014q4	17,615.9	16,151.4	**272**
2015q1	17,649.3	16,177.3	**273**
2015q2	17,913.7	16,333.6	**274**
2015q3	18,060.2	16,414.0	**275**
2015q4	18,164.8	16,470.6	**276**
2016q1	18,221.1	16,492.7	**277**

145	9.710673	**2016**

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 206

Cost of Long-Term Debt

Exhibits in Support
Of Opening Testimony

August 11, 2016

Staff Exhibit 206 is Confidential and

Is subject to Protective Order No.16-141.

(Provided in electronic format)

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

VL Gas and Water Industry Profiles

Exhibits in Support
of Opening Testimony

August 11, 2016

Stocks in *Value Line's* Natural Gas Utility Industry have performed nicely thus far in 2016. (Some were even trading at record-high price levels at the time of this writing.) We believe one factor is expectations of generally decent earnings in 2016. Too, during this period of greater financial market uncertainty (caused by concerns over such matters as persistently low oil prices and China's decelerating economy) the equities in our category appear more enticing than those of other sectors. That's largely because they offer well-covered, generous amounts of dividend income, which provide a measure of much-needed stability. What's more, there are some selections here that are favorably ranked for Timeliness, not a common occurrence since their historical price movements have tended to be steady.

Natural Gas Pricing

Natural gas prices have hovered at relatively low levels for some time. One reason for that is a supply glut created, in part, by fracking activities in North America. (Hydraulic fracturing, a controversial procedure, involves the injection of fluid into rock formations at high pressure in order to free up natural resources.) Warmer-than-usual temperatures during the important winter season are not helping matters, either, because they have held back demand. At this juncture, it seems that natural gas prices will remain under pressure.

Although the low gas pricing bodes ill for the operating performance of companies that produce this commodity, regulated utility units generally benefit. That's partially because this scenario tends to lead to decreased prices for customers, which might well decrease bad-debt expense. Moreover, there is a heightened possibility that homeowners will switch from alternative fuel sources, such as oil or propane, to natural gas. (At present, it's estimated that more than 50% of all households within the United States use natural gas.)

Rate Cases

Rate filings are a very important factor for natural gas utilities. Federal authorities establish wholesale service tariffs, and state regulators determine retail distribution rates. Adequate returns on common equity are necessary to keep these businesses viable. Higher rates are sought to pay for the cost of expansion, storm damage, and/or to cover the expenses of maintaining reliable service. In order to promote healthy relationships with customers and regulators, managements endeavor to keep operating and service costs as low as possible. At times, however, political pressure can compel authorities to limit rates of return, to the detriment of utility companies. But for the most part, regulators desire to strike an equitable balance between the interests of shareholders and customers. When the regulatory environment is relatively quiet, utilities may place greater emphasis on cost-reduction measures and nonregulated businesses (discussed below).

Nonregulated Activities

Some of the companies in our category have devoted considerable resources to the nonregulated arena (which includes pipelines and energy marketing & trading) and it appears that trend will continue in the coming years. Indeed, these businesses provide opportunities for utilities to widen their revenue streams. And the fact that nonregulated segments can provide upside to earnings per share is notable, given that the return on equity is set by the regulatory state commissions (typically in the 10%-12% range) on the regulated divisions.

INDUSTRY TIMELINESS: 18 (of 97)

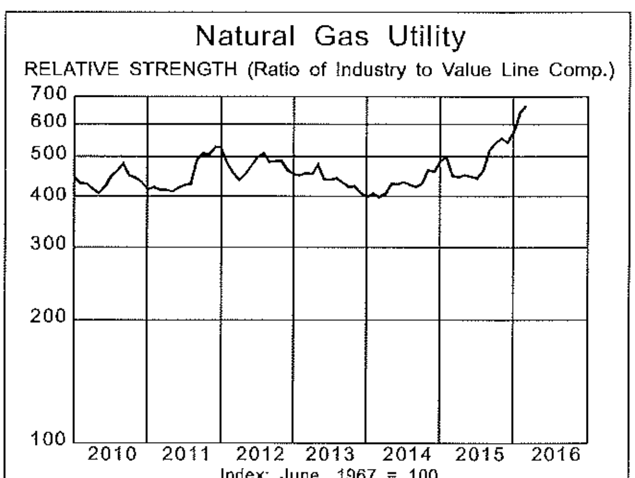
Attractive Dividends

The main feature of utility equities is their dividend income, which is well covered by corporate profits. (It's important to mention that the Financial Strength ratings for the 12 companies in our universe are no lower than B+.) At the time of this report, the average yield for the group was approximately 3.0%, significantly higher than the *Value Line* median of 2.5%. Standouts include *Southwest Gas, Northwest Natural Gas, Laclede Group, AGL Resources,* and *South Jersey Industries.* When the financial markets exhibit heightened volatility, which appears to be more common these days, solid dividend yields tend to act as an anchor, so to speak.

Conclusion

Stocks within the Natural Gas Utility Industry ought to draw the attention of income-hungry investors with a conservative orientation, given that a number of these issues are ranked favorably for Safety and boast high grades for Price Stability. Momentum accounts (i.e., those focused on short-term investment performance) should find something to like here, as well. It is important to mention that companies possessing larger nonregulated operations might offer a higher potential for returns, but profits could be more volatile than for companies with a greater emphasis on the more stable utility segment. As always, our readers are advised to carefully examine the following reports before making a commitment.

Frederick L. Harris, III



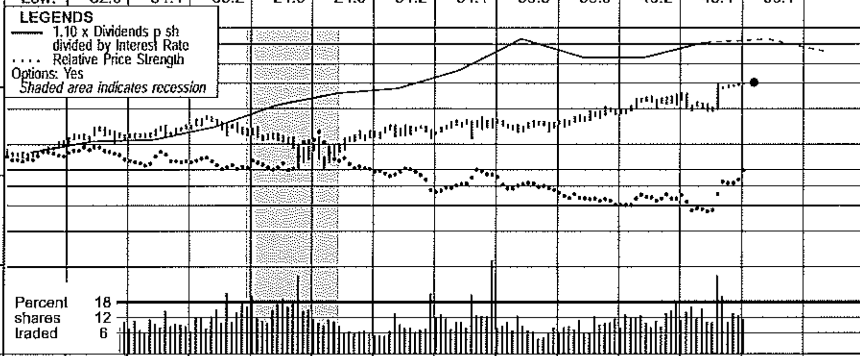
AGL RESOURCES NYSE-GAS

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
64.61	20.6	(Trailing: 21.9 Median: 14.0)	1.22	3.3%	VALUE LINE

TIMELINESS – Suspended 9/4/15
SAFETY 1 Raised 9/9/11
TECHNICAL – Suspended 9/4/15
BETA .60 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9	49.3	56.7	64.0	65.0
Low:	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6	38.9	45.2	46.4	63.1

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+15%)	7%
Low	65	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	2	5	0	1
to Sell	1	2	0	1	3	1	0	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	204	193	224
to Sell	205	197	209
Hld's(000)	77042	75486	76517

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.2	-10.4
3 yr.	71.4	20.6
5 yr.	114.1	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	19.97	33.28	38.83	45.01	32.74	*35.25*	*37.80*	Revenues per sh A	*44.00*
2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.06	5.82	6.15	7.87	6.23	*6.85*	*7.40*	"Cash Flow" per sh	*8.80*
1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	2.31	2.64	4.71	2.94	*3.30*	*3.60*	Earnings per sh A B	*4.65*
1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	1.90	1.74	1.88	1.96	2.04	*2.12*	*2.16*	Div'ds Decl'd per sh CF■	*2.40*
2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.65	6.64	6.30	6.43	8.53	*7.40*	*7.30*	Cap'l Spending per sh	*7.20*
11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.33	28.96	30.54	31.63	32.64	*33.35*	*35.05*	Book Value per sh D	*40.15*
54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.10	117.86	118.89	119.65	120.38	*122.00*	*123.00*	Common Shs Outst'g E	*125.00*
13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	18.8	17.2	16.7	10.9	18.5	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	1.18	1.09	.94	.57	.95	*Value Line*		Relative P/E Ratio	*.95*
6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	4.4%	4.3%	3.8%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*
						2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	3922.0	4617.0	5385.0	3941.0	*4300*	*4650*	Revenues ($mill) A	*5500*
						212.0	211.0	207.6	222.0	234.0	172.0	271.0	313.0	562.0	353.0	*400*	*445*	Net Profit ($mill)	*580*
						37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	36.4%	36.6%	37.6%	36.3%	*37.5%*	*38.0%*	Income Tax Rate	*38.0%*
						8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	6.9%	6.8%	10.4%	9.0%	*9.4%*	*9.5%*	Net Profit Margin	*10.5%*
						50.2%	50.2%	50.3%	52.6%	48.0%	51.8%	49.4%	51.2%	48.8%	45.5%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*47.0%*
						49.8%	49.8%	49.7%	47.4%	52.0%	48.2%	50.6%	48.8%	51.2%	54.5%	*52.0%*	*52.0%*	Common Equity Ratio	*53.0%*
						3231.0	3335.0	3327.0	3754.0	3486.0	6879.0	6740.0	7444.0	7386.0	7204.0	*7835*	*8270*	Total Capital ($mill)	*9605*
						3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	8347.0	8781.0	9090.0	9791.0	*10475*	*11105*	Net Plant ($mill)	*13225*
						8.0%	7.7%	7.4%	6.9%	7.6%	3.1%	5.4%	5.4%	8.8%	6.1%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
						13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	7.9%	8.6%	14.9%	9.0%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.5%*
						13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	7.9%	8.6%	14.9%	9.0%	*10.0%*	*10.5%*	Return on Com Equity	*11.5%*
						6.3%	5.3%	5.1%	5.3%	5.6%	.7%	2.0%	2.5%	8.7%	2.8%	*3.5%*	*4.0%*	Retained to Com Eq	*5.5%*
						52%	58%	60%	57%	57%	86%	75%	71%	41%	69%	*64%*	*60%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $4830 mill. Due in 5 Yrs $2764 mill.
LT Debt $3275 mill. LT Interest $181 mill.
(Total interest coverage: 4.7x)

Leases, Uncapitalized Annual rentals $33 mill.
Pension Assets-12/15 $847 mill. Oblig. $1067 mill.

Pfd Stock None

Common Stock 120,384,325 shs.
as of 2/5/15
MARKET CAP: $7.8 billion (Large Cap)

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	105	39	27
Other	2628	2851	2088
Current Assets	2733	2890	2115
Accts Payable	432	312	673
Debt Due	1842	2152	1555
Other	848	755	772
Current Liab.	3122	3219	3000
Fix. Chg. Cov.	373%	611%	465%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	4.5%	4.0%	*2.0%*
"Cash Flow"	6.5%	6.5%	*4.5%*
Earnings	4.0%	3.5%	*5.0%*
Dividends	5.0%	2.5%	*3.5%*
Book Value	6.0%	7.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1709	904	675	1329	4617
2014	2462	889	589	1445	5385
2015	1721	674	584	962	3941
2016	*1600*	*800*	*650*	*1250*	*4300*
2017	*1700*	*900*	*700*	*1350*	*4650*

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1.31	.41	.24	.68	2.64
2014	2.81	.48	.19	1.24	4.71
2015	1.62	.35	.09	.89	2.94
2016	*1.75*	*.35*	*.15*	*1.05*	*3.30*
2017	*1.80*	*.40*	*.20*	*1.20*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.36	.46	.46	.46	1.74
2013	.47	.47	.47	.47	1.88
2014	.49	.49	.49	.49	1.96
2015	.51	.51	.51	.51	2.04
2016	.53				

BUSINESS: AGL Resources Inc. is a public utility holding company. Distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Virginia Natural Gas, Florida City Gas and Elkton Gas. Acquired Nicor in 2011. The utilities have more than 4.5 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Illinois. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. BlackRock Inc. owns 8.0% of common stock; officers/directors, less than 1.0% (3/15 Proxy). President & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources ended 2015 on a sour note. Indeed, the company had earnings per share of $0.89, which were hurt by warmer-than-usual temperatures, but that was partially offset by decent results in the wholesale division. Too, some merger-related costs and a small goodwill impairment dragged on fourth-quarter results. Still, the company remains in decent shape for 2016, as cooler temperatures have occurred across the utility coverage areas in the first quarter.

The deal to be acquired by Southern Co. continues to advance. The company has jointly filed for approval in all required jurisdictions, and has received shareholder approval. It passed through the Hart-Scott-Rodino waiting period. This deal is expected to close in the second half of 2016, and should create the nation's second-largest public utility. As the stock price is near our long-term Target Price Range, we think the $66 a share in cash remains a decent deal for AGL shareholders.

The company should have better results in 2016. Indeed, we assume normal temperatures, and the company has been able to achieve better infrastructure replacement recovery rates. These augur well for earnings growth. In addition, the pipeline investments remain on track. These have higher allowable returns and should notably enhance throughput. This ought to boost margins considerably once completed. All told, we think the company will earn $3.30 a share in 2016, and $3.60 a share in 2017.

The dividend was recently raised 4%, to $0.53 a share quarterly. This remains well covered by earnings and should continue to be paid as long as the company remains public. Still, this yield is much lower than for others in the industry.

Shares of AGL Resources have been suspended for Timeliness pending the merger. The stock holds little appreciation potential if the deal is completed, but the share price may fall sharply should the deal fall apart over regulatory concerns, though we think that possibility is less likely. Continuing to hold the shares for the dividend has a bit of appeal, but most long-term holders should sell their shares, given the slim discount to the bid price.

John E. Seibert III *March 4, 2016*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. May not add up due to rounding. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13; '14, ($0.67). Next earnings report due late April. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2015: $1,922 million, $15.97/share.(E) In millions. (F) Excluding special dividends from the Nicor merger.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	60

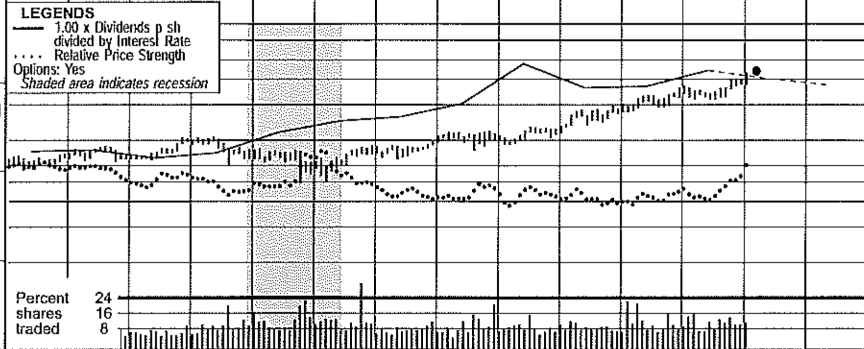
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	70.45	P/E RATIO	21.7 (Trailing: 22.5; Median: 15.0)	RELATIVE P/E RATIO	1.28	DIV'D YLD	2.5%	VALUE LINE

TIMELINESS **2** Raised 10/30/15
SAFETY **1** Raised 6/6/14
TECHNICAL **3** Raised 3/4/16
BETA .80 (1.00 = Market)

High:	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3	47.4	58.2	64.8	71.2
Low:	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4	34.9	44.2	50.8	60.0

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2019 | 2020 | 2021
120 – 100 – 80 – 64 – 48 – 32 – 24 – 20 – 16 – 12 – 8

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+30%)	9%
Low	70	(Nil)	3%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	6	1	0	0	0	2	7	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	157	136	130
to Sell	132	134	137
Hld's(000)	69286	68505	69743

Percent shares traded 24 – 16 – 8

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.1	-10.4
3 yr.	103.1	20.6
5 yr.	152.8	40.9

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	*32.70*	*33.45*	Revenues per sh A	*45.85*
4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	*5.95*	*6.15*	"Cash Flow" per sh	*7.35*
2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	*3.25*	*3.45*	Earnings per sh A B	*4.00*
1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	*1.68*	*1.80*	Div'ds Decl'd per sh C■	*2.15*
5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	*9.80*	*10.00*	Cap'l Spending per sh	*10.20*
20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	*31.35*	*32.50*	Book Value per sh	*36.65*
81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	*107.00*	*110.00*	Common Shs Outst'g D	*120.00*
13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.73	.84	.82	.83	.84	.90	1.01	.89	.85	.89	*Value Line*		Relative P/E Ratio	*1.25*
4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*
6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	3886.3	4940.9	4142.1	*3500*	*3680*	Revenues ($mill) A	*5500*
162.3	170.5	180.3	179.7	201.2	199.3	192.2	230.7	289.8	315.1	*350*	*380*	Net Profit ($mill)	*480*
37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	38.2%	39.2%	38.3%	*38.5%*	*38.5%*	Income Tax Rate	*40.0%*
2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	5.9%	5.9%	7.6%	*10.0%*	*10.3%*	Net Profit Margin	*8.7%*
57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	45.3%	48.8%	44.3%	43.5%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	54.7%	51.2%	55.7%	56.5%	*55.0%*	*55.0%*	Common Equity Ratio	*55.0%*
3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	4315.5	5036.1	5542.2	5650.2	*6100*	*6500*	Total Capital ($mill)	*8000*
3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	5475.6	6030.7	6725.9	7430.6	*8040*	*8500*	Net Plant ($mill)	*10200*
6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	6.1%	5.9%	6.4%	6.6%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	*10.5%*	*10.5%*	Return on Com Equity	*11.0%*
3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	2.8%	4.0%	4.7%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
63%	65%	65%	68%	62%	62%	65%	56%	50%	51%	*51%*	*52%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $3218.7 mill. Due in 5 Yrs $1157.9 mill.
LT Debt $2455.5 mill. LT Interest $145.0 mill.
(LT interest earned: 5.4x; total interest coverage: 5.4x)
Leases, Uncapitalized Annual rentals $16.5 mill.
Pfd Stock None
Pension Assets-9/15 $450.9 mill. Oblig. $508.6 mill.
Common Stock 102,106,896 shs. as of 1/29/16
MARKET CAP: $7.2 billion (Large Cap)

CURRENT POSITION ($MILL.)	2014	2015	12/31/15
Cash Assets	42.3	28.7	78.9
Other	733.5	602.3	784.4
Current Assets	775.8	631.0	863.3
Accts Payable	311.6	238.9	280.5
Debt Due	196.7	457.9	763.2
Other	402.4	458.0	471.4
Current Liab.	910.7	1154.8	1515.1
Fix. Chg. Cov.	637%	743%	730%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-2.0%	-6.5%	.5%
"Cash Flow"	5.0%	4.5%	5.0%
Earnings	5.5%	7.0%	6.0%
Dividends	2.0%	2.5%	6.5%
Book Value	5.0%	5.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	1034.2	1309.0	857.9	685.2	3886.3
2014	1255.1	1964.3	942.7	778.8	4940.9
2015	1258.8	1540.1	686.4	656.8	4142.1
2016	906.2	*1220*	*700*	*673.8*	*3500*
2017	*950*	*1300*	*730*	*700*	*3680*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	.85	1.23	.36	.08	2.50
2014	.95	1.38	.45	.23	2.96
2015	.96	1.35	.55	.23	3.09
2016	1.00	*1.42*	*.57*	*.26*	*3.25*
2017	*1.06*	*1.47*	*.62*	*.30*	*3.45*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.345	.345	.345	.35	1.39
2013	.35	.35	.35	.37	1.42
2014	.37	.37	.37	.39	1.50
2015	.39	.39	.39	.42	1.59
2016	.42				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to roughly three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2015: 66%, residential; 29%, commercial; 3%, industrial; and 2% other. The company has around 4,760 employees. Officers and directors own approximately 1.5% of common stock (12/15 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corporation got off to a respectable start in fiscal 2016 (concludes on September 30th). Specifically, first-quarter earnings per share advanced approximately 4.2%, to $1.00, compared to the same period the prior year. One contributor was the bread-and-butter natural gas distribution operation, which benefited from rate adjustments in the Mid-Tex, Mississippi, and West Texas divisions. Notably, through last December 31st, the company finished four regulatory proceedings resulting in a $13.3 million increase in annual operating income, and seven ratemaking initiatives were in progress seeking another $27.4 million of annual operating income. But results for this segment were constrained a bit by diminished consumption, given warmer-than-usual temperatures. Elsewhere, the regulated pipeline business was boosted by higher revenue from the Gas Reliability Infrastructure Program (GRIP) filing approved in fiscal 2015. A rise in operating expenses provided somewhat of an offset here, however.

We anticipate more of the same during the remaining nine months. Consequently, Atmos' bottom line stands to advance around 5%, to $3.25 a share, for the entire year. Assuming that operating margins expand further, fiscal 2017 share net might well grow at a similar percentage rate, to $3.45.

The stock has traded at record heights since our last report in December. It appears that stems partially from the Dallas-headquartered company's respectable first-quarter profits, and expectations of more glad tidings over the course of the fiscal year. Consequently, these shares possess a 2 (Above Average) rank for Timeliness.

There are other noteworthy characteristics here. The current dividend is decent, and our 2019-2021 projections show that additional, steady increases in the distribution will occur. The payout ratio during that period ought to be in the 50%-55% range, which is manageable. Moreover, the Safety rank resides at 1 (Highest), and the Price Stability rating is excellent (i.e., 95 out of 100). All told, the equity ought to draw the attention of a variety of investors.

Frederick L. Harris, III *March 4, 2016*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢. Next egs. rpt. due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	95

LACLEDE GROUP NYSE-LG

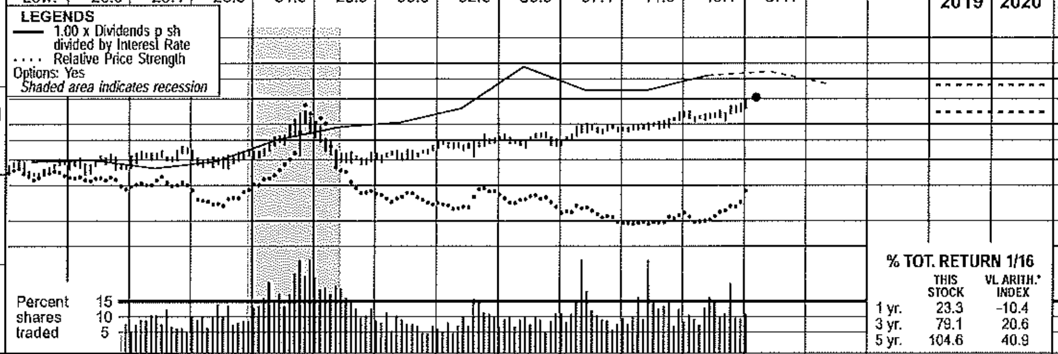
RECENT PRICE	65.18	P/E RATIO	19.2 (Trailing: 20.7 / Median: 14.0)	RELATIVE P/E RATIO	1.14	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS **3** Raised 10/16/15
SAFETY **2** Raised 6/20/03
TECHNICAL **3** Raised 3/4/16
BETA .70 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0	48.5	55.2	61.0	66.4
Low:	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5	37.4	44.0	49.1	57.1

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range
2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+15%)	7%
Low	55	(-15%)	Nil

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	6
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	116	115	102
to Sell	69	77	95
Hld's(000)	35230	35958	35808

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.3	-10.4
3 yr.	79.1	20.6
5 yr.	104.6	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	*37.50*	*42.20*	Revenues per sh A	*55.20*
2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	*6.40*	*6.75*	"Cash Flow" per sh	*7.50*
1.37	1.61	1.18	1.62	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	*3.40*	*3.60*	Earnings per sh A B	*4.20*
1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	*1.92*	*1.96*	Div'ds Decl'd per sh C ■	*2.20*
2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	*7.15*	*7.20*	Cap'l Spending per sh	*7.40*
14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	*38.10*	*39.65*	Book Value per sh D	*44.45*
18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	*44.00*	*45.00*	Common Shs Outst'g E	*48.00*
14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.84	*Value Line*		Relative P/E Ratio	*.95*
6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1017.0	1627.2	1976.4	*1650*	*1900*	Revenues ($mill) A	*2650*
50.5	49.8	57.6	64.3	54.0	63.8	62.6	52.8	84.6	136.9	*150*	*160*	Net Profit ($mill)	*200*
32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	29.6%	25.0%	27.6%	31.2%	*28.0%*	*28.0%*	Income Tax Rate	*30.0%*
2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.2%	5.2%	6.9%	*9.1%*	*8.5%*	Net Profit Margin	*7.5%*
49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.1%	46.6%	55.1%	53.0%	*54.5%*	*52.5%*	Long-Term Debt Ratio	*51.5%*
50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	63.9%	53.4%	44.9%	47.0%	*45.5%*	*47.5%*	Common Equity Ratio	*48.5%*
798.9	784.5	876.1	906.3	899.9	937.7	941.0	1959.0	3359.4	3345.1	*3420*	*3735*	Total Capital ($mill)	*4395*
763.8	793.8	823.2	855.9	884.1	928.7	1019.3	1776.6	2759.7	2941.2	*3090*	*3245*	Net Plant ($mill)	*3755*
8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	7.9%	3.3%	3.1%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	*9.0%*	*9.0%*	Return on Com Equity	*9.5%*
5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	1.0%	1.5%	3.7%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
59%	63%	56%	53%	64%	56%	59%	81%	73%	58%	*56%*	*54%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $2188.6 mill. Due in 5 Yrs $525.0 mill.
LT Debt $1851.5 mill. LT Interest $70.0 mill.
(Total interest coverage: 4.6x)

Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-9/15 $448.9 mill. Oblig. $652.3 mill.
Pfd Stock None
Common Stock 43,424,462 shs. as of 1/31/16

MARKET CAP: $2.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2014	2015	12/31/15
Cash Assets	16.1	13.8	4.6
Other	588.8	516.3	631.4
Current Assets	604.9	530.1	636.0
Accts Payable	176.7	146.5	159.5
Debt Due	287.1	418.0	337.1
Other	319.0	289.3	350.9
Current Liab.	782.8	853.8	847.5
Fix. Chg. Cov.	360%	365%	458%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-5.0%	-15.5%	6.5%
"Cash Flow"	4.0%	0.5%	9.5%
Earnings	3.0%	-1.0%	9.0%
Dividends	2.5%	3.0%	3.5%
Book Value	7.5%	8.0%	4.5%

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
	QUARTERLY REVENUES ($ mill.)A				
2013	307.0	397.6	165.3	147.1	1017.0
2014	468.6	694.5	241.8	222.3	1627.2
2015	619.6	877.4	275.2	204.2	1976.4
2016	399.4	*700*	*200*	*350.6*	*1650*
2017	*475*	*775*	*250*	*400*	*1900*

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
	EARNINGS PER SHARE A B F				
2013	1.14	1.34	.25	d.30	2.02
2014	1.09	1.59	.33	d.35	2.35
2015	1.09	2.18	.32	d.43	3.16
2016	1.08	*2.25*	*.35*	*d.28*	*3.40*
2017	*1.20*	*2.30*	*.35*	*d.25*	*3.60*

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
	QUARTERLY DIVIDENDS PAID C ■				
2012	.415	.415	.415	.415	1.66
2013	.425	.425	.425	.425	1.70
2014	.44	.44	.44	.44	1.76
2015	.46	.46	.46	.46	1.84
2016	.49				

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City. Has roughly 1.6 million customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2015: 2.7 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 2%; other, 8%. Has around 3,078 employees. Officers and directors own 3.2% of common shares (1/16 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group reported worse-than-expected fiscal first-quarter results (ended December 31, 2015). Indeed, earnings were hurt by much-warmer temperatures across the service region, though these were partially offset by a favorable movement in the Alagasco adjustment rate and an increase in the infrastructure system replacement surcharge for infrastructure upgrades. Too, the company benefited from 1% year-over-year customer growth. We think Laclede remains on track for earnings per share of $3.40 in 2016.

The company should do well in the years ahead. Results are likely to show the most improvement in the second half of the year, as costs will probably ease. Notably, the warmer winter weather allowed for system reliability checks. This development should lower overtime costs in the quarters ahead. Laclede stands to benefit from increases in system reliability and the replacement of older portions of the Missouri Gas pipeline system. This should allow share earnings to expand to $3.60 in 2017.

A new pipeline may be in the works for Laclede. The company expects to build a pipeline from western Illinois, allowing for cheaper natural gas to reach its Missouri customers. This project would have a total cost of between $170 million and $200 million. Though a deal has not been formalized, management expects to partner with established pipeline companies to build the diversion. Given that pipelines generally have higher allowable rates than utilities, and that natural gas transportation costs would be lower, we think the move will significantly boost share-net growth in the years ahead.

Shares of Laclede Group appear to be fully valued at the recent quotation. The share price has jumped and is now trading inside of our long-term Target Price Range. Meanwhile, the yield does not stand out when compared to others in the industry. Still, these shares maintain a solid and growing payout, which remains well covered by earnings. Though conservative income investors may find some appeal here, long-term accounts would be best served waiting until a more favorable purchasing opportunity arises.

John E. Seibert III *March 4, 2016*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '14: $383.8 mill., $8.85/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	80

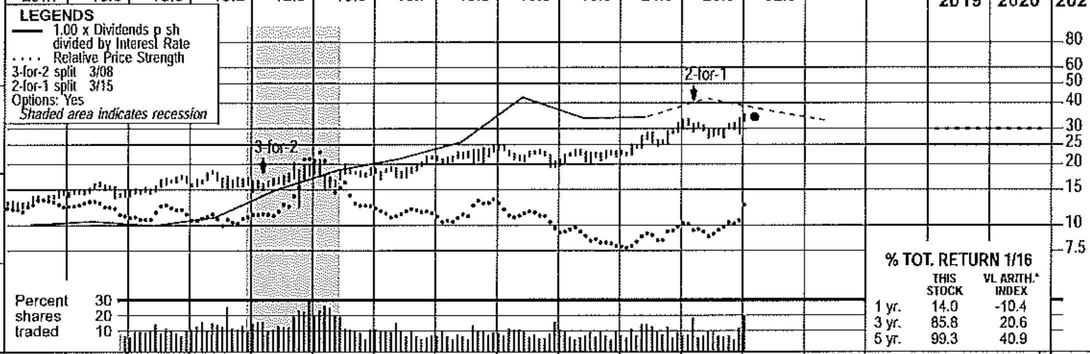
NEW JERSEY RES. NYSE-NJR

RECENT PRICE **34.29** | P/E RATIO **21.4** (Trailing: 20.1 Median: 16.0) | RELATIVE P/E RATIO **1.27** | DIV'D YLD **2.8%** | **VALUE LINE**

TIMELINESS **3** Lowered 10/31/14
SAFETY **1** Raised 9/15/06
TECHNICAL **2** Raised 3/4/16
BETA .80 (1.00 = Market)

High:	16.4	17.7	18.8	20.6	21.2	22.0	25.2	25.1	23.8	32.1	34.1	36.6			Target Price Range	
Low:	13.6	13.8	15.2	12.3	15.0	16.7	19.8	19.3	19.5	21.9	26.8	32.3			2019 | 2020 | 2021	

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/08
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(-15%)	*Nil*
Low	25	(-25%)	*-4%*

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	7	6	7
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	117	103	105
to Sell	96	113	103
Hld's(000)	51597	50230	49793

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.0	-10.4
3 yr.	85.8	20.6
5 yr.	99.3	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
14.71	25.61	22.06	31.14	30.44	38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	*30.30*	*35.30*	Revenues per sh A	*38.55*
1.00	1.06	1.07	1.19	1.25	1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	*2.50*	*2.35*	*2.60*	"Cash Flow" per sh	*2.70*
.60	.65	.70	.79	.85	.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	*1.60*	*1.80*	Earnings per sh B	*1.90*
.38	.39	.40	.41	.43	.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	*.96*	*.98*	Div'ds Decl'd per sh C■	*1.02*
.62	.55	.51	.57	.72	.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	1.65	*1.70*	*1.75*	Cap'l Spending per sh	*1.80*
4.14	4.40	4.35	5.13	5.62	5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	*13.60*	*14.45*	Book Value per sh D	*16.90*
79.17	79.99	83.00	81.70	83.22	82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	*85.00*	*85.00*	Common Shs Outst'g E	*85.00*
14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.91	*estimates*		Relative P/E Ratio	*.90*
4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%			Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1070.2 mill. Due in 5 Yrs $321.9 mill.
LT Debt $848.2 mill. LT Interest $25.4 mill.
Incl. $53.2 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/15 $256.4 mill. Oblig. $394.4 mill.
Pfd Stock None
Common Stock 85,923,516 shs. as of 2/1/16
MARKET CAP: $2.9 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	3198.1	3738.1	2734.0	*2575*	*3000*	Revenues ($mill) A	*3280*
78.5	65.3	113.9	101.0	101.8	106.5	112.4	113.7	176.9	151.5	*135*	*155*	Net Profit ($mill)	*165*
38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	7.1%	25.4%	30.2%	*32.0%*	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	5.0%	3.6%	4.7%	5.5%	*5.3%*	*5.2%*	Net Profit Margin	*5.0%*
34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	36.6%	38.2%	43.2%	*43.5%*	*43.5%*	Long-Term Debt Ratio	*41.0%*
65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	63.4%	61.8%	56.8%	*56.5%*	*56.5%*	Common Equity Ratio	*59.0%*
954.0	1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	1400.3	1564.4	1950.6	*2060*	*2215*	Total Capital ($mill)	*2435*
934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	1643.1	1884.1	2128.3	*2170*	*2215*	Net Plant ($mill)	*2350*
9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	9.2%	9.0%	12.1%	*8.5%*	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	*13.7%*	*12.0%*	*12.5%*	Return on Shr. Equity	*11.5%*
12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.7%	*12.0%*	*12.5%*	Return on Com Equity	*11.5%*
6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	6.2%	5.2%	11.0%	6.8%	*5.0%*	*6.0%*	Retained to Com Eq	*5.0%*
50%	64%	40%	50%	52%	55%	55%	59%	40%	51%	*60%*	*54%*	All Div'ds to Net Prof	*53%*

CURRENT POSITION ($MILL.)

	2014	2015	12/31/15
Cash Assets	2.2	4.9	1.7
Other	680.5	539.6	539.6
Current Assets	682.7	544.5	587.2
Accts Payable	330.3	273.2	235.7
Debt Due	335.5	77.5	222.0
Other	125.3	85.4	117.2
Current Liab.	791.1	436.1	574.9
Fix. Chg. Cov.	1007%	750%	750%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	3.0%	-.5%	*NMF*
"Cash Flow"	6.5%	7.0%	*2.0%*
Earnings	7.5%	7.5%	*1.5%*
Dividends	7.0%	7.5%	*3.0%*
Book Value	8.0%	5.5%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	736.0	960.9	767.5	733.7	3198.1
2014	878.4	1579.6	688.3	591.9	3738.2
2015	824.1	1013.1	458.5	438.3	2734.0
2016	444.3	*1085*	*525*	*520.7*	*2575*
2017	*550*	*1190*	*635*	*625*	*3000*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	.43	.82	.12	d.01	1.37
2014	.47	1.81	.05	d.23	2.10
2015	.65	1.16	.03	d.06	1.78
2016	.58	*1.13*	*.01*	*d.12*	*1.60*
2017	*.63*	*1.18*	*.06*	*d.07*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.19	.19	.19	.40	.97
2013	--	.20	.20	.20	.60
2014	.21	.21	.21	.23	.86
2015	.23	.23	.23	.24	.93
2016	.24				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 512,300 customers at 9/30/15 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2015 volume: 341 bill. cu. ft. (14% interruptible, 21% residential and commercial and electric utility, 65% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2015 dep. rate: 2.5%. Has 991 empls. Off./dir. own about 1.4% of common (12/15 Proxy). Chrmn., CEO & Pres.: Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources is off to a difficult start this fiscal year (began October 1st). Indeed, revenues fell roughly 46% on a year-over-year basis, due to sharply lower natural gas distribution and energy service volumes. However, this can be largely viewed as a technicality owing to declining natural gas prices as commodities continue to slip. NJR's overall number of customer meters and system throughput continue to climb. In fact, the NJNG unit added 2,046 new customer accounts during the first quarter. On the profitability front, total operating expenses rose 710 basis points as a percentage of the top line. All told, the first-quarter bottom line fell about 11%, to $0.58 a share. This was $0.04 below our earlier call, and has prompted us to trim a nickel off our 2016 earnings estimate, to $1.60 a share. The remainder of the year will likely reflect the depressed commodity prices owing to the glut of supply on the markets as well as the warmer-than-normal weather patterns.

Meanwhile, we have introduced our 2017 top- and bottom-line estimates at $3.0 billion and $1.80 a share, respectively. NJR continues to focus on expanding its network through growth projects, boosting system reliability, integrity, and capacity. The New Jersey based utility provider is also raising its exposure to green initiatives through solar and wind projects. At the same time, the NJNG division is anticipating adding 24,000 to 28,000 new customers over the next three years. These efforts should help to turn things around for NJR.

The financial position deteriorated a bit during the first quarter. Cash reserves declined more than 65% over that time frame, to about $1.7 billion, which is relatively low compared to NJR's historical levels. Meanwhile, the long-term debt load has remained pretty stable versus 2015's figure, but is near the higher end of the company's spectrum when viewed against the past five or 10 years.

At this juncture, we think most investor funds could be better utilized elsewhere. Shares of NJR are trading somewhat above our Target Price Range, thus suggesting a lack of capital appreciation potential for the pull to 2019-2021.

Bryan J. Fong *March 4, 2016*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late April.
(C) Dividends historically paid in early Jan., April, July, and October. 1Q '13 div'd paid in 4Q '12. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2015: $410.2 million, $4.82/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	60

NISOURCE INC. NYSE-NI

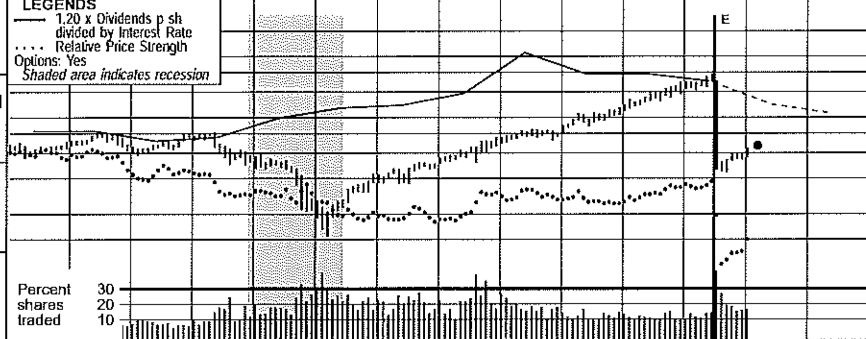
RECENT PRICE 21.80 | P/E RATIO 25.6 (Trailing: 34.6 Median: 19.0) | RELATIVE P/E RATIO 1.51 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS – Suspended 6/5/15
SAFETY 3 New 9/4/15
TECHNICAL – Suspended 6/5/15
BETA NMF (1.00 = Market)

High:	25.5	24.8	25.4	19.8	15.8	18.0	24.0	26.2	33.5	44.9	49.2	22.1
Low:	20.4	19.5	17.5	10.4	7.8	14.1	17.7	22.3	24.8	32.1	16.0	19.0

Target Price Range 2019 | 2020 | 2021

LEGENDS
—— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+15%)	6%
Low	18	(-15%)	-1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	1	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	198	236	184
to Sell	195	182	252
Hld's(000)	258960	262826	264800

Percent shares traded 30 20 10

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-50.0	-10.4
3 yr.	-15.8	20.6
5 yr.	31.1	40.9

NiSource acquired Columbia Energy on November 1, 2000, paying approximately $6 billion in cash and stock. Columbia shareholders who chose cash received $70 a share, plus a security with a face value of $2.60. Those who chose stock received $74 a share in NiSource common stock. Shareholders' selections were prorated to reflect a 30% stock portion of the transaction. In 2003, NiSource sold Columbia's exploration and production business.

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	*15.65*	*16.30*	Revenues per sh	*18.45*
3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	*2.70*	*2.90*	"Cash Flow" per sh	*3.25*
1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	*1.00*	*1.10*	Earnings per sh A	*1.40*
.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	*.64*	*.68*	Div'd Decl'd per sh B ■	*.80*
2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	*4.40*	*4.60*	Cap'l Spending per sh	*5.55*
18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	*12.65*	*13.05*	Book Value per sh C	*14.20*
273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	*320.00*	*322.00*	Common Shs Outst'g D	*325.00*
19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.89	*Value Line*		Relative P/E Ratio	*1.00*
4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*
7490.0	7939.8	8874.2	6649.4	6422.0	6019.1	5061.2	5657.3	6470.6	4651.8	*5000*	*5250*	Revenues ($mill)	*6000*
314.6	312.0	369.8	231.2	294.6	303.8	410.6	490.9	530.7	198.6	*320*	*355*	Net Profit ($mill)	*600*
35.2%	35.6%	33.4%	41.8%	32.4%	35.0%	34.4%	34.8%	36.9%	41.6%	*37.0%*	*37.0%*	Income Tax Rate	*37.5%*
4.2%	6.6%	--	--	--	--	--	--	2.9%	2.9%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.7%	52.4%	55.7%	55.1%	54.7%	55.6%	55.1%	56.3%	56.9%	60.7%	*60.0%*	*60.0%*	Long-Term Debt Ratio	*60.0%*
49.3%	47.6%	44.3%	44.9%	45.3%	44.4%	44.9%	43.7%	43.1%	39.3%	*40.0%*	*40.0%*	Common Equity Ratio	*40.0%*
10160	10671	10673	10819	10859	11264	12373	13480	14331	9792.0	*10170*	*10510*	Total Capital ($mill)	*11505*
9694.5	10032	10276	10592	11097	11800	12916	14365	16017	12112	*12475*	*12850*	Net Plant ($mill)	*14040*
4.8%	4.6%	5.2%	4.0%	4.5%	4.4%	5.0%	5.2%	5.3%	4.0%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
6.3%	6.1%	7.8%	4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	*8.0%*	*8.5%*	Return on Shr. Equity	*10.0%*
6.3%	6.1%	7.8%	4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	*8.0%*	*8.5%*	Return on Com Equity	*10.0%*
1.2%	1.2%	2.5%	NMF	.8%	.9%	2.5%	3.1%	3.4%	NMF	*3.0%*	*3.0%*	Retained to Com Eq	*4.0%*
80%	81%	68%	110%	87%	85%	67%	62%	61%	NMF	*64%*	*62%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $6949.6 mill. **Due in 5 Yrs** $2598.8 mill.
LT Debt $5948.5 mill. **LT Interest** $450 mill.
(Interest cov. earned: 2.1x) (64% of Cap'l)

Leases, Uncapitalized Annual rentals $18.4 mill.
Pension Assets-12/14 $1.75 bill. **Oblig.** $2.21 bill.

Pfd Stock None

Common Stock 319,741,768 shs.
as of 2/10/16

MARKET CAP: $7.0 billion (Large Cap)

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	26.8	25.4	15.5
Other	2132.4	2441.1	1561.7
Current Assets	2159.2	2466.5	1577.2
Accts Payable	619.0	670.6	433.4
Debt Due	1240.8	1843.5	1001.1
Other	1318.6	1440.8	1223.0
Current Liab.	3178.4	3954.9	2657.5
Fix. Chg. Cov.	267%	274%	210%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-3.5%	-7.5%	.5%
"Cash Flow"	-1.0%	-.5%	1.0%
Earnings	-1.0%	3.5%	1.5%
Dividends	-.5%	.5%	-2.5%
Book Value	-.5%	-1.0%	-2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1782.2	1201.5	1076.8	1596.8	5657.3
2014	2320.5	1335.1	1123.9	1691.1	6470.6
2015	1852.2	884.6	817.2	1097.8	4651.8
2016	*1700*	*900*	*900*	*1500*	*5000*
2017	*1750*	*950*	*950*	*1600*	*5250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.69	.23	.16	.49	1.57
2014	.85	.25	.10	.49	1.67
2015	.61	d.23	.05	.20	.63
2016	*.50*	*.10*	*.05*	*.35*	*1.00*
2017	*.55*	*.10*	*.05*	*.40*	*1.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.23	.24	.24	.94
2013	.24	.24	.25	.25	.98
2014	.25	.25	.26	.26	1.02
2015	.26	.26	.155	.155	.83
2016	.155				

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 461,000 electric in Indiana, 3.4 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, Massachusetts through its Columbia subsidiaries. Revenue breakdown, 2015: electrical, 34%; gas, 66%; other, less than 1%. Generating sources, 2015: coal, 77.3%; purchased & other, 22.7%. 2015 reported depreciation rates: 3.0% electric, 1.8% gas. Has 7,596 employees. Chairman: Ian M. Rolland. President & Chief Executive Officer: Robert C. Skaggs, Jr. Incorporated: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource reported mixed fourth-quarter results. Indeed, warmer winter weather and the spinoff of Columbia Pipeline Group Gas caused earnings per share to fall to $0.20. Still, these factors were partially offset by better rates across the service area. All told, 2015 was a transformative year for NiSource.

Infrastructure spending should drive growth in 2016. Indeed, the company invested $1.37 billion in infrastructure replacement spending in 2015, and appears likely to execute around $1.4 billion in such outlays over the course of 2016. This should allow for better system reliability and lower service costs. The upgrades at NIPSCOs coal plants should bring NiSource under compliance with environmental standards, and the finished deployment of automated meter reading should allow for lower service costs. Too, the company reached a deal for higher rates at its NIPSCO segment, which will increase by around 5.4%, including higher fixed rates. This plan still requires regulatory approval, and would take effect in the second half of the year. All told, we project the company will earn $1.00 a share in 2016, and $1.10 in 2017.

The balance sheet remains somewhat leveraged. Though the company has net liquidity of around $1.2 billion, and no significant debt due until 2017, debt makes up a significant portion of total capitalization. In addition, the average interest rate is around 5.88%, which is somewhat higher than for competitors. Still, management will likely look to pay down the total debt load somewhat over the coming years, and equiy should build.

The payout has some appeal. It's well covered by earnings and should continue to grow around 4%-6% annually over the coming years. Still, a recent run-up in the share price has caused the yield to stand out less.

Shares of NiSource do not hold much appreciation potential at the recent quotation. Indeed, the shares are trading in the middle of our long-term Target Price Range, thanks to a run-up since our December report. Still, these shares offer a decent yield, as well as solid dividend growth prospects that may well appeal to certain income-oriented investors.

John E. Seibert III *March 4, 2016*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4¢); gains (losses) on disc. ops.: '05, 10¢; '06, (11¢); '07, 3¢; '08, ($1.14); '15, (30¢). Next egs. report due late April. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '15: $1944.4 million, $6.08/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)
(F) Suspended due to spinoff of CPGX

Company's Financial Strength	B+
Stock's Price Stability	NMF
Price Growth Persistence	NMF
Earnings Predictability	NMF

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 52.35 | P/E RATIO 24.0 (Trailing: 26.7 Median: 18.0) | RELATIVE P/E RATIO 1.42 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Raised 12/4/15
SAFETY 1 Raised 3/18/05
TECHNICAL 2 Raised 3/4/16
BETA .65 (1.00 = Market)

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	50	(-5%)	3%

Insider Decisions

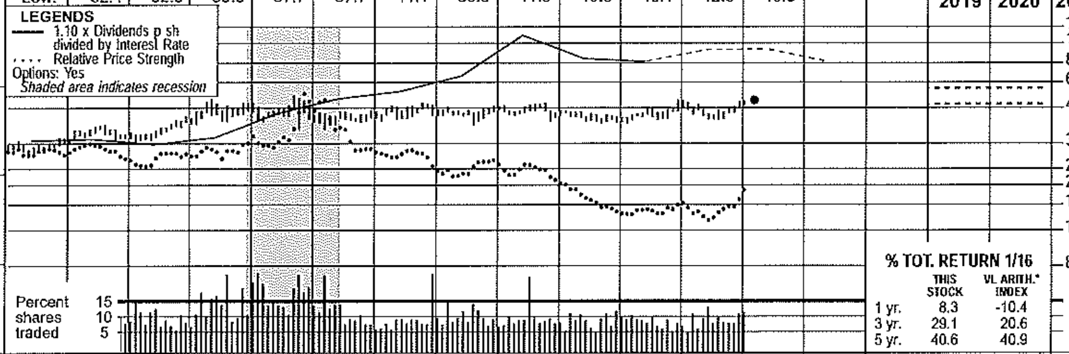
	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	3	0
to Sell	1	0	1	0	0	0	0	4	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	93	80	69
to Sell	55	76	74
Hld's(000)	17253	16711	16793

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8	46.6	52.6	52.3	53.5
Low:	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0	40.0	40.1	42.0	49.3

Target Price Range 2019 | 2020 | 2021



% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.3	-10.4
3 yr.	29.1	20.6
5 yr.	40.6	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	*26.39*	*28.10*	*29.30*	Revenues per sh	*31.80*
3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	*4.90*	*5.00*	*5.30*	"Cash Flow" per sh	*6.35*
1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	*2.20*	*2.35*	Earnings per sh A	*3.15*
1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	*1.87*	*1.91*	Div'ds Decl'd per sh B■	*2.05*
3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	*5.80*	*6.15*	*6.45*	Cap'l Spending per sh	*6.80*
17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	*28.47*	*29.85*	*30.95*	Book Value per sh D	*35.40*
25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	*27.42*	*27.75*	*28.00*	Common Shs Outst'g C	*28.00*
12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.20	*Value Line*		Relative P/E Ratio	*1.05*
5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $846.9 mill. Due in 5 Yrs $360.0 mill.
LT Debt $621.7 mill. LT Interest $45.0 mill.

(Total interest coverage: 3.0x)

Pension Assets-12/14 $279.2 mill. Oblig. $487.3 mill.

Pfd Stock None

Common Stock 27,371,642 shares as of 10/23/15

MARKET CAP $1.4 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1013.2	1033.2	1037.9	1012.7	812.1	848.8	730.6	758.5	754.0	723.8	*780*	*820*	Revenues ($mill)	*890*
65.2	74.5	68.5	75.1	72.7	63.9	59.9	60.5	58.7	53.7	*61.0*	*65.0*	Net Profit ($mill)	*88.0*
36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	42.4%	40.8%	41.5%	*40.0%*	*40.0%*	*39.0%*	Income Tax Rate	*39.0%*
6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	8.2%	8.0%	7.8%	7.4%	*7.8%*	*8.0%*	Net Profit Margin	*9.9%*
46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	48.5%	47.6%	44.8%	*42.4%*	*44.5%*	*44.5%*	Long-Term Debt Ratio	*43.5%*
53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	51.5%	52.4%	55.2%	*57.6%*	*55.5%*	*55.5%*	Common Equity Ratio	*56.5%*
1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	1424.7	1433.6	1389.0	*1357.6*	*1495*	*1555*	Total Capital ($mill)	*1755*
1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	1973.6	2062.9	2121.6	*2182.7*	*2295*	*2385*	Net Plant ($mill)	*2685*
7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	5.7%	5.8%	5.8%	*4.0%*	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	*6.9%*	*7.5%*	*7.5%*	Return on Shr. Equity	*9.0%*
10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	*6.9%*	*7.5%*	*7.5%*	Return on Com Equity	*9.0%*
4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	1.6%	1.5%	1.1%	*.4%*	*1.0%*	*1.5%*	Retained to Com Eq	*3.0%*
59%	52%	59%	56%	61%	73%	80%	81%	85%	*95%*	*85%*	*81%*	All Div'ds to Net Prof	*65%*

CURRENT POSITION ($MILL.)	2013	2014	9/30/15
Cash Assets	9.5	9.5	5.2
Other	321.0	353.1	272.7
Current Assets	330.5	362.6	277.9
Accts Payable	96.1	91.4	54.4
Debt Due	248.2	274.7	225.2
Other	88.5	103.3	105.7
Current Liab.	432.8	469.4	385.3
Fix. Chg. Cov.	316%	321%	298%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	1.0%	-6.5%	*2.0%*
"Cash Flow"	3.0%	-1.0%	*3.5%*
Earnings	2.5%	-4.0%	*5.0%*
Dividends	3.5%	3.5%	*1.5%*
Book Value	3.5%	3.0%	*3.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	277.9	131.7	88.2	260.7	758.5
2014	293.4	133.1	87.2	240.3	754.0
2015	261.7	138.3	93.1	230.7	723.8
2016	*270*	*145*	*95.0*	*270*	*780*
2017	*280*	*155*	*100*	*285*	*820*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1.40	.08	d.31	1.07	2.24
2014	1.40	.04	d.32	1.04	2.16
2015	1.04	.08	d.24	1.08	1.96
2016	*1.20*	*.10*	*d.20*	*1.10*	*2.20*
2017	*1.25*	*.15*	*d.20*	*1.15*	*2.35*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.445	.445	.445	.455	1.79
2013	.455	.455	.455	.460	1.83
2014	.460	.460	.460	.465	1.85
2015	.465	.465	.465	.4675	1.86
2016	.4675				

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 704,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugane, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 35%; commercial, 22%; industrial, gas transportation, and other, 43%. Employs 1,092. BlackRock Inc. owns 9.2% of shares; officers and directors, 2.1% (4/15 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas had better-than-expected fourth-quarter results. The Portland area had weather that was slightly cooler than the year-prior period, which helped to boost throughput at utility segment. In addition, a 1.4% customer growth rate and an increase in gas margins allowed earnings per share to grow 3%, to $1.08. The company was able to overcome a $3.5 million, non-cash environmental remediation charge, as well.

Northwest Natural Gas received an unfavorable outcome concerning expense recoveries. It was ordered to forgo the collection of $15 million of environmental remediation expenses and related interest costs. This will result in a $2.8 million pretax charge in the first quarter of 2016. Still, stronger operating margins should more than offset this setback. All told, we think the company can earn $2.20 a share in 2016.

Northwest Natural Gas announced that CEO, Gregg Kantor, will step down effective August 1st. However, he will stay in an advisory role until the end of 2016. The current COO, David Anderson, will succeed Mr. Kantor. Though we expect no immediate change in strategy, it will be interesting to see what, if any, changes ultimately emerge.

The Mist storage facility should boost long-term results. The company is expected to put the facility into service in the winter of 2018-2019, which should allow for better natural gas sales over the coming years. This move will cost around $125 million and, in time, provide a benefit to cash flows.

The dividend remains the main draw. It was raised to $0.4675 a share quarterly, and has been increased 60 years in a row. We think Northwest remains likely to continue this uptrend over the coming years, though it appears likely at a lower growth rate than during the previous decade until the Mist facility comes on line.

Shares of Northwest Natural Gas are not attractive at the recent quotation. Indeed, a recent run-up in the share price has put the shares near the middle of our Target Price Range. This has made the yield less attractive, and most long-term accounts would be best served waiting for a dip in price.

John E. Seibert III *March 4, 2016*

(A) Diluted earnings per share. Excludes nonrecurring items: '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢; May not sum due to rounding. Next earnings report due in early May.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2014: $368.9 million, $13.52/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	95

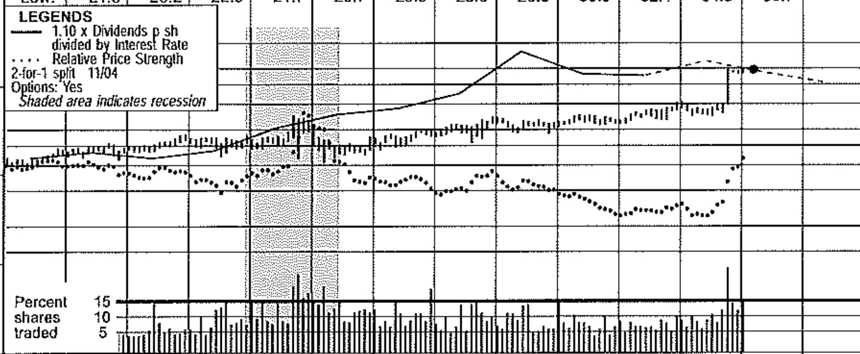
PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 59.28 | P/E RATIO 30.4 (Trailing: 34.1; Median: 19.0) | RELATIVE P/E RATIO 1.80 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS – Suspended 11/6/15
SAFETY 2 New 7/27/90
TECHNICAL – Suspended 11/6/15
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6	35.5	41.0	59.1	59.5
Low:	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.5	30.9	32.1	34.9	56.7

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(-25%)	-3%
Low	35	(-40%)	-9%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	11	12	12	29
to Sell	2	1	1	1	1	1	1	1	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	112	109	112
to Sell	85	92	91
Hld's(000)	43377	45755	46102

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	53.4	-10.4
3 yr.	105.3	20.6
5 yr.	150.6	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	15.54	17.07	18.87	17.38	*18.15*	*18.75*	Revenues per sh A	*20.50*
1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	3.09	3.29	3.37	3.37	*3.60*	*3.70*	"Cash Flow" per sh	*4.05*
1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	1.66	1.78	1.84	1.73	*1.95*	*2.00*	Earnings per sh AB	*2.20*
.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	1.19	1.23	1.26	1.31	*1.35*	*1.39*	Div'ds Decl'd per sh C■	*1.51*
1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	7.33	8.01	5.91	5.62	*5.95*	*5.95*	Cap'l Spending per sh	*5.95*
8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	14.21	15.87	16.80	18.07	*19.00*	*19.60*	Book Value per sh D	*21.55*
63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	72.32	72.25	74.88	77.88	78.94	*80.00*	*80.00*	Common Shs Outst'g E	*80.00*
14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	18.9	19.2	18.5	18.9	22.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*18.0*
.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	1.22	1.04	.99	1.15	*estimates*		Relative P/E Ratio	*1.13*
5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	3.7%	3.7%	3.6%	3.4%			Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 10/31/15
Total Debt $1903.7 mill. Due in 5 Yrs $410.0 mill.
LT Debt $1523.7 mill. LT Interest $61.6 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/15 $356.9 mill. Oblig. $354.6 mill.

Pfd Stock None

Common Stock 80,985,282 shs. as of 12/11/15

MARKET CAP: $4.8 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	1122.8	1278.2	1470.0	1371.7	*1450*	*1500*	Revenues ($mill) A	*1640*
97.2	104.4	110.0	122.8	111.8	113.6	119.8	134.4	143.8	137.0	*155*	*160*	Net Profit ($mill)	*175*
34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	29.7%	32.6%	34.5%	25.0%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	10.7%	10.5%	9.8%	10.0%	*10.8%*	*10.8%*	Net Profit Margin	*10.8%*
48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	48.7%	49.7%	52.1%	51.7%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*49.5%*
51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	51.3%	50.3%	47.9%	48.3%	*50.0%*	*50.5%*	Common Equity Ratio	*50.5%*
1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	2002.0	2363.5	2733.0	2950.0	*3045*	*3095*	Total Capital ($mill)	*3245*
2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	3105.1	3634.5	3989.4	4348.0	*4400*	*4500*	Net Plant ($mill)	*4750*
7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	7.0%	6.8%	6.4%	5.8%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.7%	11.3%	11.0%	9.6%	*10.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.7%	11.3%	11.0%	9.6%	*10.5%*	*10.0%*	Return on Com Equity	*10.5%*
2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	3.3%	3.6%	3.4%	2.4%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
74%	70%	69%	64%	72%	73%	72%	69%	69%	75%	*69%*	*70%*	All Div'ds to Net Prof	*69%*

CURRENT POSITION ($MILL.)

	2013	2014	10/31/15
Cash Assets	8.1	9.6	13.7
Other	340.0	338.4	242.2
Current Assets	348.1	348.0	255.9
Accts Payable	140.1	139.7	152.0
Debt Due	500.0	355.0	380.0
Other	76.6	127.3	103.6
Current Liab.	716.7	622.0	635.6
Fix. Chg. Cov.	325%	325%	325%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	--	-7.0%	2.5%
"Cash Flow"	4.5%	3.0%	3.5%
Earnings	4.5%	3.0%	3.5%
Dividends	4.0%	3.5%	3.0%
Book Value	5.0%	5.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2013	515.9	399.4	162.9	200.0	1278.2
2014	657.7	462.2	164.2	185.8	1469.9
2015	607.3	424.9	158.3	181.2	1371.7
2016	*625*	*445*	*180*	*200*	*1450*
2017	*635*	*455*	*195*	*215*	*1500*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2013	1.18	.74	d.03	d.11	1.78
2014	1.26	.80	d.09	d.13	1.84
2015	1.18	.84	d.10	d.18	1.73
2016	*1.23*	*.89*	*d.05*	*d.12*	*1.95*
2017	*1.24*	*.90*	*d.04*	*d.10*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.29	.30	.30	.60	1.49
2013	--	.31	.31	.31	.93
2014	.31	.32	.32	.32	1.27
2015	.32	.33	.33	.33	1.31
2016	.33				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 992,551 customers in North Carolina, South Carolina, and Tennessee. 2015 revenue mix: residential (48%), commercial (27%), industrial (15%), other (10%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 47.0% of revenues. '15 deprec. rate: 2.5%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has 1,879 employees. Off./dir. own about 1.4% of common stock, BlackRock; 8.2% (2/16 proxy). Chrmn., CEO & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Shares of Piedmont Natural Gas have basically flatlined since our December review. The stock has hovered right around the acquisition price of $60.00 per share in cash. Management signed a definitive agreement to be acquired by Duke Energy (DUK) when the deal was originally announced back in October. DUK will also assume about $1.8 billion in Piedmont's debt. Combined with the cash offer, this values the company at approximately $6.7 billion. The deal was already unanimously approved by the boards of both companies. More recently, Piedmont's shareholders approved the transaction. At this point, the companies have filed for approval with the North Carolina Utilities Commission and with the Tennessee Regulatory Authority. The acquisition is progressing nicely, and is anticipated to close by the end of 2016.

Meanwhile, we look for the company's top and bottom lines to rebound in fiscal 2016. Substantial revenue growth will be tough to come by given the pressures impacting natural gas prices these days. Nonetheless, a nice mid-single-digit topline gain does seem plausible. This ought to reflect continually rising new customer accounts. Last year, the company added roughly 17,000 accounts, representing approximately 5% year-over-year growth. At the same time, a healthy capital expansion plan put roughly $450 million into supporting utility customer growth, system infrastructure, integrity and reliability, and nonutility joint ventures. All of these factors should equate to rising system throughput and help to drive the bottom line more than 12.5% higher, to $1.95 a share this year.

The Timeliness rank on Piedmont shares remains suspended due to the pending acquisition. PNY is no longer trading on earnings or fundamentals. Instead, the stock will likely hover right around the tender offer price of $60.00 per share until the deal is finalized. That said, current shareholders may prefer to lock in gains at this level in order to redeploy capital elsewhere. The purchase price is above our Target Price Range for these shares. If for some reason the transaction is not completed, we would expect the equity's price to fall back to preannouncement levels.

Bryan J. Fong *March 4, 2016*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '10, 41¢. Next earnings report due mid-April.
Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October. 2013 Q1 dividend paid in Q4 of 2012. ■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2015: $861.6 million, $10.92/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	95

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
26.48	16.4	(Trailing: 20.6 / Median: 17.0)	0.97	4.1%	VALUE LINE

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	16.2	17.1	20.6	20.3	20.4	27.1	29.0	29.0	31.1	30.6	30.4	26.9
Low:	12.5	12.8	15.6	12.6	16.0	18.6	21.4	22.9	25.3	25.9	21.2	22.1

TIMELINESS **3** Raised 2/19/16

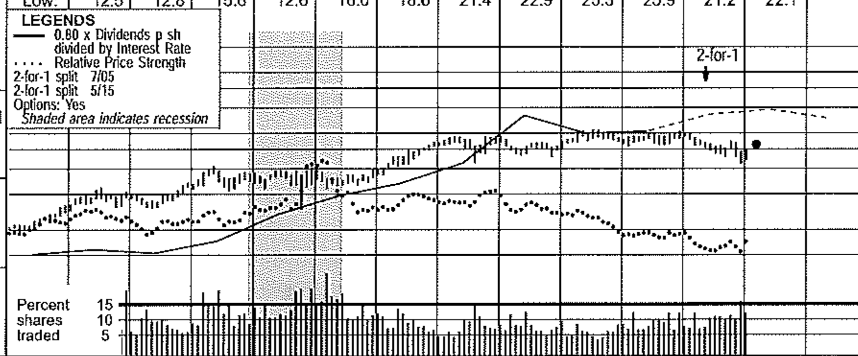
SAFETY **2** Lowered 1/4/91

TECHNICAL **5** Lowered 1/8/16

BETA .85 (1.00 = Market)

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
2-for-1 split 5/15
Options: Yes
Shaded area indicates recession

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	15%
Low	30	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	2	1	2	1	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	107	83	105
to Sell	64	79	59
Hld's(000)	40934	42248	42947

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.0	-10.4
3 yr.	2.0	20.6
5 yr.	12.5	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
11.22	17.65	10.35	13.17	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	*14.15*	*14.60*	*15.20*	Revenues per sh	*18.60*
.97	.95	1.06	1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	*2.50*	*2.65*	*2.85*	"Cash Flow" per sh	*3.55*
.54	.57	.61	.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	*1.48*	*1.60*	*1.75*	Earnings per sh A	*2.20*
.37	.37	.38	.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	*1.08*	*1.15*	Div'ds Decl'd per sh B ■	*1.40*
1.11	1.41	1.74	1.18	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	*4.45*	*4.65*	*4.85*	Cap'l Spending per sh	*5.75*
3.62	3.91	4.84	5.63	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	*14.30*	*15.30*	*16.20*	Book Value per sh C	*18.60*
46.00	47.44	48.83	52.92	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	*70.00*	*72.00*	*74.00*	Common Shs Outst'g D	*78.00*
13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	*17.5*	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	*.89*	*Value Line*		Relative P/E Ratio	*1.00*
5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	*4.0%*	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
	931.4	956.4	962.0	845.4	925.1	828.6	706.3	731.4	887.0	*990*	*1050*	*1125*	Revenues ($mill)	*1450*
	72.0	61.8	67.7	71.3	81.0	87.0	93.3	97.1	104.0	*105*	*115*	*130*	Net Profit ($mill)	*170*
	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	10.8%	- -	10.8%	*20.0%*	*22.0%*	*22.0%*	Income Tax Rate	*25.0%*
	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	13.2%	13.3%	11.7%	*10.6%*	*11.0%*	*11.6%*	Net Profit Margin	*11.7%*
	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	*48.5%*	*49.0%*	*48.5%*	Long-Term Debt Ratio	*47.5%*
	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	55.0%	54.9%	52.0%	*51.5%*	*51.0%*	*51.5%*	Common Equity Ratio	*52.5%*
	801.1	839.0	848.0	856.4	910.1	1048.3	1337.6	1507.4	1791.9	*1950*	*2150*	*2325*	Total Capital ($mill)	*2775*
	920.0	948.9	982.6	1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	*2350*	*2450*	*2550*	Net Plant ($mill)	*2900*
	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	7.4%	6.8%	6.4%	*6.0%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	*10.5%*	*10.5%*	*11.0%*	Return on Shr. Equity	*11.5%*
	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	*10.5%*	*10.5%*	*11.0%*	Return on Com Equity	*11.5%*
	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	*3.5%*	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
	37%	48%	49%	51%	50%	52%	55%	59%	61%	*68%*	*68%*	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1366.7 mill. Due in 5 Yrs $868.5 mill.
LT Debt $937.4 mill. LT Interest $22.0 mill.
(Total interest coverage: 4.0x)

Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $180.5 mill. Oblig. $265.4 mill.

Pfd Stock None

Common Stock 69,294,447 shs.
as of 11/2/15, adj. for 2-for-1 split

MARKET CAP: $1.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	9/30/15
Cash Assets	3.8	4.2	2.1
Other	479.1	562.5	476.8
Current Assets	482.9	566.7	478.9
Accts Payable	259.8	273.0	189.1
Debt Due	374.9	395.6	429.3
Other	130.3	181.6	188.6
Current Liab.	765.0	850.2	807.0
Fix. Chg. Cov.	370%	432%	475%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	-1.0%	-5.5%	*7.0%*
"Cash Flow"	8.0%	7.5%	*5.0%*
Earnings	8.0%	6.5%	*5.5%*
Dividends	8.5%	10.0%	*6.5%*
Book Value	8.5%	8.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	255.6	122.6	128.8	224.4	731.4
2014	350.2	133.3	122.4	281.1	887.0
2015	383.0	177.7	141.1	*288.2*	*990*
2016	*405*	*175*	*155*	*315*	*1050*
2017	*430*	*190*	*165*	*340*	*1125*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.76	.16	d.02	.62	1.52
2014	1.01	.15	d.05	.47	1.57
2015	.86	.03	d.07	*.66*	*1.48*
2016	*.90*	*.05*	*Nil*	*.65*	*1.60*
2017	*.95*	*.08*	*.02*	*.70*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	- -	.202	.202	.423	.83
2013	- -	.222	.222	.458	.90
2014	- -	.237	.237	.488	.96
2015	- -	.251	.251	.515	1.02
2016					

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 366,854 customers in New Jersey's southern counties. Gas revenue mix '14: residential, 43%; commercial, 19%; cogeneration and electric generation, 17%; industrial, 21%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 700 employees. Off./dir. own .8% of common shares; BlackRock, Inc., 9.5%; The Vanguard Group, Inc., 6.9% (3/15 proxy). Pres. & CEO: Michael J. Renna. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have traded higher over the past three months. We think that weakness in the broader equity markets has encouraged investors to seek relatively safe alternatives. Also, the stock had been trading near a multiyear low three months ago. Despite strong top-line performance in the first three quarters of 2015, greater costs have made for lackluster earnings. However, we do expect a more favorable bottom-line comparison for the fourth quarter. The company was set to report December-period results as this Issue went to press.

The board of directors has increased the payout by 5%. Starting with the December payout, the quarterly dividend is now $0.264. Dividend growth will probably continue in the coming years.

We expect a strong performance from the company's core businesses going forward. Prospects for utility South Jersey Gas appear favorable. Natural gas remains the fuel of choice within its service territory. All in all, we expect customer additions and infrastructure investment to drive earnings higher here. Elsewhere, the company's nonutility operations should also perform well overall. South Jersey Energy Group's earnings ought to gain from an increasing contribution from fuel supply management contracts. Additional announced contracts are scheduled to come on-line in 2016 and 2017. Over the long haul, we expect strong contributions from the company's commodity marketing and fuel supply management lines. This, along with expected benefits from the Penn East pipeline, ought to drive bottom-line growth and improve earnings quality.

Conservative investors with a long time horizon may find something to like here. This equity offers good risk-adjusted total return potential for the pull to late decade. This should be supported by healthy growth at the company in the coming years. The dividend yield remains attractive, despite the recent appreciation in the share price. South Jersey earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Also, volatility is below average (Beta: 0.85). This stock is neutrally ranked for year-ahead performance.

Michael Napoli, CFA *March 4, 2016*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $1.05; '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46. Excl. nonrecur. gain (loss): '01, $0.07; '08, $0.16; '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11). Earnings may not sum due to rounding. Next egs. report due early May. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. in 2014: $357.2 mill., $5.23 per shr. (D) In mill., adj. for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	80

SOUTHWEST GAS NYSE-SWX

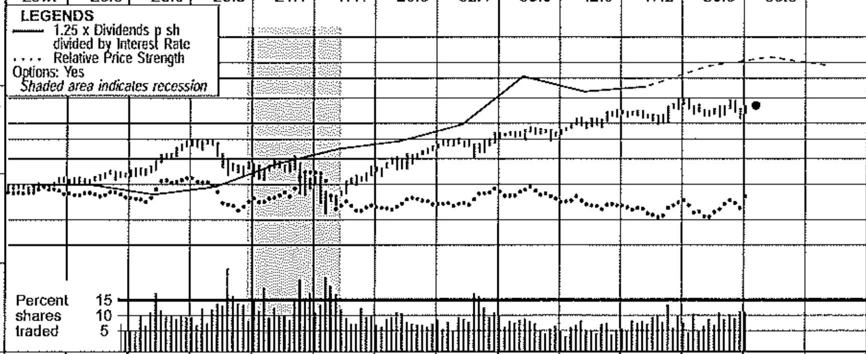
RECENT PRICE 59.05 | P/E RATIO 18.9 (Trailing: 21.2 / Median: 16.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 3/4/16
SAFETY 3 Lowered 1/4/91
TECHNICAL 2 Raised 3/4/16
BETA .80 (1.00 = Market)

High:	28.1	39.4	39.9	33.3	29.5	37.3	43.2	46.1	56.0	64.2	63.7	60.7	
Low:	23.5	26.0	26.5	21.1	17.1	26.3	32.1	39.0	42.0	47.2	50.5	53.5	

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+45%)	12%
Low	60	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	2	1
to Sell	0	0	0	0	3	0	0	2	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	94	109	109
to Sell	81	80	84
Hld's(000)	36094	36799	37243

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.5	-10.4
3 yr.	43.3	20.6
5 yr.	81.0	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	*51.55*	*53.00*	Revenues per sh	*58.50*
4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	*9.00*	*9.50*	"Cash Flow" per sh	*11.60*
1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	*3.20*	*3.50*	Earnings per sh A	*4.80*
.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	*1.80*	*1.92*	Div'ds Decl'd per sh B■†	*2.30*
7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	*9.80*	*10.20*	Cap'l Spending per sh	*11.70*
16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	*34.70*	*35.00*	Book Value per sh	*37.75*
31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	*49.00*	*50.00*	Common Shs Outst'g C	*53.00*
16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	*Value Line*		Relative P/E Ratio	*.95*
4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	1927.8	1950.8	2121.7	2463.6	*2525*	*2650*	Revenues ($mill)	*3100*
80.5	83.2	61.0	87.5	103.9	112.3	133.3	145.3	141.1	138.3	*155*	*175*	Net Profit ($mill)	*255*
37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	36.2%	35.0%	35.7%	*36.5%*	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	6.9%	7.4%	6.7%	5.6%	*6.1%*	*6.6%*	Net Profit Margin	*8.2%*
60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	49.2%	49.4%	52.4%	49.3%	*49.5%*	*49.5%*	Long-Term Debt Ratio	*48.5%*
39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	50.8%	50.6%	47.6%	50.7%	*50.5%*	*50.5%*	Common Equity Ratio	*51.5%*
2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	2576.9	2793.7	3123.9	3143.5	*3350*	*3450*	Total Capital ($mill)	*3900*
2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	3343.8	3486.1	3658.4	3891.1	*4050*	*4250*	Net Plant ($mill)	*4650*
5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	6.4%	6.3%	5.7%	*5.5%*	*5.5%*	*6.0%*	Return on Total Cap'l	*7.5%*
8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	*9.0%*	*10.0%*	Return on Shr. Equity	*13.0%*
8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	*9.0%*	*10.0%*	Return on Com Equity	*13.0%*
5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	6.1%	6.1%	5.0%	3.9%	*4.0%*	*4.5%*	Retained to Com Eq	*6.5%*
42%	44%	63%	48%	43%	43%	40%	41%	47%	55%	*57%*	*55%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1560.2 mill. **Due in 5 Yrs** $405.0 mill.
LT Debt $1540.4 mill. **LT Interest** $72.0 mill.
(Total interest coverage: 3.8x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/14 $799.7 mill.
Oblig. $1132.4 mill.

Pfd Stock None

Common Stock 47,375,398 shs.
as of 10/28/15

MARKET CAP: $2.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	9/30/15
Cash Assets	41.1	39.6	33.0
Other	453.6	567.2	445.6
Current Assets	494.7	606.8	478.6
Accts Payable	183.5	168.0	129.3
Debt Due	11.1	24.2	19.8
Other	239.6	277.9	345.6
Current Liab.	434.2	470.1	494.7
Fix. Chg. Cov.	430%	395%	383%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	1.0%	-1.5%	*4.5%*
"Cash Flow"	4.5%	6.0%	*5.0%*
Earnings	8.5%	11.0%	*7.0%*
Dividends	5.0%	8.0%	*7.5%*
Book Value	5.0%	5.0%	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	613.5	411.6	387.3	538.4	1950.8
2014	608.4	453.2	432.5	627.7	2121.7
2015	734.2	538.6	505.4	685.4	2463.6
2016	*760*	*560*	*520*	*685*	*2525*
2017	*790*	*585*	*545*	*720*	*2640*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1.73	.22	d.06	1.22	3.11
2014	1.51	.21	.04	1.25	3.01
2015	1.53	.10	d.10	1.38	2.92
2016	*1.60*	*.20*	*Nil*	*1.40*	*3.20*
2017	*1.70*	*.25*	*.05*	*1.50*	*3.50*

Calendar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.265	.295	.295	.295	1.15
2013	.295	.330	.330	.330	1.29
2014	.330	.365	.365	.365	1.43
2015	.365	.405	.405	.405	1.58
2016	.405	.450			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.9 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2014 margin mix: residential and small commercial, 85%; large commercial and industrial, 4%; transportation, 11%. Total throughput: 1.9 billion therms. Has 6,232 employees. Off. & Dir. own 1.5% of common stock; BlackRock Inc., 9.6%; The Vanguard Group, Inc., 6.9%; GAMCO Investors, Inc., 6.8%; T. Rowe Price Assoc., Inc., 6.5% (3/15 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: John Hester. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Tel.: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded higher in recent months. Utility stocks have fared particularly well lately, as volatility in the broader equity markets has prompted investors to seek safer alternatives. This may well continue to be the case going forward, though it's worth pointing out that the company's operations are not immune to a macroeconomic downturn.

The board of directors has increased the dividend by 11%. Starting with the May dividend, the quarterly payout will be $0.45 per share. Dividend growth will probably continue going forward.

The company finished the year on a good note. The natural gas segment gained from rate relief and growth in the customer base, while the construction services business benefited from additional pipe replacement work and favorable weather conditions. Even so, dramatic growth in construction expenses hurt earnings for full-year 2015. Greater employee-related expenses also pressured performance. On top of that, weakness in equity markets has resulted in a reduction of the cash surrender value of company-owned life insurance policies.

We anticipate solid performance in the current year. This trend will probably continue in 2017. The utility business ought to benefit from modest customer growth, infrastructure tracking programs, and expansion projects. Greater operating expenses should be a partial offset here, though. Elsewhere, construction services subsidiary Centuri will probably experience healthy demand, given the need to replace aging infrastructure. The long-term fundamentals for this business appear particularly favorable. With a strong base of utility clients, this line should be able to grow its business with multiyear pipeline replacement programs.

These shares are favorably ranked for Timeliness. We expect solid growth for the company over the pull to late decade. Meanwhile, the dividend yield is decent, though not outstanding, for a gas utility. Total return potential is modest here, and relatively well defined. Southwest Gas, however, earns good scores for Price Stability, Earnings Predictability, and Price Growth Persistence.

Michael Napoli, CFA *March 4, 2016*

(A) Diluted earnings. Excl. nonrec. gains (losses): '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due early May. (B) Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions. (D) Totals may not sum due to rounding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	80

UGI CORP. NYSE-UGI

RECENT PRICE 36.11 | P/E RATIO 17.6 (Trailing: 18.9, Median: 14.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Lowered 6/26/15
SAFETY 2 Raised 9/17/04
TECHNICAL 5 Lowered 1/22/16
BETA .95 (1.00 = Market)

High:	20.0	19.3	19.8	19.2	18.3	21.7	22.4	22.4	28.8	39.7	38.6	36.8	
Low:	12.8	13.5	15.2	12.5	14.1	15.9	16.0	17.3	21.9	26.8	31.5	31.6	

Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

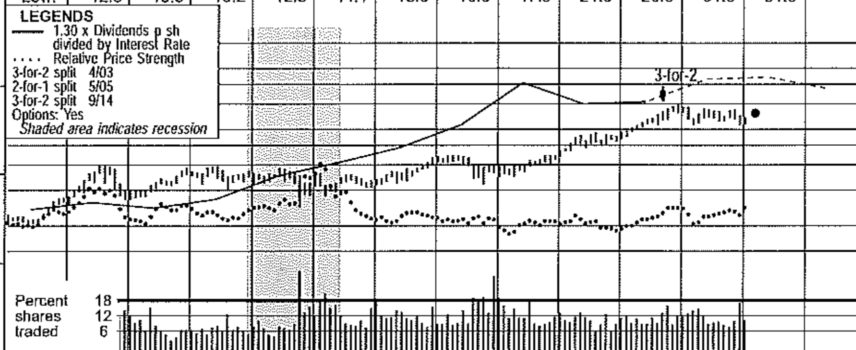
	Price	Gain	Ann'l Total Return
High	35	(-5%)	2%
Low	30	(-15%)	-1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	1	0	2	0	0	2	1
to Sell	0	3	1	0	2	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	201	154	141
to Sell	165	182	171
Hld's(000)	132585	134878	134852



% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.6	-10.4
3 yr.	56.8	20.6
5 yr.	89.1	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
14.50	20.09	17.76	23.62	24.63	31.10	33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	*39.45*	*42.30*	Revenues per sh A	*49.00*
1.16	1.32	1.36	1.59	1.63	2.09	2.05	2.26	2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	*4.35*	*4.65*	"Cash Flow" per sh	*5.25*
.35	.47	.60	.76	.81	1.15	1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	*2.05*	*2.25*	Earnings per sh AB	*2.70*
.34	.35	.36	.38	.40	.43	.46	.48	.50	.52	.60	.68	.71	.74	.79	.90	*.92*	*.95*	Div'ds Decl'd per sh C ■	*1.04*
.58	.64	.76	.79	.87	1.01	1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	*3.00*	*3.15*	Cap'l Spending per sh	*3.25*
2.04	2.08	2.55	4.45	5.43	6.35	6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	*17.00*	*18.35*	Book Value per sh D	*22.30*
121.47	122.83	124.66	128.10	153.63	157.20	158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	*170.00*	*175.00*	Common Shs Outst'g E	*170.00*
13.6	12.1	11.4	12.6	13.4	13.8	14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*12.0*
.88	.62	.62	.72	.71	.73	.76	.80	.80	.69	.69	.94	1.04	.87	.83	.97	*Value Line*		Relative P/E Ratio	*.75*
7.0%	6.2%	5.3%	3.9%	3.7%	2.7%	3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
5221.0	5476.9	6648.2	5737.8	5591.4	6091.3	6519.2	7194.7	8277.3	6691.1	*6900*	*7400*	Revenues ($mill) A	*8330*
176.2	191.8	215.5	258.5	261.0	232.9	199.4	278.1	337.2	*355*	*370*	*405*	Net Profit ($mill)	*475*
30.5%	23.8%	30.6%	29.4%	32.0%	29.8%	34.8%	27.6%	30.6%	*30.0%*	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
3.4%	3.5%	3.2%	4.5%	4.7%	3.8%	3.1%	3.9%	4.1%	*5.3%*	*5.4%*	*5.4%*	Net Profit Margin	*5.7%*
64.1%	60.7%	58.4%	56.2%	44.0%	51.6%	60.0%	58.7%	56.4%	56.0%	*54.5%*	*52.5%*	Long-Term Debt Ratio	*48.5%*
35.9%	39.3%	41.6%	43.8%	56.0%	48.4%	40.0%	41.3%	43.6%	44.0%	*45.5%*	*47.5%*	Common Equity Ratio	*51.5%*
3064.6	3360.7	3405.0	3630.0	3256.7	4088.0	5580.7	6034.7	6092.7	6133.8	*6525*	*6765*	Total Capital ($mill)	*7350*
2214.7	2397.4	2449.5	2903.6	3053.2	3204.5	4233.1	4480.2	4543.7	4994.1	*5475*	*6000*	Net Plant ($mill)	*8000*
7.5%	7.4%	7.9%	8.9%	10.1%	7.4%	5.6%	6.6%	7.5%	*5.7%*	*5.7%*	*6.0%*	Return on Total Cap'l	*6.5%*
16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	12.4%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.5%*
16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	12.4%	*12.5%*	*12.5%*	Return on Com Equity	*12.5%*
9.4%	8.7%	9.5%	10.9%	8.9%	6.0%	3.6%	6.1%	7.6%	7.0%	*7.0%*	*7.5%*	Retained to Com Eq	*8.0%*
41%	40%	38%	33%	38%	49%	60%	45%	40%	44%	*44%*	*41%*	All Div'ds to Net Prof	*37%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $4066.1 mill. Due in 5 Yrs $2124 mill.
LT Debt $3422.4 mill. LT Interest $242 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $73.4 mill.
Pension Assets-9/15 $472 mill. Oblig. $466 mill.

Pfd Stock None

Common Stock 171,914,720 shares as of 1/31/16

MARKET CAP: $6.2 bill. (Mid. Cap)

CURRENT POSITION ($MILL.)	2014	2015	12/31/15
Cash Assets	419.5	369.7	403.0
Other	1243.5	1090.1	1271.0
Current Assets	1663.0	1459.8	1674.0
Accts Payable	459.8	392.9	423.3
Debt Due	288.0	447.9	643.7
Other	683.1	838.1	844.7
Current Liab.	1430.9	1678.9	1911.7
Fix. Chg. Cov.	338%	338%	340%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	7.0%	3.0%	2.0%
"Cash Flow"	9.0%	7.5%	4.5%
Earnings	8.0%	3.0%	4.5%
Dividends	7.0%	8.0%	4.0%
Book Value	13.5%	10.0%	6.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	2018	2542	1374	1259	7194.7
2014	2316	3163	1486	1311	8277.3
2015	2005	2456	1148	1082	6691.1
2016	1607	*2660*	*1350*	*1283*	*6900*
2017	*1735*	*2785*	*1475*	*1405*	*7400*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	.60	.99	.09	d.09	1.59
2014	.70	1.23	.10	d.11	1.92
2015	.66	1.23	.03	.01	2.01
2016	.64	*1.31*	*.11*	*d.01*	*2.05*
2017	*.69*	*1.36*	*.16*	*.04*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.175	.175	.18	.18	.71
2013	.18	.18	.19	.19	.74
2014	.19	.19	.20	.22	.80
2015	.22	.22	.23	.23	.90
2016	.23				

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 21.7% of net income in 2015), UGI International (18.8%), Gas Utility (41.2%), Midstream & Marketing (38.8%), and Corp. & Other -21%. UGI Utilities distributes natural gas and electricity to over 617,000 customers mainly in Pennsylvania; 27%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Wellington Management Co. holds 9.6% of stock; officers/dir., about 3% (12/15 proxy). Has 8,500 empls. CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Telephone: 610-337-1000. Internet: www.ugicorp.com.

UGI Corp. is facing a difficult operating environment this year. Many companies in this space have been getting hurt by the downturn in commodity prices. This is evident in the almost 20% year-over-year decline in UGI's revenues, to roughly $1.6 billion in the December quarter. The AmeriGas Propane, UGI Utilities, and Midstream & Marketing divisions all registered year-over-year drops in their respective contributions to the top line. This can partially be attributed to the unseasonably warmer-than-normal weather patterns in UGI's service territory. Temperatures have been approximately 25% higher than normal, which is obviously weighing on customer usage. On the upside, the UGI International segment has been getting a boost from last year's purchase of the Total LPG Distribution business in France (Totalgaz), now called Finigaz. The integration of those operations is progressing nicely, and that unit contributed about $145 million in incremental revenues last quarter. On the profitability front, although the reduced commodity prices hurt the top line, they also helped to lower costs; total operating expenses fell 14.8% as a percentage of the top line. Combined, these factors equated to a modest 3% bottom-line decline, to $0.64 a share. However, this was lower than we previously anticipated.

Consequently, we have trimmed a dime off our fiscal 2016 (ends September 30th) earnings estimate, to $2.05 a share. This would represent a minimal rise of about 2% for the year. The continual shrinking spread between natural gas and heating oil is weighing on consumers' decisions to switch to propane. That said, UGI was sneeessful in adding more than 5,400 new residential heating and commercial customers in the first quarter. The expansion of its liquid natural gas peaking capabilities augnrs well for its Midstream & Marketing arm. Finally, infrastructure enhancement and capital growth projects should position UGI for healthy long-term earnings growth. We have introduced our fiscal 2017 top- and bottom-line estimates at $7.4 billion and $2.25 a share, respectively.

At this juncture, these neutrally ranked shares appear fully valued.

Bryan J. Fong *March 4, 2016*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. items: '99, 13¢; '01, d1¢; '03, 22¢; '04, d6¢; '05, 3¢; '06, 5¢; '07, 12¢. Next egs. report due late April. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/15: $3,564 mill., $20.61/sh. (E) In mill., adjusted for stock splits.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	85
Earnings Predictability	75

WGL HOLDINGS NYSE-WGL

RECENT PRICE 67.67 | P/E RATIO 21.5 (Trailing: 21.2; Median: 15.0) | RELATIVE P/E RATIO 1.27 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 2 Raised 2/19/16
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Raised 2/5/16
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0	47.0	56.8	65.6	69.1
Low:	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0	38.0	35.4	50.9	60.0

2019-21 PROJECTIONS

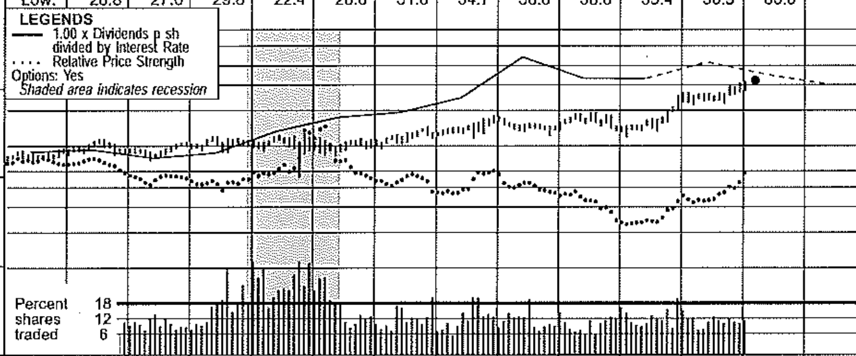
	Price	Gain	Ann'l Total Return
High	60	(-10%)	*Nil*
Low	50	(-25%)	*-4%*

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	13	0	0
to Sell	0	0	0	0	0	1	1	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	116	117	109
to Sell	99	104	113
Hld's(000)	31712	32440	32753



Target Price Range

	2019	2020	2021

120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.0	-10.4
3 yr.	76.4	20.6
5 yr.	121.8	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	47.07	47.70	53.73	53.42	*52.00*	*54.00*	Revenues per sh A	*59.00*
3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	4.53	4.29	4.80	5.60	*5.65*	*5.80*	"Cash Flow" per sh	*6.45*
1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	2.31	2.68	3.16	*3.15*	*3.20*	Earnings per sh B	*3.55*
1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	1.66	1.72	1.83	*1.87*	*1.93*	Div'ds Decl'd per sh C ■	*2.03*
2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	4.87	6.04	7.63	9.32	*16.70*	*18.00*	Cap'l Spending per sh	*21.00*
15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	24.64	24.65	24.08	24.97	*26.40*	*27.65*	Book Value per sh D	*31.80*
46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	51.52	51.70	51.76	49.79	*50.00*	*50.00*	Common Shs Outst'g E	*50.00*
14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	15.3	18.2	15.2	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.97	1.02	.80	.93	*Value Line*		Relative P/E Ratio	*.95*
4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	3.9%	3.9%	4.2%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1498.5 mill. Due in 5 Yrs $225.0 mill.
LT Debt $945.6 mill. LT Interest $50.5 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x) (43% of Total Capital)
Pension Assets-9/15 $1,218.7 mill. Oblig. $1,218.7 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 49,847,937 shs. as of 1/31/16

MARKET CAP: $3.4 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	2466.1	2780.9	2659.8	*2600*	*2700*	Revenues ($mill) A	*2950*
96.0	102.9	122.9	128.7	115.0	115.5	138.4	119.7	139.0	158.2	*158*	*160*	Net Profit ($mill)	*175*
39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	40.1%	30.2%	29.0%	39.0%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	5.7%	4.9%	5.0%	6.0%	*6.1%*	*6.0%*	Net Profit Margin	*6.0%*
37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	31.2%	28.7%	34.8%	42.6%	*42.5%*	*44.0%*	Long-Term Debt Ratio	*48.0%*
60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	67.3%	69.8%	63.8%	56.1%	*56.0%*	*55.0%*	Common Equity Ratio	*51.0%*
1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	1826.8	1954.0	2215.6	*2345*	*2510*	Total Capital ($mill)	*3120*
2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	2907.5	3314.4	3672.7	*4070*	*4510*	Net Plant ($mill)	*6135*
7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	7.5%	8.1%	8.3%	*8.0%*	*8.0%*	Return on Total Cap'l	*7.0%*
10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	10.7%	9.2%	10.9%	12.7%	*12.0%*	*11.5%*	Return on Shr. Equity	*11.0%*
10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	10.8%	9.3%	11.0%	12.7%	*12.0%*	*11.5%*	Return on Com Equity	*11.0%*
3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.8%	2.6%	4.3%	5.4%	*5.0%*	*4.5%*	Retained to Com Eq	*4.5%*
69%	66%	57%	57%	67%	64%	56%	72%	62%	57%	*59%*	*60%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2014	2015	12/31/15
Cash Assets	8.8	6.7	15.8
Other	826.7	774.7	902.2
Current Assets	835.5	781.4	918.0
Accts Payable	313.2	325.1	309.3
Debt Due	473.5	357.0	552.9
Other	233.6	300.8	318.7
Current Liab.	1020.3	982.9	1180.9
Fix. Chg. Cov.	535%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	2.5%	-1.5%	2.5%
"Cash Flow"	2.5%	1.5%	5.0%
Earnings	3.5%	1.5%	5.0%
Dividends	2.5%	3.0%	2.5%
Book Value	4.0%	3.0%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	686.7	891.4	478.1	409.9	2466.1
2014	680.5	1174.0	467.5	458.9	2780.9
2015	749.2	1001.7	441.2	467.7	2659.8
2016	613.4	*1055*	*450*	*481.6*	*2600*
2017	*640*	*1080*	*475*	*505*	*2700*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	1.14	1.75	d.03	d.55	2.31
2014	.99	1.84	.02	d.17	2.68
2015	1.16	2.02	.22	d.23	3.16
2016	1.18	*2.00*	*.21*	*d.24*	*3.15*
2017	*1.20*	*2.01*	*.22*	*d.23*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.39	.40	.40	.40	1.59
2013	.40	.42	.42	.42	1.66
2014	.42	.44	.44	.44	1.74
2015	.44	.463	.463	.463	
2016	.463	.488			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,129,865 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy-related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. BlackRock, Inc. owns 8.7% of common stock; Off./dir. less than 1% (1/16 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

Since our December review, shares of WGL Holdings are trading about 10% higher in price. This likely reflects the better-than-expected December-period bottom line. In comparison, the S&P 500 declined almost 8% over this same period.
Meanwhile, the company did post somewhat mixed financial results for its fiscal first quarter (ended December 31st). On the downside, revenues declined 18%, due to double-digit decreases in both utility and nonutility volumes. On the upside, operating expenses fell 290 basis points as a function of the top line. After accounting for a 3.6% reduction in the company's income tax expense, the bottom line managed a modest increase, to $1.18 a share. This was $0.02 higher than our earlier call, which prompted us to raise our fiscal 2016 (ends September 30th) earnings estimate, to $3.15 a share. This also falls nicely within management's guidance range of $3.00-$3.20. Meantime, we have introduced our fiscal 2017 top- and bottom-line estimates at $2.7 billion and $3.20 a share, respectively. Growth ought to be fueled by new customer accounts (WGL is up about 12,500 from last year's first quarter), as well as from capital projects intended to widen its pipeline system. For example, the Constitution Pipeline is expected in service by the end of this year. Investments in the Central Penn Line and Mountain Valley Pipeline, as well as a proposed rate case in Virginia, are all interesting developments.
The financial position is in good shape and improving. The long-term debt load has remained stable and accounts for about 43% of total capital. Note that the company gets a high mark (A) for Financial Strength. What's more, the board recently approved a roughly 5.5% hike in the quarterly dividend, to $0.4875. Nonetheless, while this is encouraging, WGL does not stand out for its dividend yield when viewed against the natural gas utility industry average.
At the moment, these high-quality shares may appeal to momentum accounts. However, WGL stock is trading above our 3- to 5-year Target Price Range, suggesting it lacks appreciation potential over that time frame.

Bryan J. Fong *March 4, 2016*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '15: $705.8 million, $14.18/sh.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	75

Since our last report in January, the stocks in the Water Utility Industry have performed well compared to the broader market averages. This is surprising considering that it was an up market and investments in this group tend to be defensive plays.

Most water utilities are spending heavily to modernize antiquated pipes, valves, and wastewater facilities. After years of deferring capital expenditures, the industry is now working overtime to upgrade the water infrastructure.

There are literally thousand and thousands of water authorities in the U.S. With so many operators, there is a tremendous amount of redundancies. This presents opportunities for the large and better financed entities to acquire smaller districts. The resulting synergies can lower costs substantially. Consolidation has been a trend for many years, but we expect the pace to accelerate and scale of the takeovers to increase.

The small number and size of investor-owned water utilities is leading to a "water premium". Institutional accounts seem to be willing to pay a high relative price to own a stake in this sector.

The water industry is currently ranked within the top quintile of all industries followed by *Value Line.* Longer-term investors should be aware that the recent strong run up in the value of water stocks has left many of the equities with subpar total return potential through 2019-2021.

Capital Budgets Are Sizable

Almost every utility in this issue is spending heavily to replace and refurbished antiquated infrastructure. In the recent past, water companies and state regulators realized that it was not prudent to defer much needed repairs in an attempt to keep customer's water bills low. Hence, even with the increases in capital spending, large capital outlays will be required for the foreseeable future.

On the positive side, state regulators apparently understand the magnitude of the issue and have been doing their best to forge reasonably constructive relationships with the companies. For investors, the importance of a state's regulatory climate cannot be understated. State authorities determine what rate of return utilities are allowed to earn on funds that have been invested.

An Incredibly Fragmented Market

In the electric utility industry, less than 50 publicly owned companies generate most of the power consumed in the U.S. By contrast, more than 50,000 separate water districts supply water to the large-, mid-, and small-sized markets in America. Furthermore, when the micro districts are included, this figure doubles to more than 100,000. In this issue, we follow the largest investor-owned water utilities in the nation, which collectively supply less than 5% of the water used each day.

Consolidation in the industry has been an ongoing theme for some time. The main reason being that many of the small-water districts can not take advantage of the economies of scale. Indeed, there is a tremendous amount of redundancy in the business. Letting the smaller entities be absorbed by the larger ones allows for substantial synergies. In fact, the savings are so great that customers of the smaller districts can see greatly improved service with no meaningful impact on water bills. (The cost savings from the mergers are plowed back into upgrading the infrastructure.)

INDUSTRY TIMELINESS: 15 (of 97)

Aqua America made nearly 300 acquisitions since 2010, but its customer base grew by only 1%-2% per year. The recent proposed $190 million takeover of Scranton, PA's wastewater assets by *American Water Works* could well be a game changer. With the EPA continually mandating new capital intensive requirements for the country's water operators, many authorities are having difficultly raising the required funds. The recent headlines regarding the poor quality drinking water fall into this category, as well. Flint is a cash-strapped city that didn't have the money needed to properly maintain its water infrastructure. Either Michigan taxpayers or a well-capitalized utility with the required expertise, is needed to rectify the situation. In the past year, a couple of states amended laws to make the acquisition of troubled water authorities easier.

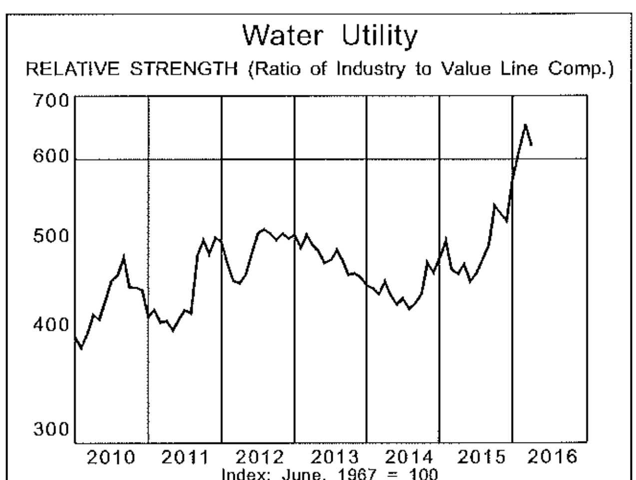
Scarcity Value

As we alluded to previously, there aren't that many investor-owned utilities in the industry. Currently, the market capitalization of all nine water companies we follow is about $25 billion. (*American Water Works* accounts for more than 50% of this amount alone). In comparison, the electric utility *Duke Energy* is more than twice the size of the entire industry. In any case, for institutional accounts looking to invest in the sector, there aren't many options. Thus, there is a scarcity premium being paid to hold stocks in this group. There are only four water companies that have market caps over $1 billion. Indeed, once purchased for the above average income, the average yield on a water stock is 2.4%, a measly 10 basis points higher than the *Value Line* median.

Conclusion

The recent strong relative price performance by stocks in this group have left many with below-average long-term total return potential. As always, we recommend subscribers read each individual report before investing.

James A. Flood



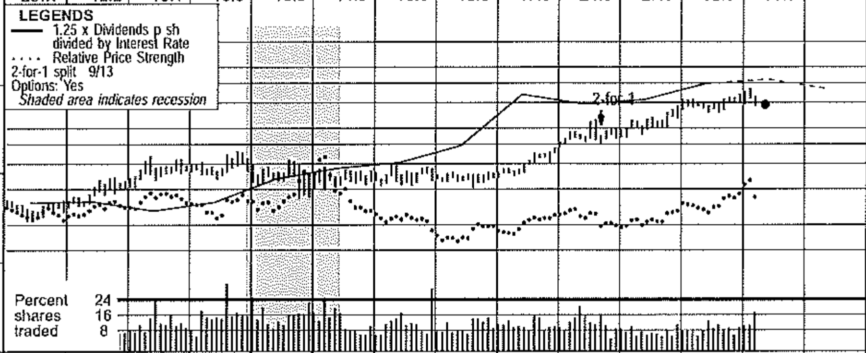
AMER. STATES WATER NYSE-AWR

RECENT PRICE 39.23 | P/E RATIO 23.4 (Trailing: 24.5 Median: 20.0) | RELATIVE P/E RATIO 1.28 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 3 Lowered 4/1/16
SAFETY 2 Raised 7/20/12
TECHNICAL 1 Raised 3/18/16
BETA .75 (1.00 = Market)

High:	17.3	21.9	23.1	21.0	19.4	19.8	18.2	24.1	33.1	38.7	44.1	47.2
Low:	12.2	15.1	16.8	13.5	14.9	15.6	15.3	17.0	24.0	27.0	35.8	38.3

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	11%
Low	40	(Nil)	4%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	5	3	4	2	11	1
to Sell	3	1	1	5	3	3	1	2	1

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	80	91	88
to Sell	82	89	88
Hld's(000)	23707	23779	23016

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.8	-5.8
3 yr.	47.3	27.9
5 yr.	151.7	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
6.08	6.53	6.89	6.99	6.81	7.03	7.88	8.75	9.21	9.74	10.71	11.12	12.12	12.19	12.17	12.56	*12.60*	*13.00*	Revenues per sh	*15.80*
1.10	1.26	1.27	1.04	1.11	1.32	1.45	1.65	1.69	1.70	2.11	2.13	2.48	2.65	2.67	2.81	*2.95*	*3.05*	"Cash Flow" per sh	*3.80*
.64	.67	.67	.39	.53	.66	.67	.81	.78	.81	1.11	1.12	1.41	1.61	1.57	1.60	*1.70*	*1.80*	Earnings per sh A	*2.25*
.43	.43	.44	.44	.44	.45	.46	.48	.50	.51	.52	.55	.64	.76	.83	.87	*.92*	*.97*	Div'd Decl'd per sh B■	*1.25*
1.51	1.59	1.34	1.88	2.51	2.12	1.95	1.45	2.23	2.09	2.12	2.13	1.77	2.52	1.89	2.39	*2.35*	*2.35*	Cap'l Spending per sh	*2.75*
6.37	6.61	7.02	6.98	7.51	7.86	8.32	8.77	8.97	9.70	10.13	10.84	11.80	12.72	13.24	12.77	*13.55*	*14.10*	Book Value per sh	*16.50*
30.24	30.24	30.36	30.42	33.50	33.60	34.10	34.46	34.60	37.06	37.26	37.70	38.53	38.72	38.29	36.50	*36.50*	*36.50*	Common Shs Outst'g C	*37.00*
15.9	16.7	18.3	31.9	23.2	21.9	27.7	24.0	22.6	21.2	15.7	15.4	14.3	17.2	20.1	24.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*20.0*
1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.36	1.41	1.00	.97	.91	.97	1.06	1.25	*estimates*		Relative P/E Ratio	*1.25*
4.2%	3.9%	3.6%	3.5%	3.6%	3.1%	2.5%	2.5%	2.9%	2.9%	3.0%	3.2%	3.1%	2.7%	2.6%	2.2%			Avg Ann'l Div'd Yield	*2.7%*

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
268.6	301.4	318.7	361.0	398.9	419.3	466.9	472.1	465.8	458.6	*460*	*475*	Revenues ($mill)	*585*
23.1	28.0	26.8	29.5	41.4	42.0	54.1	62.7	61.1	60.5	*62.0*	*66.0*	Net Profit ($mill)	*83.0*
40.5%	42.6%	37.8%	38.9%	43.2%	41.7%	39.9%	36.3%	38.4%	38.4%	*38.0%*	*37.0%*	Income Tax Rate	*36.0%*
12.2%	8.5%	6.9%	3.2%	5.8%	2.0%	2.5%	--	2.5%	.5%	*1.0%*	*1.5%*	AFUDC % to Net Profit	*1.0%*
48.6%	46.9%	46.2%	45.9%	44.3%	45.4%	42.2%	39.8%	39.1%	41.1%	*42.0%*	*42.5%*	Long-Term Debt Ratio	*57.0%*
51.4%	53.1%	53.8%	54.1%	55.7%	54.6%	57.8%	60.2%	60.9%	58.9%	*58.0%*	*57.5%*	Common Equity Ratio	*43.0%*
551.6	569.4	577.0	665.0	677.4	749.1	787.0	818.4	832.6	791.5	*860*	*900*	Total Capital ($mill)	*1060*
750.6	776.4	825.3	866.4	855.0	896.5	917.8	981.5	1003.5	1060.8	*1105*	*1150*	Net Plant ($mill)	*1370*
6.0%	6.7%	6.4%	5.9%	7.6%	7.1%	8.3%	8.9%	8.6%	9.0%	*9.0%*	*8.5%*	Return on Total Cap'l	*9.5%*
8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	11.9%	12.7%	12.0%	13.0%	*12.5%*	*13.0%*	Return on Shr. Equity	*13.5%*
8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	11.9%	12.7%	12.0%	13.0%	*12.5%*	*13.0%*	Return on Com Equity	*13.5%*
2.7%	3.9%	3.1%	3.2%	5.8%	5.3%	6.6%	6.8%	5.7%	6.0%	*6.0%*	*6.0%*	Retained to Com Eq	*6.0%*
67%	58%	64%	61%	47%	49%	45%	47%	53%	54%	*54%*	*54%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $325.8 mill. Due in 5 Yrs $41.6 mill.
LT Debt $325.5 mill. LT Interest $21.1 mill.
(41% of Cap'l)

Leases, Uncapitalized: Annual rentals $2.5 mill.
Pension Assets-12/15 $142.2 mill.
Oblig. $168.9 mill.
Pfd Stock None.

Common Stock 36,523,179 shs.
as of 2/22/16

MARKET CAP: $1.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	38.2	76.0	4.4
Accts Receivable	23.8	18.8	18.9
Other	129.6	114.7	109.4
Current Assets	191.6	209.5	132.7
Accts Payable	49.8	41.9	50.6
Debt Due	6.3	.3	.3
Other	44.8	57.1	72.6
Current Liab.	100.9	99.3	123.5

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	6.0%	4.5%	4.5%
"Cash Flow"	9.0%	8.0%	6.0%
Earnings	12.0%	12.0%	6.0%
Dividends	6.5%	10.0%	7.0%
Book Value	5.5%	6.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	110.6	120.7	130.9	109.9	472.1
2014	102.0	115.6	138.3	109.9	465.8
2015	100.9	114.6	133.0	110.1	458.6
2016	*100*	*115*	*135*	*110*	*460*
2017	*102*	*120*	*140*	*113*	*475*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.35	.43	.53	.30	1.61
2014	.28	.39	.54	.36	1.57
2015	.32	.41	.56	.31	1.60
2016	*.31*	*.47*	*.59*	*.33*	*1.70*
2017	*.35*	*.50*	*.60*	*.35*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.14	.14	.1775	.1775	.64
2013	.1775	.1775	.2025	.2025	.76
2014	.2025	.2025	.213	.213	.83
2015	.213	.213	.224	.224	.87
2016	.224				

BUSINESS: American States Water Co. operates as a holding company. Through its principal subsidiary, Golden States Water Company, it supplies water to 260,151 customers in 75 cities and 10 counties. Service areas include the greater metropolitan areas of Los Angeles and Orange Counties. The company also provides electric utility services to 23,846 customers in the city of Big Bear Lake and in areas of San Bernardino County. Sold Chaparral City Water of Arizona (6/11). Has 707 employees. Blackrock, Inc., owns 9.8% of out. shares; Vanguard, 8.5%; off. & dir. 1.5%. (4/15 Proxy). Chairman: Lloyd Ross. President & Chief Executive Officer: Robert J. Sprowls. Inc: CA. Address: 630 East Foothill Boulevard, San Dimas, CA 91773. Tel: 909-394-3600. Internet: www.aswater.com.

Shares of American States Water continue to struggle. For the second straight quarter, the stock has underperformed both the water industry and the market averages. Since our January report, the value of the equity has declined 4% while many water utility stocks posted double-digit gains, and the S&P 500 Index rose about 2%.

We think the company's earnings may break out of their narrow range in 2016. Over the past three years, American States' share net has been close to $1.60. Last year's bottom line was held back due to an accounting practice regarding a water revenue adjusted mechanism (WRAP). In brief, a utility can't recognize certain revenues that can't be collected over a certain time. The funds will eventually be recouped, but have to be deferred. Indeed, management estimates that $1.4 million in revenues earned in 2015, will be realized in 2016. All told, the company's earnings should increase a solid 6%, to $1.70 a share. We are introducing our 2017 share-earnings estimate at $1.80, another healthy 6% increase.

Results at American States' nonregulated business will be the wild card. Through its ASUS subsidiary, the company installs and operates water facilities at major U.S. Army bases. The contracts to run the camps are for 50 years and enable American States to earn more than it does on its regulated operations. The armed forces are privatizing this business at many bases, and ASUS continues to bid on new proposals. Since the firm has enjoyed success here, we are assuming it will land more contracts in the future. In 2015, this business accounted for 20% of the company's net income, a percentage that may well increase in the coming years.

This equity is an Average (3) selection for year-ahead performance. AWR gets good marks for Safety (2: Above Average), Financial Strength (A), Earnings Predictability (90), and also has a low Beta coefficient (0.75). And even though conservative accounts are willing to accept lower future payouts in return for a reduced risk profile, we do not think that the stock's potential returns through 2019-2021 are sufficient. Hence, investors can do better elsewhere on a risk-adjusted basis.

James A. Flood *April 15, 2016*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 7¢; '05, 13¢; '06, 3¢; '08, (14¢); '10, (23¢) '11, 10¢. Next earnings report due early May.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	90

AMERICAN WATER NYSE-AWK

RECENT PRICE	69.05	P/E RATIO	24.7 (Trailing: 26.2 / Median: NMF)	RELATIVE P/E RATIO	1.35	DIV'D YLD	2.1%	VALUE LINE

TIMELINESS **2** Lowered 4/8/16

SAFETY **3** New 7/25/08

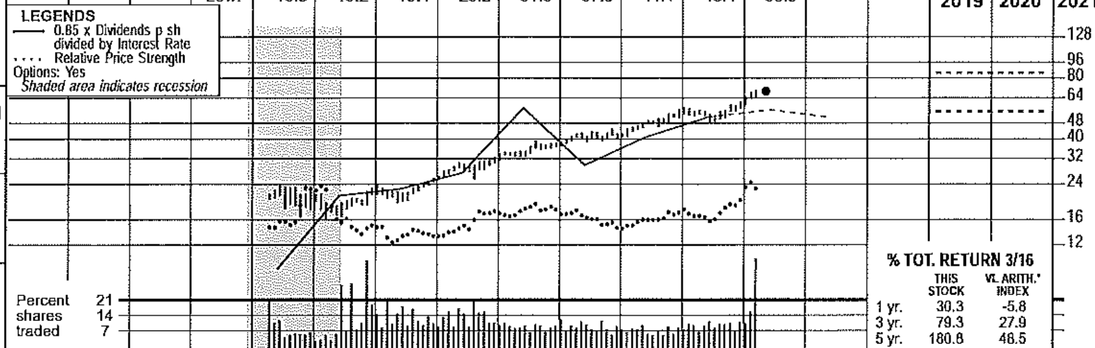
TECHNICAL **2** Raised 3/18/16

BETA .70 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	23.7	23.0	25.8	32.8	39.4	45.1	56.2	61.2	70.1
Low:	16.5	16.2	19.4	25.2	31.3	37.0	41.1	48.4	58.9

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 0.85 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+25%)	8%
Low	55	(-20%)	-2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	1	0	0	4	0	0	10
to Sell	0	0	1	0	0	4	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	247	211	241
to Sell	206	220	227
Hld's(000)	145636	148013	147408

Percent shares traded 21 14 7

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.3	-5.8
3 yr.	79.3	27.9
5 yr.	180.8	46.5

2000	2001	2002	2003	2004	2005	2006	2007E	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	--	--	--	--	--	13.08	13.84	14.61	13.98	15.49	15.18	16.25	16.28	16.78	17.72	*18.70*	*19.75*	Revenues per sh	*22.30*
--	--	--	--	--	--	.65	d.47	2.87	2.89	3.56	3.73	4.27	4.36	4.75	5.13	*5.40*	*5.70*	"Cash Flow" per sh	*6.60*
--	--	--	--	--	--	d.97	d2.14	1.10	1.25	1.53	1.72	2.11	2.06	2.39	2.64	*2.80*	*3.05*	Earnings per sh A	*3.75*
--	--	--	--	--	--	--	--	.40	.82	.86	.90	1.21	.84	1.21	1.33	*1.45*	*1.57*	Div'd Decl'd per sh B■	*2.05*
--	--	--	--	--	--	4.31	4.74	6.31	4.50	4.38	5.27	5.25	5.50	5.33	6.51	*6.15*	*6.10*	Cap'l Spending per sh	*6.00*
--	--	--	--	--	--	23.86	28.39	25.64	22.91	23.59	24.11	25.11	26.52	27.39	28.25	*29.05*	*30.95*	Book Value per sh D	*34.65*
--	--	--	--	--	--	160.00	160.00	160.00	174.63	175.00	175.66	176.99	178.25	179.46	178.28	*179.00*	*181.00*	Common Shs Outst'g C	*187.50*
--	--	--	--	--	--	--	--	18.9	15.6	14.6	16.8	16.7	19.9	20.0	20.5	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
--	--	--	--	--	--	--	--	1.14	1.04	.93	1.05	1.06	1.12	1.05	1.04	*Value Line*		Relative P/E Ratio	*1.20*
--	--	--	--	--	--	--	--	1.9%	4.2%	3.8%	3.1%	3.4%	2.0%	2.5%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $6544.0 mil. Due in 5 Yrs $1272.0 mil.
LT Debt $5862.0 mil. LT Interest $293.0 mil.
(54% of Cap'l)

Leases, Uncapitalized: Annual rentals $14.0 mill.
Pension Assets 12/15 $1376.0 mill
Oblig. $1584.0 mill.
Pfd Stock $12.0 mill. Pfd Div'd $.5 mill

Common Stock 178,008,765 shs.
as of 2/19/2016

MARKET CAP: $12.3 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
2093.1	2214.2	2336.9	2440.7	2710.7	2666.2	2876.9	2901.9	3011.3	3159.0	*3350*	*3575*	Revenues ($mill)	*4180*
d155.8	d342.3	187.2	209.9	267.8	304.9	374.3	369.3	429.8	476.0	*500*	*550*	Net Profit ($mill)	*700*
--	--	37.4%	37.9%	40.4%	39.5%	40.7%	39.1%	39.4%	39.1%	*38.5%*	*38.5%*	Income Tax Rate	*37.0%*
--	--	--	--	--	--	6.2%	5.1%	5.1%	1.4%	*2.5%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
56.1%	50.9%	53.1%	56.9%	56.8%	55.7%	53.9%	52.4%	52.4%	53.7%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
43.9%	49.1%	46.9%	43.1%	43.2%	44.2%	46.1%	47.6%	47.4%	46.2%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
8692.8	9245.7	8750.2	9289.0	9561.3	9580.3	9635.5	9940.7	10364	10911	*11610*	*12300*	Total Capital ($mill)	*14540*
8720.6	9318.0	9991.8	10524	11059	11021	11739	12391	12900	13933	*14600*	*15400*	Net Plant ($mill)	*17200*
NMF	NMF	3.7%	3.8%	4.4%	4.8%	5.4%	5.1%	5.5%	5.7%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	7.8%	8.7%	9.4%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	7.8%	8.7%	9.4%	*9.5%*	*10.0%*	Return on Com Equity	*10.5%*
NMF	NMF	3.0%	1.8%	2.8%	3.5%	3.6%	4.7%	4.3%	4.7%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
--	--	34%	65%	56%	52%	57%	40%	50%	50%	*52%*	*51%*	All Div'ds to Net Prof	*55%*

CURRENT POSITION ($MILL.)

	2013	2014	12/31/15
Cash Assets	27.0	23.1	45.0
Accts Receivable	244.6	267.1	255.0
Other	523.4	638.3	357.0
Current Assets	550.4	661.4	657.0
Accts Payable	264.6	285.8	126.0
Debt Due	644.5	511.1	682.0
Other	326.4	444.1	725.0
Current Liab.	1235.5	1241.0	1533.0

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	3.0%	4.5%
"Cash Flow"	--	9.0%	5.5%
Earnings	--	13.0%	8.0%
Dividends	--	10.0%	10.5%
Book Value	--	2.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	636.1	724.3	829.2	712.3	2901.9
2014	679.0	754.8	846.1	731.4	3011.3
2015	698.0	782.0	896.0	783.0	3159.0
2016	*735*	*830*	*950*	*835*	*3350*
2017	*775*	*865*	*975*	*960*	*3575*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.32	.57	.84	.33	2.06
2014	.39	.62	.86	.52	2.39
2015	.44	.68	.96	.56	2.64
2016	*.46*	*.74*	*1.03*	*.57*	*2.80*
2017	*.53*	*.77*	*1.10*	*.65*	*3.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.23	.25	.50	1.21
2013	--	.28	.28	.28	.84
2014	.28	.31	.31	.31	1.21
2015	.31	.34	.34	.34	1.33
2016	.34				

BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to over 15 million people in over 47 states and Canada. (Regulated presence in 16 states.) Nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 86.8% of 2015 revenues. New Jersey is its largest market accounting for 25.7% of regulated revenues. Has 6,700 employees. BlackRock, Inc., owns 10.2% of outstanding shares; Vanguard, 7.2%; officers & directors, less than 1.0%. (4/16 Proxy). President & CEO: Susan Story. Chairman: George Mackenzie. Address: 1025 Laurel Oak Road, Voorhaes, NJ 08043. Tel.: 856-346-8200. Internet: www.amwater.com.

Shares of American Water Works have been on an impressive run. Since our January report, the value of the stock has risen nearly 15%, or 1,300 basis points greater than the broader market averages. A partial reason for the strong showing was the company's inclusion into the S&P 500 Index. This resulted in greater demand for AWK, as specific index funds were forced to purchase the equity.

Meanwhile, a recently proposed acquisition could augur well for future takeovers. The water industry is comprised of thousands of small municipally run districts. In the recent past, bigger investor-owned utilities have been gradually absorbing hundreds of these small water authorities into their operations. Due to the vast amounts of redundancies in the industry, significant cost savings have been generated. The recent $190 million agreement to acquire the wastewater assets from the cash-strapped city of Scranton is substantially larger than previous purchases. Thus, the size of mergers could well climb as economically depressed districts struggle to raise the capital needed to be in compliance with EPA requirements. As the largest member of the group, by a wide margin, American Water stands to benefit the most from this trend.

Controlling expenses and increasing the rate base should continue to drive the utility's earnings growth. In this decade, management has been focused on lowering the company's operating and maintenance (O&M) ratio. With the exception of last year (a rise caused by the purchase of a nonregulated business), this percentage has been on the decline. Indeed, the ratio, which stood at 44% in 2010, fell to 36% in 2015, and should be reduced to 34% by 2020. Also, American Water plans on spending $1.1 billion annually over the next five years to upgrade its water infrastructure. As these expenditures are incorporated into the rate base, profits should expand.

This stock is mainly for momentum investors. AWK is favorably ranked for year-ahead performance. With the recent spike in the value of the equity, however, all the positive developments we expect from the company through 2019-2021 appear to be factored into the share price.

James A. Flood *April 15, 2016*

(A) Diluted earnings. Excludes nonrecurring losses: '08, $4.62; '09, $2.63; '11, $0.07. Discontinued operations: '06, ($0.04); '11, $0.03; '12, ($0.10); '13,($0.01). GAAP used as of 2014. Next earnings report due early May. Quarterly earnings may not sum due to rounding. (B) Dividends paid in March, June, September, and December. ■ Div. reinvestment available. Two payments made in 4th quarter of 2012. (C) In millions. (D) Includes intangibles. In 2015: $1.38 billion, $7.74/share. (E) Pro forma numbers for '06 & '07.

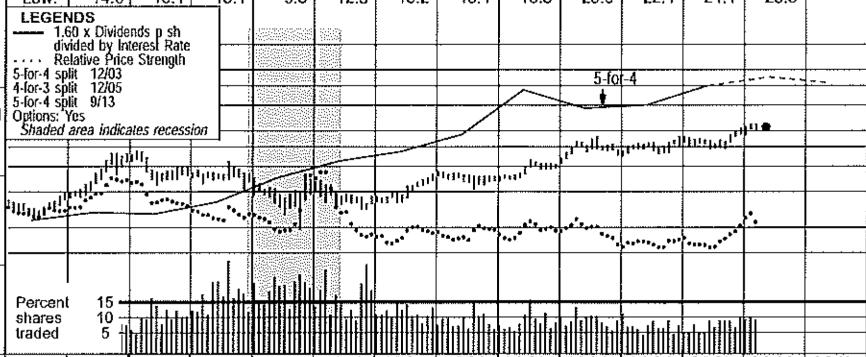
Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	35

AQUA AMERICA NYSE-WTR

RECENT PRICE **31.39** | P/E RATIO **25.7** (Trailing: 27.5 / Median: 22.0) | RELATIVE P/E RATIO **1.40** | DIV'D YLD **2.4%** | **VALUE LINE**

TIMELINESS 3 Lowered 3/25/16
SAFETY 2 Raised 4/20/12
TECHNICAL 2 Raised 3/11/16
BETA .75 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	23.4	23.8	21.3	17.6	17.2	18.4	19.0	21.5	28.1	28.2	31.1	32.4
Low:	14.0	16.1	15.1	9.8	12.3	13.2	15.4	16.8	20.6	22.4	24.4	28.3



Target Price Range 2019 | 2020 | 2021
80 60 50 40 30 25 20 15 10 7.5

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	12%
Low	35	(+10%)	6%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	1	3	0	1	0
to Sell	1	0	2	1	1	4	1	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	156	166	182
to Sell	145	138	149
Hld's(000)	82530	84833	83005

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.8	-5.8
3 yr.	36.2	27.9
5 yr.	97.8	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
1.97	2.16	2.28	2.38	2.78	3.08	3.23	3.61	3.71	3.93	4.21	4.10	4.32	4.32	4.37	4.61	*4.80*	*5.10*	Revenues per sh	*6.05*
.61	.69	.76	.77	.87	.97	1.01	1.10	1.14	1.29	1.42	1.45	1.51	1.82	1.89	1.87	*2.10*	*2.25*	"Cash Flow" per sh	*2.65*
.37	.41	.43	.46	.51	.57	.56	.57	.58	.62	.72	.83	.87	1.16	1.20	1.14	*1.35*	*1.45*	Earnings per sh A	*1.75*
.23	.24	.26	.28	.29	.32	.35	.38	.41	.44	.47	.50	.54	.58	.63	.69	*.74*	*.80*	Div'd Decl'd per sh B■	*1.05*
.93	.87	.96	1.06	1.23	1.47	1.64	1.43	1.58	1.66	1.89	1.90	1.98	1.73	1.84	2.07	*2.10*	*2.10*	Cap'l Spending per sh	*2.10*
3.08	3.32	3.49	4.27	4.71	5.04	5.57	5.85	6.26	6.50	6.81	7.21	7.90	8.63	9.27	9.78	*10.90*	*11.70*	Book Value per sh	*13.10*
139.78	142.47	141.49	154.31	158.97	161.21	165.41	166.75	169.21	170.61	172.46	173.60	175.43	177.93	178.59	176.54	*177.00*	*177.00*	Common Shs Outst'g C	*177.00*
18.2	23.6	23.6	24.5	25.1	31.8	34.7	32.0	24.9	23.1	21.1	21.3	21.9	21.2	20.8	23.5	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.50	1.54	1.34	1.34	1.39	1.19	1.09	1.19	*Value Line*		Relative P/E Ratio	*1.40*
3.3%	2.5%	2.5%	2.5%	2.3%	1.8%	1.8%	2.1%	2.8%	3.1%	3.1%	2.8%	2.8%	2.4%	2.5%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1795.9 mill. Due in 5 Yrs $441.5 mill.
LT Debt $1743.6 mill. LT Interest $75.4 mill.
(50% of Cap'l)

Pension Assets-12/15 $238.6 mill.
Oblig. $306.5 mill.

Pfd Stock None

Common Stock 177,042,334 shares
as of 2/10/16

MARKET CAP: $5.6 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
533.5	602.5	627.0	670.5	726.1	712.0	757.8	768.6	779.9	814.2	*850*	*900*	Revenues ($mill)	*1070*
92.0	95.0	97.9	104.4	124.0	144.8	153.1	205.0	213.9	201.8	*240*	*255*	Net Profit ($mill)	*310*
39.6%	38.9%	39.7%	39.4%	39.2%	32.9%	39.0%	10.0%	10.5%	6.9%	*10.0%*	*11.0%*	Income Tax Rate	*25.0%*
--	--	--	--	--	--	--	1.1%	2.4%	3.1%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
51.6%	55.4%	54.1%	55.6%	56.6%	52.7%	52.7%	48.9%	48.5%	50.3%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
48.4%	44.6%	45.9%	44.4%	43.4%	47.3%	47.3%	51.1%	51.5%	49.7%	*49.0%*	*48.0%*	Common Equity Ratio	*48.0%*
1904.4	2191.4	2306.6	2495.5	2706.2	2646.8	2929.7	3003.6	3216.0	3469.5	*3930*	*4330*	Total Capital ($mill)	*4850*
2506.0	2792.8	2997.4	3227.3	3469.3	3612.9	3936.2	4167.3	4402.0	4688.9	*4930*	*5170*	Net Plant ($mill)	*5500*
6.4%	5.9%	5.7%	5.6%	5.9%	6.9%	6.6%	8.0%	7.8%	6.9%	*7.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	13.4%	12.9%	11.7%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.5%*
10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	13.4%	12.9%	11.7%	*12.5%*	*12.5%*	Return on Com Equity	*13.5%*
3.7%	3.2%	2.8%	2.7%	3.7%	4.6%	4.3%	6.7%	6.1%	4.7%	*7.0%*	*7.0%*	Retained to Com Eq	*4.5%*
63%	67%	70%	72%	65%	60%	61%	50%	52%	60%	*55%*	*55%*	All Div'ds to Net Prof	*60%*

CURRENT POSITION ($MILL.)

	2013	2014	12/31/15
Cash Assets	5.1	4.1	3.2
Receivables	95.4	97.0	99.1
Inventory (AvgCst)	11.4	12.8	12.4
Other	59.8	38.6	13.7
Current Assets	171.7	152.5	128.4
Accts Payable	65.8	60.0	56.5
Debt Due	123.0	70.0	52.3
Other	78.1	95.3	84.4
Current Liab.	266.9	225.3	193.2

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	5.0%	2.5%	5.5%
"Cash Flow"	8.0%	8.0%	6.0%
Earnings	8.5%	13.0%	7.0%
Dividends	8.0%	7.5%	9.0%
Book Value	7.0%	7.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	180.0	195.7	204.3	188.6	768.6
2014	182.7	195.3	210.5	191.4	779.9
2015	190.3	205.8	221.0	197.1	814.2
2016	*197*	*215*	*233*	*205*	*850*
2017	*205*	*225*	*255*	*215*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.26	.30	.36	.24	1.16
2014	.24	.31	.38	.27	1.20
2015	.27	.32	.38	.17	1.14
2016	*.28*	*.35*	*.42*	*.30*	*1.35*
2017	*.30*	*.37*	*.46*	*.32*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.132	.132	.132	.14	.54
2013	.14	.14	.152	.152	.58
2014	.152	.152	.165	.165	.63
2015	.165	.165	.178	.178	.69
2016	.178				

BUSINESS: Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately three million residents in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Florida, Indiana, and five other states. Has 1,617 employees. Acquired AquaSource, 7/13; North Maine Utilities, 7/15; and others. Water supply revenues '2015: residential, 69%; commercial, 18%; industrial & other, 13%. Officers and directors own less than 1% of the common stock; Vangurad Group, 7.7%; Blackrock, Inc, 7.3%; State Street Capital, 5.5% (3/16 Proxy). President & Chief Executive Officer: Christopher Franklin. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Tel.: 610-525-1400. Internet: www.aquaamerica.com.

Aqua America's earnings should get back on track this year. In the final quarter of 2015, the water utility had to take a $0.12-a-share impairment charge related to the poor performance of a non regulated business. In any case, with the help of rate relief in several states and synergies realized from previous acquisitions, we expect Aqua's share earnings to recover to $1.35 in 2016, an 18% increase over 2014's depressed level. Next year, we think the bottom line should climb a solid 7%, to $1.45 a share.

Acquisitions may play an even more important role in the company's strategy. The American water market consists of over 50,000 major-to-midsized water districts. Because there are many redundancies in the industry, large utilities can buy small ones and realize significant cost savings when absorbing them into existing operations. Since 2000, Aqua has bought almost 300 small water operations. Management recently indicated a proclivity to acquire much-bigger systems. The likely candidates are water districts in financially depressed areas. There are many municipally-run water utilities that don't have the needed capital required to modernize aging infrastructures and to make costly improvements mandated by the EPA. The city of Scranton, PA recently agreed to sell its wastewater assets to American Water Works for $190 million. Last year, both Indiana and New Jersey passed laws making the process easier for a strong water company to take over a weak one. These larger potential purchases should enable Aqua to maintain healthy earnings and dividend growth for the foreseeable future.

Finances will probably weaken modestly. Aqua was able to keep its debt-to-total capital ratio below 50% for 2013 and 2014 before exceeding it in 2015. With a capital budget of about $1.1 billion over the next three years, we think the ratio will be about 52% through late decade.

The stock's strong performance has removed much of its appeal. Since mid-August, shares of Aqua have outpaced the S&P 500 Index by about 1,700 basis points. Thus, most of the company's positive attributes appear to be fully reflected in the current price of the equity.

James A. Flood *April 15, 2016*

(A) Diluted egs. Excl. nonrec. gains: '00, 2¢; '01, 2¢; '02, 4¢; '03, 3¢; '12, 18¢. Excl. gain from disc. operations: '12, 7¢; '13, 9¢; '14, 11¢. May not sum due to rounding. Next earnings report due early May.
(B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount).
(C) In millions, adjusted for stock splits.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

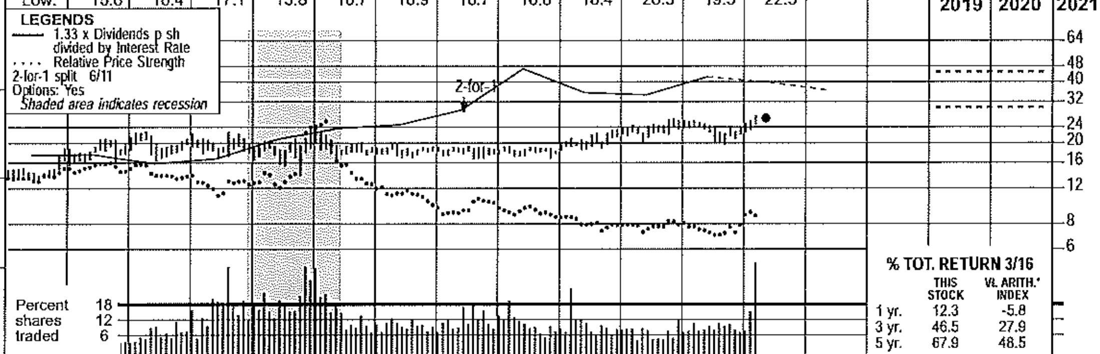
CALIFORNIA WATER NYSE-CWT

RECENT PRICE 26.59 | P/E RATIO 25.8 (Trailing: 28.3; Median: 20.0) | RELATIVE P/E RATIO 1.41 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 3 Raised 1/8/16
SAFETY 3 Lowered 7/27/07
TECHNICAL 2 Lowered 4/15/16
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	21.1	22.9	22.7	23.3	24.1	19.8	19.4	19.3	23.4	26.4	26.0	27.3
Low:	15.6	16.4	17.1	13.8	16.7	16.9	16.7	16.8	18.4	20.3	19.5	22.5

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+70%)	16%
Low	30	(+15%)	6%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	1	1	1	1	1	1	1
Options	0	0	0	10	10	1	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	82	69	69
to Sell	66	74	75
Hld's(000)	29659	28655	30579

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	-5.8
3 yr.	46.5	27.9
5 yr.	67.9	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
8.08	8.13	8.67	8.18	8.59	8.72	8.10	8.88	9.90	10.82	11.05	12.00	13.34	12.23	12.50	12.29	*12.60*	*13.00*	Revenues per sh	*14.70*
1.26	1.10	1.32	1.26	1.42	1.52	1.36	1.56	1.86	1.93	1.93	2.07	2.32	2.21	2.47	2.22	*2.35*	*2.65*	"Cash Flow" per sh	*3.25*
.66	.47	.63	.61	.73	.74	.67	.75	.95	.98	.91	.86	1.02	1.02	1.19	.94	*1.05*	*1.35*	Earnings per sh A	*1.60*
.55	.56	.56	.56	.57	.57	.58	.58	.59	.59	.60	.62	.63	.64	.65	.67	*.69*	*.71*	Div'd Decl'd per sh B ■	*.99*
1.23	2.04	2.91	2.19	1.87	2.01	2.14	1.84	2.41	2.66	2.97	2.83	3.04	2.58	2.76	3.69	*3.65*	*3.55*	Cap'l Spending per sh	*3.30*
6.45	6.48	6.56	7.22	7.83	7.90	9.07	9.25	9.72	10.13	10.45	10.76	11.28	12.54	13.11	13.41	*13.55*	*14.25*	Book Value per sh C	*16.00*
30.29	30.36	30.36	33.86	36.73	36.78	41.31	41.33	41.45	41.53	41.67	41.82	41.98	47.74	47.81	47.88	*48.00*	*48.00*	Common Shs Outst'g D	*50.00*
19.6	27.1	19.8	22.1	20.1	24.9	29.2	26.1	19.8	19.7	20.3	21.3	17.9	20.1	19.7	24.8	*Bold figures are*		Avg Ann'l P/E Ratio	*23.0*
1.27	1.39	1.08	1.26	1.06	1.33	1.58	1.39	1.19	1.31	1.29	1.34	1.14	1.13	1.04	1.26	*Value Line*		Relative P/E Ratio	*1.45*
4.3%	4.4%	4.5%	4.2%	3.9%	3.1%	2.9%	3.0%	3.1%	3.1%	3.2%	3.4%	3.5%	3.1%	2.8%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*2.6%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $552.5 mill. Due in 5 Yrs $175.3 mill.
LT Debt $512.3 mill. LT Interest $27.2 mill.
(44% of Cap'l)

Pension Assets-12/15 $328.6 mill.
Oblig. $501.9 mill.

Pfd Stock None

Common Stock 47,875,000 shs.

MARKET CAP: $1.3 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
334.7	367.1	410.3	449.4	460.4	501.8	560.0	584.1	597.5	588.3	*605*	*625*	Revenues ($mill) E	*735*
25.6	31.2	39.8	40.6	37.7	36.1	42.6	47.3	56.7	45.0	*50.0*	*65.0*	Net Profit ($mill)	*80.0*
37.4%	39.9%	37.7%	40.3%	39.5%	40.5%	37.5%	30.3%	33.0%	35.3%	*32.0%*	*32.0%*	Income Tax Rate	*35.0%*
10.6%	8.3%	8.6%	7.6%	4.2%	7.6%	8.0%	4.3%	2.7%	4.2%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
43.5%	42.9%	41.6%	47.1%	52.4%	51.7%	47.8%	41.6%	40.1%	44.4%	*44.5%*	*43.5%*	Long-Term Debt Ratio	*42.0%*
55.9%	56.6%	58.4%	52.9%	47.6%	48.3%	52.2%	58.4%	59.9%	55.6%	*55.5%*	*56.5%*	Common Equity Ratio	*58.0%*
670.1	674.9	690.4	794.9	914.7	931.5	908.2	1024.9	1045.9	1154.5	*1175*	*1210*	Total Capital ($mill)	*1375*
941.5	1010.2	1112.4	1198.1	1294.3	1381.1	1457.1	1515.8	1590.4	1701.8	*1775*	*1815*	Net Plant ($mill)	*1900*
5.2%	5.9%	7.1%	6.5%	5.5%	5.5%	6.3%	6.0%	6.3%	5.1%	*5.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	9.0%	7.9%	9.1%	7.0%	*7.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	9.0%	7.9%	9.1%	7.0%	*7.5%*	*9.5%*	Return on Com Equity	*10.0%*
1.0%	1.8%	3.8%	3.8%	3.0%	2.3%	3.4%	3.4%	4.1%	2.0%	*2.5%*	*4.5%*	Retained to Com Eq	*4.0%*
86%	77%	61%	60%	66%	71%	62%	56%	55%	71%	*66%*	*52%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	27.5	19.6	8.8
Other	112.0	134.5	118.8
Current Assets	139.5	154.1	127.6
Accts Payable	55.1	59.4	66.4
Debt Due	54.7	85.7	40.2
Other	56.8	72.6	41.9
Current Liab.	166.6	217.7	148.5

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	4.0%	5.0%	*2.0%*
"Cash Flow"	6.0%	5.5%	*5.0%*
Earnings	5.0%	4.0%	*6.0%*
Dividends	1.5%	2.0%	*6.5%*
Book Value	5.5%	5.0%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.)E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	111.4	154.6	184.4	133.7	584.1
2014	110.5	158.4	191.2	137.4	597.5
2015	122.0	144.4	183.5	138.4	588.3
2016	*125*	*150*	*190*	*140*	*605*
2017	*130*	*155*	*195*	*145*	*625*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.01	.28	.61	.12	1.02
2014	d.11	.36	.70	.24	1.19
2015	.03	.21	.52	.18	.94
2016	*.03*	*.22*	*.60*	*.20*	*1.05*
2017	*.05*	*.35*	*.65*	*.30*	*1.35*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.1575	.1575	.1575	.1575	.63
2013	.16	.16	.16	.16	.64
2014	.1625	.1625	.1625	.1625	.65
2015	.1675	.1675	.1675	.1675	.67
2016	.1725				

BUSINESS: California Water Service Group provides regulated and nonregulated water service to 477,900 customers in 85 communities in the state of California. Accounts for over 94% of total customers. Also operates in Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '15: residantial, 70%; business, 20%; industrial, 5%; public authorities, 4%; other 1%. '15 reported depreciation rate: 4.0%. Has 1,155 employees. President, Chairman, and CEO: Peter C. Nelson. Inc.: DE. Address: 1720 North First St., San Jose, CA 95112-4598. Tel.: 408-367-8200. Internet: www.calwatergroup.com.

The California Water Service Group did not have the best financial showing in 2015. Both the top and bottom lines contracted on a year-over-year basis. Revenues of $588 million slipped nearly $10 million from the prior-year tally. The earnings decline was even more pronounced. Annual share net shrank by a quarter, to $0.94, its lowest figure in almost five years. Indeed, the ongoing pressures of the California drought, alongside higher maintenance and pension expenses, contributed to the lackluster performance.

Our approach to 2016 is a cautious one. Namely, the unbilled revenues figure (incurred expenses that CWT is waiting to be reimbursed for) is slightly thinner than for previous quarters. On top of that, with a higher tax rate in place, bottom-line growth will probably be limited. As a result, we have trimmed our 2016 share-net estimate by $0.15, to $1.05.

However, earnings should see a meaningful rebound in 2017. At the moment, unfavorable drought conditions seem to be on their last leg. As the environment improves, related expenses will probably abate. Too, the main catalyst on the horizon is the California General Rate Case, which has an ask of just below $700 million. All in all, we think CWT will earn $1.35 a share in 2017. Revenues should get a lift, as well.

Further capital investments might be in the cards over the pull to late decade. Improvements to the infrastructure, water supply, and tanks are at the top of the list. We think there is the potential for some acquisition activity, too. CWT is in good financial shape, with decent liquidity and a debt profile in line with the industry's average.

The dividend remains a feature here. At present, CWT shares yield 2.6%, somewhat low compared to historical levels. Nevertheless, we think the payout ratio will be consistent through late decade, with steady dividend hikes.

California Water shares are neutrally ranked for relative year-ahead price performance. What's more, investors with a long-term bent will find better options elsewhere, at this juncture, as total return potential three to five years hence is below the *Value Line* median.

Nicholas P. Patrikis *April 15, 2016*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (4¢); '01, 2¢; '02, 4¢; '11, 4¢. Next earnings report due late May.
(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. intangible assets. In '15 : $7.5 mill., $0.16/sh.
(D) In millions, adjusted for splits.
(E) Excludes non-reg. rev.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	85

CONNECTICUT WATER NDQ-CTWS

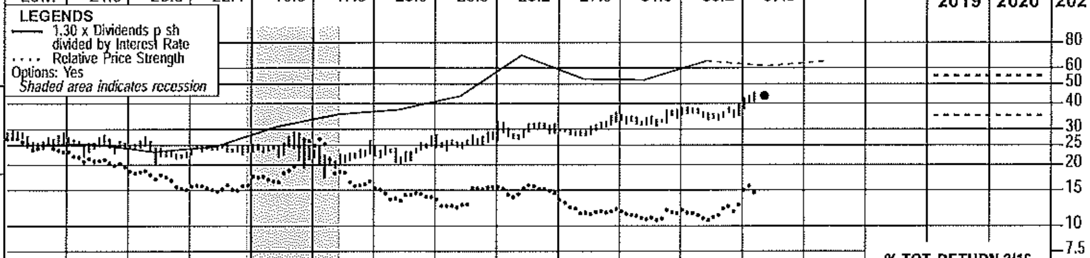
RECENT PRICE	43.81	P/E RATIO	21.4 (Trailing: 21.5; Median: 21.0)	RELATIVE P/E RATIO	1.17	DIV'D YLD	2.4%	VALUE LINE

TIMELINESS 3 Lowered 3/25/16
SAFETY 3 New 1/18/13
TECHNICAL 2 Raised 3/11/16
BETA .60 (1.00 = Market)

High:	28.2	27.7	25.6	29.0	26.4	27.9	29.1	32.8	36.4	37.5	39.9	45.7	
Low:	21.9	20.3	22.4	19.3	17.3	20.0	23.3	26.2	27.8	31.0	33.2	37.5	

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	8%
Low	35	(-20%)	-2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	54	50	51
to Sell	37	34	44
Hld's(000)	4391	4527	4535

Percent shares traded 12 8 4

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.8	-5.8
3 yr.	68.8	27.9
5 yr.	100.2	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
5.70	5.93	5.77	5.91	6.04	5.81	5.68	7.05	7.24	6.93	7.65	7.93	9.47	8.29	8.45	8.58	*9.00*	*9.20*	Revenues per sh	*13.35*
1.73	1.78	1.78	1.89	1.91	1.62	1.52	1.90	1.95	1.93	2.04	2.11	2.64	2.63	2.97	3.18	*3.25*	*3.45*	"Cash Flow" per sh	*3.60*
1.09	1.13	1.12	1.15	1.16	.88	.81	1.05	1.11	1.19	1.13	1.13	1.53	1.66	1.92	2.04	*2.10*	*2.20*	Earnings per sh A	*2.35*
.79	.80	.81	.83	.84	.85	.86	.87	.88	.90	.92	.94	.96	.98	1.01	1.05	*1.09*	*1.30*	Div'd Decl'd per sh B■	*1.35*
1.43	1.86	1.98	1.49	1.58	1.96	1.96	2.24	2.44	3.28	3.06	2.61	2.79	3.02	4.11	4.29	*5.80*	*4.35*	Cap'l Spending per sh	*3.35*
8.92	9.25	10.06	10.46	10.94	11.52	11.60	11.95	12.23	12.67	13.05	13.50	20.95	17.92	18.83	20.02	*21.15*	*21.75*	Book Value per sh D	*22.90*
7.28	7.65	7.94	7.97	8.04	8.17	8.27	8.38	8.46	8.57	8.68	8.76	8.85	11.04	11.12	11.19	*11.35*	*11.50*	Common Shs Outst'g C	*12.00*
18.2	21.5	24.3	23.5	22.9	28.6	29.0	23.0	22.2	18.4	20.7	23.0	19.4	18.4	17.5	17.6	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
1.18	1.10	1.33	1.34	1.21	1.52	1.57	1.22	1.34	1.23	1.32	1.44	1.23	1.03	.92	.89	*Value Line*		Relative P/E Ratio	*1.20*
4.0%	3.3%	3.0%	3.0%	3.1%	3.4%	3.6%	3.6%	3.6%	4.1%	3.9%	3.6%	3.2%	3.2%	3.0%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
46.9	59.0	61.3	59.4	66.4	69.4	83.8	91.5	94.0	96.0	*102*	*106*	Revenues ($mill)	*160*
6.7	8.8	9.4	10.2	9.8	9.9	13.6	18.3	21.3	22.7	*24.0*	*25.5*	Net Profit ($mill)	*28.0*
23.5%	32.4%	27.2%	19.5%	35.2%	41.3%	32.0%	28.0%	14.4%	4.2%	*7.5%*	*19.0%*	Income Tax Rate	*27.0%*
--	--	1.7%	--	--	--	1.7%	2.0%	2.4%	2.2%	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.0%*
44.4%	47.8%	46.9%	50.6%	49.5%	53.2%	49.0%	46.9%	45.7%	44.2%	*45.0%*	*46.0%*	Long-Term Debt Ratio	*47.5%*
55.1%	51.8%	52.7%	49.1%	50.2%	46.5%	50.8%	52.9%	54.1%	55.8%	*55.0%*	*54.0%*	Common Equity Ratio	*52.5%*
174.1	193.2	196.5	221.3	225.6	254.2	364.6	373.6	386.8	401.7	*435*	*465*	Total Capital ($mill)	*525*
268.1	284.3	302.3	325.2	344.2	362.4	447.9	471.9	506.9	546.3	*565*	*590*	Net Plant ($mill)	*675*
4.9%	5.5%	5.9%	5.5%	5.4%	4.9%	4.8%	5.9%	6.4%	6.6%	*6.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.9%	8.7%	9.0%	9.3%	8.6%	8.3%	7.3%	9.2%	10.1%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
7.0%	8.7%	9.1%	9.4%	8.7%	8.3%	7.3%	9.2%	10.2%	10.1%	*10.0%*	*10.0%*	Return on Com Equity	*10.5%*
NMF	1.6%	1.9%	2.3%	1.6%	1.4%	2.8%	3.8%	4.8%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*4.5%*
105%	82%	79%	76%	81%	83%	62%	59%	53%	52%	*52%*	*51%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $180.5 mill. Due in 5 Yrs $19.3 mill.
LT Debt $177.7 mill. LT Interest $7.0 mill.
(44% of Cap'l)

Leases, Uncapitalized: Annual rentals $.3 mill.
Pension Assets-12/15 $56.6 mill.
Oblig. $75.8 mill.

Pfd Stock $0.8 mill. Pfd Divd NMF

Common Stock 11,192,882 shs.

MARKET CAP: $500 million (Small Cap)

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	18.4	2.5	.7
Accounts Receivable	12.3	12.0	11.0
Other	16.2	21.7	15.3
Current Assets	46.9	36.2	27.0
Accts Payable	10.8	10.0	11.9
Debt Due	4.1	4.4	2.8
Other	7.8	9.2	22.2
Current Liab.	22.7	23.6	36.9

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	4.0%	4.5%	*6.0%*
"Cash Flow"	4.0%	7.5%	*4.0%*
Earnings	4.0%	9.0%	*4.5%*
Dividends	2.0%	2.0%	*4.5%*
Book Value	6.5%	9.5%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	19.7	22.6	27.6	21.6	91.5
2014	20.3	25.4	27.6	20.7	94.0
2015	20.0	26.6	28.4	21.0	96.0
2016	*22.5*	*27.5*	*30.0*	*22.0*	*102*
2017	*23.0*	*28.0*	*32.0*	*23.0*	*106*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.24	.39	.86	.17	1.66
2014	.27	.67	.76	.22	1.92
2015	.28	.77	.79	.20	2.04
2016	*.32*	*.68*	*.85*	*.25*	*2.10*
2017	*.34*	*.70*	*.88*	*.28*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.238	.238	.2425	.2425	.962
2013	.2425	.2425	.2475	.2475	.98
2014	.2475	.2475	.2575	.2575	1.01
2015	.2575	.2575	.2675	.2675	1.05
2016	.2675				

BUSINESS: Connecticut Water Service, Inc. is a non-operating holding company, whose income is derived from earnings of its wholly-owned subsidiary companies (regulated water utilities). In 2015, 92% of net income was derived from these activities. Provides water services to 400,000 people in 77 municipalities throughout Connecticut and Maine. Acquired The Maine Water Company, January, 2012; Biddeford and Saco Water, December, 2012. Incorporated: Connecticut. Has 266 employees. Chairman/President/Chief Executive Officer: Eric W. Thornburg. Officers and directors own 2.6% of the common stock; BlackRock, Inc. 7.0%; (4/16 proxy). Address: 93 West Main Street, Clinton, CT 06413. Telephone: (860) 669-8636. Internet: www.ctwater.com.

Connecticut Water Service reported fourth-quarter results roughly in line with our expectations. Earnings of $0.20 for the period were merely a penny shy of our call. Likewise, revenues of $21.0 million missed by a fraction. Nonetheless, year-over-year top- and bottom-line comparisons were solid, giving investors reason to cheer.

Shares of Connecticut Water have risen sharply since our January review. The stock is up approximately 15% in price over the past three months, etching a new all-time high along the way.

Dividend growth is encouraging. The company has indeed stepped up it's game, increasing the payout growth rate in both 2014 and 2015. This trend ought to help the annual return catch up with the stock's steady ascent. At that point, the yield will likely hover around the 3% level over the next several years, in our view.

We are introducing our 2017 top- and bottom-line estimates. Connecticut Water should continue to reap the rewards of the repair tax credit, as well as a lower tax rate. Additionally, benefits from the pipeline in Mansfield (currently under way), a project to meet the long-term water supply for the University of Connecticut and surrounding community, ought to be noticeable next year. All told, we look for 2017 revenue and earnings of $106 million and $2.20 a share, respectively.

Capital expenditures ought to remain elevated in the near-to-intermediate term. Management has set aside $66 million for major projects this year. These endeavors include the upgrading of the wastewater facility, along with repairing its aging infrastructure. Once the latter is completed, spending should return to more-normal levels.

This equity is pegged to move in line with the broader market averages over the coming six to 12 months. On top of that, these shares do not stand out for the long haul. Much of the growth we envision over the 3- to 5-year time frame appears to already be baked into the stock price, as Connecticut Water is trading well within our recently raised Target Price Range. We recommend investors remain on the sidelines, for now.

Nicholas P. Patrikis *April 15, 2016*

(A) Diluted earnings. Next earnings report due late May.
(B) Dividends historically paid in mid-March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.
(D) Includes intangibles. In 2015: $30.4 million/$2.72 a share.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	85

CONSOL. WATER CO. NDQ-CWCO

RECENT PRICE	11.95	P/E RATIO	20.6 (Trailing: 23.4, Median: 25.0)	RELATIVE P/E RATIO	1.13	DIV'D YLD	2.5%	VALUE LINE

TIMELINESS 3 Raised 11/20/15
SAFETY 3 New 1/17/14
TECHNICAL 4 Lowered 4/15/16
BETA .85 (1.00 = Market)

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+150%)	27%
Low	20	(+65%)	16%

Insider Decisions

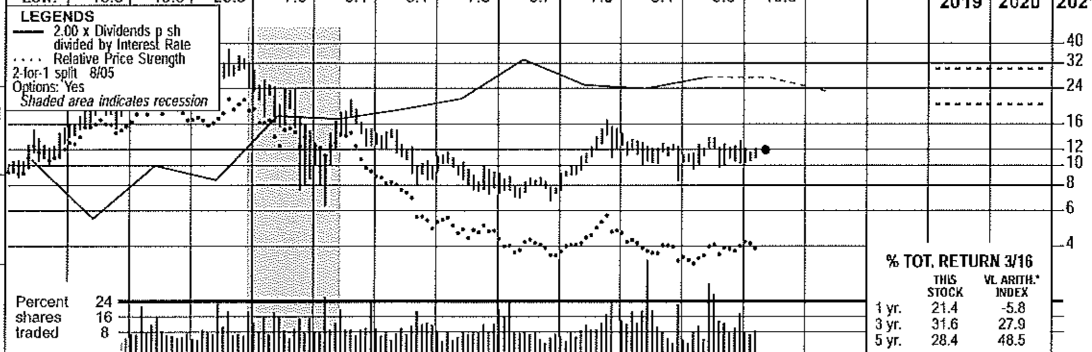
	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	2	1	0	0	0	5	7	0	1
to Sell	2	0	0	0	0	5	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	50	39	34
to Sell	13	30	27
Hld's(000)	6572	7086	6793

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	22.5	31.8	37.5	29.8	21.3	15.1	11.7	9.2	16.9	14.5	13.8	12.4	
Low:	13.6	19.8	23.3	7.6	6.4	8.1	7.3	6.7	7.5	8.4	9.6	10.3	

Target Price Range
2019 | 2020 | 2021



% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.4	-5.8
3 yr.	31.6	27.9
5 yr.	28.4	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
1.24	1.41	1.52	1.68	2.02	1.12	2.71	3.41	4.52	3.99	3.49	3.79	4.49	4.35	4.46	3.86	*5.25*	*5.60*	Revenues per sh	*10.00*
.46	.52	.50	.63	.77	.37	.87	1.20	.95	1.18	.86	.83	1.17	.96	.80	.88	*1.00*	*1.10*	"Cash Flow" per sh	*1.65*
.34	.35	.32	.42	.49	.23	.59	.79	.50	.74	.43	.42	.64	.58	.42	.51	*.60*	*.70*	Earnings per sh A	*1.20*
.17	.20	.21	.21	.23	.12	.24	.20	.33	.28	.30	.30	.30	.30	.30	.30	*.30*	*.30*	Div'd Decl'd per sh B■	*.40*
.30	.24	.39	.19	.24	.77	1.83	.54	.46	.18	.09	.96	.31	.29	.32	.21	*.65*	*1.35*	Cap'l Spending per sh	*.40*
2.30	2.45	2.64	3.89	4.20	2.54	7.49	8.21	8.36	8.53	8.69	8.83	9.20	9.44	9.58	9.81	*10.10*	*10.65*	Book Value per sh	*11.90*
7.73	7.84	7.99	11.37	11.51	23.46	14.13	14.40	14.53	14.54	14.55	14.57	14.59	14.69	14.72	14.78	*14.85*	*15.00*	Common Shs Outst'g C	*16.00*
10.4	13.9	21.6	19.3	23.1	80.0	43.0	35.4	37.8	19.0	26.9	22.4	12.4	20.0	28.3	22.7	*Bold figures are*		Avg Ann'l P/E Ratio	*21.0*
.68	.71	1.18	1.10	1.22	4.26	2.32	1.88	2.27	1.27	1.71	1.41	.79	1.12	1.49	1.15	*Value Line*		Relative P/E Ratio	*1.30*
4.9%	4.2%	3.1%	2.6%	2.0%	.7%	.9%	.7%	1.7%	2.0%	2.6%	3.2%	3.8%	2.6%	2.5%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*1.6%*
						38.2	49.2	65.7	58.0	50.7	55.2	65.5	63.8	65.6	57.1	*78.0*	*84.0*	Revenues ($mill)	*160*
						7.5	11.4	7.2	10.8	6.3	6.1	9.3	8.6	6.3	7.5	*9.0*	*10.5*	Net Profit ($mill)	*19.0*
						--	--	--	--	--	--	--	--	--	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
						--	--	--	--	--	4.0%	--	--	--	--	*NMF*	*NMF*	AFUDC % to Net Profit	*NMF*
						18.2%	15.9%	14.8%	13.8%	11.8%	5.1%	3.7%	--	3.7%	--	*Nil*	*Nil*	Long-Term Debt Ratio	*Nil*
						81.8%	84.1%	85.2%	86.2%	88.2%	94.9%	96.3%	99.8%	99.8%	100.0%	*100%*	*100%*	Common Equity Ratio	*100%*
						129.3	140.7	142.7	143.9	143.3	135.6	139.4	138.9	141.2	145.0	*150*	*160*	Total Capital ($mill)	*190*
						63.6	65.0	65.1	61.2	56.2	64.3	61.6	58.6	56.4	53.7	*60.0*	*75.0*	Net Plant ($mill)	*240*
						6.5%	8.8%	5.7%	8.1%	4.9%	5.0%	7.0%	6.2%	4.4%	5.2%	*6.0%*	*6.5%*	Return on Total Cap'l	*10.0%*
						7.1%	9.6%	5.9%	8.7%	5.0%	4.7%	6.9%	6.2%	4.4%	5.2%	*6.0%*	*6.5%*	Return on Shr. Equity	*10.0%*
						7.1%	9.6%	5.9%	8.7%	5.0%	4.7%	6.9%	6.2%	4.4%	5.1%	*6.0%*	*6.5%*	Return on Com Equity	*10.0%*
						4.2%	6.5%	2.8%	4.6%	1.5%	1.0%	3.6%	3.0%	1.2%	2.1%	*3.0%*	*4.0%*	Retained to Com Eq	*6.5%*
						41%	33%	52%	46%	69%	79%	48%	51%	73%	60%	*50%*	*43%*	All Div'ds to Net Prof	*33%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $7.0 mill. Due in 5 Yrs $7.0 mill.
LT Debt None LT Interest None

Leases, Uncapitalized: Annual rentals $.7 mill.

No Defined Benefit Pension Plan

Pfd Stock NMF (38,804 shares out.) **Div'd** NMF

Common Stock 14,785,922 shs.
as of 3/8/16

MARKET CAP: $175 million (Small Cap)

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	42.2	40.7	50.4
Accts Receivable	18.9	11.8	9.5
Other	6.5	6.9	5.5
Current Assets	67.6	59.4	65.4
Accts Payable	7.2	6.0	4.8
Debt Due	5.2	9.0	7.0
Other	11.2	1.2	1.4
Current Liab.	23.6	16.2	13.2

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	10.0%	1.0%	*15.5%*
"Cash Flow"	4.0%	-2.5%	*11.0%*
Earnings	3.0%	-2.0%	*15.5%*
Dividends	5.0%	--	*5.0%*
Book Value	10.5%	2.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	16.6	16.6	15.4	15.2	63.8
2014	16.3	16.9	17.0	15.4	65.6
2015	14.7	14.4	14.6	13.4	57.1
2016	*16.1*	*19.6*	*21.8*	*20.5*	*78.0*
2017	*20.3*	*20.5*	*22.2*	*21.0*	*84.0*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.26	.19	.06	.07	.58
2014	.04	.19	.13	.06	.42
2015	.13	.15	.12	.11	.51
2016	*.15*	*.16*	*.16*	*.13*	*.60*
2017	*.21*	*.16*	*.16*	*.17*	*.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.075	.075	.075	.075	.30
2013	.075	.075	.075	.075	.30
2014	.075	.075	.075	.075	.30
2015	.075	.075	.075	.075	.30
2016	.075				

BUSINESS: Consolidated Water Co. Ltd. develops and operates seawater desalination plants and water distribution systems in areas where naturally occurring supplies of potable water are scarce or nonexistent. Its desalination process involves reverse osmosis tech. It provides water in the Cayman Islands, Belize, the Bahamas, the British Virgin Islands, and Bali. At 12/31/15, it operated 14 plants with a capacity of 26.5 million gallons per day. Inc.: Cayman Isl. Has 127 employees. Pres./CEO: Frederick McTaggart. Off./dir. own 3.3% of stock; Thomson, Horstmann, & Bryant, 6.2% (4/15 proxy). Address: Regatta Office Park Windward Three, 4th Floor, West Bay Road P.O. Box 1114 Grand Cayman, KYI-1102, Cayman Islands. Tel.: (345) 945-4277. Int.: www.cwco.com.

Consolidated Water has made an acquisition. Effective February 11th, the company had a 51% stake in Aerex Industries, a manufacturer of products used to treat municipal and industrial water and wastewater. To date, the only financial information disclosed was that the purchase price was $7.7 million and Aerex had revenues of over $19 million in 2015. *(Note: Our presentation only includes Aerex's impact on Consolidated's revenues.)*

Otherwise, the situation remains about the same in the Caribbean. The builder and operator of desalination facilities, continues to be involved in ongoing disputes with regulators from the three main nations where it operates in the region. In the Caymans, the company and authorities are haggling over a change in the pricing model. Accounts receivable from the government of the Bahamas continue to climb, but management states that this does not reflect any dispute with the company. Also, in the British Virgin Islands, lengthy litigation over the Bar Bay plant is still ongoing. In some countries, regulators are not signing long-term contracts, most likely as a bargaining chip.

On the bright side, lower expenses should propel earnings. Absent 2015's abnormal legal fees, along with the development costs associated with a major project in Mexico, we expect Consolidated's share earnings to recover to $0.60 in 2016 and $0.70 in 2017.

Two large projects will have a meaningful impact on the company's long-term prospects. The Nua Dusa plant located on Bali is in the red, but we think this situation will change due to the lack of potable water on the island. Also, the planning for the proposed $600 million desalination facility in Mexico has been completed. If all goes as expected, this facility, in which Consolidated will own 12%, will be providing water to the arid and populated cities of San Diego and Tijuana.

These shares are only for investors willing to live with some uncertainty. CWCO has a small but healthy balance sheet. Moreover, its total return potential through 2019-2021 is very attractive. Still, much of this is offset by regulatory risk and the possibility of the construction program not meeting expectations.

James A. Flood *April 15, 2016*

(A) Fully diluted earnings. Next earnings report due early May. (B) Dividends historically paid in late January, April, July and October. ■ Dividend reinvestment plan available.

(C) In millions adjusted for stock split.

Company's Financial Strength	B+
Stock's Price Stability	30
Price Growth Persistence	10
Earnings Predictability	50

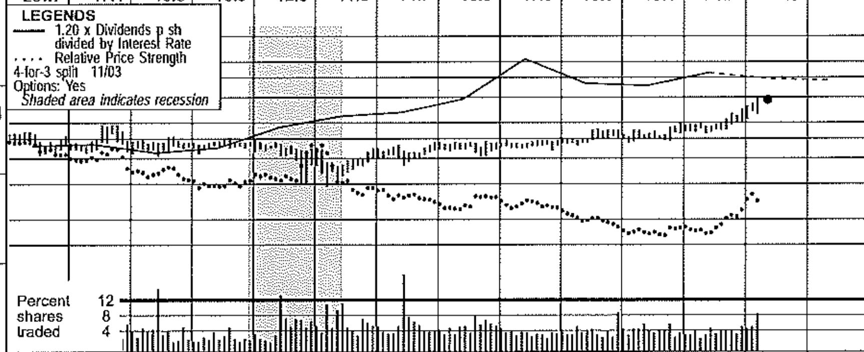
MIDDLESEX WATER NDQ-MSEX

RECENT PRICE 31.05 | P/E RATIO 24.1 (Trailing: 25.5; Median: 20.0) | RELATIVE P/E RATIO 1.32 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 2 Raised 3/18/16
SAFETY 2 New 10/21/11
TECHNICAL 2 Lowered 4/8/16
BETA .70 (1.00 = Market)

High:	23.5	20.5	20.2	19.8	17.9	19.3	19.4	19.6	22.5	23.7	28.0	32.1
Low:	17.1	16.5	16.9	12.0	11.6	14.7	16.5	17.5	18.6	19.1	21.2	25.0

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+15%)	6%
Low	25	(-20%)	-2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	43	47	41
to Sell	36	42	50
Hld's(000)	6487	6614	6584

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	40.0	-5.8
3 yr.	75.4	27.9
5 yr.	103.8	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
5.39	5.87	5.98	6.12	6.25	6.44	6.16	6.50	6.79	6.75	6.60	6.50	6.98	7.19	7.26	7.77	**8.00**	**8.00**	Revenues per sh	**9.40**
.99	1.18	1.20	1.15	1.28	1.33	1.33	1.49	1.53	1.40	1.55	1.46	1.56	1.72	1.84	1.97	**2.10**	**2.20**	"Cash Flow" per sh	**2.45**
.51	.66	.73	.61	.73	.71	.82	.87	.89	.72	.96	.84	.90	1.03	1.13	1.22	**1.30**	**1.35**	Earnings per sh A	**1.40**
.61	.62	.63	.65	.66	.67	.68	.69	.70	.71	.72	.73	.74	.75	.76	.78	**.81**	**.84**	Div'd Decl'd per sh B■	**.91**
1.32	1.25	1.59	1.87	2.54	2.18	2.31	1.66	2.12	1.49	1.90	1.50	1.36	1.26	1.40	1.59	**1.75**	**1.80**	Cap'l Spending per sh	**2.05**
6.98	7.11	7.39	7.60	8.02	8.26	9.52	10.05	10.03	10.33	11.13	11.27	11.48	11.82	12.24	12.74	**13.25**	**13.95**	Book Value per sh	**15.60**
10.11	10.17	10.36	10.48	11.36	11.58	13.17	13.25	13.40	13.52	15.57	15.70	15.82	15.96	16.12	16.23	**16.25**	**16.50**	Common Shs Outst'g C	**17.00**
28.7	24.6	23.5	30.0	26.4	27.4	22.7	21.6	19.8	21.0	17.8	21.7	20.8	19.7	18.5	19.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**21.0**
1.87	1.26	1.28	1.71	1.39	1.46	1.23	1.15	1.19	1.40	1.13	1.36	1.32	1.11	.97	.97	*estimates*		Relative P/E Ratio	**1.30**
4.2%	3.8%	3.7%	3.5%	3.4%	3.5%	3.7%	3.7%	4.0%	4.7%	4.2%	4.0%	4.0%	3.7%	3.7%	3.3%			Avg Ann'l Div'd Yield	**3.0%**

CAPITAL STRUCTURE as of 12/31/15
Total Debt 144.9 mill. Due in 5 Yrs $30.8 mill.
LT Debt $136.2 mill. LT Interest $5.6 mill.
(39% of Cap'l)

Pension Assets-12/15 $52.9 mill.
Oblig. $72.5 mill.
Pfd Stock $2.4 mill. Pfd Div'd: $.1 mill.

Common Stock 16,225,000 shs.

MARKET CAP: $500 million (Small Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
81.1	86.1	91.0	91.2	102.7	102.1	110.4	114.8	117.1	126.0	**130**	**132**	Revenues ($mill)	**160**
10.0	11.8	12.2	10.0	14.3	13.4	14.4	16.6	18.4	20.0	**21.0**	**22.0**	Net Profit ($mill)	**24.0**
33.4%	32.6%	33.2%	34.1%	32.1%	32.7%	33.9%	34.1%	35.0%	34.5%	**35.0%**	**35.0%**	Income Tax Rate	**34.0%**
--	--	--	--	6.8%	6.1%	3.4%	1.9%	1.7%	1.9%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.5%**
49.5%	49.0%	45.6%	46.6%	43.1%	42.3%	41.5%	40.4%	40.5%	39.4%	**39.0%**	**40.0%**	Long-Term Debt Ratio	**40.0%**
47.5%	49.6%	51.8%	52.1%	55.8%	56.6%	57.4%	58.7%	58.8%	59.8%	**61.0%**	**60.0%**	Common Equity Ratio	**60.0%**
264.0	268.8	259.4	267.9	310.5	312.5	316.5	321.4	335.8	345.4	**355**	**365**	Total Capital ($mill)	**440**
317.1	333.9	366.3	376.5	405.9	422.2	435.2	446.5	465.4	481.9	**495**	**515**	Net Plant ($mill)	**565**
5.1%	5.6%	5.8%	5.0%	5.7%	5.2%	5.4%	5.9%	6.3%	6.6%	**6.5%**	**7.0%**	Return on Total Cap'l	**6.0%**
7.5%	8.6%	8.6%	7.0%	8.1%	7.5%	7.8%	8.7%	9.2%	9.6%	**10.0%**	**10.0%**	Return on Shr. Equity	**9.0%**
7.8%	8.7%	8.9%	7.0%	8.2%	7.5%	7.8%	8.7%	9.3%	9.6%	**10.0%**	**10.0%**	Return on Com Equity	**9.0%**
1.3%	1.8%	2.0%	.1%	2.1%	1.0%	1.4%	2.4%	3.1%	3.5%	**3.5%**	**3.5%**	Retained to Com Eq	**3.0%**
84%	79%	78%	98%	75%	87%	83%	73%	67%	63%	**62%**	**61%**	All Div'ds to Net Prof	**65%**

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	4.8	2.7	3.5
Other	21.0	20.2	20.9
Current Assets	25.8	22.9	24.4
Accts Payable	6.3	6.4	6.5
Debt Due	33.8	24.9	8.7
Other	12.6	12.6	13.1
Current Liab.	52.7	43.9	28.3

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	1.5%	2.0%	4.0%
"Cash Flow"	4.0%	4.5%	5.0%
Earnings	5.0%	5.5%	3.5%
Dividends	1.5%	1.5%	3.0%
Book Value	4.5%	3.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	27.0	29.1	31.3	27.4	114.8
2014	27.1	29.2	32.7	28.1	117.1
2015	28.8	31.7	34.7	30.8	126.0
2016	**29.5**	**32.5**	**35.5**	**32.5**	**130**
2017	**30.0**	**33.0**	**36.0**	**33.0**	**132**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.20	.28	.36	.19	1.03
2014	.20	.29	.42	.22	1.13
2015	.22	.31	.41	.28	1.22
2016	**.23**	**.33**	**.45**	**.29**	**1.30**
2017	**.25**	**.34**	**.46**	**.30**	**1.35**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.185	.185	.185	.1875	.74
2013	.1875	.1875	.1875	.19	.75
2014	.19	.19	.19	.1925	.76
2015	.1925	.1925	.1925	.19875	.78
2016	.19875				

BUSINESS: Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 60,000 retail customers, primarily in Middlesex County, New Jersey. In 2015, the Middlesex System accounted for 59% of operating revenues. At 12/31/15, the company had 293 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers & directors own 3.5% of the common stock; BlackRock Institutional Trust Co., 6.6% (4/15 proxy). Add.: 1500 Ronson Road, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: www.middlesexwater.com.

Middlesex Water Company shares rose more than 15% in price over the past three months. The stock has been trending higher since the middle of 2015, piggybacking off a string of better-than-expected financial results. Indeed, MSEX traded at an all-time high during the period, at $32 per share.

Financials continue to impress. The company ended the year on the right foot, registering high single-digit top- and bottom-line growth, on an annual basis. Full-year revenues increased to $126 million (approximately 8% year over year), while share net ticked up $0.09 (nearly 9%) from the prior-year figure, to $1.22. Rate increases and greater weather-driven customer demand from the company's New Jersey systems were primarily responsible for the strong performance.

We are optimistic about 2016 and 2017 earnings prospects, despite steadily increasing operations and maintenance costs. The recently approved rate hike from New Jersey regulators will be in effect through this year, boosting revenues. Though expenses are a concern, namely employee benefits, retirement, and healthcare, we think MSEX is doing a solid job navigating the waters. All things considered, we are lifting our 2016 earnings estimate by a dime, to $1.30 a share. Meanwhile, we are introducing our 2017 share-net forecast of $1.35.

Dividend growth ought to persist over the pull to late decade. The company has a pristine track record of payout hikes, and as of last year, ramped up the rate at which it will increase. Thus, we have tweaked our model to incorporate dividend growth of 2¢ per year, rather than the traditional 1¢ rise. At present, however, the yield is less appealing than investors may be used to, due largely to the recent surge in price. Over the long haul, we think a 3.0% annual return is likely in the cards.

Middlesex shares are ranked to outperform the broader market averages over the coming six to 12 months. Conversely, investors with an eye to late decade may want to stay on the sidelines, for now, as much of the gains we envision out to 2019-2021 appear to already be baked into the stock price, rendering capital appreciation potential subpar.

Nicholas P. Patrikis *April 15, 2016*

(A) Diluted earnings. May not sum due to rounding. Next earnings report due late May.
(B) Dividends historically paid in mid-Feb., May, Aug., and November.■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

SJW CORP. NYSE-SJW | RECENT PRICE **36.41** | P/E RATIO **18.2** (Trailing: 19.8 / Median: 24.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **2.2%** | **VALUE LINE**

TIMELINESS **2** Raised 3/11/16
SAFETY **3** New 4/22/11
TECHNICAL **1** Raised 4/1/16
BETA .75 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	27.8	45.3	43.0	35.1	30.4	28.2	26.8	26.9	30.1	33.7	35.7	37.9
Low:	16.1	21.2	27.7	20.0	18.2	21.6	20.9	22.6	24.5	25.5	27.5	28.6

Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

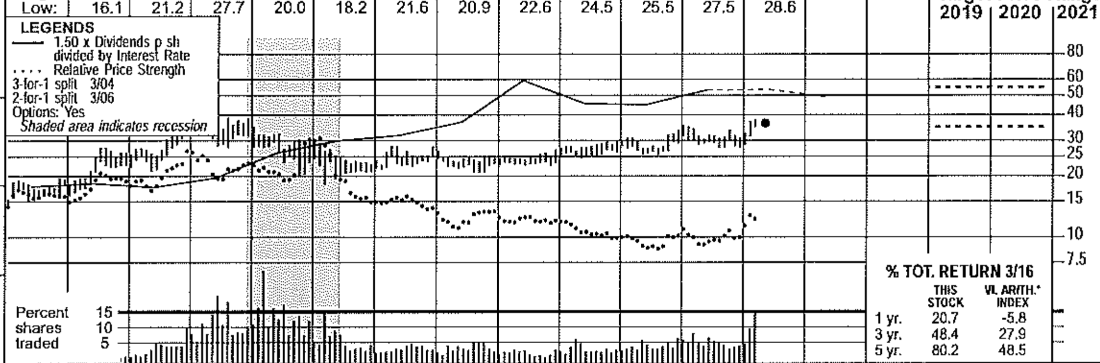
	Price	Gain	Ann'l Total Return
High	55	(+50%)	13%
Low	35	(-5%)	2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	1	0	1	0	0	0	3	0	0
Options	0	0	0	0	0	0	0	9	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	63	61	43
to Sell	49	44	59
Hld's(000)	10749	9038	8694



% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.7	-5.8
3 yr.	48.4	27.9
5 yr.	80.2	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
6.74	7.45	7.97	8.20	9.14	9.86	10.35	11.25	12.12	11.68	11.62	12.85	14.01	13.73	15.76	14.97	*15.10*	*15.25*	Revenues per sh	*18.50*
1.23	1.49	1.55	1.75	1.89	2.21	2.38	2.30	2.44	2.21	2.38	2.80	2.97	2.90	4.42	3.86	*3.85*	*3.95*	"Cash Flow" per sh	*3.95*
.58	.77	.78	.91	.87	1.12	1.19	1.04	1.08	.81	.84	1.11	1.18	1.12	2.54	1.85	*1.80*	*1.95*	Earnings per sh A	*2.00*
.41	.43	.46	.49	.51	.53	.57	.61	.65	.66	.68	.69	.71	.73	.75	.78	*.82*	*.85*	Div'd Decl'd per sh B■	*1.05*
1.89	2.63	2.06	3.41	2.31	2.83	3.87	6.62	3.79	3.17	5.65	3.75	5.67	4.68	5.02	5.24	*5.35*	*5.50*	Cap'l Spending per sh	*5.00*
7.90	8.17	8.40	9.11	10.11	10.72	12.48	12.90	13.99	13.66	13.75	14.20	14.71	15.92	17.75	18.83	*19.00*	*19.75*	Book Value per sh	*22.40*
18.27	18.27	18.27	18.27	18.27	18.27	18.28	18.36	18.18	18.50	18.55	18.59	18.67	20.17	20.29	20.38	*20.50*	*21.00*	Common Shs Outst'g C	*23.00*
33.1	18.5	17.3	15.4	19.6	19.7	23.5	33.4	26.2	28.7	29.1	21.2	20.4	24.3	11.2	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	*22.0*
2.15	.95	.94	.88	1.04	1.05	1.27	1.77	1.58	1.91	1.85	1.33	1.30	1.37	.59	.84	*Value Line*		Relative P/E Ratio	*1.40*
2.1%	3.0%	3.4%	3.5%	3.0%	2.4%	2.0%	1.7%	2.3%	2.8%	2.8%	2.9%	3.0%	2.7%	2.6%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $418.9 mill. Due in 5 Yrs $21.2 mill.
LT Debt $380.8 mill. LT Interest $21.0 mill. (50% of Cap'l)

Leases, Uncapitalized: Annual rentals $6.6 mill.

Pension Assets-12/15 $105.0 mill. Oblig. $164.3 mill.

Pfd Stock None.

Common Stock 20,381,949 shs.

MARKET CAP: $750 million (Small Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
189.2	206.6	220.3	216.1	215.6	239.0	261.5	276.9	319.7	305.1	*310*	*320*	Revenues ($mill)	*425*
22.2	19.3	20.2	15.2	15.8	20.9	22.3	23.5	51.8	37.9	*37.5*	*40.0*	Net Profit ($mill)	*45.0*
40.8%	39.4%	39.5%	40.4%	38.8%	41.1%	41.1%	38.7%	32.5%	38.1%	*39.0%*	*39.5%*	Income Tax Rate	*38.0%*
2.1%	2.7%	2.3%	2.0%	--	--	--	--	2.0%	1.0%	*1.5%*	*1.5%*	AFUDC % to Net Profit	*1.5%*
41.8%	47.7%	46.0%	49.4%	53.7%	56.6%	55.0%	51.1%	51.6%	49.8%	*50.5%*	*51.5%*	Long-Term Debt Ratio	*51.5%*
58.2%	52.3%	54.0%	50.6%	46.3%	43.4%	45.0%	48.9%	48.4%	50.2%	*49.5%*	*48.5%*	Common Equity Ratio	*48.5%*
391.8	453.2	470.9	499.6	550.7	607.9	610.2	656.2	744.5	764.6	*790*	*855*	Total Capital ($mill)	*1065*
541.7	645.5	684.2	718.5	785.5	756.2	831.6	898.7	963.0	1036.8	*1100*	*1200*	Net Plant ($mill)	*1325*
7.0%	5.7%	5.8%	4.4%	4.3%	4.9%	5.0%	5.0%	8.3%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	7.3%	14.4%	9.9%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.0%*
9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	7.3%	14.4%	9.9%	*9.5%*	*9.5%*	Return on Com Equity	*9.0%*
5.2%	3.5%	3.3%	1.2%	1.2%	3.1%	3.3%	2.8%	10.2%	5.7%	*5.0%*	*5.5%*	Retained to Com Eq	*4.0%*
46%	57%	59%	80%	80%	61%	59%	62%	29%	42%	*45%*	*45%*	All Div'ds to Net Prof	*60%*

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	2.3	2.4	5.2
Accts Receivable	14.5	15.0	16.4
Other	22.9	50.7	51.8
Current Assets	39.7	68.1	73.4
Accts Payable	12.6	7.0	16.2
Debt Due	23.0	13.8	38.1
Other	23.6	23.9	25.3
Current Liab.	59.2	44.7	79.6

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	5.0%	4.5%	3.5%
"Cash Flow"	6.5%	10.0%	2.5%
Earnings	6.5%	15.0%	1.5%
Dividends	4.0%	2.5%	6.0%
Book Value	6.0%	5.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	50.1	74.2	85.2	67.4	276.9
2014	54.6	70.4	125.4	69.3	319.7
2015	62.1	72.4	83.0	87.6	305.1
2016	*65.0*	*75.0*	*90.0*	*80.0*	*310*
2017	*67.0*	*78.0*	*92.0*	*83.0*	*320*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.07	.37	.44	.24	1.12
2014	.04	.34	1.88	.28	2.54
2015	.23	.36	.46	.80	1.85
2016	*.20*	*.40*	*.60*	*.60*	*1.80*
2017	*.25*	*.45*	*.65*	*.60*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.1775	.1775	.1775	.1775	.71
2013	.1825	.1825	.1825	.1825	.73
2014	.1875	.1875	.1875	.1875	.75
2015	.1950	.1950	.1950	.1950	.78
2016	.2025				

BUSINESS: SJW Corporation engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 229,000 connections with a total population of roughly one million people in the San Jose area and 12,000 connections that reaches about 36,000 residents in the region between San Antonio and Austin, Texas. The company also offers nonregulated water-related services and owns and operates commercial real estate investments. Has about 399 employees. Officers and directors (including Nancy O. Moss) own 28.3% of outstanding shares. Chairman: Charles J. Toeniskoetter. Incorporated: California. Address: 110 West Taylor Street, San Jose, CA 95110. Telephone: (408) 279-7800. Internet: www.sjwater.com.

SJW Corp. ended the year on a strong note. The water utility delivered better-than-expected top- and bottom-line results for the fourth quarter. Revenues of $87.6 million bested our target by roughly $15 million. Similarly, net income of $0.80 a share for the period came in well above the Street's and our estimate. Indeed, the outperformance can be partly attributed to the accumulation of lost revenue at the end of 2015, as a result of Mandatory Conservation Revenue Adjustment Memorandum. This form of revenue recognition helped bolster financials this year, and ought to continue to do so going forward. What's more, investors have taken notice of the favorable operating environment, sending the stock price more than 20% higher over the past three months, establishing a new 52-week high.

The stage is set for a profitable 2016 and beyond. Despite embarking on the fourth consecutive year of drought conditions, which have undoubtedly raised costs overall, the company has actually experienced lower water production expenses of late. Meanwhile, selling and administrative costs, as well as pension expenses, should begin to cool. In addition, the General Rate Case proceeding may be another positive for the bottom line, even with substantial capital investments on tap. On balance, we are raising our full-year 2016 earnings estimate by $0.25, to $1.80 a share. Too, we are introducing our 2017 projection at $1.95 per share.

SJW Corp. pays a decent dividend. At the recent quotation, the payout yields a somewhat unimpressive 2.2%. That said, the distribution is poised to increase year-after-year, like the company has done throughout its operating history. Moreover, we anticipate a similarly healthy yield over the 3- to 5-year stretch.

Shares of SJW Corp. have been raised two notches for Timeliness, to 2, and are now favorably ranked for relative year ahead price performance. We think there is some room to run in the near-term, as investors may look to piggyback off of strong earnings results. Conversely, this issue offers little upside potential for the pull to 2019-2021. SJW stock is already trading above the lower-end of our Target Price Range.

Nicholas P. Patrikis *April 15, 2016*

(A) Diluted earnings. Excludes nonrecurring losses : '03, $1.97; '04, $3.78; '05, $1.09; '06, $16.36; '08, $1.22; '10, $0.46. GAAP accounting as of 2013. Next earnings report due late May. Quarterly earnings may not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock splits.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	20
Earnings Predictability	50

YORK WATER NDQ-YORW

RECENT PRICE	29.87	P/E RATIO	29.6 (Trailing: 30.8 Median: 24.0)	RELATIVE P/E RATIO	1.62	DIV'D YLD	2.1%	VALUE LINE

TIMELINESS 2 Lowered 4/1/16
SAFETY 3 Lowered 7/17/15
TECHNICAL 2 Raised 3/11/16
BETA .70 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	17.9	21.0	18.5	16.5	18.0	18.0	18.1	18.5	22.0	24.3	26.7	31.0
Low:	11.7	15.3	15.5	6.2	9.7	12.8	15.8	16.8	17.6	18.8	19.7	23.8

Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

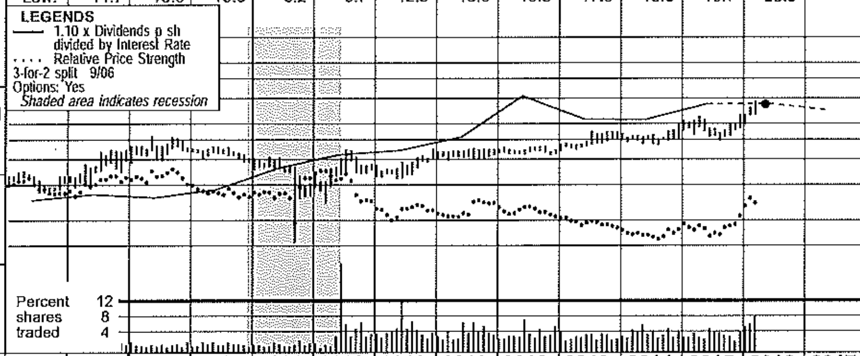
	Price	Gain	Ann'l Total Return
High	35	(+15%)	6%
Low	25	(-15%)	-2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	4	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	34	30	36
to Sell	31	27	24
Hld's(000)	3769	3840	3820



% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.9	-5.8
3 yr.	74.5	27.9
5 yr.	100.3	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	2.05	2.05	2.17	2.18	2.58	2.56	2.79	2.89	2.95	3.07	3.18	3.21	3.27	3.58	3.68	*4.00*	*4.40*	Revenues per sh	*5.40*
--	.59	.57	.65	.65	.79	.77	.86	.88	.95	1.07	1.09	1.12	1.19	1.36	1.47	*1.55*	*1.70*	"Cash Flow" per sh	*1.90*
--	.43	.40	.47	.49	.56	.58	.57	.57	.64	.71	.71	.72	.75	.89	.97	*1.00*	*1.08*	Earnings per sh A	*1.25*
--	.34	.35	.37	.39	.42	.45	.48	.49	.51	.52	.53	.54	.55	.57	.60	*.63*	*.66*	Div'd Decl'd per sh B	*.85*
--	.75	.66	1.07	2.50	1.69	1.85	1.69	2.17	1.18	.83	.74	.94	.76	1.10	1.08	*1.60*	*1.10*	Cap'l Spending per sh	*.85*
--	3.79	3.90	4.06	4.65	4.85	5.84	5.97	6.14	6.92	7.19	7.45	7.73	7.98	8.15	8.52	*8.80*	*9.35*	Book Value per sh	*10.15*
--	9.46	9.55	9.63	10.33	10.40	11.20	11.27	11.37	12.56	12.69	12.79	12.92	12.98	12.83	12.81	*12.50*	*12.00*	Common Shs Outst'g C	*12.00*
--	17.8	26.9	24.5	25.7	26.3	31.2	30.3	24.6	21.9	20.7	23.9	24.4	26.3	23.1	23.5	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
--	.91	1.47	1.40	1.36	1.40	1.68	1.61	1.48	1.46	1.32	1.50	1.55	1.48	1.22	1.19	*Value Line*		Relative P/E Ratio	*1.40*
--	4.4%	3.3%	3.2%	3.1%	2.9%	2.5%	2.8%	3.5%	3.6%	3.5%	3.1%	3.1%	2.8%	2.8%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*
						28.7	31.4	32.8	37.0	39.0	40.6	41.4	42.4	45.9	47.1	*50.0*	*53.0*	Revenues ($mill)	*65.0*
						6.1	6.4	6.4	7.5	8.9	9.1	9.3	9.7	11.5	12.6	*12.5*	*13.0*	Net Profit ($mill)	*15.0*
						34.4%	36.5%	36.1%	37.9%	38.5%	35.3%	37.6%	37.6%	29.8%	27.2%	*28.5%*	*28.5%*	Income Tax Rate	*32.5%*
						7.2%	3.6%	10.1%	--	1.2%	1.1%	1.1%	.8%	1.8%	1.6%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
						48.3%	46.5%	54.5%	45.7%	48.3%	47.1%	46.0%	45.1%	44.8%	44.5%	*45.0%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
						51.7%	53.5%	45.5%	54.3%	51.7%	52.9%	54.0%	54.9%	55.2%	55.5%	*55.0%*	*53.5%*	Common Equity Ratio	*53.0%*
						126.5	125.7	153.4	160.1	176.4	180.2	184.8	188.4	189.4	196.4	*200*	*210*	Total Capital ($mill)	*230*
						174.4	191.6	211.4	222.0	228.4	233.0	240.3	244.2	253.2	261.4	*270*	*275*	Net Plant ($mill)	*290*
						6.2%	6.7%	5.7%	6.2%	6.5%	6.4%	6.4%	6.5%	7.4%	7.7%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
						9.3%	9.5%	9.2%	8.6%	9.8%	9.5%	9.3%	9.3%	11.0%	11.5%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.5%*
						9.3%	9.5%	9.2%	8.6%	9.8%	9.5%	9.3%	9.3%	11.0%	11.5%	*11.5%*	*11.5%*	Return on Com Equity	*12.5%*
						2.2%	1.7%	1.4%	1.9%	2.7%	2.5%	2.4%	2.4%	3.9%	4.5%	*4.0%*	*4.5%*	Retained to Com Eq	*4.0%*
						77%	82%	85%	78%	72%	73%	74%	74%	64%	61%	*64%*	*61%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $87.3 mill. Due in 5 Yrs $30.5 mill.
LT Debt $87.3 mill. LT Interest $5.1 mill.
(45% of Cap'l)

Pension Assets 12/15 $31.8 mill.
Oblig. $39.5 mill.

Pfd Stock None

Common Stock 12,812,377 shs.

MARKET CAP: $375 million (Small Cap)

CURRENT POSITION ($MILL.)	2013	2014	12/31/15
Cash Assets	7.6	1.5	2.9
Accounts Receivable	3.8	4.0	3.5
Inventory (Avg. Cost)	.7	.8	.8
Other	3.1	4.9	4.6
Current Assets	15.2	11.2	11.8
Accts Payable	1.8	1.6	1.8
Debt Due	--	--	--
Other	6.0	4.3	4.4
Current Liab.	7.8	5.9	6.2

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	4.5%	3.0%	*7.5%*
"Cash Flow"	7.0%	6.5%	*6.0%*
Earnings	5.5%	6.0%	*6.0%*
Dividends	4.0%	2.5%	*6.5%*
Book Value	6.5%	4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	10.1	10.7	10.9	10.7	42.4
2014	10.6	11.8	12.0	11.5	45.9
2015	11.2	11.9	12.4	11.6	47.1
2016	*11.5*	*12.5*	*13.0*	*13.0*	*50.0*
2017	*12.0*	*13.0*	*13.5*	*14.5*	*53.0*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.17	.18	.19	.21	.75
2014	.16	.22	.23	.28	.89
2015	.20	.22	.28	.27	.97
2016	*.20*	*.26*	*.28*	*.26*	*1.00*
2017	*.22*	*.27*	*.30*	*.29*	*1.08*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.134	.134	.134	.134	.535
2013	.138	.138	.138	.138	.552
2014	.1431	.1431	.1431	.1431	.572
2015	.1495	.1495	.1495	.1555	.604
2016	.1555				

BUSINESS: The York Water Company is the oldest investor-owned regulated water utility in the United States. It has operated continuously since 1816. As of December 31, 2015, the company's average daily availability was 35.4 million gallons and its service territory had an estimated population of 194,000. Has more than 66,000 customers. Residential customers accounted for 63% of 2015 revenues; commercial and industrial (29%); other (8%). It also provides sewer billing services. Incorporated: PA. York had 108 full-time employees at 12/31/15. President/CEO: Jeffrey R. Hines. Officers/directors own 1.1% of the common stock (4/16 proxy). Address: 130 East Market Street, York, Pennsylvania 17401. Telephone: (717) 845-3601. Internet: www.yorkwater.com.

York Water shares continue to march higher. The stock rose more than 20% in value since our January full-page review, driven by a better-than-expected earnings report. Moreover, this equity has surged approximately 50% from the midway point of last year.

Several factors are contributing to York's well-performing financials. For one, IRS Tangible Property Rules, which allow for more favorable quarterly reporting rather than year end, ought to remain a tailwind to profitability. This has resulted in a lower effective tax rate and should persist over the intermediate term. Second, lower operating expenses may play a marginal role in share-net growth. Lastly, revenues are apt to get a boost from the purchase of 1,700 wastewater connections, expected to close in the back end of 2016.

All things considered, bottom-line expansion is likely in the cards for this year and next. We are leaving unaltered our 2016 earnings called, at $1.00 per share. In 2017, we look for more-pronounced high single-digit growth, to $1.08 a share, underpinned by a slightly reduced share count, as well as the abovementioned drivers.

Increased capital investments, coupled with acquisitions, augur well for growth over the long haul. Indeed, an aging infrastructure in need of upgrading should attract a large allocation of funds in the near term. Additional resources will likely be used for acquisitions. Management has indicated capital spending of roughly $20 million and $13 million in 2016 and 2017, respectively. We expect this figure to cool a bit looking out to the 2019-2021 time frame, considering major pipeline replacements should no longer be an issue.

York Water is ranked (Timeliness: 2) to outperform the broader market averages over the coming six to 12 months. Momentum accounts may still have some success here, given quarterly earnings comparisons should continue to impress. However, the prolonged run-up in price does give us pause. To that end, capital appreciation potential out to late decade is limited, even with our increased Target Price Range.

Nicholas P. Patrikis *April 15, 2016*

(A) Diluted earnings. Next earnings report due late May.
(B) Dividends historically paid in mid-January, April, July, and October.
(C) In millions, adjusted for splits.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	95

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 208

Other Growth Resources

Exhibits in Support
of Opening Testimony

August 11, 2016

Pages 1, 4 and 5 of Exhibit 208 are Excel spreadsheets and are also provided in electronic format.

Social Security
Official Social Security Website

Staff Extraction of Real GDP Data and Assumptions for Historical and Future Calendar Years.

Table V.B2

Additional Economic Factors

Historical Data:

5-Year Periods:	Real GDP
1960 to 1965	5.00
1965 to 1970	3.50
1970 to 1975	2.70
1975 to 1980	3.70
1980 to 1985	3.30
1985 to 1990	3.40
1990 to 1995	2.60
1995 to 2000	4.30
2000 to 2005	2.50
2005 to 2010	0.80

Economic Cycles

Periods:	Real GDP
1966 to 1973	3.60
1973 to 1979	3.00
1979 to 1989	3.10
1989 to 2000	3.30
2000 to 2007	2.40
2007 to 2014	1.10

Single Years:

Year:	Real GDP
2004	3.80
2005	3.30
2006	2.70
2007	1.80
2008	**-0.30**
2009	**-2.80**
2010	**2.50**
2011	1.60
2012	2.30
2013	2.20
2014	2.30

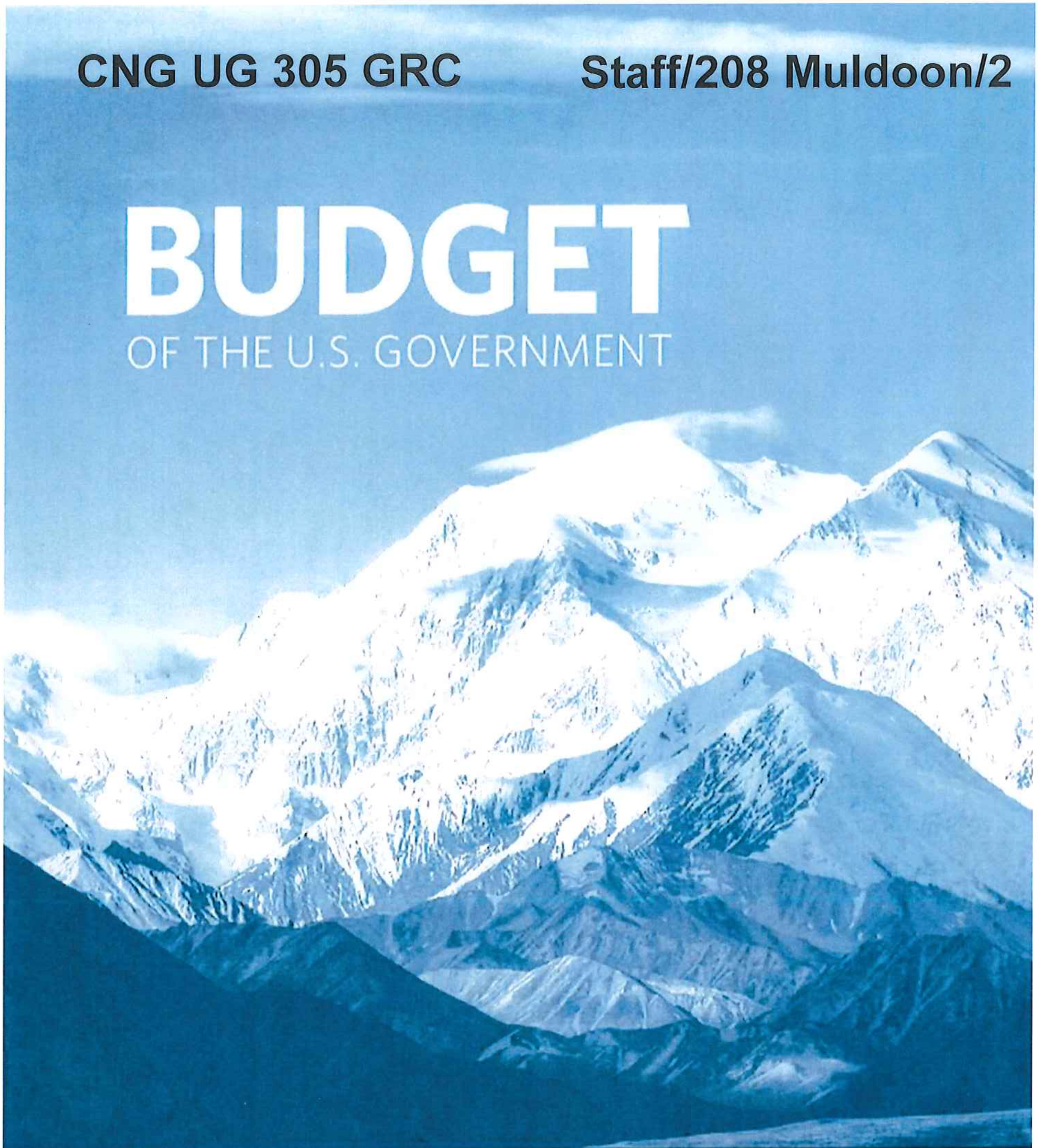
Projections

Low Cost		Intermediate		High Cost	
Yr	GDP	Yr	GDP	Yr	GDP
2015	4.20	2015	3.30	2015	1.90
2016	4.60	2016	3.30	2016	1.70
2017	4.20	2017	3.30	2017	2.30
2018	3.80	2018	3.10	2018	2.50
2019	3.40	2019	2.90	2019	2.30
2020	3.10	2020	2.70	2020	2.20
2021	2.90	2021	2.60	2021	2.20
2022	2.80	2022	2.40	2022	2.10
2023	2.80	2023	2.20	2023	1.90
2024	2.70	2024	2.20	2024	1.60
2025	2.70	2025	2.20	2025	1.70
2030	2.60	**2030**	**2.10**	2030	1.60
2035	2.70	**2035**	**2.10**	2035	1.60
2040	2.80	**2040**	**2.20**	2040	1.60
2045	2.80	**2045**	**2.10**	2045	1.50
2050	2.80	2050	2.10	2050	1.50
2055	2.70	2055	2.10	2055	1.40
2060	2.70	2060	2.00	2060	1.40
2065	2.70	2065	2.10	2065	1.40
2070	2.80	2070	2.10	2070	1.30
2075	2.80	2075	2.10	2075	1.30
2080	2.80	2080	2.10	2080	1.30
2085	2.70	2085	2.00	2085	1.30
2090	2.70	2090	2.00	2090	1.30

CNG UG 305 GRC Staff/208 Muldoon/2

BUDGET

OF THE U.S. GOVERNMENT



FISCAL YEAR 2017

OFFICE OF MANAGEMENT AND BUDGET

Table S–12. Economic Assumptions [1]

(Calendar years)

	Actual 2014	Projections 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Gross Domestic Product (GDP):													
Nominal level, billions of dollars	17,348	17,948	18,669	19,510	20,345	21,237	22,155	23,121	24,128	25,179	26,272	[illegible]	[illegible]
Percent change, nominal GDP, year/year	4.1	3.5	4.0	4.5	4.3	4.4	4.3	4.4	4.4	4.4	4.3	4.3	4.3
Real GDP, percent change, year/year	2.4	2.4	2.6	2.6	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Real GDP, percent change, Q4/Q4	2.5	2.2	2.7	2.5	2.4	2.3	2.3	2.3	2.3	2.3	2.3	[illegible]	2.3
GDP chained price index, percent change, year/year	1.6	1.0	1.4	1.9	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Consumer Price Index, [2] **percent change, year/year**	1.6	0.1	1.5	2.1	2.1	2.3	2.2	2.3	2.3	2.3	2.3	2.3	2.3
Interest rates, percent: [3]													
91-day Treasury bills [4]	*	*	0.7	1.8	2.6	3.1	3.3	3.4	3.4	3.3	3.3	3.2	3.2
10-year Treasury notes	2.5	2.1	2.9	3.5	3.9	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Unemployment rate, civilian, percent [3]	6.2	5.3	4.7	4.5	4.6	4.6	4.7	4.7	4.8	4.9	4.9	4.9	4.9

* 0.05 percent or less.

Note: A more detailed table of economic assumptions appears in Chapter 2, "Economic Assumptions and Interactions with the Budget," in the *Analytical Perspectives* volume of the Budget.

[1] Based on information available as of mid-November 2015.

[2] Seasonally adjusted CPI for all urban consumers.

[3] Annual average.

[4] Average rate, secondary market (bank discount basis).

Staff Extract from 2017 White House Budget

This file presents data that supplement information in CBO's January 2016 report *The Budget and Economic Outlook: 2016 to 2*
https://www.cbo.gov/publication/51129
https://www.cbo.gov/about/products/budget_economic_data#1

Staff Extract from Jan 2016 Congressional Budget Office Projections

January 2016 Baseline Forecast—Data Release (Calendar Year)

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	**2024**	**2025**	**2026**
Output														
Gross Domestic Product (GDP)	Billions of dollars	17348	17957	18689	19505	20326	21102	21923	22823	23766	24746	25764	26831	27942
	Percentage change	4.1	3.5	4.1	4.4	4.2	3.8	3.9	4.1	4.1	4.1	**4.1**	**4.1**	**4.1**
Gross National Product (GNP)	Billions of dollars	17611	18168	18881	19676	20472	21239	22058	22956	23894	24870	25882	26940	28042
	Percentage change	4.1	3.2	3.9	4.2	4.0	3.8	3.9	4.1	4.1	4.1	4.1	4.1	4.1
Potential GDP	Billions of dollars	17897	18360	18936	19595	20338	21149	22020	22934	23882	24866	25890	26961	28078
	Percentage change	3.3	2.6	3.1	3.5	3.8	4.0	4.1	4.2	4.1	4.1	4.1	4.1	4.1
Real GDP	Billions of 2009 dollars	15962	16350	16752	17180	17565	17884	18216	18591	18975	19363	19756	20157	20567
	Percentage change	2.4	2.4	2.5	2.6	2.3	1.8	1.9	2.1	2.1	2.1	2.0	2.0	2.0
Real GNP	Billions of 2009 dollars	16187	16527	16908	17312	17671	17978	18302	18670	19045	19425	19808	20198	20596
	Percentage change	2.5	2.1	2.3	2.4	2.1	1.7	1.8	2.0	2.0	2.0	**2.0**	**2.0**	**2.0**
Real Potential GDP	Billions of 2009 dollars	16465	16716	16974	17259	17576	17924	18297	18681	19067	19457	19852	20255	20667
	Percentage change	1.6	1.5	1.6	1.7	1.8	2.0	2.1	2.1	2.1	2.1	2.0	2.0	2.0

ref2016.d032416a

Report: Annual Energy Outlook 2016 · Scenario ref2016 · Datekey d032416a · Reference case · Release Date May 2016

20. Macroeconomic Indicators

(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2040
Real Gross Domestic Product	15,962	16,349	16,841	17,335	17,740	18,155	18,555	18,928	19,337	19,811	20,287	20,765	21,227	21,699	22,179	22,638	23,113	23,588	24,054	24,551	25,074	25,598	26,140	26,688	27,255	27,821	28,397	2.2%
Components of Real Gross Domestic Product																												
Real Consumption	10,876	11,221	11,577	11,961	12,283	12,606	12,861	13,106	13,368	13,665	13,990	14,348	14,695	15,036	15,401	15,747	16,092	16,446	16,800	17,155	17,517	17,881	18,262	18,648	19,053	19,466	19,870	2.3%
Real Investment	2,718	2,842	2,996	3,201	3,315	3,400	3,513	3,593	3,699	3,837	3,959	4,068	4,165	4,257	4,341	4,422	4,520	4,619	4,693	4,796	4,921	5,051	5,174	5,294	5,415	5,532	5,661	2.8%
Real Government Spending	2,838	2,860	2,919	2,935	2,946	2,956	2,967	2,968	2,983	3,007	3,034	3,056	3,083	3,115	3,149	3,183	3,222	3,252	3,285	3,320	3,358	3,396	3,434	3,473	3,514	3,555	3,602	0.9%
Real Exports	2,086	2,119	2,193	2,291	2,382	2,489	2,615	2,757	2,906	3,068	3,225	3,374	3,525	3,684	3,850	4,012	4,178	4,355	4,536	4,722	4,913	5,105	5,299	5,501	5,702	5,908	6,113	4.3%
Real Imports	2,529	2,662	2,815	3,030	3,165	3,274	3,374	3,465	3,582	3,723	3,874	4,032	4,186	4,333	4,497	4,656	4,824	5,003	5,171	5,345	5,529	5,721	5,905	6,094	6,284	6,484	6,683	3.8%
Energy Intensity (thousand Btu per 2009 dollar of GDP)																												
Delivered Energy	4.52	4.38	4.30	4.22	4.17	4.10	4.03	3.96	3.88	3.81	3.73	3.65	3.57	3.50	3.42	3.36	3.29	3.24	3.18	3.13	3.08	3.04	2.99	2.95	2.91	2.87	2.83	-1.7%
Total Energy	6.15	5.92	5.79	5.69	5.60	5.52	5.42	5.33	5.22	5.12	5.00	4.89	4.78	4.68	4.57	4.48	4.39	4.32	4.25	4.18	4.12	4.06	3.99	3.94	3.88	3.82	3.77	-1.8%
Price Indices																												
GDP Chain-type Price Index (2009=1.000)	1.087	1.098	1.119	1.142	1.165	1.188	1.213	1.242	1.270	1.295	1.319	1.344	1.371	1.398	1.426	1.455	1.486	1.518	1.552	1.586	1.622	1.659	1.695	1.733	1.771	1.809	1.848	2.1%
Consumer Price Index (1982-84=1.00)																												
All-urban	2.37	2.37	2.39	2.45	2.52	2.59	2.65	2.72	2.80	2.86	2.92	2.99	3.05	3.12	3.19	3.27	3.35	3.43	3.51	3.60	3.69	3.78	3.88	3.97	4.07	4.17	4.27	2.4%
Energy Commodities and Services	2.43	2.02	1.82	1.95	2.09	2.28	2.41	2.52	2.61	2.70	2.78	2.87	2.97	3.06	3.14	3.25	3.34	3.45	3.56	3.69	3.81	3.92	4.05	4.17	4.32	4.46	4.61	3.4%
Wholesale Price Index (1982=1.00)																												
All Commodities	2.05	1.91	1.89	1.95	2.01	2.08	2.14	2.19	2.24	2.29	2.33	2.37	2.41	2.45	2.50	2.55	2.59	2.65	2.70	2.76	2.82	2.87	2.92	2.98	3.04	3.10	3.16	2.0%
Fuel and Power	2.10	1.60	1.49	1.64	1.78	1.96	2.10	2.18	2.26	2.36	2.45	2.53	2.60	2.67	2.74	2.83	2.91	3.00	3.10	3.21	3.30	3.39	3.48	3.58	3.69	3.81	3.92	3.7%
Metals and Metal Products	2.15	2.01	1.97	2.03	2.08	2.11	2.15	2.20	2.24	2.29	2.32	2.35	2.38	2.42	2.46	2.50	2.55	2.59	2.64	2.69	2.75	2.80	2.85	2.90	2.96	3.01	3.06	1.7%
Industrial Commodities excluding Energy	1.98	1.94	1.96	2.01	2.05	2.09	2.13	2.18	2.22	2.26	2.30	2.33	2.37	2.41	2.44	2.48	2.53	2.57	2.62	2.67	2.72	2.76	2.81	2.86	2.91	2.96	3.01	1.8%
Interest Rates (percent, nominal)																												
Federal Funds Rate	0.09	0.13	0.89	1.88	2.79	3.33	3.32	3.22	3.03	3.02	3.13	3.22	3.26	3.21	3.21	3.24	3.24	3.25	3.25	3.23	3.25	3.23	3.22	3.20	3.18	3.10	3.08	--
10-Year Treasury Note	2.54	2.14	2.57	2.72	3.27	3.86	3.83	3.77	3.64	3.60	3.62	3.66	3.69	3.68	3.70	3.74	3.77	3.79	3.81	3.82	3.84	3.82	3.81	3.79	3.78	3.72	3.72	--
AA Utility Bond Rate	4.19	4.01	4.53	4.74	5.30	5.87	5.87	5.74	5.49	5.35	5.34	5.41	5.52	5.55	5.59	5.68	5.73	5.78	5.83	5.85	5.88	5.85	5.85	5.80	5.79	5.73	5.71	--
Value of Shipments (billion 2009 dollars)																												
Non-Industrial and Service Sectors	23,338	24,085	24,839	25,313	25,740	26,292	26,750	27,093	27,441	27,978	28,610	29,265	29,835	30,363	30,954	31,512	32,042	32,587	33,134	33,688	34,285	34,833	35,391	35,954	36,571	37,139	37,701	1.8%
Total Industrial	7,165	7,229	7,506	7,783	7,977	8,174	8,351	8,513	8,645	8,841	9,011	9,146	9,264	9,383	9,493	9,619	9,776	9,915	10,042	10,209	10,385	10,562	10,735	10,918	11,114	11,286	11,483	1.9%
Agriculture, Mining, and Construction	1,957	1,931	2,056	2,205	2,320	2,404	2,493	2,529	2,550	2,585	2,613	2,620	2,630	2,641	2,650	2,670	2,710	2,735	2,731	2,753	2,790	2,828	2,856	2,881	2,908	2,923	2,955	1.7%
Manufacturing	5,208	5,299	5,450	5,578	5,657	5,770	5,858	5,984	6,095	6,256	6,398	6,527	6,633	6,742	6,843	6,949	7,066	7,181	7,312	7,456	7,595	7,734	7,879	8,036	8,207	8,363	8,528	1.9%
Energy-Intensive	1,718	1,704	1,728	1,759	1,800	1,853	1,892	1,927	1,954	1,986	2,014	2,046	2,076	2,094	2,109	2,128	2,147	2,168	2,192	2,217	2,242	2,267	2,293	2,324	2,356	2,385	2,417	1.4%
Non-Energy-Intensive	3,490	3,594	3,722	3,819	3,857	3,917	3,967	4,057	4,141	4,271	4,384	4,481	4,557	4,648	4,734	4,821	4,920	5,013	5,120	5,239	5,353	5,467	5,586	5,713	5,850	5,978	6,111	2.1%
Total Shipments	30,504	31,314	32,345	33,096	33,717	34,466	35,101	35,606	36,086	36,819	37,621	38,411	39,098	39,746	40,447	41,131	41,818	42,503	43,176	43,897	44,670	45,396	46,125	46,872	47,685	48,425	49,184	1.8%
Population and Employment (millions)																												
Population, with Armed Forces Overseas	319.5	321.9	324.5	327.1	329.8	332.4	335.0	337.6	340.2	342.8	345.3	347.8	350.3	352.8	355.2	357.5	359.9	362.1	364.4	366.6	368.7	370.8	372.8	374.8	376.8	378.7	380.6	0.7%
Population, aged 16 and over	254.2	256.6	259.3	261.9	264.3	266.8	269.3	271.7	274.1	276.6	279.0	281.2	283.5	285.7	287.8	289.9	292.0	294.0	296.1	298.1	300.1	302.0	304.0	305.9	307.7	309.5	311.3	0.8%
Population, aged 65 and over	46.5	48.1	49.7	51.3	53.0	54.8	56.7	58.6	60.5	62.4	64.3	66.2	68.0	69.7	71.3	72.9	74.3	75.4	76.4	77.3	78.3	79.4	80.4	81.1	81.5	82.0	82.4	2.2%
Employment, Nonfarm	138.5	141.8	144.1	146.4	147.6	148.9	150.3	151.1	152.0	153.2	154.6	155.9	157.0	157.9	158.8	159.6	160.6	161.3	162.1	162.8	163.8	164.6	165.6	166.6	167.6	168.7	169.9	0.7%
Employment, Manufacturing	12.2	12.5	12.7	12.9	13.0	13.1	13.1	13.2	13.3	13.3	13.4	13.4	13.3	13.3	13.1	13.1	13.0	12.9	12.8	12.7	12.7	12.6	12.5	12.4	12.4	12.3	12.3	-0.1%
Key Labor Indicators																												
Labor Force (millions)	155.9	157.3	159.7	161.9	163.8	165.4	166.6	167.7	168.7	169.6	170.5	171.4	172.5	173.6	174.7	176.0	177.2	178.4	179.6	180.8	181.8	182.7	183.7	184.8	185.9	187.1	188.2	0.7%
Nonfarm Labor Productivity (2009=1.00)	1.05	1.06	1.08	1.09	1.11	1.13	1.15	1.16	1.19	1.21	1.23	1.25	1.27	1.30	1.32	1.35	1.37	1.40	1.42	1.45	1.48	1.50	1.53	1.55	1.58	1.61	1.63	1.7%
Unemployment Rate (percent)	6.15	5.31	4.99	4.89	4.92	4.77	4.72	4.84	5.03	5.08	5.01	4.90	4.84	4.82	4.79	4.78	4.78	4.77	4.79	4.81	4.78	4.76	4.73	4.72	4.73	4.77	4.78	--
Key Indicators for Energy Demand																												
Real Disposable Personal Income	11,836	12,225	12,649	13,069	13,486	13,868	14,197	14,493	14,808	15,143	15,503	15,888	16,287	16,706	17,099	17,467	17,826	18,177	18,538	18,906	19,291	19,689	20,088	20,495	20,916	21,342	21,789	2.3%
Housing Starts (millions)	1.06	1.18	1.36	1.54	1.64	1.70	1.74	1.73	1.72	1.72	1.72	1.71	1.70	1.70	1.65	1.64	1.66	1.64	1.60	1.60	1.62	1.66	1.66	1.66	1.65	1.64	1.65	1.3%
Commercial Floorspace (billion square feet)	83.1	83.8	84.7	85.6	86.6	87.7	88.7	89.8	90.8	91.9	93.0	94.0	95.1	96.1	97.2	98.2	99.3	100.3	101.4	102.5	103.5	104.6	105.6	106.7	107.7	108.8	109.8	1.1%
Unit Sales of Light-Duty Vehicles (millions)	16.44	17.36	17.87	18.27	18.07	17.80	17.11	16.95	16.91	17.14	17.17	17.29	17.33	17.47	17.62	17.61	17.69	17.76	17.79	17.85	18.05	18.18	18.32	18.44	18.72	18.78	18.97	0.4%

GDP = Gross domestic product. Btu = British thermal unit. -- = Not applicable.

Sources: 2014 and 2015: IHS Economics, Industry and Employment models, November 2015.

Projections: U.S. Energy Information Administration, AEO2016 National Energy Modeling System run ref2016.d032416a.

Independent Statistics & Analysis
eia U.S. Energy Information Administration

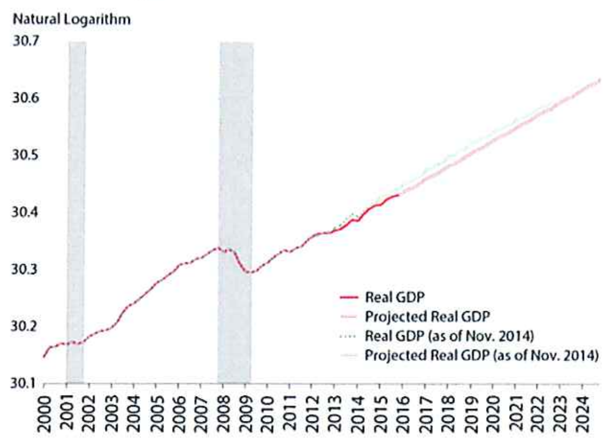
Revisiting GDP Growth Projections

by Fernando M. Martin — Federal Reserve Bank of St. Louis (FRED) Mar. 4 2016
https://research.stlouisfed.org/publications/economic-synopses/2016/03/04/revisiting-gdp-growth-projections/

Based largely on predicted trends for **labor force participation, GDP is projected to grow at an average annual rate of 2.2 percent over the next decade**.

Gross domestic product (GDP) contracted significantly during the Great Recession and has **grown at a considerably slower pace than its historical average during the subsequent recovery**. Both GDP and GDP per capita have diverged noticeably from their pre-recession trends: As of 2015:Q4, they are 19 percent and 16 percent below their 1955-2007 trends, respectively. In this essay, I use the most recent data to review the performance of a previous GDP forecast and present new projections up to 2024.

Actual and Projected Real GDP



NOTE: The gray bars indicate recessions as determined by the National Bureau of Economic Research.
SOURCE: Bureau of Economic Analysis, Bureau of Labor Statistics, and author's calculations.

In a previous essay, I proposed using trends in labor force participation to project GDP for 2014-22.[1] This projection relied on two main elements: the fact that GDP per labor force participant appeared to be converging back to its pre-Great Recession trend and the high accuracy of Bureau of Labor Statistics (BLS) labor force projections, which are largely based on predictable demographic trends. Since publication of that essay, there have been five new releases of quarterly GDP, updates to previously released data, and a new BLS labor force projection.

Instead of expressing GDP per capita, which corrects for the effects of a growing population, one can divide GDP by the labor force. Doing so accounts for the effects of changing demographics and labor force attachment. Although GDP per labor force participant also contracted severely during the Great Recession, it has nevertheless been converging back to its pre-recession trend. Since 2010, it has grown at an average annual rate of 1.8 percent—higher than its trend annual growth rate of 1.5 percent between 1955 and 2007. The **decline in labor force participation rates** explains the difference in performance between GDP and GDP per capita on the one hand and GDP per labor force participant on the other. After the labor force participation rate peaked at 67.3 percent in 2000:Q1, it has steadily declined: As of 2015:Q4, it was 62.5 percent. The most recent BLS projections estimate it will reach 60.9 percent in 2024.[2] This projection is based on estimating that the labor force will grow at an average annual rate of 0.5 percent in the 2014-24 period—considerably slower than the estimated average annual population growth rate of 0.8 percent.

Assuming that GDP per labor force participant continues to grow at the same rate as it did for the 2010-15 period, I can use the BLS projections for labor force participation to project GDP growth. The figure shows actual and projected real GDP from 2000 to 2024. In addition, it shows these same variables as calculated in November 2014.

The November 2014 projection of GDP for 2015:Q4 overestimated it by 0.9 percent. That is, actual GDP was 0.9 percent lower than expected. However, most of the difference can be attributed to revisions in GDP figures: GDP figures for 2013 and the first three quarters of 2014 were revised downward on average by 0.8 percent and 0.6 percent, respectively. Another part of the difference can be explained by the faster-than-anticipated decline in labor force participation.

Despite these updates, **the average annual growth rate of GDP for the next decade** remains the same: **2.2 percent**. Using the current estimates, the annual growth rate of real GDP is expected to converge to 2.3 percent by 2024. Note that this rate is **somewhat higher than** the annual growth projected by the **Congressional Budget Office** for potential GDP, which is expected to converge toward **2.0 percent** over the next decade.[4] The current projections also **predict** a **widening** of the (negative) **gap between real GDP and** its **pre-recession trend**: from 19 percent in 2015:Q4 to 26 percent in 2024:Q4.

Notes:

1 See Martin (2014).

2 See Toossi (2015) for a description and analysis of the most recent labor force projections.

3 Note that the previous essay showed figures with GDP per capita but described the calculations for GDP and presented results for GDP growth. The GDP series displayed in the current figure simply multiplies the GDP per capita series of the previous essay by the total population, as measured in November 2014.

4 See Congressional Budget Office. "The Budget and Economic Outlook: 2015 to 2025." January 26, 2015; https://www.cbo.gov/publication/49892.

References:

1. Martin, Fernando M. "Projecting GDP Growth Using Trends in Labor Force Participation." Federal Reserve Bank of St. Louis Economic Synopses, No. 26, November 24, 2014; https://research.stlouisfed.org/publications/economic-synopses/2014/11/24/projecting-gdp-growth-using-trends-in-labor-force-participation/.

2. Toossi, Mitra. "Labor Force Projections to 2024: The Labor Force Is Growing, but Slowly." Bureau of Labor Statistics, Monthly Labor Review, December 2015; http://www.bls.gov/opub/mlr/2015/article/labor-force-projections-to-2024.htm.

ECONOMIC RESEARCH
FEDERAL RESERVE BANK OF ST. LOUIS

Title:	**Gross Domestic Product: Implicit Price Deflator**
Series ID:	GDPDEF
Source:	US. Bureau of Economic Analysis
Release:	Gross Domestic Product
Seasonal Adjustment:	Seasonally Adjusted
Frequency:	Quarterly
Units:	Index 2009=100
Date Range:	1947-01-01 to 2016-01-01
Last Updated:	2016-04-28 8:01 AM CDT
Notes:	**BEA Account Code: A191RD3**

The number of decimal places reported varies over time. A Guide to the National Income and Product Accounts of the United States (NIPA) - http://www.bea.gov/national/pdf/nipaguid.pdf

DATE	VALUE
1947-01-01	12.566
1947-04-01	12.745
1947-07-01	12.957
1947-10-01	13.276
1948-01-01	13.379
1948-04-01	13.497
1948-07-01	13.747
1948-10-01	13.789
1949-01-01	13.717
1949-04-01	13.579
1949-07-01	13.509
1949-10-01	13.518
1950-01-01	13.490
1950-04-01	13.538
1950-07-01	13.832
1950-10-01	14.090
1951-01-01	14.596
1951-04-01	14.692
1951-07-01	14.701
1951-10-01	14.869
1952-01-01	14.863
1952-04-01	14.882
1952-07-01	15.048
1952-10-01	15.091
1953-01-01	15.096
1953-04-01	15.125
1953-07-01	15.188
1953-10-01	15.219

DATE	VALUE
1954-01-01	15.266
1954-04-01	15.281
1954-07-01	15.300
1954-10-01	15.343
1955-01-01	15.417
1955-04-01	15.481
1955-07-01	15.590
1955-10-01	15.743
1956-01-01	15.902
1956-04-01	15.997
1956-07-01	16.197
1956-10-01	16.264
1957-01-01	16.485
1957-04-01	16.601
1957-07-01	16.701
1957-10-01	16.711
1958-01-01	16.892
1958-04-01	16.940
1958-07-01	17.043
1958-10-01	17.123
1959-01-01	17.169
1959-04-01	17.194
1959-07-01	17.258
1959-10-01	17.326
1960-01-01	17.397
1960-04-01	17.443
1960-07-01	17.506
1960-10-01	17.560
1961-01-01	17.598
1961-04-01	17.641
1961-07-01	17.687
1961-10-01	17.745
1962-01-01	17.837
1962-04-01	17.866
1962-07-01	17.903
1962-10-01	17.938
1963-01-01	18.017
1963-04-01	18.047
1963-07-01	18.069
1963-10-01	18.216
1964-01-01	18.274
1964-04-01	18.318
1964-07-01	18.392
1964-10-01	18.476
1965-01-01	18.569
1965-04-01	18.652
1965-07-01	18.726
1965-10-01	18.853

DATE	VALUE
1966-01-01	18.975
1966-04-01	19.131
1966-07-01	19.317
1966-10-01	19.481
1967-01-01	19.562
1967-04-01	19.661
1967-07-01	19.849
1967-10-01	20.067
1968-01-01	20.290
1968-04-01	20.504
1968-07-01	20.706
1968-10-01	20.999
1969-01-01	21.217
1969-04-01	21.488
1969-07-01	21.790
1969-10-01	22.071
1970-01-01	22.382
1970-04-01	22.694
1970-07-01	22.880
1970-10-01	23.182
1971-01-01	23.536
1971-04-01	23.846
1971-07-01	24.088
1971-10-01	24.288
1972-01-01	24.664
1972-04-01	24.815
1972-07-01	25.048
1972-10-01	25.366
1973-01-01	25.661
1973-04-01	26.052
1973-07-01	26.549
1973-10-01	27.077
1974-01-01	27.592
1974-04-01	28.248
1974-07-01	29.067
1974-10-01	29.923
1975-01-01	30.601
1975-04-01	31.059
1975-07-01	31.612
1975-10-01	32.139
1976-01-01	32.473
1976-04-01	32.803
1976-07-01	33.226
1976-10-01	33.815
1977-01-01	34.359
1977-04-01	34.841
1977-07-01	35.270
1977-10-01	36.036

DATE	VALUE
1978-01-01	36.573
1978-04-01	37.242
1978-07-01	37.865
1978-10-01	38.661
1979-01-01	39.352
1979-04-01	40.304
1979-07-01	41.165
1979-10-01	41.986
1980-01-01	42.859
1980-04-01	43.800
1980-07-01	44.808
1980-10-01	46.046
1981-01-01	47.196
1981-04-01	48.081
1981-07-01	48.946
1981-10-01	49.863
1982-01-01	50.561
1982-04-01	51.170
1982-07-01	51.907
1982-10-01	52.483
1983-01-01	52.907
1983-04-01	53.265
1983-07-01	53.823
1983-10-01	54.219
1984-01-01	54.796
1984-04-01	55.257
1984-07-01	55.705
1984-10-01	56.079
1985-01-01	56.724
1985-04-01	57.075
1985-07-01	57.406
1985-10-01	57.738
1986-01-01	58.020
1986-04-01	58.252
1986-07-01	58.487
1986-10-01	58.813
1987-01-01	59.240
1987-04-01	59.637
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1987-10-01	60.567
1988-01-01	61.043
1988-04-01	61.633
1988-07-01	62.359
1988-10-01	62.859
1989-01-01	63.550
1989-04-01	64.207
1989-07-01	64.672
1989-10-01	65.122
1990-01-01	65.841
1990-04-01	66.520
1990-07-01	67.114
1990-10-01	67.622

DATE	VALUE
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1991-10-01	69.643
1992-01-01	69.942
1992-04-01	70.388
1992-07-01	70.723
1992-10-01	71.201
1993-01-01	71.606
1993-04-01	72.041
1993-07-01	72.475
1993-10-01	72.853
1994-01-01	73.206
1994-04-01	73.571
1994-07-01	73.969
1994-10-01	74.376
1995-01-01	74.803
1995-04-01	75.132
1995-07-01	75.489
1995-10-01	75.861
1996-01-01	76.272
1996-04-01	76.562
1996-07-01	76.778
1996-10-01	77.168
1997-01-01	77.647
1997-04-01	77.857
1997-07-01	78.135
1997-10-01	78.395
1998-01-01	78.523
1998-04-01	78.687
1998-07-01	78.981
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1999-04-01	79.891
1999-07-01	80.180
1999-10-01	80.547
2000-01-01	81.163
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2000-07-01	82.152
2000-10-01	82.593
2001-01-01	83.112
2001-04-01	83.699
2001-07-01	83.973
2001-10-01	84.227
2002-01-01	84.497
2002-04-01	84.812
2002-07-01	85.190
2002-10-01	85.651
2003-01-01	86.179
2003-04-01	86.455
2003-07-01	86.934
2003-10-01	87.346

DATE	VALUE
2004-01-01	88.108
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2004-07-01	89.422
2004-10-01	90.049
2005-01-01	90.883
2005-04-01	91.543
2005-07-01	92.399
2005-10-01	93.100
2006-01-01	93.832
2006-04-01	94.587
2006-07-01	95.247
2006-10-01	95.580
2007-01-01	96.654
2007-04-01	97.194
2007-07-01	97.531
2007-10-01	97.956
2008-01-01	98.516
2008-04-01	98.995
2008-07-01	99.673
2008-10-01	99.815
2009-01-01	100.062
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2010-04-01	100.968
2010-07-01	101.429
2010-10-01	101.949
2011-01-01	102.399
2011-04-01	103.145
2011-07-01	103.768
2011-10-01	103.917
2012-01-01	104.466
2012-04-01	104.943
2012-07-01	105.508
2012-10-01	105.935
2013-01-01	106.363
2013-04-01	106.623
2013-07-01	107.128
2013-10-01	107.589
2014-01-01	108.009
2014-04-01	108.606
2014-07-01	109.044
2014-10-01	109.067
2015-01-01	109.099
2015-04-01	109.674
2015-07-01	110.029
2015-10-01	110.286
2016-01-01	110.479

A Guide to the National Income and Product Accounts of the United States

This guide presents information on the structure, definitions, and presentation that underlie the national income and product accounts (NIPAs) produced by the Bureau of Economic Analysis. The NIPAs show the composition of production and the distribution of incomes earned in production. Thus, they represent a critical element of the U.S. economic accounts, which are designed to provide a consistent and comprehensive picture of the Nation's economy. The NIPAs feature several widely followed measures of aggregate U.S. economic activity, including gross domestic product (GDP), gross domestic income (GDI), personal income, and personal saving among others. This guide is organized as follows:

Background and History of the NIPAs 1
Definitions and Classifications Underlying the NIPAs 4
  Real Output and Related Measures 15
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Background and History of the NIPAs

The estimation of national income was initiated during the early 1930s, when the lack of comprehensive economic data frustrated the efforts of Presidents Hoover and Roosevelt to design policies to combat the Great Depression. In response to this need, the Department of Commerce commissioned Simon Kuznets of the National Bureau of Economic Research (NBER) to develop estimates of national income. Professor Kuznets headed a small group within the Bureau of Foreign and Domestic Commerce's Division of Economic Research. Professor Kuznets coordinated the work of researchers at the NBER in New York and his staff at Commerce. The estimates were presented in a report to the Senate in 1934, *National Income, 1929–32.*

The entry of the United States into World War II led to increased demand for data that could be used for wartime planning. Early in 1942, annual estimates of gross national product (GNP) were introduced to complement the estimates of national income. In addition, estimates were developed to detail how income was generated, received, and spent by various sectors of the economy.

The U.S. national income and product statistics were first presented as part of a complete and consistent accounting system in the July 1947 supplement to the Survey of Current Business. The supplement contained 48 tables covering the years 1929–46. All estimates were presented in current dollars; no adjustments were yet made for changes in purchasing power. Quarterly estimates were available for only a few of the aggregates (national income, GNP, and personal income, and their major components). Monthly estimates were presented for personal income and its major components.

In 1951, annual estimates of real GNP and of implicit price deflators were introduced as supplementary tables. Real GNP was calculated by holding fixed the prices of a particular base year that is—GNP was calculated in "constant dollars." In 1954, these inflation-adjusted estimates were formally integrated into the standard NIPA tables.

Another revision, published in 1958, introduced changes in the accounting system and added new information to the accounts. Five summary accounts were adopted as a concise, general presentation of output, income, outlays, foreign transactions, saving, and investment. Quarterly estimates of real GNP were introduced. Government sector tables provided a new breakdown of expenditures by type and function for the Federal Government and for state and local governments. The foreign transactions tables were expanded in detail and integrated with the balance of payments accounts. Regional estimates were introduced, as were estimates of the net stock of fixed assets in manufacturing.

In the 1965 comprehensive revision, for the first time, the components of GNP were benchmarked to the detailed estimates contained in the 1958 input-output table, which provided a better understanding of the structural relationships within the economy.

During the 1960s and 1970s, the estimates of capital stock were expanded to cover all business and government owned fixed assets and consumer durable goods. In 1976, in order to provide a more consistent valuation, the estimates of consumption of fixed capital (CFC) were shifted to a current-cost basis. Previously, the estimates were on a book-value basis—that is, valued at historical cost—reflecting a mixture of prices for the various years in which the assets were acquired.

In 1985, BEA introduced quality-adjusted price indexes for computers and peripheral equipment that were developed with the assistance and advice of researchers from the IBM Corporation. The indexes, which were based on a statistical technique known as "hedonic" regression, adjusted for the rapid improvements in speed and capacity of computer equipment. These hedonic price indexes provide improved measures of price change for computers and peripheral equipment during periods when quality characteristics change rapidly and when prices decline as new products are introduced.

In 1991, BEA changed its featured measure of U.S. production from GNP to GDP. GDP covers the goods and services produced by labor and property located in the United States and is thus consistent with key economic indicators of employment, productivity, and industry output. The change also facilitated comparisons of economic activity in the United States with that in other countries.

In 1993, the *System of National Accounts 1993 (SNA 1993)* was adopted by the international community in order to facilitate international comparisons of national economic statistics and to serve as a guide for countries as they develop their economic accounting systems.[1] BEA actively participated in preparing *SNA 1993* and announced its plan to move toward consistency with *SNA 1993.* Since then, the major improvements in the NIPAs have been designed, at least in part, to incorporate the SNA's concepts and definitions wherever feasible.[2]

In 1996, BEA introduced several major improvements to the NIPAs. BEA began estimating the changes in real GDP and its components by chaining together year-by-year quantity changes that were calculated using the Fisher index formula, rather than estimating real GDP on the basis of prices of a single, arbitrary base year.[3] Government expenditures for equipment and structures were recognized as fixed investment, thereby providing a more complete measure of investment through the consistent treatment of fixed assets whether purchased by the public or the private sector. The method for calculating CFC was changed to reflect the results of studies on the prices of used equipment and structures in resale markets that found that depreciation generally tends to follow a geometric pattern.

The 1999 comprehensive revision of the NIPAs further improved the definitions underlying the accounts and the statistical underpinnings of the current-dollar estimates, quantities, and prices in the accounts. For example, business and government expenditures for software were recognized as fixed investment. Government employee retirement plans were reclassified so that they would be treated similarly to private pension plans. A new method was introduced for calculating the real value of unpriced bank services by incorporating measures of banking activity. The consumer price indexes that were used for deflating personal consumption expenditures (PCE) were revised back to 1978 to reflect the use of a geometric mean formula.

The most recent comprehensive revision of the NIPAs, which was released beginning in 2003, further improved and updated the accounts. For example, a more complete and accurate measure of insurance services was adopted that includes estimates of the implicit services provided by property and casualty insurance companies; the new measure eliminates large swings in measured insurance services associated with catastrophic losses. An improved measure of banking services that includes the services received by borrowers was introduced; previously, such services were only allocated to depositors. A new treatment of government activity that recognizes that governments produce services and that goods and services purchased by governments are intermediate inputs was adopted. An expanded definition of national income that includes all net incomes earned in production was introduced; the new definition is more consistent with international guidelines. The presentation of the NIPAs was changed to reflect these improvements and to introduce a redesigned set of tables that provides more information in an easier to use format and that offers more flexibility for the addition of new tables. The new tables also improve the comparability of the NIPAs with other U.S. accounts (such as the Federal Reserve Board's flow of funds accounts) and with accounts of other nations and the System of National Accounts.

The improvements introduced over the years have reflected not only BEA's own experience, research, and strategic planning but also the reviews and recommendations of scholars and other experts.

In the 1950s, there were two major reviews of the accounts. The first was prepared by the NBER.[4] The second resulted from a symposium on the accounts held by the Conference on Research in Income and Wealth.[5] Both of these reviews dealt with emerging issues of the time, many of which related to expanding the complexity and scope of the accounts to more accurately portray the U.S. economy. They also dealt with conceptual issues, such as the treatment of capital gains and the coverage of nonmarket production and consumption, and they discussed the need for better integration of the income and product accounts, flow of funds, and other aspects of the existing accounts.

1. Commission of the European Communities, International Monetary Fund, Organisation for Economic Co-operation and Development, United Nations, and the World Bank, *System of National Accounts 1993 (SNA 1993)* Brussels/Luxembourg, New York, Paris, and Washington, DC, 1993.

2. See Charles Ian Mead, Karin E. Moses, and Brent R. Moulton, "The NIPAs and the System of National Accounts," Survey of Current Business 84 (December 2004): 17–32.

3. The chain-type measures of real output and prices eliminate the overstatement of real GDP growth for periods after the reference year and the understatement of real GDP growth for periods before the reference year.

4. U.S. Congress, Joint Economic Committee, Subcommittee on Economic Statistics, "The National Economic Accounts of the United States: Review, Appraisal, and Recommendations," in *The National Economic Accounts of the United States*, report by the National Accounts Review Committee, National Bureau of Economic Research, 85th Congress, October 1957.

5. "A Critique of the United States Income and Product Accounts." *Studies in Income and Wealth*, vol. 22. Princeton, NJ: Princeton University Press, for the National Bnreau of Economic Research, 1958.

In 1971, on the occasion of the 50th anniversary of the SURVEY, BEA published a special volume containing 43 papers contributed by some of the country's most prominent economists.[6] BEA catalogued and prioritized the suggestions from these papers, and BEA's Director at that time, George Jaszi, responded to them.

In 1977, a report was prepared by the Advisory Committee on Gross National Product Data Improvement (referred to as the Creamer Report after its chair, Daniel Creamer).[7] The report addressed concerns about the relatively large revisions to the GNP estimates in the early 1970s and focused on needed improvements in the source data.

In 1979, the Conference on Research in Income and Wealth addressed several aspects of the NIPAs role as a system of information about the behavior of the economy.[8] Topics included the concepts and structure of the accounts, deflation and the treatment of quality change in price indexes, and source data. The last topic included an evaluation of major parts of the Creamer Report.

In 1982, the General Accounting Office published a report that reviewed quarterly GNP revisions in order to reevaluate the relative importance of the Creamer Report's recommendations and to reassess the reliability of the GNP estimates.[9] The report focused more on statistical than on conceptual issues and suggested that priorities be placed on those recommendations that would most reduce GNP revisions. In addition, as the title indicates, it urged BEA to take a more proactive role in obtaining the source data needed to improve the accounts.

In 1995, BEA began a comprehensive review of its national, international, and regional economic accounts. Outside perspective was obtained by comments and discussions of a strategic plan that BEA presented in the SURVEY and at a conference of users.[10]

In 2000, BEA established an advisory committee that meets about twice a year to discuss issues and possible improvements to the accounts. The papers that are presented to the advisory committee are made available on BEA's Web site <www.bea.gov>.

In 2004, BEA participated in a Conference on Research in Income and Wealth on "A New Architecture for the U.S. National Accounts."[11] The purpose of the conference was to initiate the development of a comprehensive and fully integrated set of U.S. national accounts. Conference participants identified short-term and long-term initiatives to more fully integrate the existing sets of accounts, to uncover gaps and inconsistencies, and to expand and integrate systems of nonmarket accounts with the core system. As part of this exercise, participants identified initiatives to integrate BEA's existing set of accounts with other U.S. economic accounts, including the productivity accounts prepared by the Bureau of Labor Statistics and the flow of funds accounts prepared by the Federal Reserve Board.

6. "The Economic Accounts of the United States: Retrospect and Prospect," SURVEY 51 (July 1971), Part II, 50th anniversary issue.

7. Office of Federal Statistical Policy and Standards, *Gross National Product Data Improvement Project Report,* report of the Advisory Committee on Gross National Product Data Improvement, Washington, DC: U.S. Department of Commerce, 1977.

8. Murray F. Foss, ed., "The U.S. National Income and Product Accounts: Selected Topics," *Studies in Income and Wealth,* vol. 47, Chicago: University of Chicago Press, for the National Bureau of Economic Research, 1983.

9. Comptroller General, *The Bureau of Economic Analysis Should Lead Efforts to Improve GNP Estimates* (Washington, DC: General Accounting Office, 1982).

10. "Mid-Decade Strategic Review of BEA's Economic Accounts: Maintaining and Improving Their Performance," SURVEY 75 (February 1995): 36–66, and "Mid-Decade Strategic Review of BEA's Economic Accounts: An Update," SURVEY 75 (April 1995): 48–56.

11. Dale W. Jorgenson, J. Steven Landefeld, and William D. Nordhaus, eds., "A New Architecture for the U.S. National Accounts," *Studies in Income and Wealth,* vol. 66, Chicago: University of Chicago Press, for the National Bureau of Economic Research, 2006.

Definitions and Classifications Underlying the NIPAs

NIPA entries

The national income and product accounts (NIPAs) are summarized in seven accounts that show the composition of production and the distribution of incomes earned in production.[12] The seven summary accounts are shown in table A. For illustrative purposes, the tables show estimates for 2005 that are based on the latest published NIPA estimates.

Each of the components in the summary accounts also enters one of the other summary accounts and is shown in one or more of the tables that make up the full set of 299 NIPA tables. Taken together, the summary accounts constitute a double-entry system in which a use (or expenditure) recorded in one account for one sector is also recorded as a source (or receipt) in an account of another sector or of the same sector.[13] This system of integrated, double-entry accounts provides a comprehensive measure of economic activity in a consistently defined framework without double counting. Thus, the NIPAs, in combination with BEA's industry, wealth, and regional accounts, can be used to trace the principal economic flows among the major sectors of the economy.

The first account, the domestic income and product account, shows the consolidated—that is, unduplicated—production of all sectors of the economy as the sum of goods and services sold to final users on the right side and the income generated by that production on the left side.[14] The private enterprise income account (account 2) provides additional information on the sources and uses of income by private enterprises, which give rise to the bulk of the output in the U.S. economy. Accounts 3–5 show the receipts and expenditures of the other major sectors of the U.S. economy: The personal sector, which is made up of households and nonprofit institutions serving households; the government sector; and the foreign sector. Account 6 provides information on the saving and investment of the domestic sectors of the economy, and account 7 provides information on capital transactions with the rest of the world.

Within the summary accounts, each entry has a counterentry, generally in another account. The parenthetical numbers that follow an entry in table A identify the counterentry by account and line number. With the exception of major income and product aggregates, entries are usually defined in the sequence in which they appear in the seven-account summary. The definition is not repeated where the counterentry appears, but a cross reference is made to the place of its first appearance. After the seven-account-summary discussion, definitions for the following items are presented: Final sales of domestic product, gross domestic purchases, final sales to domestic purchasers, net interest, fixed assets, produced assets, nonproduced assets, population, personal saving as a percentage of disposable personal income, gross saving as a percentage of gross national income, U.S. residents, foreign residents, and the rest of the world.

12. Prior to the 2003 comprehensive revision, the NIPAs were summarized in five accounts, which are shown in table A of the August 2002 SURVEY on pages 38–39. For a discussion of the differences between the old and new summary accounts, see Nichole Mayerhauser, Shelly Smith, and David F. Sullivan, "Preview of the 2003 Comprehensive Revision of the National Income and Product Accounts: New and Redesigned Tables," SURVEY 83 (August 2003): 8–15.

13. For more information on the concepts underlying the accounts, see U.S. Bureau of Economic Analysis (BEA), "An Introduction to National Economic Accounting," methodology paper, forthcoming, and *SNA 1993*.

14. The estimate of GDP avoids double counting (of, for example, the semiconductors that go into computers or the flour that goes into bread) because the purchase by one business of materials and services on current account (intermediate purchases) from another business is canceled by the corresponding sale by another business in the consolidation.

Major aggregates

Gross domestic product (GDP) (1–34), the featured measure of U.S. output, is the market value of the goods and services produced by *labor and property located in the United States.*[15] Because the labor and property are located in the United States, the suppliers— that is, the workers and, for property, the owners—may be either U.S. residents or residents of the rest of the world.

Gross domestic income (GDI) (1–12) measures output as the costs incurred and the incomes earned in the production of GDP.[16] In theory, GDP should equal GDI, but in practice, they differ because their components are estimated using largely independent and less than perfect source data. This difference is termed the "statistical discrepancy" (described below).

Gross national product (GNP) is the market value of the goods and services *produced by labor and property supplied by U.S. residents.* Because the labor and property are supplied by U.S. residents, they may be located either in the United States or abroad. The difference between GDP and GNP is net receipts of income from the rest of the world. These net receipts represent income from the goods and services produced abroad using labor and property supplied hy U.S. residents less payments to the rest of the world for the goods and services produced in the United States using labor and property supplied by foreign residents. The income receipts and payments are measured as compensation of employees, corporate profits (earnings of both incorporated and unincorporated affiliates), and interest.

Net domestic product (NDP) is the net market value of the goods and services attributable to labor and property located in the United States and is equal to GDP less consumption of fixed capital (CFC). NDP may be viewed as an estimate of sustainable product, which is a rough measure of the level of consumption that can be maintained while leaving capital assets intact.

Net national product (NNP) is the net market value of goods and services attributable to the labor and property supplied by U.S. residents and is equal to GNP less CFC. The measure of CFC used for both NDP and NNP relates only to fixed capital located in the United States. The investment in capital is measured by private fixed investment and government gross investment.

National income includes all net incomes (net of CFC) earned in production.[17] National income is the sum of compensation of employees, proprietors' income with inventory valuation adjustment (IVA) and capital consumption adjustment (CCAdj), rental income of persons with CCAdj, corporate profits with IVA and CCAdj, net interest and miscellaneous payments, taxes on production and imports, business current transfer payments, and the current surplus of government enterprises, less subsidies.[18]

Gross national income (GNI) is equal to national income plus CFC. (GNI and GNP also differ by the statistical discrepancy.)

Personal income (3–26) is the income received by persons from all sources—that is, from participation in production and from current transfer receipts from both government and business. "Persons" consists of individuals, nonprofit institutions that primarily serve households, private noninsured welfare funds, and private trust funds. Personal income is calculated as compensation of employees, received; proprietors' income with IVA and CCAdj; rental income of persons with CCAdj; personal income receipts on assets; and personal current transfer receipts; less contributions for government social insurance.

Disposable personal income is personal income less personal current taxes. It is the income available to persons for spending or saving.

Account 1. Domestic income and product account

This account presents the product and the income produced by labor and property located in the United States.

GDP is measured as the sum of personal consumption expenditures, gross private domestic investment (including change in private inventories and before deduction of charges for CFC), net exports of goods and services (exports less imports), and government

15. In the NIPAs, the United States consists of the 50 states (before 1960, Alaska and Hawaii were not included), the District of Columbia, and U.S. military installations, embassies, and consulates abroad.

16. Capital gains and losses are not included in NIPA measures, because they result from the revaluation and sale of existing assets rather than from current production.

17. Prior to the 2003 comprehensive revision, national income consisted only of "factor incomes."

18. Inventory valuation adjustment (IVA) is the difference between the cost of inventory withdrawals valued at acquisition cost and the cost of inventory withdrawals valued at replacement cost. The IVA is needed because inventories as reported by business are often charged to cost of sales (that is, withdrawn) at their acquisition (historical) cost rather than at their replacement cost (the concept underlying the NIPAs). As prices change, businesses that value inventory withdrawals at acquisition cost may realize profits or losses. Inventory profits, a capital-gains-like element in business income (corporate profits and nonfarm proprietors' income), result from an increase in inventory prices, and inventory losses, a capital-loss-like element, result from a decrease in inventory prices. In the NIPAs, inventory profits or losses are shown as adjustments to business income; that is, they are shown as the IVA with the sign reversed. No adjustment is needed to farm proprietors' income because farm inventories are measured on a current-market cost basis.

The private capital consumption adjustment (CCAdj) converts depreciation that is on a historical-cost (book value) basis—the capital consumption allowance (CCA)—to depreciation that is on a current-cost basis—consumption of fixed capital (CFC)—and is derived as the difference between private CCA and private CFC.

Table A. Summary National Income and Product Accounts, 2005

[Billions of dollars]

Account 1. Domestic Income and Product Account

Line		
1	Compensation of employees, paid	7,036.6
2	Wage and salary accruals	5,671.1
3	Disbursements (3–12 and 5–11)	5,671.1
4	Wage accruals less disbursements (4–9 and 6–11)	0.0
5	Supplements to wages and salaries (3–14)	1,365.5
6	Taxes on production and imports (4–16)	922.4
7	*Less:* Subsidies (4–8)	57.3
8	Net operating surplus	2,878.2
9	Private enterprises (2–19)	2,893.6
10	Current surplus of government enterprises (4–26)	–15.4
11	Consumption of fixed capital (6–13)	1,604.8
12	**Gross domestic income**	**12,384.8**
13	Statistical discrepancy (6–19)	71.0
14	**GROSS DOMESTIC PRODUCT**	**12,455.8**

Line		
15	Personal consumption expenditures (3–3)	8,742.4
16	Durable goods	1,033.1
17	Nondurable goods	2,539.3
18	Services	5,170.0
19	Gross private domestic investment	2,057.4
20	Fixed investment (6–2)	2,036.2
21	Nonresidential	1,265.7
22	Structures	338.6
23	Equipment and software	927.1
24	Residential	770.4
25	Change in private inventories (6–4)	21.3
26	Net exports of goods and services	–716.7
27	Exports (5–1)	1,303.1
28	Imports (5–9)	2,019.9
29	Government consumption expenditures and gross investment (4–1 and 6–3)	2,372.8
30	Federal	878.3
31	National defense	589.3
32	Nondefense	289.0
33	State and local	1,494.4
34	**GROSS DOMESTIC PRODUCT**	**12,455.8**

Account 2. Private Enterprise Income Account

Line		
1	Income payments on assets	2,552.4
2	Interest and miscellaneous payments (3–20 and 4–21)	2,411.4
3	Dividend payments to the rest of the world (5–14)	81.8
4	Reinvested earnings on foreign direct investment in the United States (5–15)	59.2
5	Business current transfer payments (net)	74.2
6	To persons (net) (3–24)	45.7
7	To government (net) (4–24)	30.1
8	To the rest of the world (net) (5–19)	–1.6
9	Proprietors' income with inventory valuation and capital consumption adjustments (3–17)	970.7
10	Rental income of persons with capital consumption adjustment (3–18)	72.8
11	Corporate profits with inventory valuation and capital consumption adjustments	1,330.7
12	Taxes on corporate income	399.3
13	To government (4–17)	384.4
14	To the rest of the world (5–19)	14.9
15	Profits after tax with inventory valuation and capital consumption adjustments	931.4
16	Net dividends (3–21 and 4–22)	576.9
17	Undistributed corporate profits with inventory valuation and capital consumption adjustments (6–10)	354.5
18	**USES OF PRIVATE ENTERPRISE INCOME**	**5,000.7**

Line		
19	Net operating surplus (1–9)	2,893.6
20	Income receipts on assets	2,107.1
21	Interest (3–20)	1,769.1
22	Dividend receipts from the rest of the world (5–6)	320.0
23	Reinvested earnings on U.S. direct investment abroad (5–7)	18.0
24	**SOURCES OF PRIVATE ENTERPRISE INCOME**	**5,000.7**

Account 3. Personal Income and Outlay Account

Line		
1	Personal current taxes (4–15)	1,203.1
2	Personal outlays	9,070.9
3	Personal consumption expenditures (1–15)	8,742.4
4	Personal interest payments (3–20)	209.4
5	Personal current transfer payments	119.2
6	To government (4–25)	72.0
7	To the rest of the world (net) (5–17)	47.1
8	Personal saving (6–9)	–34.8
9	**PERSONAL TAXES, OUTLAYS, AND SAVING**	**10,239.2**

Line		
10	Compensation of employees, received	7,030.3
11	Wage and salary disbursements	5,664.8
12	Domestic (1–3 less 5–11)	5,661.9
13	Rest of the world (5–3)	2.9
14	Supplements to wages and salaries (1–5)	1,365.5
15	Employer contributions for employee pension and insurance funds	933.2
16	Employer contributions for government social insurance	432.3
17	Proprietors' income with inventory valuation and capital consumption adjustments (2–9)	970.7
18	Rental income of persons with capital consumption adjustment (2–10)	72.8
19	Personal income receipts on assets	1,519.4
20	Personal interest income (2–2 and 3–4 and 4–7 and 5–5 less 2–21 less 4–21 less 5–13)	945.0
21	Personal dividend income (2–16 less 4–22)	574.4
22	Personal current transfer receipts	1,526.6
23	Government social benefits (4–4)	1,480.9
24	From business (net) (2–6)	45.7
25	*Less:* Contributions for government social insurance (4–19)	880.6
26	**PERSONAL INCOME**	**10,239.2**

Account 4. Government Receipts and Expenditures Account

Line			Line		
1	Consumption expenditures (1–29)	1,975.7	14	Current tax receipts	2,520.7
2	Current transfer payments	1,517.8	15	Personal current taxes (3–1)	1,203.1
3	Government social benefits	1,484.0	16	Taxes on production and imports (1–6)	922.4
4	To persons (3–23)	1,480.9	17	Taxes on corporate income (2–13)	384.4
5	To the rest of the world (5–18)	3.1	18	Taxes from the rest of the world (5–18)	10.8
6	Other current transfer payments to the rest of the world (net) (5–18)	33.9	19	Contributions for government social insurance (3–25)	880.6
7	Interest payments (3–20)	348.0	20	Income receipts on assets	98.3
8	Subsidies (1–7)	57.3	21	Interest and miscellaneous receipts (2–2 and 3–20)	95.8
9	*Less:* Wage accruals less disbursements (1–4)	0.0	22	Dividends (3–21)	2.4
10	Net government saving (6–12)	–312.5	23	Current transfer receipts	102.1
11	Federal	–309.2	24	From business (net) (2–7)	30.1
12	State and local	–3.3	25	From persons (3–6)	72.0
			26	Current surplus of government enterprises (1–10)	–15.4
13	**GOVERNMENT CURRENT EXPENDITURES AND NET SAVING**	**3,586.3**	27	**GOVERNMENT CURRENT RECEIPTS**	**3,586.3**

Account 5. Foreign Transactions Current Account

Line			Line		
1	Exports of goods and services (1–27)	1,303.1	9	Imports of goods and services (1–28)	2,019.9
2	Income receipts from the rest of the world	513.3	10	Income payments to the rest of the world	481.5
3	Wage and salary receipts (3–13)	2.9	11	Wage and salary payments (1–3)	9.2
4	Income receipts on assets	510.4	12	Income payments on assets	472.2
5	Interest (3–20)	172.4	13	Interest (3–20)	331.2
6	Dividends (2–22)	320.0	14	Dividends (2–3)	81.8
7	Reinvested earnings on U.S. direct investment abroad (2–23)	18.0	15	Reinvested earnings on foreign direct investment in the United States (2–4)	59.2
			16	Current taxes and transfer payments to the rest of the world (net)	86.6
			17	From persons (net) (3–7)	47.1
			18	From government (net) (4–5 and 4–6 less 4–18)	26.1
			19	From business (net) (2–8 and 2–14)	13.3
			20	Balance on current account, national income and product accounts (7–1)	–771.4
8	**CURRENT RECEIPTS FROM THE REST OF THE WORLD**	**1,816.5**	21	**CURRENT PAYMENTS TO THE REST OF THE WORLD AND BALANCE ON CURRENT ACCOUNT**	**1,816.5**

Account 6. Domestic Capital Account

Line			Line		
1	Gross domestic investment	2,454.5	8	Net saving	7.2
2	Private fixed investment (1–20)	2,036.2	9	Personal saving (3–8)	–34.8
3	Government fixed investment (1–29)	397.1	10	Undistributed corporate profits with inventory valuation and capital consumption adjustments (2–17)	354.5
4	Change in private inventories (1–25)	21.3			
5	Capital account transactions (net) (7–2)	4.4	11	Wage accruals less disbursements (private) (1–4)	0.0
6	Net lending or net borrowing (–), national income and product accounts (7–3)	–775.8	12	Net government saving (4–10)	–312.5
			13	*Plus:* Consumption of fixed capital (1–11)	1,604.8
			14	Private	1,352.6
			15	Government	252.2
			16	General government	207.2
			17	Government enterprises	45.1
			18	*Equals:* Gross saving	1,612.0
			19	Statistical discrepancy (1–13)	71.0
7	**GROSS DOMESTIC INVESTMENT, CAPITAL ACCOUNT TRANSACTIONS, AND NET LENDING**	**1,683.1**	20	**GROSS SAVING AND STATISTICAL DISCREPANCY**	**1,683.1**

Account 7. Foreign Transactions Capital Account

Line			Line		
			2	Capital account transactions (net) (6–5)	4.4
			3	Net lending or net borrowing (–), national income and product accounts (6–6)	–775.8
1	**BALANCE ON CURRENT ACCOUNT, NATIONAL INCOME AND PRODUCT ACCOUNTS (5–20)**	**–771.4**	4	**CAPITAL ACCOUNT TRANSACTIONS (NET) AND NET LENDING, NATIONAL INCOME AND PRODUCT ACCOUNTS**	**–771.4**

NOTE. Numbers in parentheses indicate accounts and items of counterentry in the accounts. For example, line 5 of account 1 is shown as "Supplements to wages and salaries (3–14)"; the counterentry is shown in account 3, line 14.

consumption expenditures and gross investment. GDP excludes intermediate purchases of goods and services by business.

Personal consumption expenditures (PCE) (1–15) measures goods and services purchased by U.S. residents. PCE consists mainly of purchases of new goods and of services by individuals from private business. In addition, PCE includes purchases of new goods and of services by nonprofit institutions (including compensation of employees), net purchases of used goods by individuals and nonprofit institutions, and purchases abroad of goods and services by U.S. residents. PCE also includes purchases of certain goods and services provided by general government and government enterprises, such as tuition payments for higher education, charges for medical care, and charges for water and other sanitary services. Finally, PCE includes imputed purchases that keep PCE invariant to changes in the way that certain activities are carried out—for example, whether housing is rented or owned, whether financial services are explicitly charged, or whether employees are paid in cash or in kind.

The following conventions are used to classify each PCE commodity: *Durable goods* (1–16) are tangible commodities that can be stored or inventoried and that have an average life of at least 3 years; *nondurable goods* (1–17) are all other tangible commodities that can be stored or inventoried; and services (1–18) are commodities that cannot be stored and that are consumed at the place and time of purchase.

Gross private domestic investment (1–19) consists of *fixed investment* (1–20) and the *change in private inventories* (1–25). Fixed investment consists of both *nonresidential* (1–21) fixed investment and *residential* (1–24) fixed investment. It is measured without a deduction for CFC and includes replacements and additions to the capital stock. It covers all investment in fixed assets by private businesses and by nonprofit institutions in the U.S., regardless of whether the fixed asset is owned by U.S. residents. (Purchases of the same types of equipment, software, and structures by government agencies are included in government gross investment.) It excludes investment by U.S. residents in other countries. Nonresidential fixed investment consists of both *structures* (1–22) and *equipment and software* (1–23).

Nonresidential structures consists of new construction (including own-account production), improvements to existing structures, expenditures on new nonresidential mobile structures, brokers' commissions on sales of structures, and net purchases of used structures by private business and by nonprofit institutions from government agencies.[19] New nonresidential construction includes hotels and motels and mining exploration, shafts, and wells. Nonresidential structures also includes equipment considered to be an integral part of a structure, such as plumbing, heating, and electrical systems.

Equipment and software consists of purchases by private business and by nonprofit institutions of new machinery, equipment, furniture, vehicles, and computer software used repeatedly, or continuously, in the processes of production for more than 1 year. Also included are dealers' margins on sales of used equipment to business and to nonprofit institutions; net purchases of used equipment from government agencies, from persons, and from the rest of the world; and own-account production of computer software. For equipment that is purchased for both business and personal use (for example, motor vehicles), the personal-use portion is included in PCE.

Residential fixed investment consists of all private residential structures and of residential equipment that is owned by landlords and rented to tenants. Residential structures consists of new construction of permanent-site single family and multifamily units, improvements (additions, alterations, and major structural replacements) to housing units, expenditures on manufactured homes, brokers' commissions on the sale of residential property, and net purchases of used structures from government agencies. Residential structures includes some types of equipment that are built into the structure, such as heating and air conditioning equipment.

Change in private inventories (1–25) is the change in the physical volume of inventories owned by private business, valued in average prices of the period. It differs from the change in the book value of inventories reported by most business; the difference is the *inventory valuation adjustment* (described above).

Net exports of goods and services (1–26) is *exports* (1–27) less *imports* (1–28) of goods and services. Income receipts and payments and current taxes and transfer payments to the rest of the world (net) are excluded.

Government consumption expenditures and gross investment (1–29), the measure of government sector final demand, consists of two major components: Current consumption expenditures by general government and gross investment by both general government and government enterprises. Consumption

19. Own-account production refers to an asset produced by a business or government for its own use.

expenditures consists of the goods and services that are produced by general government, less sales to other sectors and own-account investment. As producers of nonmarket services, governments generally provide services to the general public without charge, for example, law enforcement services, national defense services, and elementary and secondary education. The value of government production, that is, government's gross output, is measured by the cost of inputs: Compensation of employees, CFC (a partial measure of the services of government capital), and intermediate goods and services purchased.[20] Therefore, government consumption expenditures is measured as the sum of these costs of production less sales by government of goods and services to other sectors (which are classified as PCE, if purchased by individuals, or as intermediate inputs, if purchased by businesses) and the value of software and construction that are produced by government for its own use (that is, own-account investment, which is classified as part of gross government investment). Gross investment consists of purchases of new structures and of equipment and software by both general government and government enterprises, net purchases of used structures and equipment, and own-account production of structures and of software. Government consumption expenditures and gross investment does not include current transactions of government enterprises, current transfer payments, interest payments, subsidies, or transactions in financial assets and in nonproduced assets such as land.

Compensation of employees, paid (1–1) shows the income accruing to employees as remuneration for their work for domestic production; it includes compensation paid to the rest of the world and excludes compensation received from the rest of the world. It is the sum of wage and salary accruals and of supplements to wages and salaries.

Wage and salary accruals (1–2) consists of the monetary remuneration of employees, including the compensation of corporate officers; commissions, tips, and bonuses; voluntary employee contributions to certain deferred compensation plans, such as 401(k) plans; employee gains from exercising nonqualified stock options; receipts-in-kind; and miscellaneous compensation of employees.[21] Wage and salary accruals consists of *disbursements* (1–3) and *wage accruals less disbursements* (1–4). Disbursements is wages and salaries as just defined except that retroactive wage payments are recorded when paid rather than when earned. Accruals less disbursements is the difference between wages earned, or accrued, and wages paid, or disbursed. In the NIPAs, wages accruals is the measure used for gross domestic income, and wage disbursements is the measure used for personal income.

Supplements to wages and salaries (1–5) consists of employer contributions for employee pension and insurance funds (3–15) and of employer contributions for government social insurance (3–16).

Taxes on production and imports (1–6) consists of Federal excise taxes and custom duties and of state and local sales taxes, property taxes (including residential real estate taxes), motor vehicle licenses, severance taxes, special assessments, and other taxes.

Subsidies (1–7) is the monetary grants paid by government agencies to private business and to government enterprises at another level of government.[22]

Net operating surplus (1–8) is a profits-like measure that shows business income after subtracting the costs of compensation of employees, taxes on production and imports (less subsidies), and CFC from gross product (or value added), but before subtracting financing costs (such as net interest) and business current transfer payments. Net operating surplus consists of *net operating surplus of private enterprises* (1–9) and *current surplus of government enterprises* (1–10). (Net operating surplus of private enterprises is discussed under account 2 below.) The current surplus of government enterprises is their current operating revenue and subsidies received from other levels of government less their current expenses. In the calculation of their current surplus, no deduction is made for net interest paid.

Consumption of fixed capital (CFC) (1–11) is the charge for the using up of private and government fixed capital located in the United States. It is defined as the decline in the value of the stock of fixed assets due to wear and tear, obsolescence, accidental damage, and aging. For most types of assets, estimates of CFC are based on geometric depreciation patterns; empirical studies on the prices of used equipment and

20. Intermediate goods also include net purchases of used goods and changes in inventories. Change in inventories is not included in government investment because source data to prepare estimates for most inventory categories are not available. At present, the estimates for a few inventory categories for which data are available, such as inventories held by the Commodity Credit Corporation and the Strategic Petroleum Reserve, are included in government consumption expenditures.

21. Miscellaneous compensation of employees includes judicial fees paid to jurors and to witnesses, compensation of prison inmates, and marriage fees paid to justices of the peace.

22. For years prior to 1959, subsidies is presented net of the current surplus of government enterprises (1–10), because detailed data to separate the series for this period are not available.

structures in resale markets have concluded that a geometric pattern of depreciation is appropriate for most types of assets.[23] For general government and for nonprofit institutions that primarily serve individuals, CFC is recorded in government consumption expenditures and in PCE, respectively, as a partial measure of the value of the current services of the fixed assets owned and used by these entities. Private capital consumption allowances consists of tax return-based depreciation charges for corporations and nonfarm proprietorships and of historical cost depreciation (calculated by BEA using a geometric pattern of price declines) for farm proprietorships, rental income of persons, and nonprofit institutions. Private capital consumption adjustment is the difference between private capital consumption allowances and private CFC.

Statistical discrepancy (1–13) is GDP less GDI or GNP less GNI. It is recorded in the NIPAs as an "income" component that reconciles the income side with the product side of the accounts. As noted above, it arises because the two sides are estimated using independent and imperfect data.[24]

Account 2. Private enterprise income account

This account presents *sources of private enterprise income* (2–24) on the right side of the account and *uses of private enterprise income* (2–18) on the left side.[25] Private enterprises consist of private businesses and the accounts of homeowners for owner-occupied housing (which is treated as if it were a business). In addition, the net interest paid by nonprofit institutions serving households is included as a use of income in this account.[26]

Net operating surplus, private enterprises (2–19), can be derived by a series of deductions from business-sector gross value added, as described above. Alternatively, it can be calculated as the sum of the domestic components of proprietors' income with inventory valuation adjustment (IVA) and capital consumption adjustment (CCAdj), rental income of persons with CCAdj, corporate profits with IVA and CCAdj, net interest and miscellaneous payments, and business current transfer payments (net).[27]

Income receipts on assets (2–20) consists of interest, dividend receipts from the rest of the world, and reinvested earnings on U.S. direct investment abroad. *Interest* (2–21) is the interest received by domestic private enterprises and includes both monetary and imputed interest receipts. Interest received by private noninsured pension plans is recorded as being directly received by persons in personal income. *Dividend receipts from the rest of the world* (2–22) consists of receipts by U.S. residents of dividends from foreign corporations plus earnings distributed by unincorporated foreign affiliates to their U.S. parents. *Reinvested earnings on U.S. direct investment abroad* (2–23) consists of receipts by U.S. residents of their share of the reinvested earnings of their incorporated foreign affiliates and reinvested earnings of their unincorporated foreign affiliates.

The uses of private enterprise income (2–18) consists of income payments on assets, business current transfer payments (net), proprietors' income with IVA and CCAdj, rental income of persons with CCAdj, and corporate profits with IVA and CCAdj.

Income payments on assets (2–1) consists of interest and miscellaneous payments, dividend payments to the rest of the world, and reinvested earnings on foreign direct investment in the United States. *Interest and miscellaneous payments* (2–2) consists of interest paid by domestic private enterprises and of rents and royalties paid by private enterprises to government.[28] Interest payments includes both monetary and imputed interest payments. *Dividend payments to the rest of the world* (2–3) consists of payments by U.S. corporations of dividends to foreign residents, plus earnings distributed by unincorporated U.S. affiliates to their foreign parents. *Reinvested earnings on foreign direct investment in the United States* (2–4) consists of payments to foreign residents of their share of the reinvested earnings of their incorporated U.S. affiliates and reinvested earnings of their unincorporated U.S. affiliates. These earnings are treated as income payments on assets because the decision to retain some of the earnings

23. Several asset types use depreciation patterns that are not geometric. For example, computers and peripheral equipment and private autos use actual empirical depreciation profiles, and missiles and nuclear fuel rods use a straight-line pattern. For more information on depreciation patterns, see U.S. Department of Commerce, Bureau of Economic Analysis, Fixed Assets and Consumer Durable Goods in the United States, 1925–97, (Washington, DC: U.S. Government Printing Office, September 2003) and <www.bea.gov/bea/dn/Fixed_assets_1925_97.pdf>.

24. For additional details on the statistical discrepancy, see Robert P. Parker and Eugene P. Seskin, "Annual Revision of the National Income and Product Accounts," Survey 77 (August 1997): 19.

25. Government enterprises are not included in account 2, because complete estimates on sources and uses of government enterprise income, notably the income payments and income receipts on assets, are not currently available. The sources and uses of government enterprise income are included, but not separately identified, in the government receipts and expenditures account.

26. Summary account 2 presents the components of private enterprise income on a national basis, that is, for labor and property supplied by U.S. residents. Consequently, for the net operating surplus to be shown in account 2 on a domestic basis consistent with summary account 1, several income flows to and from the rest of the world must also be shown in account 2.

27. *Net interest and miscellaneous payments*, a component of national income, consists of interest and miscellaneous payments (2–2) less interest receipts (2–21). For a definition of net interest, see the section "other definitions" (page 14).

28. Interest payments on mortgage and home improvement loans and on home equity loans are included in interest paid by private enterprises because home ownership is treated as a business in the NIPAs.

within a U.S. enterprise represents a deliberate investment decision on the part of the foreign investor.[29]

Business current transfer payments (net) (2–5) consists of payments *to persons (net)* (2–6), *to government (net)* (2–7), and *to the rest of the world (net)* (2–8) by private business for which no current services are performed. Payments for net insurance settlements—actual insured losses (or claims payable) less a normal level of losses—are also treated as business current transfer payments. Business current transfer payments to government (net), consists of Federal deposit insurance premiums and other current transfer payments (largely fines and regulatory and inspection fees), less net insurance settlements from the National Flood Insurance Program, state and local fines and other current transfer payments (largely donations and tobacco settlements), and net insurance settlements paid to state and local governments as policyholders. Business current transfer payments to the rest of the world (net) consists of net insurance settlements paid to the rest of the world as policyholders.

Proprietors' income with inventory valuation and capital consumption adjustments (2–9) is the current-production income (including income in kind) of sole proprietorships and partnerships and of tax-exempt cooperatives. The imputed net rental income of owner occupants of farm and nonfarm dwellings is included in rental income of persons. Proprietors' income excludes dividends and monetary interest received by nonfinancial business and rental income received by persons not primarily engaged in the real estate business; these incomes are included in dividends, net interest, and rental income of persons.

Rental income of persons with capital consumption adjustment (2–10) is the net current production income of persons (except those primarily engaged in the real estate business) from the rental of real property, the imputed net rental income of owner occupants of farm and nonfarm dwellings, and the royalties received by persons from patents, copyrights, and rights to natural resources.

Corporate profits with inventory valuation and capital consumption adjustment (2–11) is the net current production income of organizations treated as corporations in the NIPAs. These organizations consist of all entities required to file Federal corporate tax returns, including mutual financial institutions and cooperatives subject to Federal income tax, private noninsured pension funds, nonprofit institutions that primarily serve business, Federal Reserve banks, and federally sponsored credit agencies.[30] With several differences, this income is measured as receipts less expenses as defined in Federal tax law. Among these differences are the following: Receipts exclude capital gains and dividends received, expenses exclude depletion and capital losses and losses resulting from bad debts, inventory withdrawals are valued at replacement cost, and depreciation is on a consistent accounting basis and is valued at replacement cost using depreciation profiles based on empirical evidence on used asset prices that generally suggest a geometric pattern of price declines. Corporate profits is included on a national income basis, which is defined as the income of U.S. residents; therefore the profits component includes income earned abroad by U.S. corporations and excludes income earned in the United States by the rest of the world.

Taxes on corporate income (2–12) consists of taxes on corporate income paid to government and taxes on corporate income paid to the rest of the world. *Taxes on corporate income paid to government* (2–13) is the sum of Federal, state, and local government income taxes on all income subject to taxes; this income includes capital gains and other income excluded from profits before tax. The taxes are measured on an accrual basis, net of applicable tax credits. *Taxes on corporate income paid to the rest of the world* (2–14) consists of nonresident taxes—that is, taxes paid by domestic corporations to foreign governments.

Profits after tax with inventory valuation adjustment and capital consumption adjustment (2–15) is corporate profits with IVA and CCAdj less taxes on corporate income. It consists of net dividends and undistributed corporate profits with IVA and CCAdj. *Net dividends* (2–16) is payments in cash or other assets, excluding the corporations' own stock, that are made by corporations located in the United States and abroad to stockholders who are U.S. residents. The payments are measured net of dividends received by U.S. corporations. Dividends paid to state and local governments are included. *Undistributed profits with inventory valuation and capital consumption adjustments* (2–17) is corporate profits after tax with IVA and CCAdj less net dividends.

Account 3. Personal income and outlay account

Personal income is the sum of compensation of employees, received; proprietors' income with IVA and CCAdj; rental income of persons with CCAdj; personal

29. This treatment is consistent with the guidelines of *SNA 1993*, paragraph 7.121.

30. The corporate profits that are associated with private noninsured pension plans are recorded as zero, and the property income is recorded as being received directly by persons in the corresponding components of personal income.

income receipts on assets; and personal current transfer receipts; less contributions for government social insurance. Personal income receipts on assets (interest, dividends, and rent) of private noninsured pension plans and of government employee retirement plans are recorded as being received directly by persons in the corresponding components of personal income.

Compensation of employees, received (3–10) consists of wage and salary disbursements and supplements to wages and salaries.

Wage and salary disbursements (3–11) consists of *domestic disbursements* (see 1–3) and *rest-of-the-world disbursements* (3–13).

Supplements to wages and salaries (see 1–5) consists of employer contributions for employee pension and insurance funds and of employer contributions for government social insurance. *Employer contributions for employee pension and insurance funds* (3–15) consists of employer payments (including payments in kind) to private pension and profit-sharing plans, publicly administered government employee retirement plans, private group health and life insurance plans, privately administered workers' compensation plans, and supplemental unemployment benefit plans. *Employer contributions for government social insurance* (3–16) consists of employer payments under the following Federal Government and state and local government programs: Old age, survivors, and disability insurance (social security); hospital insurance; unemployment insurance; railroad retirement; pension benefit guaranty; veterans life insurance; publicly administered workers' compensation; military medical insurance; and temporary disability insurance.[31]

Proprietors' income with inventory valuation and capital consumption adjustments (see 2–9).

Rental income of persons with capital consumption adjustment (see 2–10).

Personal income receipts on assets (3–19) consists of personal interest income and personal dividend income. *Personal interest income* (3–20) is the interest income (monetary and imputed) of persons, including individuals and nonprofit institutions serving households, from all sources. It equals private enterprise interest payments (see 2–2) plus *personal interest payments* (3–4), plus *government interest payments* (4–7), plus *interest receipts from the rest of the world* (5–5), less *private enterprise interest receipts* (see 2–21), less *government interest receipts* (see 4–21), less *interest payments to the rest of the world* (5–13). *Personal interest payments* (3–4) consists of all interest paid by individuals except mortgage interest, which is reflected in rental income of persons.

Personal dividend income (3–21) is the dividend income of persons from all sources. It equals *net dividends paid by corporations* (see 2–16) less *government receipts of dividends* (4–22), which consists of dividends received by state and local governments.

Personal current transfer receipts (3–22) consists of income payments to persons for which no current services are performed and of net insurance settlements. It is shown as the sum of government social benefits and current transfer receipts from business (net) (see 2–6). *Government social benefits* (3–23) includes benefits from government social insurance funds and social assistance benefits from certain other programs.

Contributions for government social insurance (3–25) includes employer contributions for government social insurance (see 3–16) and payments by employees, self employed, and other individuals who participate in the following government programs: Old age, survivors, and disability insurance (social security); hospital insurance; supplementary medical insurance, including the Medicare Prescription Drug benefit; unemployment insurance; railroad retirement; veterans life insurance; and temporary disability insurance.

Personal current taxes (3–1) is tax payments (net of refunds) by U.S. residents that are not chargeable to business expense. Personal taxes includes taxes on income, including realized net capital gains, and on personal property. Personal contributions for government social insurance is not included. Taxes paid by U.S. residents to foreign governments and taxes paid by foreigners to the U.S. Government are both included in *current taxes and transfer payments to the rest of the world from government (net).*

Personal outlays (3–2) is the sum of personal consumption expenditures (see 1–15), personal interest payments (see 3–4), and personal current transfer payments. *Personal current transfer payments* (3–5) consists of transfer payments *to government* (3–6) and *to the rest of the world* (3–7). Payments to government includes donations, fees, and fines paid to Federal, state, and local governments. Payments to the rest of the world is personal remittances in cash and in kind to the rest of the world less such remittances from the rest of the world.

Personal saving (3–8) is personal income less the sum of personal outlays and personal current taxes. It is the current saving of individuals (including proprietors and partnerships), nonprofit institutions that primarily serve households, life insurance carriers, private noninsured welfare funds, private noninsured pension plans, publicly administered government employee retirement plans, and private trust funds. Personal saving may also be viewed as the net acquisition

31. Publicly administered government employee retirement plans are classified as employee pension and insurance funds, not as government social insurance programs.

of financial assets (such as cash and deposits, securities, and the change in life insurance and pension fund reserves), plus the net investment in produced assets (such as residential housing, less depreciation), less the net increase in financial liabilities (such as mortgage debt, consumer credit, and security credit), less net capital transfers received.

Account 4. Government receipts and expenditures account

Government current receipts (4–27) is the sum of current tax receipts, contributions for government social insurance, income receipts on assets, current transfer receipts, and current surplus of government enterprises. *Current tax receipts* (4–14) consists of personal current taxes (see 3–1), taxes on production and imports (see 1–6), taxes on corporate income (see 2–13), and *taxes from the rest of the world* (4–18), which are mostly income taxes received by the Federal Government from foreigners.[32]

Contributions for government social insurance (see 3–25).

Income receipts on assets (4–20) consists of interest and miscellaneous receipts and dividends. *Interest and miscellaneous receipts* (4–21) includes monetary and imputed interest received by government on loans and investments from persons, from business, and from the rest of the world; miscellaneous receipts include Federal Outer Continental Shelf royalties and state and local rents and royalties. (Interest received by government employee retirement plans is recorded as being received directly by persons in personal income.)

Dividends received by government (see 3–21).

Current transfer receipts (4–23) consists of receipts *from business (net)* (4–24) (see 2–7) and receipts *from persons* (4–25) (see 3–6).

Current surplus of government enterprises (see 1–10).

Consumption expenditures (see 1–29).

Current transfer payments (4–2) is government social benefits and other current transfer payments to the rest of the world. *Government social benefits* (4–3) consists of government social benefits payments to *persons* (4–4) (see 3–23) and government social benefits payments *to the rest of the world* (4–5), which are U.S. Government transfers, mainly social security benefits, to former residents of the United States. *Other current transfer payments to the rest of the world (net)* (4–6) consists of U.S. Government military and nonmilitary grants in cash and nonmilitary grants-in-kind to foreign governments.

Interest payments (4–7) is interest paid by government to persons, to business, and to the rest of the world (that is, to foreign businesses, governments, and persons). Interest paid consists of monetary interest paid on public debt and other financial obligations.

Subsidies (see 1–7).

Wage accruals less disbursements (see 1–4).

Net government saving (4–10) is the sum of government current receipts (lines 14, 19, 20, 23, and 26 of account 4) less the sum of government current expenditures (lines 1, 2, 7, 8, less line 9 of account 4). It may also be viewed as the net acquisition of financial assets by government and government enterprises, plus the net investment in fixed assets (such as roads and highways, less depreciation), plus the net government purchases of nonproduced assets, less the net increase in financial liabilities, less net capital transfers.

Account 5. Foreign transactions current account

Imports of goods and services (see 1–28).

Income payments to the rest of the world (5–10) consists of wage and salary payments (see 1–3) and income payments on assets (5–12), which is the sum of interest (see 3–20), dividends (see 2–3), and reinvested earnings on foreign direct investment in the United States (see 2–4).

Current taxes and transfer payments to the rest of the world (net) is the sum of transfer payments *from persons (net)* (see 3–7), *from government (net)* (see 4–5 and 4–6 less 4–18), and *from business (net)* (see 2–8 and 2–14).

Balance on current account, national income and product accounts (5–20) is U.S. exports of goods and services and income receipts from the rest of the world less U.S. imports of goods and services, income payments to the rest of the world, and current taxes and transfer payments to the rest of the world (net). It may also be viewed as the acquisition of foreign assets by U.S. residents less the acquisition of U.S. assets by foreign residents. It includes the statistical discrepancy in the balance of payments accounts.

Exports of goods and services (see 1–27).

Income receipts from the rest of the world (5–2) consists of wage and salary receipts (see 3–13) and *income receipts on assets* (5–4), which is the sum of interest (see 3–20), dividends (see 2–22), and reinvested earnings on U.S. direct investment abroad (see 2–23).

Account 6. Domestic capital account

This account presents gross saving and the statistical discrepancy on the right side and "gross domestic investment, capital transfers, and net lending" on the left.

Gross saving (6–18) is net saving plus the consumption of fixed capital (see 1–11). *Net saving* (6–8) is

32. Taxes from the rest of world also includes some taxes on production and some current transfers, but the source data do not permit the reliable separation of the taxes on income.

calculated as the sum of personal saving (see 3–8), undistributed corporate profits with inventory valuation and capital consumption adjustments (see 2–17), private wage accruals less disbursements (see 1–4), and net government saving (see 4–10). It supplements the NIPA gross saving measure and provides a useful measure of the saving that is available for adding to the Nation's net stock of fixed assets.

Statistical discrepancy (see 1–13).

Gross domestic investment (6–1) measures the total investment in the United States in fixed assets (that is, the structures, equipment, and software that are used in production) and in inventories (change in private inventories). It is the sum of private fixed investment (see 1–20), government fixed investment (see 1–29), and change in private inventories (1–25).

Capital accounts transactions (net) (6–5) consist of capital transfers (mainly debt forgiveness and migrants' transfers) and the transfers of nonproduced nonfinancial assets to (or from) the rest of the world.

Net lending or net borrowing (–), national income and product accounts (6–6) is equal to the balance on current account less capital accounts transactions (net). It may be viewed as an indirect measure of the net acquisition of foreign assets by U.S. residents less the net acquisition of U.S. assets by foreign residents.

Account 7. Foreign transactions capital account

The right side of this account shows capital accounts transactions (net) (see 6–5) and net lending or net borrowing (–), national income and product accounts (see 6–6). The left side shows the balance on current account, national income and product accounts (see 5–20).

Other definitions

Final sales of domestic product is GDP less change in private inventories; equivalently, it is the sum of PCE, private fixed investment, government consumption expenditures and gross investment, and net exports of goods and services.

Gross domestic purchases is the market value of goods and services purchased by U.S. residents, regardless of where those goods and services were produced. It is GDP less net exports of goods and services; equivalently, it is the sum of PCE, gross private domestic investment, and government consumption expenditures and gross investment.

Final sales to domestic purchasers is gross domestic purchases less change in private inventories.

Net interest is the interest paid by private enterprises less the interest received by private enterprises, plus the interest paid by the rest of the world less the interest received by the rest of the world. Interest payments on mortgage and home improvement loans and on home equity loans are included in interest paid by private enterprises because home ownership is treated as a private enterprise. Interest received by private noninsured pension plans is recorded as being directly received by persons in personal income. Interest paid by nonprofits serving households is included in interest paid by private enterprises, while interest received by nonprofits serving households is included in the interest received by persons. In addition to monetary interest, net interest includes imputed interest. Imputed interest is made up of 1) imputed income paid to policy holders by property and casualty insurance companies and life insurance companies, measured as the investment income earned on policyholders' reserves; 2) implicit services provided by financial intermediaries other than commercial banks, measured as the property income received by them less the interest paid by them to business, households and institutions, governments, and the rest of the world; and 3) implicit services provided by commercial banks in the form of both depositor and borrower services.[33]

Fixed assets are produced assets that are themselves used repeatedly, or continuously, in processes of production for more than 1 year. Fixed assets consist of equipment, software, and structures (including, by convention, owner-occupied housing); consumer durable goods are not included. *Fixed investment* is the net acquisition of fixed assets.

Produced assets are nonfinancial assets that have come into existence as outputs from a production process; they include fixed assets and private inventories.

Nonproduced assets are nonfinancial assets that are used for production but have not themselves been produced; they include naturally occurring assets, such as land and mineral deposits.

Population is the total population of the United States, including the Armed Forces overseas and the institutionalized population. The monthly estimate is the average of Census Bureau survey estimates for the first of the month and the first of the following month; the

33. Commercial banks provide implicit services to both depositors and borrowers. Depositor services are measured as the difference between the interest received by depositors and the interest they would have received had they been paid a risk-free rate of interest (reference rate). Depositors receive a lower interest rate for their deposits in exchange for the unpriced services provided by banks. Borrower services are measured as the difference between the interest paid by borrowers and the interest they would have paid had they borrowed at the reference rate. Borrowers pay a higher interest rate for loans in exchange for the unpriced services provided to them by banks. The unpriced depositor services are recorded as imputed interest paid by financial intermediaries and received by depositors. The unpriced borrower services are recorded as negative imputed interest received by the financial intermediaries and negative interest paid by borrowers. Thus, imputed interest paid by private enterprises includes the interest paid by financial intermediaries for depositor services and the negative interest paid by businesses and owner-occupied housing in their role as borrowers.

quarterly and annual estimates are the averages of the relevant monthly estimates.

Personal saving as a percentage of disposable personal income (DPI), frequently referred to as "the personal saving rate," is calculated on a monthly, quarterly, and annual basis as the ratio of personal saving to DPI.

Gross saving as a percentage of gross national income (GNI), sometimes referred to as "the national saving rate," is calculated on a quarterly and annual basis as the ratio of gross saving—the sum of net saving and consumption of fixed capital—to GNI.

U.S. residents are individuals, governments, business enterprises, trusts, associations, nonprofit organizations, and similar institutions that have the center of their economic interest in the United States and that reside or expect to reside in the United States for 1 year or more. (For example, business enterprises residing in the United States include U.S. affiliates of foreign companies.) In addition, U.S. residents include all U.S. citizens who reside outside the United States for less than 1 year and U.S. citizens residing abroad for 1 year or more who meet one of the following criteria: Owners or employees of U.S. business enterprises who reside abroad to further the enterprises' business and who intend to return within a reasonable period; U.S. Government civilian and military employees and members of their immediate families; and students who attend foreign educational institutions.

Foreign residents are those residing and pursuing economic interests outside the United States. They also include international institutions located in the United States, foreign nationals employed by their home governments in the United States, and foreign affiliates of U.S. companies.

The rest of the world consists of foreign residents who are transactors with U.S. residents.

Real Output and Related Measures

In addition to estimating the current-dollar market value of GDP, BEA estimates "real," or inflation-adjusted, GDP and its components.

Quantity and price indexes

BEA's chain-type quantity and price indexes, in combination with the current-dollar estimates, provide users with the basic data series from which all other analytical tables and presentations of the NIPAs are derived.

Changes in current-dollar GDP measure the changes in the market value of the goods, services, and structures produced in the economy in a particular period. These changes can be decomposed into quantity and price components that, in turn, can be expressed as index numbers with the reference year—at present, the year 2000—equal to 100. These are referred to as "chain-type" indexes. Percent changes in real GDP and its components are equal to the percent changes of the quantity indexes; percent changes in prices are equal to the percent changes of the price indexes.[34]

The annual changes in quantities and prices in the NIPAs are calculated using a Fisher formula that incorporates weights from 2 adjacent years. For example, the 2003–04 change in real GDP uses prices for 2003 and 2004 as weights, and the 2003–04 change in prices uses quantities for 2003 and 2004 as weights.[35] These annual changes are "chained" (multiplied) together to form time series of quantity and price indexes. Quarterly changes in quantities and prices are calculated using a Fisher formula that incorporates weights from two adjacent quarters; quarterly indexes are adjusted for consistency to the annual indexes before percent changes are calculated. (For more details, see appendix 1, "Formulas for Calculating Chain-Type Quantity and Price Indexes.")

The Fisher formula produces percent changes in quantities and prices that are not affected by the choice of reference year. In addition, the use of the Fisher formula has several other advantages over fixed-weighted measures: (1) It eliminates substitution bias in real GDP growth that tends to cause an understatement of growth for periods before the reference year and an overstatement of growth for periods after the reference year; (2) it eliminates the distortion of growth in components and in industries that result from the fixed-weighted indexes; and (3) it eliminates the anomalies that arise from using recent-period price weights to measure periods in the past when a far different set of prices prevailed.[36]

34. Indexes are not presented for change in private inventories, for net exports, and for most of the "net" series in tables 2.4.3, 2.4.4, 2.5.3, 2.5.4, 3.9.3, 3.9.4, 5.2.3, 5.4.3, 5.4.4, 5.8.3, and 5.8.4 because indexes for these series are not meaningful.

35. Because the source data available for most components of GDP are measured in dollars rather than in units, the quantities of most of the detailed components used to calculate percent changes are obtained by deflation. For deflation, quantities are approximated by real values (expressed, at present, with 2000 as the reference year) that are calculated by dividing the current-dollar value of the component by its price index, where the price index uses 2000 as the reference year. Two other methods, quantity extrapolation and direct valuation, are also used to calculate real values for a number of the most detailed GDP components. For quantity extrapolation, the real values are obtained by extrapolating the current-dollar estimates for the reference year in both directions by quantity indicators; for example, the real values for "mining exploration, shafts, and wells structures" are extrapolated using oilwell footage drilled. For direct valuation, the real values are obtained by multiplying reference-year prices by quantity data for each period; for example, the real values of "natural gas inventories" are calculated using quantities and prices of natural gas stocks. For more information, see "Updated Summary Methodologies," in the November 2005 SURVEY.

36. For further discussion, see J. Steven Landefeld, Brent. R Moulton, and Cindy M. Vojtech, "Chained-Dollar Indexes: Issues, Tips on Their Use, and Upcoming Changes," SURVEY 83 (November 2003): 6–16; J. Steven Landefeld and Robert P. Parker, "BEA's Chain Indexes, Time Series, and Measures of Long Term Economic Growth," SURVEY 77 (May 1997): 58–68; and Jack E. Triplett, "Economic Theory and BEA's Alternative Quantity and Price Indexes," SURVEY 72 (April 1992): 49–52.

Chained-dollar measures

BEA also prepares measures of real GDP and its components in a dollar-denominated form, designated "chained (2000) dollar estimates." For GDP and most other series, these estimates are computed by multiplying the current-dollar value in 2000 by a corresponding quantity index number and then dividing by 100. For example, if a current-dollar GDP component equaled $100 in 2000 and if real output for this component increased 15 percent by 2004, then the chained (2000) dollar value of this component in 2004 would be $115 (= $100 x 115/100). (For a list of the chained-dollar series that are not calculated in this way, see appendix 2, "Chained Measures in the NIPAs Not Calculated as Fisher Indexes.")

The chained (2000) dollar, or "real," estimates provide measures to calculate the percent changes for GDP and its components that are consistent with those calculated from the chain-type quantity indexes; any differences will be small and due to rounding. For most components of GDP, the chained-dollar estimates also provide rough approximations of their relative importance and of their contributions to real GDP growth for years close to 2000.[37] However, for some components—such as computers and other high-tech equipment with rapid growth in real sales and falling prices—chained-dollar levels (as distinct from chain-weighted indexes and percent changes) overstate the relative importance of such components to GDP growth.[38]

In addition, chained-dollar values for the detailed GDP components will not necessarily sum to the chained-dollar estimate of GDP (or any intermediate aggregate) because the relative prices used as weights for any period other than the reference year differ from those used for the reference year. BEA provides a measure of the extent of such differences by showing a "residual" line on chained-dollar tables that indicates the difference between GDP (or other major aggregate) and the sum of the most detailed components in the table.

For periods close to the reference year, when there usually has not been much change in the relative prices that are used as the weights for calculating the chain-type index, the residuals tend to be small, and the chained (2000) dollar estimates can be used to approximate the contributions to growth and to aggregate the detailed estimates.

Contributions

For periods further from the reference year, the residual tends to become larger, and the chained-dollar estimates are less useful for analyses of contributions to growth.[39] For this reason, BEA also shows contributions of major components to the percent change in real GDP (and to the percent change in other major aggregates) that use exact formulas for attributing growth. (For details, see appendix 3, "Calculation of Component Contributions to the Change in GDP and Other Major Aggregates.")

The contributions tables have table numbers with the format #.#.2, and the presentation is limited to the contributions to the percent change in GDP (or in another major aggregate) from the preceding year or quarter. For some analytical purposes, it may be desirable to calculate contributions to growth for more than a single quarter or year or to calculate contributions to growth for aggregates not shown in these tables. An article in the SURVEY provides information on how to prepare chained-dollar series with different reference years that permit the calculation of close approximations of contributions to real growth for any period.[40] The article shows how to calculate a chained-dollar series for any period by using the percent changes in the chain-type indexes to compute chained-dollar series indexed to the current dollars of whatever reference year is appropriate for the analysis. In the article, different reference years are used depending upon the time period analyzed; for example, for decades and business cycles, the midpoints of the periods are used.[41]

Current-dollar shares

Two tables show the percentage shares of GDP and GDI that are accounted for by major components. These shares, which are calculated on a current-dollar

37. The availability of chained-dollar estimates before 1990 has been limited to key aggregates. However, detailed quantity indexes, which are accurate for all periods, are presented in tables with table numbers having format #.#.3, most of which begin with 1929. These quantity indexes can be used in place of chained-dollar estimates in analyses that require data on real GDP or its components over time, as well as to calculate percent changes. For GDP and its major components, annual growth rates beginning with 1930 and quarterly growth rates beginning with the second quarter of 1947 are presented in table 1.1.1.

38. The problems associated with chained-dollar levels for components with rapidly changing prices is the result of using a fixed reference year in conjunction with a chain index whose weights change every period to reflect changes in relative prices. It is mathematically impossible to "force" chained-dollar levels to reflect both the current-period weights and period-to-period percent changes that are consistent with a chain index.

39. This is why most of the chained-dollar series for detailed components are shown beginning with 1990, although chained (2000) dollar estimates for selected series for earlier periods are shown in tables 1.1.6, 1.2.6, 1.3.6, 1.4.6, 1.7.6, and 1.8.6.

40. See Laudefeld and Parker, "BEA's Chain Indexes," 63–66.

41. NIPA tables 1.1.6A, 1.1.6B, 1.1.6C, aud 1.1.6D present annual estimates of real GDP and its major components in chained (1937) dollars, chained (1952) dollars, chained (1972) dollars, and chained (1982) dollars, respectively. However, users should be aware that contributions calculated from these tables are approximations and may produce misleading results for periods far from those reference years or when relative prices are changing rapidly, such as during the energy crisis of 1973–75.

basis, provide data users with an accurate measure of the size and importance of the components of GDP and GDI. Table 1.1.10, which shows the shares of GDP, is published annually and quarterly, and table 1.11, which shows the shares of GDI, is published annually.

Price indexes

BEA's featured aggregate price measure is the price index for gross domestic purchases, which measures the prices paid for goods and services *purchased* by U.S. residents. This index is derived from the prices of PCE, gross private domestic investment, and government consumption expenditures and gross investment. In contrast, the GDP price index measures the prices paid for goods and services *produced* by the U.S. economy and is derived from the prices of PCE, gross private domestic investment, net exports, and government consumption expenditures and gross investment. Thus, the two indexes differ with respect to coverage of the prices of exported and imported goods and services. Price changes in goods and services produced abroad and sold in the United States are reflected in the gross domestic purchases measure but not in the GDP measure; price changes in goods and services produced by the U.S. economy and sold abroad are reflected in the GDP price measure but not in the gross domestic purchases price measure. For example, a change in the price of imported petroleum that is fully passed on to U.S. consumers would be fully reflected in the price index for gross domestic purchases but not in the GDP price index, because imports are subtracted in deriving GDP.

Implicit price deflators

BEA also prepares another price index, the implicit price deflator (IPD), which is calculated as the ratio of the current-dollar value to the corresponding chained-dollar value, multiplied by 100 (see appendix 1, "Formulas for Calculating Chain-Type Quantity and Price Indexes"). The values of the IPD are very close to the values of the corresponding chain-type price index for all periods. IPDs for GDP and its major components are presented as index numbers in NIPA table 1.1.9.

Command-basis GNP and terms of trade

BEA also prepares another measure of "real" output—*command-basis GNP* (tables 1.8.3 and 1.8.6). Command-basis GNP is a measure of the goods and services produced by the U.S. economy in terms of their purchasing power. GNP and command-basis GNP differ in how their real values are prepared: In estimating real GNP, the current-dollar values of the detailed components of exports of goods and services are deflated by export prices, the current-dollar values of the detailed components of imports of goods and services are deflated by import prices, and the current-dollar value of most factor income is deflated by the IPD for final sales to domestic purchasers. In estimating command-basis GNP, the current-dollar value of the sum of exports of goods and services and of income receipts is deflated by the IPD for the sum of imports of goods and services and of income payments.

The *terms of trade* is a measure of the relationship between the prices that are received by U.S. producers for exports of goods and services and the prices that are paid by U.S. purchasers for imports of goods and services. When the terms of trade improve (that is, when export prices rise relative to import prices), the purchasing power, or command value of U.S. GNP in international markets, increases by more than the production of goods and services valued in U.S. prices. Conversely, when the terms of trade deteriorate (that is, when export prices fall relative to import prices), the purchasing power, or command value of U.S. GNP in international markets, increases by less than the production of goods and services valued in U.S. prices.

The terms of trade is measured by the following ratio, with the decimal point shifted two places to the right: In the numerator, the IPD for the sum of exports of goods and services and of income receipts; in the denominator, the IPD for the sum of imports of goods and services and of income payments. Changes in the terms of trade reflect the interaction of several factors, including movements in exchange rates, changes in the composition of traded goods and services, and changes in producers' profit margins. For example, if the U.S. dollar depreciates against a foreign currency, a foreign manufacturer may choose to absorb this cost by reducing the profit margin on the product it sells to the United States, or it may choose to raise the price of the product and risk a loss in market share.

Classifications of Production

In the NIPAs, production is classified by type of product, by sector, by legal form of organization, and by industry.

Type of product

Type of product classifications—goods (durable and nondurable), services, and structures—are presented for GDP and the components of final sales of domestic product.

Goods are tangible products that can be stored or inventoried, services are products that cannot be stored and are consumed at the place and time of their purchase, and structures are products that are usually constructed at the location where they will be used and that typically have long economic lives. In cases in which a product has characteristics of more than one of these classifications (for example, restaurant meals), or in which source data do not provide detail on type of product (for example, foreign travel), the product is classified on the basis of the dominant characteristic.

Accordingly, the following products are included in goods: Restaurant meals; expenditures abroad by U.S. residents except for travel (for example, expenditures of U.S. military and embassy personnel abroad); replacement parts whose installation cost is minimal; dealers' margins on used equipment; and movable household appliances, such as refrigerators, even when they are included in the purchase price of a new home.

The following products are included in services: Food that is included in airline transportation and hospital charges; natural gas and electricity (except in exports and imports); goods and services that are included in current operating expense of nonprofit institutions (for example, office supplies); foreign travel by U.S. residents; expenditures in the United States by foreigners; repair services, which include the cost of parts (except replacement parts whose installation cost is minimal); defense research and development; and exports and imports of certain goods, primarily military equipment purchased and sold by the Federal Government.

Government consumption expenditures for the Federal Government and state and local governments are recognized as services produced by general government. The value of these services, most of which are not sold in the market, are measured by the cost of inputs: Compensation, consumption of fixed capital (CFC), and intermediate goods and services purchased less own-account investment and sales to other sectors. (Purchases by general government of goods and services are classified as intermediate purchases.)

The following products are included in structures: Manufactured homes; certain types of installed equipment, such as elevators, heating, and air conditioning systems; brokers' commissions on sale of structures; architectural and engineering fees included in the value of structures; land development costs; and mining exploration, shafts, and wells.

In PCE, in exports, in imports, and in government intermediate goods and services purchased, durable goods have an average life of at least 3 years. In fixed investment, equipment and software consists of goods that have an average life of at least 1 year. In change in private inventories, goods held by manufacturing and trade establishments are classified as durable goods or nondurable goods in accordance with the classification of the industry of the establishment holding the inventories. Inventories held by construction establishments are classified as durable goods. Inventories held by establishments other than those in manufacturing, trade, and construction are classified as nondurable goods.

Sector

In the NIPAs, a breakdown of GDP is also shown in terms of the three sectors of the economy—business, households and institutions, and general government; the term "value added" refers to the product of sectors.

Business: Production by all entities that produce goods and services for sale at a price intended at least to approximate the costs of production, corporate and noncorporate private entities organized for profit, and certain other entities that are treated as business in the NIPAs. These entities include mutual financial institutions, private noninsured pension funds, cooperatives, nonprofit organizations (that is, entities classified as nonprofit by the Internal Revenue Service (IRS) in determining income tax liability) that primarily serve business, Federal Reserve banks, federally sponsored credit agencies, and government enterprises.[42] Gross value added of the business sector is measured as GDP less the gross value added of households and institutions and of general government.[43]

Households and institutions: The households and institutions sector comprises households and nonprofit institutions serving households (NPISHs). The gross value added of households is measured by the services of owner-occupied housing and the compensation paid to domestic workers. The gross value added of NPISHs is measured by the compensation paid to the employees of these institutions, the rental value of fixed assets owned and used by these institutions, and the rental income of persons for tenant-occupied housing owned by these institutions.

General government: The government sector comprises all Federal Government and state and local government agencies except government enterprises. The gross value added of general government is measured as the sum of the compensation of the employees of these agencies and of their CFC.

Legal form of organization

For the domestic business sector, income and its components are shown for corporate business and noncorporate business. Noncorporate business, in turn, comprises sole proprietorships and partnerships, other private business, and government enterprises

42. For more detail on government enterprises, see the section "Legal form of organization."

43. Gross value added of financial and of nonfinancial corporations are also shown in the NIPA tables. They are calculated based on the costs incurred and the incomes earned from production.

(employee compensation and current surplus of enterprises).

Corporate business: This legal form comprises all entities required to file Federal corporate tax returns (IRS Form 1120 series). These entities include mutual financial institutions and cooperatives subject to Federal income tax, nonprofit institutions that primarily serve business, Federal Reserve banks, and federally sponsored credit agencies.

Sole proprietorships: This legal form comprises all entities that would be required to file IRS Schedule C (Profits or Loss from Business) or Schedule F (Farm Income and Expenses) if the proprietor met the filing requirements.

Partnerships: This legal form comprises all entities required to file Federal partnership income tax returns, IRS Form 1065 (U.S. Partnership Return of Income).

Other private business: This legal form comprises all entities that would be required to report rental and royalty income on the individual income tax return in IRS Schedule E (Supplemental Income and Loss) if the individual met the filing requirements, tax-exempt cooperatives, and buildings and equipment and software owned and used by NPISHs.

Government enterprises: This legal form consists of government agencies that cover a substantial proportion of their operating costs by selling goods and services to the public and that maintain their own separate accounts. A "mixed" treatment of government enterprises is used in the NIPAs: Some types of transactions are recorded as if they were part of the business sector, and others are recorded as if they were part of the general government sector. The following transactions of government enterprises are treated like those of businesses and included in the NIPA business sector: (1) Their sales to final users are recorded as sales by businesses, (2) their purchases of materials and business services are considered intermediate, and (3) their compensation payments and CFC are deducted in calculating their income. Within the business sector, government enterprises are classified as noncorporate businesses.

Other transactions of government enterprises are treated like those of other government agencies: (1) Their interest payments are combined with those of general government rather than those of business, (2) their investment in equipment and software and in structures is combined with general government investment rather than with business investment in gross private domestic investment, and (3) their profit-like income, the current surplus of government enterprises (see definition on page 9), accrues to general government.

Industry

Industrial distributions are presented for national income and its components, capital consumption allowances, employment and hours, and the change in private inventories and the stock of private inventories.[44] For the estimates of income and employment by industry beginning with 1998, the classification underlying the distributions of private activities is based on the North American Industrial Classification System (NAICS).[45] For the estimates of inventories beginning with the first quarter of 1997, the estimates are also based on NAICS. For estimates before these dates, the industry classifications are based on the Standard Industrial Classification (SIC).[46]

The industry distributions in most of the tables in "Income and Employment" (table section 6; see Presentation of the NIPAs below) are shown as follows: Estimates for 1929–48 based on the 1942 SIC are shown in tables designated as part A; estimates for 1948–87 based on the 1972 SIC are shown as part B; estimates for 1987–2000 based on the 1987 SIC are shown as part C; and estimates for 1998 forward are based on the 1997 NAICS are shown as part D. The industry distributions based on the 1997 NAICS reflect the corresponding shift of most of the NIPA source data to a NAICS basis. The estimates for earlier years have not been adjusted to the 1997 NAICS basis because of a lack of adequate source data. Instead, the estimates for 1948 are shown on the basis of both the 1942 and 1972 SIC, the estimates for 1987 are shown on the basis of both the 1972 and the 1987 SIC, and the estimates for 1998–2000 are shown on the basis of both the 1987 SIC and the 1997 NAICS.

44. An industrial distribution of fixed investment based on data collected from establishments is prepared as part of the procedure used to estimate fixed assets. For further information, see *Fixed Assets and Consumer Durable Goods in the United States, 1925–97* (Washington, DC: U.S. Government Printing Office, September 2003). Industrial distributions of gross output, intermediate inputs, and gross product are also prepared; for further information, see Brian C. Moyer, Mark A. Planting, Paul V. Kern, and Abigail M. Kish, "Improved Annual Industry Accounts for 1998–2003: Integrated Annual Input-Output Accounts and Gross-Domestic-Product-by-Industry Accounts," SURVEY 84 (June 2004): 21–57; Robert E. Yuskavage and Yvon H. Pho, "Gross Domestic Product by Industry for 1987–2000: New Estimates on the North American Industry Classification System," SURVEY 84 (November 2004): 33–53; and George M. Smith, Matthew J. Gruenberg, Tameka R.L. Harris, and Erich H. Strassner, "Annual Industry Accounts: Revised Estimates for 2001–2003," SURVEY 85 (January 2005): 9–43.

45. See Executive Office of the President, Office of Management and Budget, *North American Industry Classification System, United States, 1997* (Washington, DC: Bernan Press, 1998).

46. See Office of Management and Budget, Statistical Policy Division, *Standard Industrial Classification Manual, 1987* (Washington, DC: U.S. Government Printing Office (GPO), 1988); Office of Management and Budget, Statistical Policy Division, *Standard Industrial Classification Manual, 1972* (Washington, DC: GPO, 1972); and Bureau of the Budget, *Standard Industrial Classification Manual, 1942* (Washington, DC: GPO, 1942).

Industrial distributions of government activities are not provided; instead, they are combined into a single category. For most series, separate estimates are shown for the activities of the Federal Government, of state and local governments, and of government enterprises. Expenditures by the Federal Government and by state and local governments are also shown by type and by function.

The industrial distributions for private activities are based on data collected from "establishments" or from "companies" (also called enterprises, or firms). Establishments are economic units, generally at a single physical location, where business is conducted or where services or industrial operations are performed (for example a factory, mill, store, hotel, movie theater, mine, farm, airline terminal, sales office, warehouse, or central administrative office). Companies consist of one or more establishments owned by the same legal entity or group of affiliated entities. Establishments are classified into an industry on the basis of their principal product or service, and companies are classified into an industry on the basis of the principal industry of all their establishments. Because large multiestablishment companies typically own establishments that are classified in different industries, the industrial distribution of the same economic activity on an establishment basis can differ significantly from that on a company basis. For example, employment of steel-manufacturing companies differs from employment of steel-manufacturing establishments because the employment of these companies includes the employment of establishments that are not classified in steel manufacturing and because it excludes the employment of establishments that manufacture steel but are not owned by steel-manufacturing companies.

Industrial distributions on a consistent establishment or company basis are not available for all NIPA components. As a result, the industrial distribution of national income reflects a mix of establishment and company data. For the following series, the industrial distributions are based on establishment data: Compensation of employees, employment, hours, inventories, rental income of persons, farm proprietors' income, farm net interest, and farm noncorporate capital consumption allowances. For nonfarm proprietors, industrial distributions of proprietors' income, net interest, and capital consumption allowances are based on company data; these data are regarded as being substantially the same as if they were based on establishment data because nearly all unincorporated companies own only one establishment (and the few multiestablishment companies usually own establishments in the same industry). For corporations, industrial distributions of profits, nonfarm net interest, and capital consumption allowances are based on company data.

In addition, individual industry series are not fully comparable over time. Historical comparability is affected primarily by two factors. First, the composition of industries may change because of changes in the NAICS or SIC basis that is used for the estimates. This factor affects estimates based on establishment data and on company data.

Second, historical comparability is affected because the industrial classification of the same establishment or company may change over time. This factor affects company-based estimates much more than establishment-based estimates. The classification of a company may change as a result of the following: Shifts in the level of consolidation of entities for which company reports are filed; mergers and acquisitions; and other shifts in principal activities, especially for large, diversified firms.

In addition to the industrial distributions of private activities, some NIPA tables show the following special industry groupings:

Financial industries consists of the following NAICS industries: Finance and insurance, and management of companies and enterprises. Finance and insurance consists of Federal Reserve banks; credit intermediation and related activities; securities, commodity contracts, and investments; insurance carriers and related activities; and funds trusts, and other financial vehicles. Management of companies and enterprises consists of bank and other holding companies.

Nonfinancial industries consists of all other private industries.

Goods-producing industries consists of the following NAICS divisions: Natural resources (agriculture, forestry, fishing, and hunting) and mining; construction; and manufacturing.

Services-producing industries consists of the following NAICS divisions: Wholesale trade, retail trade, transportation and warehousing, and utilities; and other services-producing industries (information; finance and insurance; real estate and rental and leasing; professional, scientific, and technical services; management of companies and enterprises; administrative and waste management services; educational services; health care and social assistance; arts, entertainment, and recreation; accommodation and food services; and other services, except government).

Presentation of the NIPAs

This section describes the release schedule for the NIPA estimates, the publication of the NIPA tables, and additional presentations of NIPA and NIPA related estimates.[47]

Release schedule

For GDP and most other NIPA series, quarterly estimates are released on the following schedule: "Advance" estimates are released near the end of the first month after the end of the quarter; as more detailed and more comprehensive data become available, "preliminary" and "final" estimates are released near the end of the second and third months, respectively.

For gross national product, gross domestic income, national income, corporate profits, and net interest, "advance" estimates are not prepared, because of a lag in the availability of source data. Except for the fourth quarter estimates, the initial estimates for these series are released with the preliminary GDP estimates, and the revised estimates are released with the final GDP estimates. For the fourth quarter, these estimates are released only with the final GDP estimates.

In addition, when the preliminary estimates of GDP for the current quarter are released, BEA releases revised estimates of private wages and salaries and affected income-side aggregates for the previous quarter.[48] This permits the incorporation of the most recently available wage and salary data from the quarterly census of employment and wages.

Monthly estimates of personal income and outlays are released near the end of the month following the reference month; estimates for the preceding 2 to 4 months are subject to revision at that time.

Annual revisions of the NIPAs are usually carried out each summer and cover the months and quarters of the most recent calendar year and of the 2 preceding years. These revisions are timed to incorporate newly available major annual source data.[49]

Comprehensive revisions are carried out at about 5-year intervals. They incorporate definitional, statistical, and presentational improvements.

Publication of the NIPA tables

Tables that present the NIPA estimates appear each month under "National Data" in the section "BEA Current and Historical Data" in the SURVEY OF CURRENT BUSINESS and on BEA's Web site.[50] The full set of NIPA tables consists of 299 tables that present annual, quarterly, and monthly estimates.

With the release of the 12th comprehensive revision of the NIPAs, the presentation of the NIPA tables was organized to group tables with similar formats in one section of the NIPA tables. To assist users in identifying the type of estimate in a table, a numbering system for NIPA tables was developed for groups of tables that display different types of estimates using similar formats. The table-numbering system highlights the type of estimate (such as current dollars, quantity indexes, and percent changes) in the table. The new system is outlined below.

Table numbers are in the format "X.Y.Z." where "X" indicates the NIPA table section, "Y" indicates the table number in the section, and "Z" indicates the type of estimate presented.

47. For additional details on the availability of BEA's products and services, see BEA's Web site at <www.bea.gov>.

48. Affected aggregates include gross domestic income, the statistical discrepancy, gross national income, national income, personal income, disposable personal income, personal saving, gross (national) saving, compensation, and gross product of corporate business. Other components that are closely linked to wages and salaries, such as personal current taxes and employer contributions for government social insurance are also revised. However, GDP and its components are not affected.

49. For a discussion of the most recent annual revision of the NIPAs, see Eugene P. Seskin and Shelly Smith, "Annual Revision of the National Income and Product Accounts," SURVEY 86 (August 2006): 7–31.

50. The NIPA estimates appear first in news releases, which are available to the general public in a variety of forms.

The table sections are numbered as follows:

1. Domestic Product and Income
2. Personal Income and Outlays
3. Government Current Receipts and Expenditures
4. Foreign Transactions
5. Saving and Investment
6. Income and Employment by Industry
7. Supplemental Tables
8. Seasonally Unadjusted Estimates

The table numbers within each section are numbered sequentially. The types of estimates are numbered as follows:

1. Percent change from preceding period in real estimates (most at annual rates)
2. Contributions to percent change in real estimates
3. Real estimates, quantity indexes
4. Price indexes
5. Current dollars
6. Real estimates, chained dollars
7. Percent change from preceding period in prices
8. Contributions to percent change in prices
9. Implicit price deflators
10. Percentage shares of GDP

For example, GDP is presented in table group 1.1; the current-dollar estimates are presented in table 1.1.5, and the chained-dollar estimates are presented in table 1.1.6.

The tables that present current-dollar estimates, but not other types of estimates, use only the first two terms of the numbering system. For example, table 3.1, "Government Current Receipts and Expenditures," that presents only current-dollar estimates is not numbered 3.1.5.

For some tables, a letter suffix following the table number indicates that there are different versions of the table for different time periods; for example, table 4.3A shows the relation of foreign transactions in the NIPAs to the corresponding items in the international transactions accounts for the period 1946–85, and table 4.3B shows the same relation (with additional detail) beginning with 1986.

Most of the full set of NIPA tables are published in the issues of the SURVEY that describe the annual and comprehensive revisions (for example, see the August 2006 SURVEY); the remaining tables are published in subsequent months. In addition, a set of "Selected NIPA Tables" is published monthly in the SURVEY; this set presents the estimates for the most recent 5 quarters and the most recent 2 years. The selected set comprises 100 tables from the first seven NIPA table sections (seasonally unadjusted estimates in the last section are compiled only once a year and thus are not included in the selected set of tables). Because the numbering system used for the full set of tables is retained in the selected set, gaps occur in the numbering of the selected tables.

A note preceding the NIPA tables indicates information on the vintage of the estimates. In general, the NIPA tables in the SURVEY present estimates for the most recent 2–4 years. Historical annual and quarterly estimates for summary NIPA series are presented annually in the SURVEY and cover the following: Current- and chained-dollar GDP for most of the components in NIPA tables 1.1.5 and 1.1.6 and for final sales of domestic product and gross national product; NIPA chained-type quantity indexes in NIPA table 1.1.3 and chain-type price indexes and implicit price deflators in NIPA tables 1.1.4 and 1.1.9; and most of the major components of national income and personal income in NIPA tables 1.12 and 2.1. For example, these estimates were published as "GDP and Other Major NIPA Series, 1929–2006:II" in the August 2006 SURVEY. In addition, historical annual and quarterly estimates for the major NIPA aggregates are published monthly iu table C.1 in the "BEA Current and Historical Data" section of the SURVEY.

An "Index to the NIPA Tables," which identifies the NIPA table (or tables) for each NIPA series and each topic covered by the NIPAs and which includes cross references for commonly used business and economic terms to the appropriate NIPA item was published in the May 2005 SURVEY, beginning on page 48. The index is also available on BEA's Web site in the Interactive NIPA table section.

Additional presentations of NIPA and NIPA-related estimates

The SURVEY also presents the following NIPA and NIPA related estimates that do not fit neatly into the system or publication schedule for the standard NIPA presentation.

"Current-Dollar and Real Value Added by Industry" presents current- and chained-dollar estimates of value added by industry, which is the contribution of each industry including government to GDP. Estimates for value added by industry for 2002–2004 were published in the December 2005 SURVEY; advance estimates for 2005 were published in the May 2006 SURVEY. (Estimates for earlier years are available on BEA's Web site.)

"Reconciliation Table" in appendix A of the "BEA

Current and Historical Data" section presents a table that reconciles NIPA estimates with related series and that provides analytically useful extensions of the NIPA estimates. This table shows the reconciliation of relevant NIPA series with related series in the international transactions accounts.

"Real Inventories, Sales, and Inventory Sales Ratios for Manufacturing and Trade," usually published in the January, April, July, and October issues of the SURVEY, shows quarterly and monthly estimates for these series. Also shown are quarterly and monthly inventories for manufacturing by stage of fabrication. Historical estimates for these series, quarterly for 1997:I–2003:IV, were published in the April 2004 SURVEY, and revised and new estimates for 2001:IV–2005:II were published in the October 2005 SURVEY. Estimates for 1959 forward are available electronically on BEA's Web site.

"Fixed Assets and Consumer Durable Goods," usually published in the September issue of the SURVEY, shows annual estimates of net stocks for private fixed assets, government owned fixed assets, and durable goods owned by consumers. Revised and new estimates for 2003–2005 were published in the September 2006 SURVEY. Estimates for net stocks and depreciation for 1925 forward and for fixed investment for 1901 forward are available electronically on BEA's Web site. For information on how these estimates are prepared, see *Fixed Assets and Consumer Durable Goods in the United States*, 1925–97, September 2003, at <www.bea.gov/bea/dn/Fixed_Assets_1925_97.pdf>.

"Selected Monthly Estimates" for personal income by type of income and for the disposition of personal income, including PCE, are published in table B.1 in the "BEA Current and Historical Data" section of the SURVEY. These estimates are also published annually in NIPA tables 2.6–2.8.6, and the estimates for the most recent months appear in the personal income and outlays news release.

"Source Data and Assumptions" shows the source data and the BEA assumptions for missing key source data that are used to prepare the advance estimates of GDP. This information is available at the time of the news release and is included in the "GDP and the Economy" articles in the SURVEY that present the advance estimates.[51]

"Reliability of the GDP Estimates" covers several articles that assess the reliability of the current quarterly estimates, which consist of the advance, preliminary, and final estimates, by comparing them with the "latest" estimates, which reflect the results of both annual and comprehensive revisions. The most recent study, which was conducted in 2005 for the period 1983–2002, found that the current quarterly estimates correctly indicated the direction of change 98 percent of the time, correctly indicated the acceleration or deceleration of aggregate economic activity about three-fourths of the time, and successfully identified whether GDP growth was high relative to trend about two-thirds of the time and whether it was low relative to trend about three-fifths of the time. For business cycles occurring during the period 1969–2002, the quarterly estimates of real GDP indicated the cyclical peaks in all five of the recessions and indicated the cyclical troughs in three of the five recessions; the two missed troughs were within one quarter of the latest estimates of the troughs.[52]

"Underlying Detail Tables" includes 62 tables that show additional information or detail underlying the NIPA estimates. These tables provide more detailed or higher frequency estimates of NIPA series that appear in the NIPA tables published elsewhere on BEA's Web site and in the SURVEY. BEA does not include these detailed estimates in the published tables because their quality is significantly less than that of the higher level aggregates in which they are included. Compared to these aggregates, the more detailed estimates are more likely to be either based on judgmental trends, on trends in the higher level aggregate, or on less reliable source data. Most of the underlying tables are updated one working day after the monthly GDP releases.

51. Additional information about source data and assumptions is also available on BEA's and STAT-USA's Web sites.

52. See Dennis J. Fixler and Bruce T. Grimm, "Reliability of the NIPA Estimates of U.S. Economic Activity," SURVEY 85 (February 2005): 8–19 and Bruce T. Grimm and Teresa L. Weadock, "Gross Domestic Product: Revisions and Source Data," SURVEY 86 (FEBRUARY 2006): 11–15.

Statistical Conventions Used for NIPA Estimates

Most of the NIPA estimates are presented in current dollars. Changes in current-dollar estimates measure the changes in the market values of goods or services that are produced or sold in the economy. For many purposes, it is necessary to decompose these changes into price and quantity components. Prices are expressed as index numbers with the reference year at present, the year 2000 equal to 100. Quantities, or "real" measures, are expressed as index numbers with the reference year (2000) equal to 100; for selected series, they are also expressed in chained (2000) dollars. (For further details, see the section "Real Output and Related Measures.")

Seasonal adjustment

Quarterly and monthly NIPA estimates are seasonally adjusted at the detailed series level when the series demonstrate statistically significant seasonal patterns. For most of the series that are seasonally adjusted by the source agency, BEA adopts the corresponding seasonal adjustment factors. Seasonal adjustment removes from the time series the average effect of variations that normally occur at about the same time and in about the same magnitude each year—for example, weather and holidays. After seasonal adjustment, cyclical and other short term changes in the economy stand out more clearly.

Annual rates

Quarterly and monthly NIPA estimates in current and chained dollars are presented at annual rates, which show the value that would be registered if the rate of activity measured for a quarter or a month were maintained for a full year. Annual rates are used so that periods of different lengths—for example, quarters and years—may be easily compared. These annual rates are determined simply by multiplying the estimated rate of activity by 4 (for quarterly data) or by 12 (for monthly data).

Percent changes in the estimates are also expressed at annual rates. Calculating these changes requires a variant of the compound interest formula,

$$r = \left[\left(\frac{GDP_t}{GDP_0}\right)^{m/n} - 1\right] \times 100 ,$$

where

- r is the percent change at an annual rate;
- GDP_t is the level of activity in the later period;
- GDP_0 is the level of activity in the earlier period;
- m is the periodicity of the data (for example, 1 for annual data, 4 for quarterly, or 12 for monthly); and
- n is the number of periods between the earlier and later periods (that is, $t-0$).

Appendix 1

Formulas for Calculating Chain-Type Quantity and Price Indexes

This appendix shows the basic calculations used to prepare annual and quarterly chain-type quantity and price indexes.

Annual indexes

The formula used to calculate the annual change in real GDP and other components of output and expenditures is a Fisher index (Q_t^F) that uses weights for 2 adjacent years (years *t–1* and *t*).

The formula for real GDP in year t relative to its value in year *t–1* is

$$Q_t^F = \sqrt{\frac{\Sigma p_{t-1} q_t}{\Sigma p_{t-1} q_{t-1}} \times \frac{\Sigma p_1 q_t}{\Sigma p_t q_{t-1}}}$$

where the *p*'s and *q*'s represent prices and quantities of detailed components in the 2 years.

Because the first term in the Fisher formula is a Laspeyres quantity index (Q_t^L), or

$$Q_t^L = \frac{\Sigma p_{t-1} q_t}{\Sigma p_{t-1} q_{t-1}}$$

and the second term is a Paasche quantity index (Q_t^P), or

$$Q_t^P = \frac{\Sigma p_t q_t}{\Sigma p_t q_{t-1}}$$

the Fisher formula can also be expressed for year *t* as the geometric mean of these indexes as follows:

$$Q_t^F = \sqrt{Q_t^L \times Q_t^P}\,.$$

The percent change in real GDP (or in a GDP component) from year *t–1* to year *t* is calculated as

$$100\,(Q_t^F - 1.0)\,.$$

Similarly, price indexes are calculated using the Fisher formula

$$P_t^F = \sqrt{\frac{\Sigma p_t q_{t-1}}{\Sigma p_{t-1} q_{t-1}} \times \frac{\Sigma p_t q_t}{\Sigma p_{t-1} q_t}}$$

which is the geometric mean of a Laspeyres price index (P_t^L) and a Paasche price index (P_t^P), or

$$P_t^F = \sqrt{P_t^L \times P_t^P}\,.$$

The chain-type quantity index value for period *t* is $I_t^F = I_{t-1}^F \times Q_t^F$, and the chain-type price index is calculated analogously. Chain-type real output and price indexes are presented with the reference year (b) equal to 100; that is, $I_b = 100$.

The current-dollar change from year *t–1* to year *t* expressed as a ratio is equal to the product of the Fisher price and quantity indexes:

$$\frac{\Sigma p_t q_t}{\Sigma p_{t-1} q_{t-1}} = \sqrt{\frac{\Sigma p_t q_{t-1}}{\Sigma p_{t-1} q_{t-1}} \times \frac{\Sigma p_t q_t}{\Sigma p_{t-1} q_t}} \times \sqrt{\frac{\Sigma p_{t-1} q_t}{\Sigma p_{t-1} q_{t-1}} \times \frac{\Sigma p_t q_t}{\Sigma p_t q_{t-1}}} = P_t^F \times Q_t^F\,.$$

Quarterly indexes

The same formulas are used to calculate the quarterly indexes except that quarterly data are substituted for annual data.

All quarterly chain-type indexes for completed years that have been included in an annual or comprehensive revision are adjusted so that the quarterly indexes average to the corresponding annual index. When an additional year is completed between annual revisions, the annual index is computed as the average of the quarterly indexes, so no adjustment is required to make the quarterly and annual indexes consistent. For example, until the 2006 annual revision was released, the chain-type indexes for the year 2005 were computed as the average of the four quarterly indexes for 2005.

Chained-dollar estimates

The chained-dollar value CD_t^F is calculated by multiplying the index value by the reference year current-dollar value ($\Sigma p_b q_b$) and dividing by 100.[1] For period *t*,

$$CD_t^F = \Sigma p_b q_b \times I_t^F / 100.$$

Implicit price deflators

The implicit price deflator IPD_t^F for period *t* is calculated as the ratio of the current-dollar value to the corresponding chained-dollar value, multiplied by 100, as follows:

$$IPD_t^F = \frac{\Sigma p_t q_t}{CD_t^F} \times 100\,.$$

1. For exceptions to this procedure, see appendix 2.

Appendix 2

Chained Measures in the NIPAs Not Calculated as Fisher Indexes

The Fisher formula described in Appendix 1, "Formulas for Calculating Chain-Type Quantity and Price Indexes," is generally preferred for calculating the chain-type quantity and price indexes presented in the NIPAs. In the preferred method, chained dollars are obtained by multiplying the Fisher quantity index by the reference-year current-dollar value and dividing by 100. However, when the components of an aggregate include large negative values, the Fisher formula may require taking the square root of a negative number. For these aggregates, another method for calculating chained dollars must be used. The inability to calculate a particular Fisher quantity index (for example, change in private inventories) because of negative values usually does not extend to the calculation of higher level aggregates (for example, quantity indexes for gross private domestic investment and for GDP can be computed). The calculation of contributions to percent change is not affected by negative values, so they can be calculated for all components.

The following paragraphs describe the cases for which the Fisher formula cannot be used.

For change in private inventories (in tables 1.1.6, 1.2.6, 1.4.6, 1.5.6, 5.2.6, 5.6.6A, 5.6.6B, 7.2.6B, and 7.3.6), chained-dollar series are calculated as the difference between end of period and beginning of period chain-weighted stocks of inventories.

The following chained-dollar series are calculated as the current-dollar value of the series divided by an appropriate implicit price deflator: Gross national income and gross domestic income (in table 1.7.6); command-basis exports of goods and services and income receipts from the rest of the world (in table 1.8.6); and disposable personal income (in tables 2.1 and 2.6).

For the following series, real values are calculated as the sum of, or the difference between, chained-dollar series measuring flows: Net exports of goods and services (in tables 1.1.6, 1.5.6, and 4.2.6); command-basis gross national product (in table 1.8.6); net value added of nonfinancial corporate business (in table 1.14); foreign travel and other, net (in table 2.5.6); net foreign travel and net foreign remittances (in table 2.4.6); Federal nondefense intermediate purchases of durable goods, of nondurable goods, and of Commodity Credit Corporation inventory change (in table 3.10.6); Federal defense intermediate purchases of other durable goods (in table 3.11.6); net investment by major type (in table 5.2.6); residential and nonresidential private net purchases of used structures (in table 5.4.6A and 5.4.6B); Federal defense and nondefense net purchases of used structures (in table 5.8.6A and 5.8.6B); and net exports of motor vehicles (in table 7.2.6B).

For the following series, quantity indexes are calculated by dividing the chained-dollar series by its reference year (that is, 2000) value and multiplying by 100: Command-basis GNP and command-basis exports of goods and services and receipts from the rest of the world (in table 1.8.3); and income receipts from the rest of the world (in table 4.2.3).

Appendix 3

Calculation of Component Contributions to the Change in GDP and Other Major Aggregates

The contributions to percent change in a real aggregate, such as real GDP, provide a measure of the composition of growth in the aggregate that is not affected by the nonadditivity of its components. This property makes contributions to percent change a valuable tool for economic analysis. The contribution to percent change ($C\%\Delta_{i,t}$) in an aggregate in period t that is attributable to the quantity change in component i is defined by the formula

$$C\%\Delta_{i,t} = 100 \times \frac{\left(\left(p_{i,t}/P^F_t\right) + p_{i,t-1}\right) \times (q_{i,t} - q_{i,t-1})}{\Sigma_j\left(\left(p_{j,t}/P^F_t\right) + p_{j,t-1}\right) \times q_{j,t-1}},$$

where

P^F_t is the Fisher price index for the aggregate in period t relative to period $t-1$;

$p_{i,t}$ is the price of the component i in period t; and

$q_{i,t}$ is the quantity of the component i in period t.

The summation with subscript j in the denominator includes all the deflation level components of the aggregate. Contributions of subaggregates (such as PCE goods) to the percent change of the aggregate (say, PCE or GDP) are calculated by summing the contributions of all the deflation level components contained in the subaggregate.

For annual estimates, no adjustments are required for contributions to sum exactly to the percent change in the aggregate. For quarterly estimates, adjustments are required to offset the effects of adjustments made to published aggregates and their quarterly percent change: namely, conforming quarterly estimates to average to the corresponding annual estimates, and expressing percent change at annual rate. The same formula is used for both annual and quarterly estimates of contributions to percent change in all periods. The only variation in the method of calculation is that when the annual contributions for the most recent year are first calculated, they are based on a weighted average of the quarterly contributions until the next annual revision.

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 209

Financial Market Snapshot

Exhibits in Support of Opening Testimony

August 11, 2016

4 Reasons Why Treasury Yields are Hurtling Lower

by Ellie Ismailidou MarketWatch — Apr. 6, 2016

Ellie is a markets reporter based in New York, covering stock and bond markets.

Yields tumbled Tuesday to a 1½-month low—but that is hardly the bottom, analysts said

Treasury prices soared Tuesday, **pushing yields to their lowest level in nearly 1½ month**, amid a global sovereign-bond rally fueled by **worries about global economic growth**.

The 10-year Treasury yield the Treasury market's benchmark, has been on a continued downtrend since mid-March. On Tuesday it closed at 1.727%, its lowest level since Feb. 25, and not far off its one-year low, reached on Feb. 11, as the following chart shows.

Here are four reasons behind the Treasury-yield slide and why analysts are predicting that yields could fall further:

1: Global Flight-to-Quality

Moves in the Treasury market have recently been closely tied to moves in so-called risk assets, namely oil and equities. On Tuesday, Treasury prices soared, pushing yields lower, as investors sold those risky assets amid a global stock-market selloff, flocking to so-called haven assets, namely U.S. government debt.

A similar trend was recorded in the first six weeks of the year, during a brutal equity selloff that led stocks to a bottom on Feb. 11. On Tuesday, the S&P 500 posted its largest single-day drop in about a month, while Treasury yields reached their lowest level in a month and a half.

2: Dovish Federal Reserve

The Treasury yield decline has intensified since **Fed Chairwoman Janet Yellen last week stressed the need for a cautious approach to raising interest rates**, **citing risks emanating from a slowdown in global growth**. After her comments, expectations for a rate increase this year diminished, with Fed-funds futures pointing on Tuesday to a 16% probability of a rate increase in June, according to CME Group's FedWatch tool.

The probability of a June rate increase tumbled by 10 percentage points on Tuesday alone, after International Monetary Fund Managing Director Christine Lagarde called on the world's economies to boost growth, warning that risks to global economy are rising.

The projection of go-slow path to interest-rate hikes has pulled short-term yields lower because they are most vulnerable to changes in the Fed-funds rate, said Tom Kersting, fixed-income strategist at Edward Jones.

3: Subdued U.S. Growth Expectations

"The Fed only really controls the so-called front end of the yield curve," Kersting said, referring to short-dated bonds. But long-term yields are mostly influenced by U.S. growth and inflation expectations, he added.

The reason is the so-called term premium, which is a significant part of long-term yields and rises when inflation expectations increase because investors want higher compensation to hold on to a bond for a longer period in a rising-price environment.

On Tuesday, a report that pointed to a wider-than-anticipated U.S. trade deficit created a "clear drag" for first-quarter growth assumptions, pulling Treasury yields lower, said Ian Lyngen, senior government bond strategist at CRT Capital, in comments emailed after market close.

The weak trade-deficit data reminded the market that "the Federal Open Market Committee's 2016 full-year growth estimate is still 2.20%—a pace that assumes an ambitious bounce back later this year that leaves us skeptical," Lyngen added.

4: Negative Yields in Europe and Japan

Rising foreign demand for Treasurys, thanks to relatively higher yields in the U.S. compared with yields in **Japan and Europe** where **aggressive central bank monetary easing** has **pushed yields to record lows**, and in some cases into even negative territory. That has also fueled the downtrend for Treasury yields. European government yields plunged Tuesday, pulling U.S. Treasury yields down with them.

The **yield on the 10-year German bond, known as the bund, fell to a one-year low** amid worries about **subdued growth** and **rekindled fears about a British exi**t, or "**Brexit**," **from the European Union** and a **Greek exit**, or "**Grexit**," **from the euro-zone**.

Strategists have pointed out that the yield differential between U.S. and European government debt will continue to drive demand for Treasurys, keeping yields in the U.S. subdued.

Weak Productivity, Rising Wages Putting Pressure on U.S. Companies

by Josh Mitchell — WSJ — Jun. 7, 2016

Economists fret how trends may affect inflation and broader growth. Though productivity fell, workers' hours and compensation have been accelerating. The Federal Reserve has been looking for stronger wage growth as a sign the economy is nearing full strength and can withstand a rise in interest rates

U.S. companies are facing a toxic combination of **dismal productivity growth**, **accelerating wages and sluggish demand**, **raising the risk they will slow hiring, cut spending further and weaken an already-fragile economy**.

Labor productivity, or the amount of goods and services employees produce per hour worked, fell at a 0.6% annual rate in the first quarter, the Labor Department said Tuesday. The drop, while less steep than initially estimated, extended a troubling slowdown that has hindered the economy's ability to lift Americans' living standards.

Stronger productivity boosts corporate profits, giving firms more money to pay their workers. **Productivity grew an average 2.2% since World War II but has expanded just 0.5% over the last five years**. Only in the five years through late 1982 has it grown as slowly.

Meanwhile, workers' hours and compensation are accelerating, suggesting the labor market is at near or a level of employment deemed to be healthy without stoking too much inflation.

Hourly compensation, encompassing everything from salaries to retirement benefits and health care costs, surged at a 3.9% annual rate in the first quarter, Tuesday's report showed. It **rose 3.7% over the past year, marking the biggest annual gain in two years**.

"It's been our forecast that pressure would build and we would see the labor market fray and weaken substantially in 2017," said Joshua Shapiro, chief U.S. economist at consultancy MFR Inc. "The big question now is, is this all occurring sooner? There's evidence building that maybe the labor market is responding quicker to the squeeze on the corporate sector than we had thought."

The Federal Reserve has been looking for stronger wage growth as a sign the economy is nearing full strength and can withstand a rise in interest rates, which have been exceptionally low since the recession. A **steady increase in wages is generally positive if accompanied by a similar rise in sales**.

U.S. Retail Sales Fell in 1st Week of June -- Redbook June 7, 2016

But the latest increase in wage growth comes as the economy is struggling to get through a rough patch tied to global economic woes, weak business investment and a depressed energy sector. The **economy grew at just a 0.8% seasonally adjusted annual rate in the first quarter and 1.4% in the fourth quarter**.

When wage compensation outruns productivity, the result is an acceleration in labor costs per unit of output. In the first quarter, those costs rose 4.5% at a yearly rate and 3% from a year earlier. If companies can't boost productivity, they must either absorb the costs in their profit margins or raise prices.

Corporate profits are being squeezed as a result, and the worry is that companies will slow hiring and further slash spending.

A different worry for the Fed is that firms will react to higher labor costs by raising prices, pushing inflation above the central bank's 2% target.

Stephen Stanley, chief economist at Amherst Pierpont Securities, said labor costs already appear to be "exerting upward pressure on inflation." He pointed to a rise in the cost of services, as measured by the Labor Department's consumer-price index, as evidence.

Companies have slowed hiring. The Labor Department said last week that the **economy added 38,000 jobs in May**, the worst month for job creation since 2010. It's added an average 116,000 jobs a month over the past three months, down sharply from average monthly gains of 219,000 over the previous 12 months.

Fed Chairwoman Janet Yellen, in a speech Monday, said she was "cautiously optimistic" that productivity would return to faster growth. "With time, I expect this effect to ease in a stronger economy," she said. "I also see no obvious slowdown in the pace or the potential benefits of innovation in America, which likewise may bear fruit more readily in a stronger economy."

She called for public policies to boost productivity, including "strengthening education and promoting innovation and investment, public and private."

Credit Spreads — Investment Grade

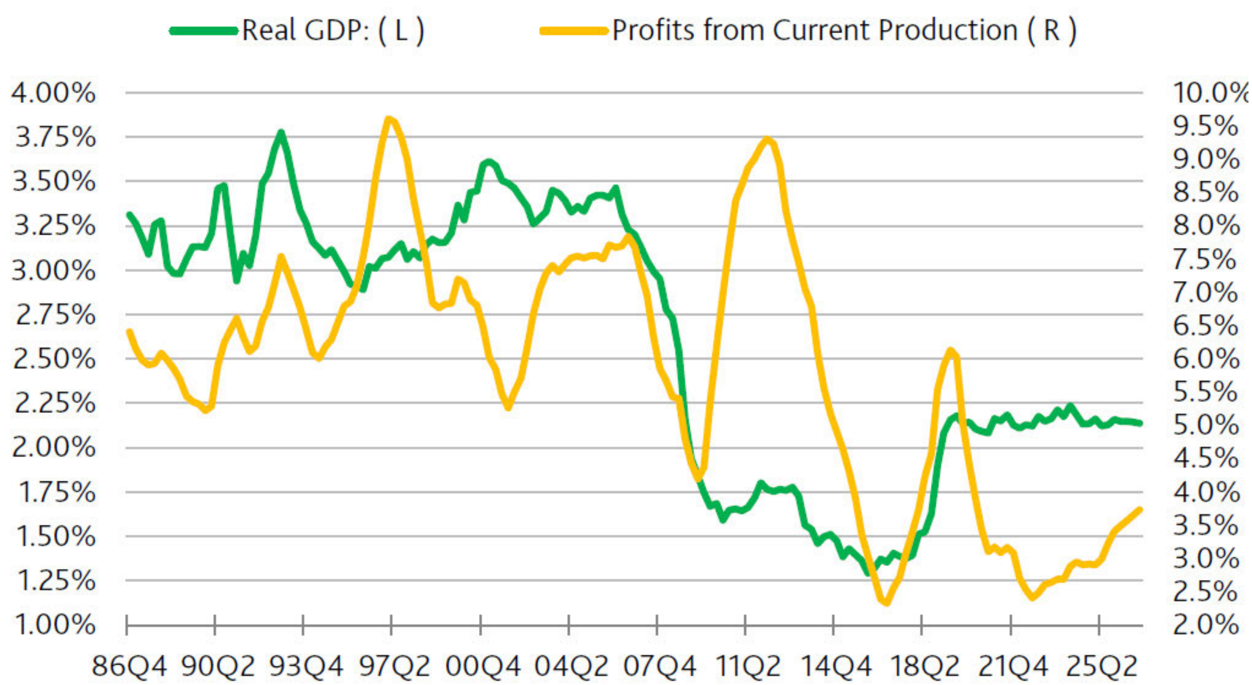
John Lonski, Chief Economist — Moodys Capital Research, Inc. — Mar. 10, 2016

Year End 2016 investment grade spreads to be less than its recent 174 bp.

Credit risks rise as long-term growth prospects fade:

Once again, the **Blue Chip consensus** has lowered its long-term growth outlooks for the US economy and corporate earnings. **Never before has the consensus viewed future prospects with as much caution as in March 2016's survey**.

Figure 1: Blue Chip Consensus Does Not Expect Growth Rates of Real GDP and Profits to Return to Pre-2007's Ranges through 2027: *10-year average annualized % changes, actual & predicted*



A prolonged downshifting of business activity has provided an air of restraint to recent prognostications. For example, US economic growth has slowed from the 3.4% of the 10-years-ended 2005 to the 1.4% of the 10-years-ended 2015, where the latter was the dullest 10-year average annual growth rate for real GDP since the 1.0% of 1930-1939.

During the 60 years prior to the meltdown of 2008-2009, the US economy grew by 3.5% annually, on average. Amid such extended prosperity, lean years of less than 3% growth would eventually be more than compensated for by years of faster than 3% growth.

However, since 2005's 3.3% annual increase, the US economy has grown no faster than 2006's 2.7%. **Americans and the rest of the world now recognize a profound downshifting by the performance of the US economy**. Until 2015, each

10-year span since at least 1939 included at least one calendar year of faster than 3% growth for US real GDP.

The **current episode of subpar growth is likely to continue**. **As inferred from recent long-term forecasts, US economic growth may remain well under 3% through 2027**. In other words, **the wait for a return of at least one year's worth of the "old normal" in terms of economic growth might be longer than 22 years**.

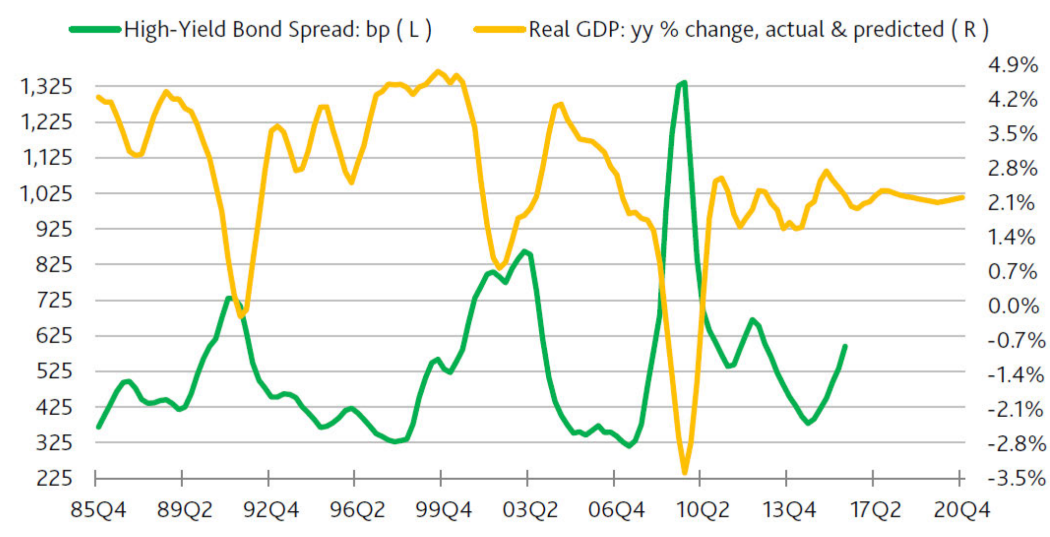
For the near term, the consensus expects US real GDP growth to slow from 2015's 2.4% to 2.1% in 2016. Moreover, the upside potential for 2016's economic growth appears limited according to how the 2.4% average of the 10 highest forecasts of 2016's US real GDP growth merely matches 2015's pace. **Longer term, US economic growth is expected to average a lackluster 2.1% through 2027** as derived from a **survey of 54 Blue Chip forecasters**.

US economic growth should remain well under the 3.4% average annualized advance of the 25-years-ended 2007. In fact, **the survey's highest 10 forecasts predict growth of only 2.5% through 2027**, while **the lowest 10 forecasts expect growth to average 1.8%**.

Real GDP's long-term outlook may preserve atypically wide spreads

The continuation of atypically slow economic growth has important implications for high-yield credit. In terms of moving yearlong averages, the high-yield bond spread shows a comparatively strong inverse correlation of -0.76 with real GDP growth. Thus far, the current recovery's 2.0% median for real GDP's yearly growth rate has been joined by a 540 bp median for the high-yield bond spread. By contrast, real GDP's median yearly growth rate of 3.6% from the previous three economic recoveries was accompanied by a 418 bp median for the high-yield bond spread. As inferred from the statistical record, if real GDP adheres to the consensus forecast and grows by 2.1% annualized, on average, through 2027, the high-yield bond spread's accompanying average might be in a range of 550 bp to 620 bp.

Figure 2: Consensus Expectation of 2.1% Average Annual Real GDP Growth Through 2027 Favors a Range of 550 bp to 620 bp for the High-Yield Bond Spread: *moving yearlong averages*

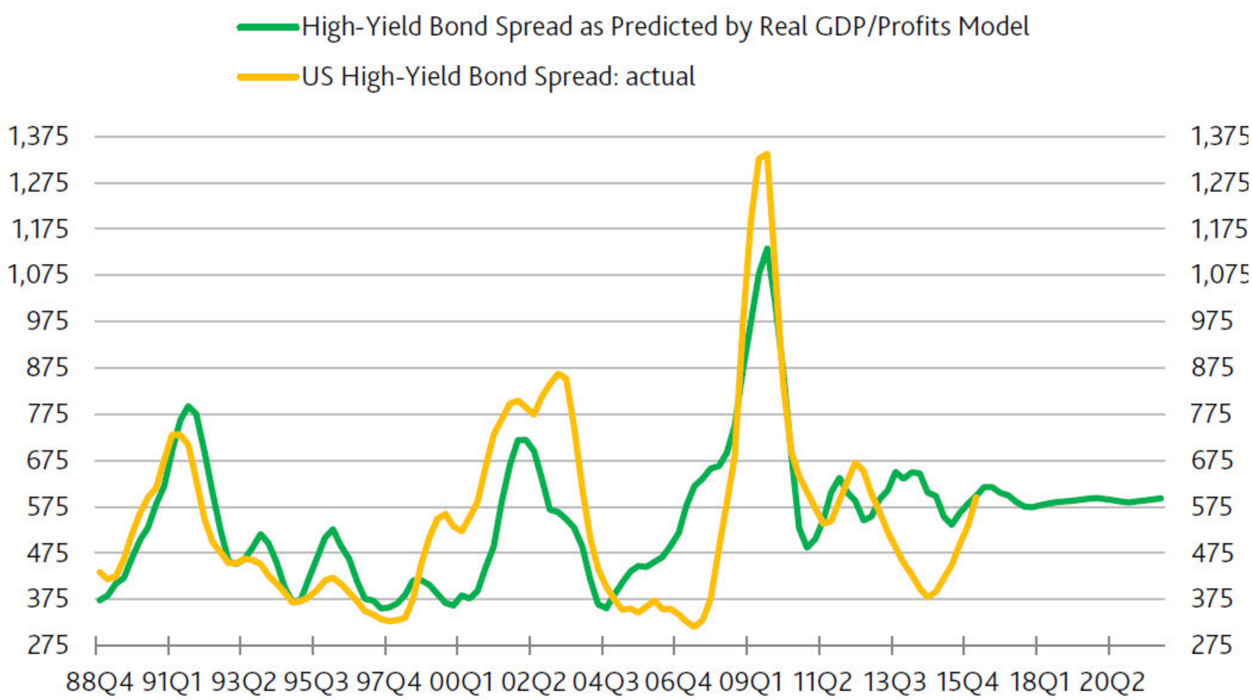


Sluggish profits will help to keep spreads wide:

The average annualized growth rate of pretax profits from current production has slowed from the 7.4% of the 20-years-ended 2007 to a prospective 3.3% for the 10-years-ended 2015. The consensus believes that profits from current production will grow by only 3.5% annualized from the end of 2015 through 2027. If correct, profits will have risen by only 3.6% annually, on average, for the 20-years-ended 2027.

The **expected deceleration** by the **average annualized 20-year growth rate of profits** from 2007's 7.4% to 2027's 3.6% suggests lower-grade business borrowers will have a thinner margin for error when meeting debt repayment obligations. When combined with the projected drop by long-term economic growth, the diminished outlook for profitability signals a 590 bp midpoint for the high-yield bond spread through 2027.

Figure 3: Consensus Projections for Real GDP and Profits Hint of a 590 bp Average for the High-Yield Bond Spread During the Next 10 Years: yearlong averages in bp



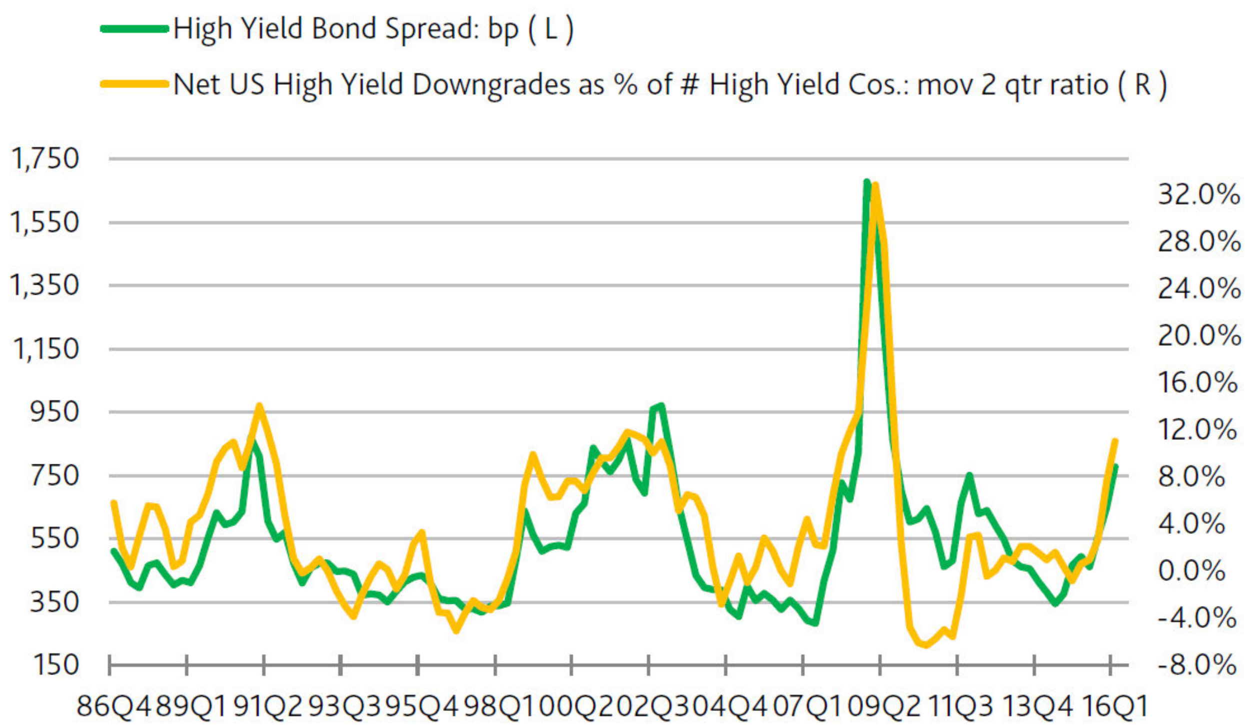
Nevertheless, this analysis precludes a possible reduction in leverage that may be prompted by diminished prospects for economic growth and corporate earnings. If the financial practices of businesses become more conservative, then the high-yield spread's future mid-point may be considerably thinner than 590 bp.

Elevated incidence of high-yield downgrades favors a wider than 700 bp high-yield spread

The US high-yield credit rating changes of 2016's unfinished first quarter show the 130 downgrades far ahead of the 27 upgrades. After excluding high-yield's oil & gas related revisions, the number of downgrades drops to 77, while upgrades barely dip to 26.

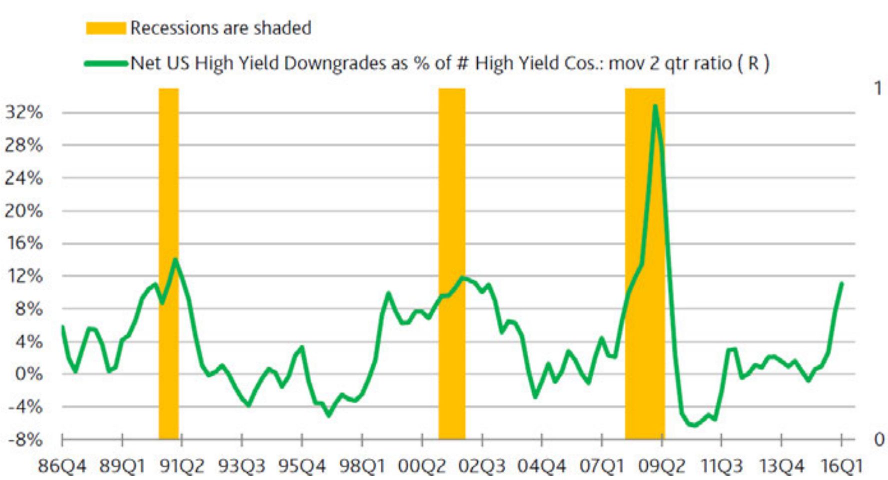
According to a methodology that has been employed since 1986, the US's net high-yield downgrades of the unfinished two quarters-ended March 2016 approaches 11.0% of the number of high-yield issuers. For those three earlier quarters, the high-yield bond spread averaged 715 bp. By contrast, the high-yield spread has averaged 778 bp during the past 13 weeks. As inferred from a simple regression analysis, which shows an R-squared statistic of 0.63, the estimated mid-point for the high-yield bond spread is 745 bp whenever net high-yield downgrades approximates 11.0% of the number of high-yield issuers.

Figure 4: A Wider than 700 bp High-Yield Bond Spread Is Statistically Consistent with the Recent Relative Frequency of Net High-Yield Downgrades



Previously, this ratio first reached 10% in Q1-2008, Q3-2001, and Q1-1990, where each incident either overlapped or immediately preceded a recession. Though **the now highly unfavorable distribution of high-yield credit rating changes does not categorically imply that a recession impends**, it **does suggest** that **the risk of a recession is at its highest level yet for the current recovery**.

Figure 5: Latest Upswing by Net High-Yield Downgrades Suggests the Current Recovery Is In Its Final Quarter



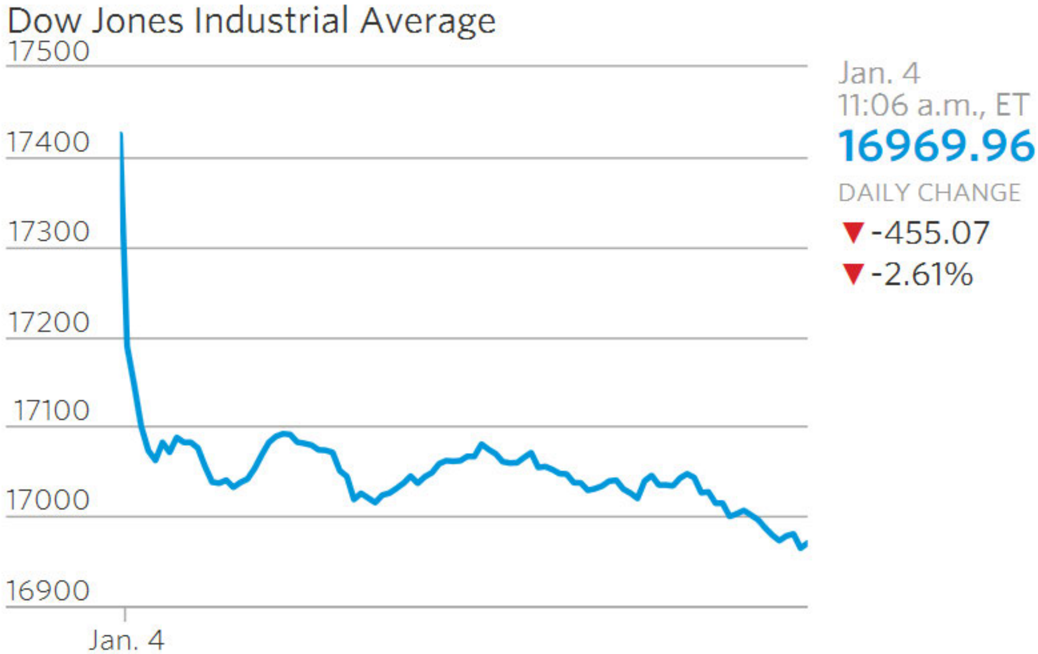
FOMC Rate Decision:

Given recent financial market volatility, the **FOMC is expected to deviate from its projections from last year and leave rates unchanged in March**. Though the commodity price dive has been deeper and longer than policymakers expected, they still see the effects of imported deflation as transient. **With steady job growth and improved wage trends in the months ahead, the Fed is likely to resume its tightening cycle**.

Dow Drops More Than 400 Points After Rout in Chinese Market

by Christopher Whittall and Riva Gold

Weak economic data in China spurs global selloff, while Shanghai Composite declines nearly 7%.



Source: WSJ Market Data Group

Global stocks started 2016 with a sharp selloff as fresh signs of economic slowdown in China deepened fears about global growth and lowered hopes for a better year.

The Dow Jones Industrial Average declined 446 points, or 2.6%, to 16979 shortly after the market opened, while the S&P 500 dropped 2.5% and the Nasdaq Composite fell 3.1%.

Weaker-than-expected manufacturing data and a falling currency triggered a 7% fall in mainland Chinese stocks that led authorities to halt trading there before the end of the session.

Meanwhile, rising tensions in the Middle East added to bearish sentiment across markets and sparked volatile trading in oil, offering a further glimpse of the themes investors say are likely to influence markets this year.

The Stoxx Europe 600 was down 2.8% recently, led by a 4.5% drop in Germany's exporter-heavy DAX index.

"It's a big [market] move by any measure," said Chris Jeffery, an asset-allocation strategist at Legal & General Investment Management, which oversees £728 billion in assets.

"China is now number two in terms of the global economy. It's hard to ever move away from it," said Mr. Jeffery.

Asian markets tumbled on the first day of trading in 2016, with declines so steep in China that authorities halted all mainland trading before the end of the day.

The selloff came after data showed Monday that Chinese factory activity fell in December, casting doubts on the effectiveness of Beijing's policies of easing monetary policy and ramping up spending to boost growth.

The CSI 300, a benchmark of the largest 300 stocks listed in Shanghai and Shenzhen, fell 7% just after 1:30 p.m. local time, triggering a new circuit-breaker system, which took effect Monday.

The Shanghai Composite Index ended 6.9% lower, recalling several steep one-day declines at various points last year.

A weaker local currency also put pressure on Chinese stocks. The offshore and onshore yuan both traded at their weakest levels since 2011 after China's central bank guided its currency weaker Monday.

"As we know with China, it doesn't take a lot for people to be spooked," said Atul Shinh, an investment specialist at Investec Asset Management, which oversees $108 billion in assets.

Losses in China weighed on other Asian markets. Japan's Nikkei Stock Average lost 3.1% and Hong Kong's Hang Seng HSNGY -3.82 % Index fell 2.7%.

Base metals prices also fell as investors worried over demand from their biggest consumer, China. Copper was recently down 1.2% at $4632 a metric ton in London trade, and nickel fell 2.9% to $8565 a ton.

Rising tensions in the Middle East also played on investors' minds. Bahrain severed diplomatic ties with Iran on Monday following Saudi Arabia's decision to cut ties with Iran on Sunday.

Investors moved into haven investments, with gold up 1.6% at $1077.30 a troy ounce and the yield on 10-year U.S. Treasurys down around 0.04 percentage point to 2.233% as prices rose.

The basic resources and auto sectors, which are both sensitive to Chinese demand, were among the worst hit in European stocks.

Miners were down 3.3%, led by a 6.5% fall in Anglo American NGLOY -6.18 % PLC and a 5.5% drop in Glencore GLNCY -5.14 % PLC.

A Ferrari sports car outside the New York Stock Exchange last October. Shares in Fiat Chrysler fell sharply on Monday as the auto maker spun off its stake in Ferrari by distributing stock to shareholders.

In the auto sector, Fiat Chrysler Automobiles FCAU -36.88 % NV was down 37% after distributing its 80% stake in sports-car unit Ferrari to shareholders. Shares in Daimler AG DDAIY -4.30 % and BMW AG

BMW -5.14 % both fell more than 4%.

European exporters were also hit by a rising euro, which gained 0.4% against the dollar to $1.0904. A stronger euro reduces the competitiveness of companies that sell their goods abroad. The dollar also fell sharply against the yen, down 1% at ¥119.0500.

In commodities markets, Brent crude oil prices were volatile. Rising tensions between Saudi Arabia and Iran had sparked speculation about a possible disruption to supply, pushing oil prices higher in Asian trade before giving up some gains following the China data release. Brent crude was last up 2.9% at $38.35 a barrel.

Some investors said the stock market selloff shouldn't last, reasoning that choppiness in Chinese equities shouldn't hurt developed markets over the longer term.

"China is volatile, [but] I don't think this makes any difference" to Europe and the U.S., said Jonathan Bell, chief investment officer at Stanhope Capital, which oversees $9.5 billion in assets.

Looking ahead, many investors expect to remain focused on the **same themes** in 2016 as last year. **Geopolitical tensions** in the Middle East, a **slowdown in Chinese growth** and the **oil** price — as well as its impact on other markets such as U.S. junk bonds — remain top of the agenda.

"**We think this year will be difficult**," said Mr. Shinh, whose top picks include shares in financial and technology companies, as well as Japanese stocks.

"We don't think we're at the end of the cycle…there are opportunities to be made. [But] it will be tricky," he added.

Fresh data this week will offer investors more clues as to the health of the U.S. economy, including the Institute for Supply Management's purchasing managers index later Monday.

Economy Growth at a Crawl

by Chico Harlan — Washington Post (Reproduced in the Oregonian) Apr. 29, 2016

The U.S. economy grew |at its weakest quarterly pace m two years between January and March, the Commerce Department reported Thursday.

The nation's gross domestic product expanded just 0.5 percent as **consumers** slowed their spending **and businesses cut back on investments** with a severity not seen since the financial crisis.

Most analysts say the United States faces little risk of recession. but the **economy** is **stuck in second gear**, providing a picture of contradictions for investors and policy makers.

Among those contradictions: Wages are beginning to rise (up 2.3 percent over the past year), and cheaper gasoline is providing an extra influx of cash, but most Americans have cut back on consumption since the middle of last year.

A slightly weakened dollar has helped to boost profits for corporate giants. But those firms are holding off on investing: Nonresidential investment plunged 5.9 percent in the first quarter, the sharpest decline since 2009.

A bright spot came in the housing sector, where real residential fixed investment rose 14.8 percent during the quarter.

GDP grew at 1.4 percent in the last quarter of 2015. For all of **2015**, the **economy grew at a 2.4 percent pace**.

Fed Leaves Policy Rate Unchanged, Lowers Outlook for Increases

by Jon Hilsenrath and Kate Davidson — WSJ — Jun. 15, 2016

Fed. Chair Yellen, Left — Fed officials project lower rate path in 2017 and 2018, and in the longer run.

The **Federal Reserve held its benchmark lending rate steady on Wednesday** and officials **lowered projections of how much they expect to raise short-term interest rates in the coming years**, signs that **persistently slow economic growth** and **low inflation** are forcing the central bank to rethink how fast it can move rates higher.

"We are quite uncertain about where rates are heading in the longer term," Chairwoman Janet Yellen said at a press conference following the Fed's two-day policy meeting.

New projections show officials expect the fed-funds rate to rise to **0.875% by the end of 2016**, according to the median projection of 17 officials. Their **forecasts imply** they see **two rate increases this year**. That is the same number of increases they saw when they last released projections in March. **However a greater number of officials now see one increase, rather than two**. In March only one official saw one rate increase this year and seven saw three or more. Now six officials see one increase this year and only two see three or more.

Ms. Yellen said a rate increase at the Fed's next meeting in July is "not impossible," but she doesn't know how quickly officials will gain confidence the economy is on firm footing. "We need to assure ourselves that the underlying momentum in the economy has not diminished," she said.

The **central bank also sees the fed funds rate at 1.625% by the end of 2017 and 2.375% at the end of 2018, lower than quarterly projections officials released in March**. Three months ago the median estimate for rates in 2018 was 3%. **In the longer run, the Fed expects its benchmark rate to reach 3%, lower than the 3.25% they saw in March**.

These projections aren't set in stone, but they do indicate how **officials' views are changing**. The **Fed doesn't see rates going as high as it saw before, and it sees taking a longer time to get to the endpoint officials have in mind**.

"Recent economic indicators have been mixed, suggesting our cautious approach to adjusting monetary policy remains appropriate," Ms. Yellen said.

The upcoming Bri**tish referendum on whether to leave the European Union was also a factor** in Fed officials' decision to leave rates unchanged, and "clearly could have consequences" for economic and global financial markets, the Fed chief added. "If it does so, it could have consequences in turn for the U.S. economic outlook that would be a factor in deciding on the appropriate path of policy," Ms. Yellen said of the so-called **Brexit vote, set for June 23**.

In their official policy statement released after the meeting, Fed officials repeated the refrain they've been using all year that they expect "economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate."

The central bank in December pushed its benchmark interest rate up from near zero to between 0.25% and 0.5%.

So far, the economy and financial markets haven't cooperated with plans to keep moving rates up. Early in the year, market turbulence and slow growth in economic output gave officials pause. Growth appears to have picked up and markets settled down, but now hiring and expected inflation are a cause of concern for officials, a mixed backdrop making them reluctant to act.

"The pace of improvement in the labor market has slowed while growth in economic activity appears to have picked up," the Fed said. While consumer spending has strengthened, business investment has been soft. Meantime, market indicators of expected inflation have declined, the Fed said, a development Ms. Yellen noted earlier this month was of some concern.

The tone of the Fed's official statement and projections suggest officials will need to see a quick turnaround in economic data and evidence of market resilience if they are to move promptly.

The Fed indicated its views about risks to the economy haven't shifted much since April. As they said then, officials said they would "**closely monitor**" **inflation indicators** and **global economic** and **financial developments**. That isn't a strong endorsement of the outlook. At moments of more confidence, as in December when the Fed raised short-term interest rates by a quarter percentage point, the Fed said risks to the economy were balanced.

The Fed slightly reduced its estimate for how much economic output will expand this year, shifting its March projection of 2.2% output growth to 2%. It also nudged down its 2017 growth projection by one tenth of one percent to 2%. At the same time it nudged up its inflation projection for the year to 1.4% from 1.2%, but held most of its other projections steady. The combination of relatively stable economic projections and a lower interest rate outlook suggest officials are slowly coming to the conclusion that the economy simply can't bear very high interest rates, even to achieve mediocre growth and low inflation.

Ms. Yellen has said headwinds are holding back the economy. It might be the case that those headwinds are persisting longer than she expected, or new ones are emerging, such as China's economic slowdown. Officials also have been weighing whether the economy's equilibrium interest rate — a rate at which the economy is in balance with stable inflation and low unemployment — has fallen because of long-running trends holding back growth and beyond the Fed's control, such as the retirement of workers and low productivity growth.

Fed officials last month appeared poised to raise rates in June or July. Ms. Yellen said in late May a move was probable "in the coming months" if the economy continued to strengthen.

A **dismal May employment report**, coupled with concerns about the June 23 British referendum on whether to leave the European Union, gave officials pause as they weigh when to next raise rates.

Employers **added just 38,000 jobs** in May and payroll growth in April and March was revised lower, the Labor Department said earlier this month. The share of Americans participating in the workforce also declined, and the number of employees stuck in part-time jobs rose, the report showed. Still, the number of Americans filing first-time claims for unemployment insurance remains at historically low levels.

The decision not to raise rates Wednesday follows recent comments from Ms. Yellen that officials want to wait for more assurance the hiring slowdown is not a harbinger of underlying weakness in the broader economy.

Ahead of Wednesday's release, **futures markets** put 1.9% probability on a rate increase in June and a 20.6% probability on a move in July. They **saw just a 16% probability of two or more rate increases by December**. A recent Wall Street Journal survey of business and academic economists found they expect four quarter-percentage-point increases in the fed-funds rate by the end of 2017, but there was no clear consensus on how many times the Fed would raise rates this year.

Ms. Yellen won a unanimous vote. Kansas City Fed President Esther George, who dissented in March and April in favor a rate increase, instead voted with the majority.

Fed Decision Makers Wrestle With So-Called "Natural Rate"

by Harriet Torry — WSJ — Jun. 13, 2016

an Janet Yellen and other Fed off

U.S. Federal Reserve Chairwoman Janet Yellen (left) and other Fed officials are struggling with the long-term view of monetary policy. Disagreement about long-term outlook leads to the writings of a long-dead Swedish expert.

While Federal Reserve officials debate when to next raise short-term interest rates, they also are wrestling with the question of how high to lift them in coming years.

Signs point toward the new normal being much lower than in the past, which has broad implications for when the Fed should tighten monetary policy, how quickly, and how far.

Fed officials disagree about their likely end point, in part because they are struggling to understand why another underlying interest rate — the mysterious natural rate — has fallen in recent years. And for that many are turning to the musings of **Knut Wicksell**, a Swedish expert on the subject who **died 90 years ago**.

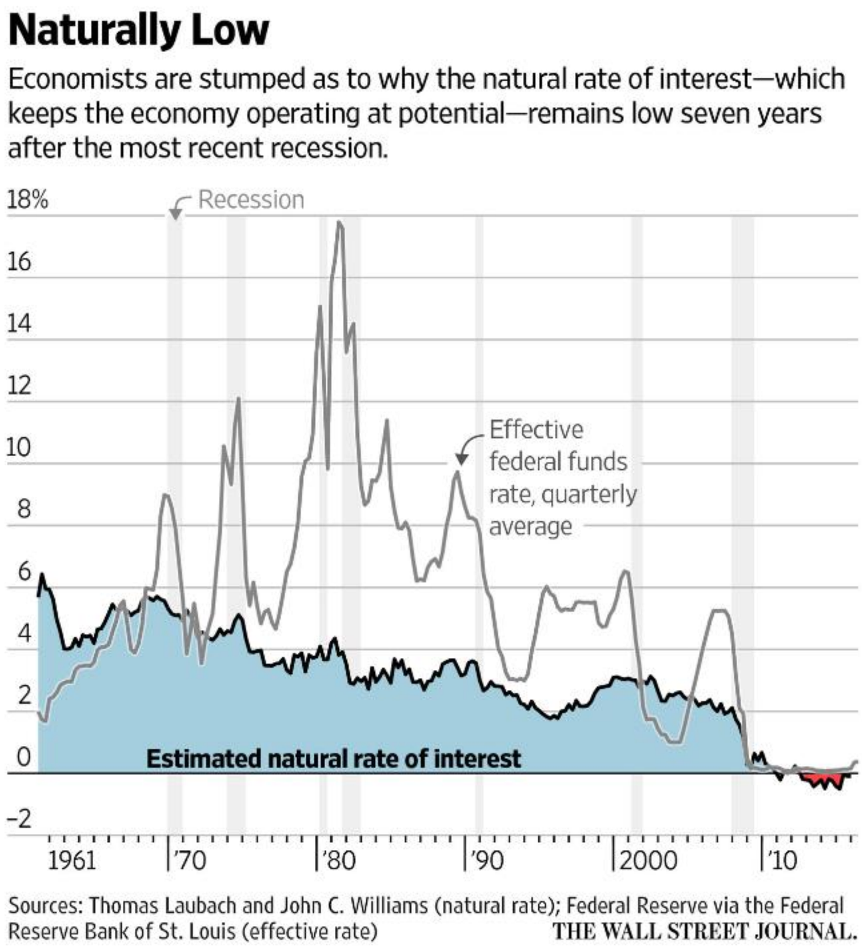
According to the textbooks, this so-called **natural rate is the inflation-adjusted rate that's consistent with the economy operating at its full potential, expanding without overheating**. Also known as the **equilibrium** or **neutral rate**, it **balances savings and investment**.

The **natural rate can't be observed directly**; the **Fed knows** it has been reached **only by how the economy responds**. "It's like discovering Pluto: you can only see the effect of the gravitational pull," said Eddy Elfenbein, an investor and blogger at the site Crossing Wall Street, comparing it to the dwarf planet whose existence was inferred from the orbits of Uranus and Neptune.

This matters **in part** because the **natural rate guides how the Fed sets** its **benchmark fed-funds rate**, which influences other borrowing costs throughout the economy. If the Fed pushes rates **too high**, it could **undermine investment** and cause a **recession**. If it holds rates **too low**, demand could grow too quickly, producing **inflation** or **financial bubbles**.

"The **practical implication** is when a Fed person talks about the natural rate of interest, what they're telling you is what they think is the **terminal rate of the next hiking cycle**," said Adam Posen, president of the Peterson Institute for International Economics and a former member of the Bank of England's monetary policy committee.

Most economists figured the natural rate was around 2% just before the financial crisis. **Today, seven years after the recession, most estimates are around or just below zero.**



"We're seeing no pickup, none whatsoever, in the natural rate even as the economy has gotten back to full strength," John Williams, the San Francisco Fed president who has spent years studying it, said in a recent interview with The Wall Street Journal.

This **implies** the **central bank won't be moving** its **benchmark federal-funds rate up much** from its current level between 0.25% and 0.50% **over** the next **few years**. This, in turn, **means lower rates for borrowers** and **lower returns to savers**.

Policy makers are likely to leave their benchmark rate unchanged Wednesday at the conclusion of their two-day policy meeting, and could consider moving in July or September if the economy improves. They also will release Wednesday new projections for where they think the rate will rest in the long term.

The **Fed's estimate of its long-run fed-funds rate has been falling**. **In March**, when officials released their most recent estimates, the **median was 3.3%.** Adjusted for their expectation of **2% inflation**, that **suggests** a **natural rate of 1.3%, down from 1.75% in June last year**.

One risk for the Fed and the economy is that a **low natural rate leaves less room for the central bank to cut rates if it wants to spur faster growth** during a recession or boost inflation to meet its 2% target.

"This is a huge challenge for us," Mr. Williams said.

The problem is economists don't fully understand why the natural rate is so low. That makes it **hard to know whether the shift is permanent or temporary**, and therefore whether the rate will rebound and by how much — and in turn where the long-term fed-funds rate will rest.

"**I think the current level of neutral or normal rates is pretty low**," Fed Chairwoman Janet **Yellen said** in Philadelphia **last week**. She expects it will rise over time, but said "that is something we're uncertain about and have to find out over time."

Economists have offered several theories for why the natural rate has fallen. Former Fed Chairman Ben **Bernanke** has cited a **glut of savings world-wide**. Harvard University economist **Lawrence Summers** blames '**secular stagnation**,' or a chronic shortfall in investment demand.

Ms. **Yellen** has said temporary headwinds that have restrained growth since the financial crisis may be responsible, such as **economic uncertainty**, a **strong dollar**, and **slower growth of productivity and** the **labor force**.

For guidance Fed officials have been revisiting the work of Mr. Wicksell, a famed Swedish economist who did much of the seminal thinking on the subject more than a hundred years ago. Speeches by senior policy makers, including Ms. Yellen, have referenced Mr. Wicksell five times in the past year alone, and Mr. Bernanke has blogged about the Swede's ideas about the relationship between interest rates, economic growth and inflation.

Mr. **Wicksell** characterized the **natural rate of interest** as "a certain rate of interest on loans which is **neutral** in respect **to commodity** prices, and tends **neither** to **raise nor** to **lower** them." But the natural rate **isn't observable** and **depends on** "a **thousand** and one **things** which determine the current economic position of a community," and those factors—**such as productivity**, **unemployment**, and **technological and demographic change**—are **constantly in flux**, he said.

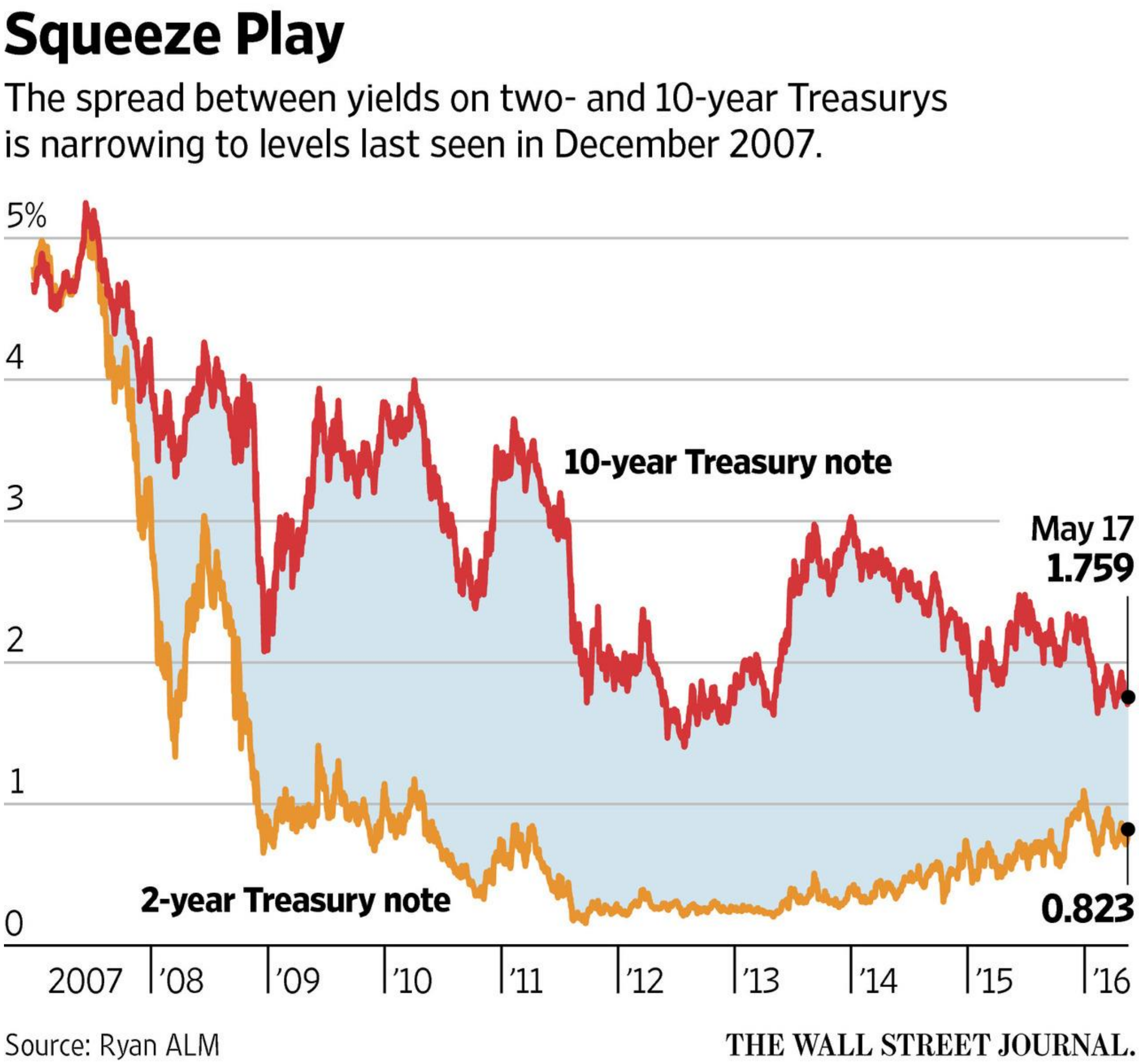
Fed Vice Chairman Stanley Fischer this year predicted the **natural rate** will **remain low** for the **next few years**, and warned that factors governing the rate are "extremely difficult" to forecast.

"The answer to the question, 'Will [the natural rate] remain at today's low levels permanently?' is that we do not know," he said in a January speech. "Eventually, history will give the answer."

Flood of Foreign Cash Flattens Yield Curve

by Min Zeng and Ben Eisen — WSJ — May 17, 2016

Why a popular market gauge of U.S. economic health has become more ambiguous:



A **wave of money fleeing low or negative interest rates overseas is helping to push down long-term Treasury yields**, hobbling a popular market gauge of U.S. economic health.

The "**yield curve**," measuring the **premium investors receive for the risk of holding 10-year U.S. government debt, rather than two-year notes, on Tuesday declined to 0.94 percentage point**, the **lowest since December 2007**. **A year ago, the gap was 1.65 points**.

The curve now is said to be **flattening**, a condition that bears scrutiny because it could lead to a situation in which short-term rates exceed long-term ones. That happened in the U.S. in June 2007, shortly before the financial crisis, and in December 2000, ahead of the 2001 downturn.

Yet some **traders and portfolio managers caution** that the yield curve's predictive value may have fallen victim to the age of easy money, in which the **flow of cash around** the **world dwarfs** the **economic trends that market indicators** have long been taken to **illuminate**.

While many U.S. investors doubt the **10-year Treasury** is a bargain at its **recent yield** of **1.75%, investors in Europe, Japan** and elsewhere have been **large buyers because yields** available **in their home countries** are even **lower**. The pool of **negative-yield bonds hit $9 trillion this month**.

The U.S. yield curve is "distorted because of negative interest rates abroad,'' said Torsten Slok, chief international economist at Deutsche Bank Securities.

The failure of U.S. yields to increase in recent months, even as the recession scare early in the year ebbed, has struck many investors as a sign of foreign capital's impact.

The 10-year yield has ticked lower this month, although U.S. retail sales and consumer-sentiment data showed strength and the Federal Reserve Bank of Atlanta's GDPNow forecasting service predicted that second-quarter U.S. economic growth would hit 2.5%. Stronger data is typically associated with higher bond yields because faster economic growth tends to push up inflation.

Craig Brothers, a portfolio manager at Bel Air Investment Advisors, still keeps measures of the yield curve prominently displayed on his Bloomberg terminal. But he looks at it less as an indicator of the economy than as a measure of where investors are putting money.

"The bond market had better predictive powers in the past than it does now," said Mr. Brothers, who manages $3 billion of mostly municipal bonds in Los Angeles.

Other factors play a role, too. The yield curve tends to flatten early in a Federal Reserve tightening cycle, as short-term yields rise in response to prospective rate increases while long-term yields rise more slowly, alongside the gathering pace of economic activity.

About half of the flattening over the past year is because of an increase in the **two-year rate, reflecting expectations for Fed rate increases this year**. **Two-year Treasury debt closed Tuesday at a yield of 0.823%, up from 0.55% a year earlier**.

Momentum also plays a role. Bond trading increasingly is driven by hedge funds and principal trading firms using superfast computers. One popular strategy, known as trend following, can lead to a cycle in which bond purchases drive down yields, begetting further purchases that further drive down yields and so on. Traders say that while this process can push yields down further than economic considerations would seem to demand, the resulting gap is **vulnerable to sudden reversals**.

"The flattening yield-curve trade is crowded,'' said Stanley Sun, interest rates strategist at Nomura Securities International in New York.

Another underrated factor: **diminished supply of Treasurys as improving U.S. economic health reduces government-funding needs.** In **April 2016**, **net issuance of Treasury notes and bonds was negative for the first time since 2008**, according to Mr. Slok at Deutsche Bank Securities.

History underlines how difficult it can be to get a handle on the swirling dynamics of this market.

A decade ago, the U.S. was running larger and larger current-account deficits and many government bonds were being purchased by China, which at the time was using U.S. Treasury purchases to help hold down the value of its currency, the yuan, and make its exports more competitive on global markets.

This arrangement fueled **fears** that the **U.S. would be vulnerable to a financing crisis if China began selling its holdings,** an argument that bearish bond investors contended would vindicate bets against Treasury debt.

Those concerns came to naught in the **financial meltdown of 2008**, which **instead ignited a powerful rally in prices of safe bonds**.

Eight years later, China is selling its Treasurys, but few expect yields to spike imminently, reflecting in part the deflationary concerns driving the economic slowdown in the world's most-populous nation. Meanwhile private investors have stepped into the breach.

On a net basis, foreign central banks sold $302 billion U.S. Treasury notes and bonds over the 12 months through March this year, according to Deutsche Bank Securities. Foreign private investors bought a net $317 billion.

Don Ellenberger, a fixed-income portfolio manager at Federated Investors, says long-term bond yields will **likely remain low** as the **world** struggles to **adjust to soft growth,** even without a U.S. recession.

"My thought is that we are going to continue to see the curve flatten, but it is going to be a **slow grind over a longer period of time**," he said.

Is Jeremy Siegel Late to Dividend-Stock Party?

by John Kimelman — Barron's / Bloomberg News — May 25, 2016

http://www.barrons.com/articles/is-jeremy-siegel-late-to-dividend-stock-party-1464215840?mod=articleRelStories

Left — Wharton professor Jeremy Siegel. The Wharton prof says we're in the first inning of a shift to income stocks. Where has he been?

Have you ever read a comment that seemed so behind the times that you checked the date of the article?

As a high-speed skimmer of financial news articles, this happens to me all the time. Often the article is indeed a few weeks or months old so it doesn't make it into this column, which regularly critiques the work of the print and digital financial media.

But a CNBC article, discussing the latest views of Wharton professor Jeremy Siegel, was written this week.

On Tuesday, **Siegel**, the **author** of the highly popular 1994 book ***Stocks for the Long Run***, said on CNBC that "I think we're in the **first inning of shifting to dividend-paying stocks**."

Even **though** the **Federal Reserve may raise rates this year**, "**investors** are becoming **convinced** they're **not** going to be **able** to **rely** on **CDs**, their **bank accounts**, **or** even **bonds as a source** of **income**," and may thus determine that "maybe they'd better **turn to stocks**," Siegel added. "Equities are the major income-producing asset of the future."

The beauty of the Internet and the explosion of financial blogs in recent years is that it doesn't take long for other voices to correct the record.

Later in the day, Jesse Felder, a well-respected financial blogger, pointed out that **investors have been chasing yield with dividend stocks for roughly seven years**.

Felder lays out the evidence with charts that show the **massive inflows into dividend-income funds**, master limited partnerships, real estate investment trusts, and high yield bonds **starting around 2009**.

The jump into these income vehicles is rather dramatic. Check out his charts for yourself.

"And after 7 years of reaching for yield, investors now have one of their largest allocations to stocks in history," Felder writes. "Only at the height of the dot-com bubble did households have a greater portion of their total financial assets tied up in equities than they did recently."

Felder also points out that "when you look at the ratio of equities to money market fund assets it becomes instantly obvious that inves**tors have been embracing the**

concept of 'there is **no alternative to stocks** for quite a long time now and to a degree never seen before."

By contrast, he adds, investors have also shifted just as dramatically out of bonds. "Even during the dot-com mania investors maintained nearly twice the current allocation to fixed income," he adds.

"So my question for Prof. Siegel is this: If investors have already shifted entirely out of bonds and money market funds, where the hell is this new, massive shift into stocks going to come from?" asks Felder. "Perchance, you're just feeling a bit too bullish once again?"

The final zinger is a knock on Siegel's general bullishness about stocks as the best investment that anyone can make for the long term.

Felder has earned the right to be a bit sarcastic. The **evidence shows that we're much deeper into the dividend-income chase than the first inning**, unless one defines an investment inning as running about seven years. Perhaps Siegel had a rain-shortened ball game in mind when he came up with the "first inning" line.

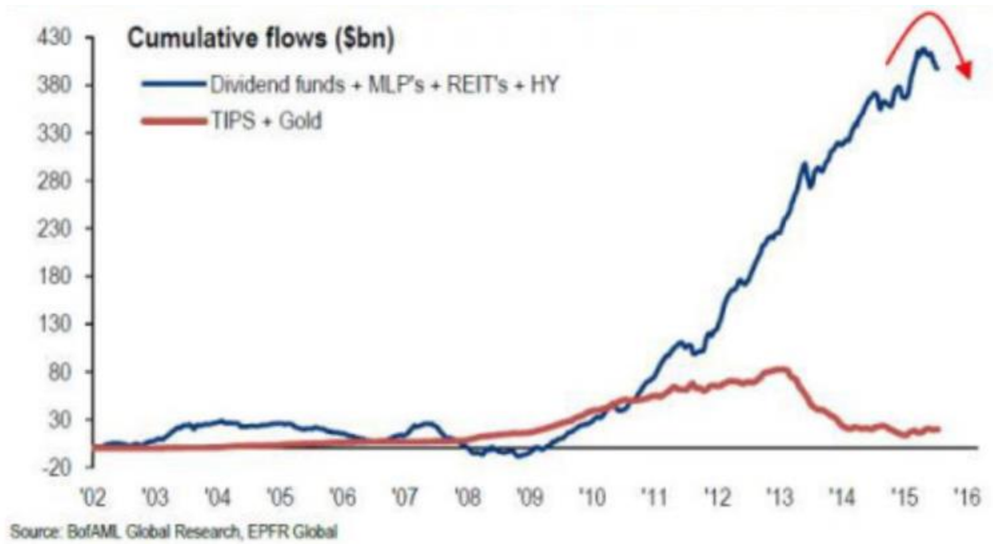
On a related note, CNBC has a piece that discusses the dangers of picking stocks with potentially unsustainable dividends.

"There's only one way to know if an investor should be afraid of what's lurking in their portfolio: earnings per share that are lower than the dividend per share, resulting in what could be a potentially unsustainable dividend payout ratio," which is defined as dividends per share divided by earnings per share.

"A high dividend payout ratio could result in a surprise cut to the dividend," writes Mitch Goldberg, president of ClientFirst Strategy. "Worse still, if the dividend was a primary reason to hold the stock, you could have one leg kicked out from under you, resulting in both a capital loss and less income when investors bail on a stock ahead of increasing fears about a dividend cut."

Seems that dividend stocks aren't quite as warm and fuzzy as many investors think they are, particularly at this stage of a bull market. One needs to tread cautiously.

Note: Professor Jeremy Siegel is a finance professor at the University of Pennsylvania's Wharton School (the top rated business school in graduate finance). **Charts referred to above are provided on the next two pages**. The charts are consistent with large cash flows away from fixed income and liquid assets to equities. What the above authors fail to appreciate is that Modern Portfolio Theory looks at long-run trends of six years and longer. Essentially, Professor Siegel is speaking at the earliest time where he is absolutely certain that he is right. That can be a lot slower than his critics who would like to see Professor Siegel take some risk in his observations.


Cumulative flows ($bn)
Dividend funds + MLP's + REIT's + HY
TIPS + Gold
430
380
330
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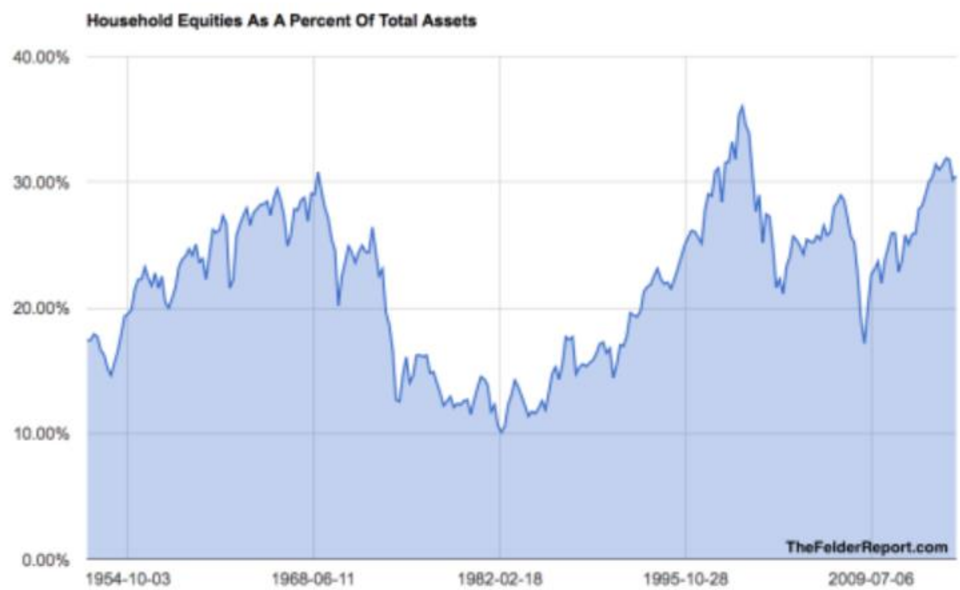
Source: BofAML Global Research, EPFR Global


Household Equities As A Percent Of Total Assets
40.00%
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1954-10-03
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1995-10-28
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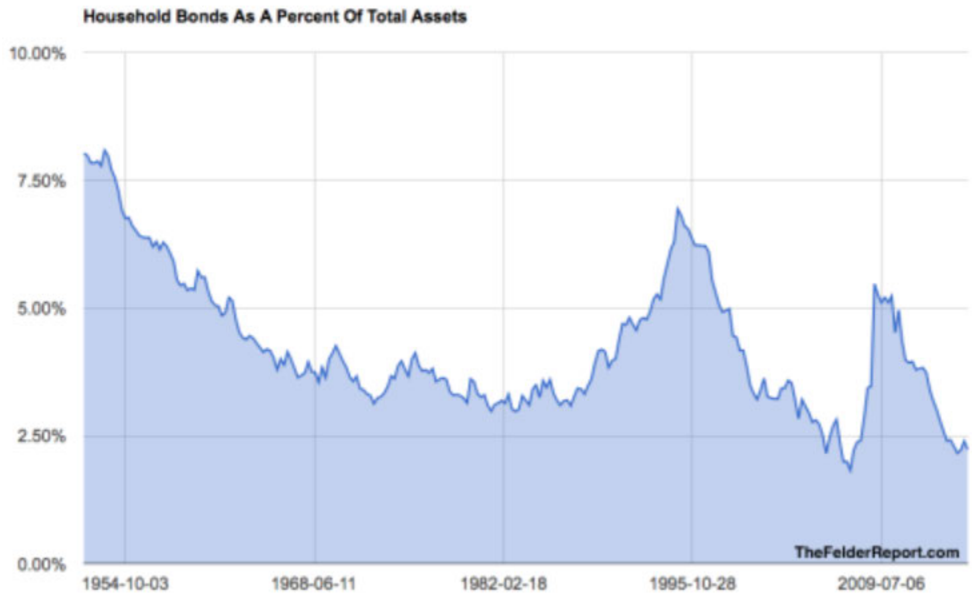
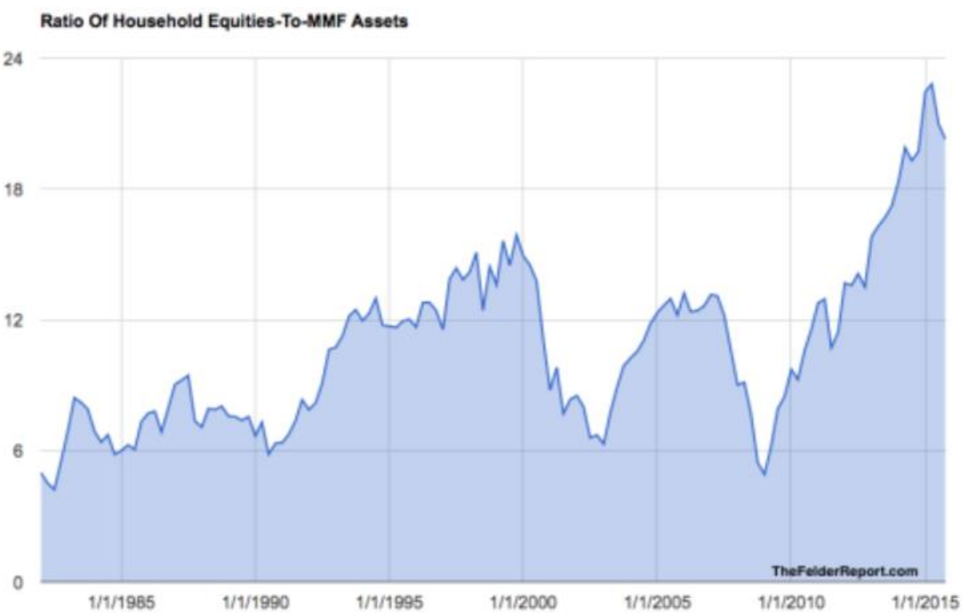
TheFelderReport.com



The next comparison is to Money Market Fund (MMF) assets:



Larry Summers Has Something to Say — the Economy is Really Sick. Is He Right?

by Peter Coy — Bloomberg Businessweek — May 16-22, 2016

The Curse of the Big Bad Rut — These are weird times. Growth is weak. Interest rates are negative. Is there a way out?

Crazy things are happening in the world economy. In **Europe and Japan, interest rates** have turned **negative**, something long thought impossible. In the **U.S., workers' productivity** is improving at the **feeblest five-year rate since 1982**. **China** is a confusing welter of **slumping growth** and **asset bubbles**.

Through it all Federal Reserve Chair Janet Yellen practices the central banker's art of draining the drama from any situation. She insists that conditions are returning to normal, albeit slowly. Her favored approach, "data dependence," is non-predictive and noncommittal, like finding your way in the dark by pointing a flashlight at your toes.

Lawrence Summers, the **Harvard economist** who almost got Yellen's job, has no patience for such patience. Since losing out to Yellen in 2013, he's been Jetting around the world-from Santiago to St. Louis to Florence, Italy-to argue that the world economy is in much worse shape than central bankers understand. Focusing on monetary policy alone, he says, they're doomed to fall short of reviving growth. They need to reach out to the governments they work for, he argues, and insist on **strong** fiscal stimulus in the form of **infrastructure spending** and the like. As an intellectual brawler from way back, he's in his element.

The jury's still out on Yellen vs. Summers. **Boring does not equal wrong**, and **provocative does not equal right**. If the U.S. economy heals nicely over the next few years under business as usual, Yellen's incrementalism will look smart. But the longer things stay weird, the more Summers appears to be onto something.

"My sense is that if Larry's hypothesis is true, it's a total game changer. It will affect how we think about macroeconomic policy for the next several decades," says Gauti Eggertsson, an Iceland native who worked in the Federal Reserve System for eight years and is now a macroeconomic theorist at Brown University. In November, after Summers presented his ideas at the Peterson Institute for International Economics, its president, Adam Posen, himself a former policymaker at the Bank of England, blogged that "All of us in the profession have a lot of work to do" to respond to the "disturbing questions" Summers raised.

For economic policymakers, the most disturbing question is **why global growth remains paltry and uneven**. The annual growth rate of gross domestic product in the U.S. in the January-March quarter was just 0.5 percent. The euro zone was stronger than the U.S., at 2.2 percent; Japan, which has been flipping in and out of recessions for a quarter century, shrank 1.1 percent. Deflation once seemed to be a strictly Japanese problem-now it's a worldwide threat. **Pessimism about growth prospects** is **reflected in low forecasts for long-term interest rates**. The annual yield on German 10-year notes is only 0.13 percent.

It wasn't obvious in the summer of 2013, when President Obama was choosing between Yellen and Summers, that **Summers** would turn out to have such out-of-the-box ideas. Obama said that "when it comes down to their basic philosophy on the future of the Fed," the differences between the candidates were so small "you couldn't slide a paper between them/' according to Democratic Senator Dick Durbin of Illinois, who attended a meeting with the president. Both were highly credentialed-she as a longtime Fed official who was a labor economist at the University of California at Berkeley's Haas School of Business; h as **Treasury secretary under Bill Clinton**, **former Harvard University president**, and **former head of Obama's National Economic Council**. If anything, Yellen seemed more likely to be an activist Fed chair and "would probably be more committed to keeping stimulus in place until the economy was definitely recovered, Michael Peroli, chief U.S. economist at JPMorgan Chase, said at the time.

But in November 2013, after Yellen was chosen but before she replaced Ben Bernanke as chair. Summers went to the International Monetary Fund in

Washington and raised the specter of "**secular stagnation**," a term **coined in the Great Depression by Harvard economist Alvin Hansen**, who lamented "sick recoveries which die in their infancy, and depressions which feed on themselves and leave a hard and seemingly immovable form of unemployment." "**Secular**" is **econo-speak** for **long-lasting**, **as opposed to cyclical**. Hansen's warnings about secular stagnation seemed to be disproved when U.S. growth accelerated m World War II and then remained strong after the war stimulus ended.

For Summers, bringing the idea of secular stagnation back into the academic debate was like putting on a moldy old coat from Grandpa's attic. But revive it he did. "Now, this may all be madness, and I may not have this right at all," he told the IMF audience, before coming around to saying, "we may well need, in the years ahead, to think about how we manage an economy in which the zero nominal interest rate is a chronic and systemic inhibitor of economic activity, holding our economies back below their potential."

In other words. Summers claimed world economies could be so unbalanced that even zero interest rates would be too high-and for many years, not just briefly as economists had believed. The speech lit up the Twitterverse and drew heavy news coverage. Journalists' attention has waned a bit, but Summers has kept developing the concept on his blog, in his Financial Times columns, in speeches, and in papers written with other economists, including Brown's Eggertsson, who's translated Summers's thinking into the formal language of general-equilibrium economics. The real world is helping Summers's case. The **longer stagnation lasts, the more it looks secular rather than just cyclical**. "I've come to a growing conviction" that the theory is right, he says.

To be clear. Summers is challenging much more than when and how much the Fed should raise interest rates. True, he criticized it for voting in December to lift the federal funds rate by a quarter of a percentage point after seven years at just more than zero. But that's an ordinary argument over how high to set the monetary thermostat.

Summers's deeper argument is that world growth is stuck in a rut because there's a chronic shortage of demand for goods and services and a concomitant excess of desired savings. The U.S. and other **industrialized nations tend to save more as their populations age**, he says. Meanwhile, **growing inequality puts a bigger share of the world's income in the pockets of rich people**, they can't spend everything they make, so **they save** it. The Investment that would ordinarily soak up those savings is falling short. That's partly because **the new economy is asset-lite**: Companies such as Uber and Airbnb prosper by exploiting assets (cars and houses) that already exist. Software, which is pure information and doesn't require the construction of factories, accounts for a bigger share of the economy. **Slow growth in output and productivity reduces investment as executives lose faith in the payoff from capital spending**.

Exhibit No. 1 in Summers's case: **Interest rates have been trending down for 30 years**, even after taking into account the decline in inflation. The interest rate, like any price, reflects supply and demand. It's fallen because the **demand for loans is weak** and the **supply** of loans **from savers**, who have extra cash to deploy, **is strong**. It used to be thought that interest rates couldn't go below zero, but the Bank of Japan and the European Central Bank, among others, are so desperate to kindle growth that they've pushed some rates below what used to be called the "zero lower bound" into negative territory.

Despite opposing the Fed's December hike. Summers continues to worry that an extended period of ultra-low and even negative rates will cause **bubbles in assets** like stocks and housing, as desperate investors chase after higher returns. He says fiscal policy needs to play a much bigger role than it has. How? On the investment side, he favors government spending to **fix America's dilapidated roads and bridges**, **combat global warming**, and **improve education-big, expensive projects that would provide value while soaking up excess savings**. A favorite line: "The United States right now has the lowest infrastructure investment rate that it has had since the second-world-war." On the savings side, he favors, among other things, **changing the tax code to get more money into the hands of lower-income and middle-class families who'd spend rather than hoard it**.

This, of course, sounds a lot like the agenda Obama has been pushing unsuccessfully for the past eight years. "To me, it looks like an opinion masquerading as a theory," Arnold Kling, a former Fed economist, wrote on his blog in 2014. Congress shows no interest in any measure that smells like fiscal stimulus especially now, with lawmakers hiding under their desks until after the election. Summers responds that his prescription is separable from his diagnosis; conservatives might prefer to fix the problem with, say, export promotion, the elimination of wasteful regulations, and big tax cuts to induce companies to build factories.

Summers has been getting more of a hearing from central bankers around the world. His message to them: Think bigger. The Fed traditionally restricts itself to managing the "**business cycle**" — **fluctuations of output around a supposed long-term upward trend**. Summers questions the very existence of a business cycle, an inherently optimistic concept implying that what goes down must come up. **When output declines**, his research shows, it **never quite gets back to its original trajectory**. Productive capacity suffers lasting damage, in part **because laid-off**

workers lose skills. That makes it imperative to **avoid** a **recession whenever possible**. Yet **Summers says the odds of a U.S. recession in the next three years are "significantly better than 50-50"**.

Lately, he's added the .idea that secular stagnation is infectious, spreading between countries by trade and investment flows. A stagnant country can try to cure its unemployment problem by pushing down the value of its currency and running a big trade surplus; that worsens unemployment in its trading partners, which suffer trade deficits, according to recent work by Eggertsson, Summers, and others. **Beggar-thy-neighbor trade theory**, in other words, is alive and well.

Summers argues that central bankers should stop focusing on the business cycle, stop jealously guarding their independence, and work with other institutions to solve the deep problems that have gotten the economy into this condition. "Central banks like to say, "Well, yeah, productivity growth's a problem. That's not our problem, though." "Inequality's a problem. That's not our problem, though," Summers said in a question-and-answer session after his Peterson talk. "I would suggest that no major central banker in the world is seriously engaged with this as an issue."

The **Federal Reserve System employs more Ph.D. economists than any other organization in the world**, so it would seem to be an ideal place to bang out big ideas about secular stagnation. But Fed economists tend to focus on short-term forecasting and the mechanics of monetary policy, says Peterson's Posen. Yellen can't afford to indulge in blue-skying. Her most important job is to move the rate setting Federal Open Market Committee along by baby steps, maintaining as much of a consensus as possible among hawks and doves and being careful not to surprise the financial markets. "If you're a member of a central bank committee, let alone the chair, every word gets scrutinized," Posen says.

On the narrow question of where rates are headed, the **Fed** is gradually drifting in Summers's direction. The **median projection** by rate setters of **where the federal funds rate will eventually settle** has come **down** a **full percentage point, to 3.25 percent**, **since** the Fed began releasing projections in **2012**. But Yellen, unlike Summers, isn't calling on Congress to amp up stimulus. In a speech in November at the Banque de France, she said. Contractionary tax-and-spending policy was "hardly ideal," but gave fiscal authorities an out by saying they had to take long-term sustainability into account.

Yellen has tiptoed around secular stagnation, referring to the theory but not endorsing it. Her right-hand man, **Vice Chair Stanley Fischer**, who taught Summers, Bernanke, and European Central Bank President Mario Draghi at MIT and once ran Israel's central bank, seems more open to the idea that something fundamental has changed. Speaking to academic economists in San Francisco in January, he referred to "the secular stagnation hypothesis, forcefully put forward by Larry Summers in a number of papers." He agreed that **interest rates will likely** "**remain low for the policy-relevant future**." He even entertained one of Summers's solutions for the savings / investment imbalance: government spending on long-term projects. Says **Summers**: "Even people who don't like to use the term 'secular stagnation' are accepting **new realities** of **excess saving relative to investment, very low rates, and chronic demand shortfall**."

One big fact is hard to square with Summers's idea that the economy suffers from a shortfall in demand-namely, the 5 percent US. unemployment rate. If Americans spend a lot more, as he desires, there might not be enough workers available to handle the demand. The result could be a bidding war for talent, climbing wages, and unacceptably high inflation.

Princeton's Alan Blinder, a former Fed Vice Chairman, is one of a group of economists who argue that economic stagnation emanates from **weak supply**, **not weak demand**. "When I go to sleep at night worrying about the economy, **I'm never worrying that Americans won't spend enough**," he says. **Robert Gordon of Northwestern** University similarly says **growth is impeded by a lack of innovation** — a supply-side explanation.

Summers, no surprise, has an **answer to those objections**. He says there may be **more slack in the labor market than is** sometimes **recognized**. And he says the demand-side and supply-side explanations for stagnation aren't mutually exclusive: Weak demand growth can itself damage the supply side of the economy — i.e., the people and machines who make stuff. **Unemployment causes workers' skills to atrophy**; **companies stop investing in equipment and software**.

Strengthening demand can turn that vicious circle around and gradually raise the economy's productive potential, Summers says. Far from crowding out private investment, government spending could induce more of it.

When interest rates can go negative, all of the verities in economics are up for grabs. Economists joke that the questions on their doctoral exams haven't changed in 50 years, but the answers have. The joke "captures a truth," Summers says.

He seems to relish being in the midst of the upheaval. "That's the effect of living backwards," the White Queen told Alice in Wonderland. "It always makes one a little giddy at first."

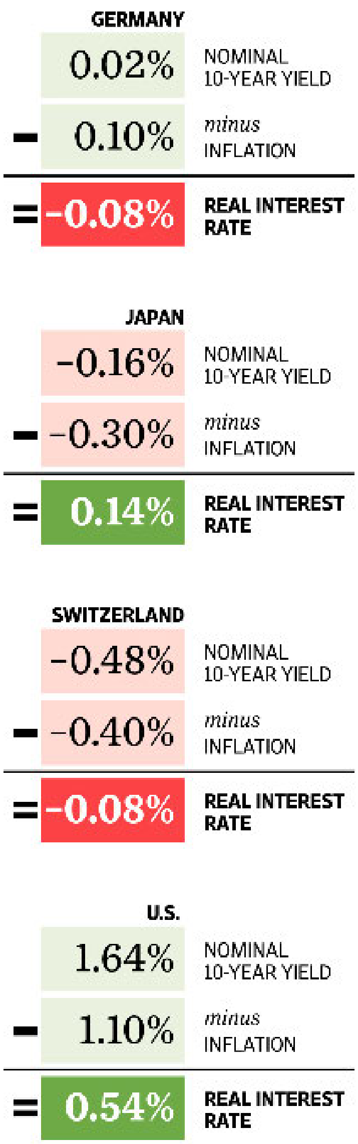
Negative Rates Alone Struggle to Lift Growth

by Min Zeng and Jon Sindreu — WSJ — Jun. 13, 2016

Central banks are having a difficult time in their efforts to stimulate slumping economies.

Add up the market value of all of the gov**ernment bonds trading at negative rates around the world**, and it comes to more than **$8 trillion**, a testament to just how hard **central bankers are pushing returns down in hopes of spurring people and businesses to spend**.

But subtract inflation, and it becomes apparent how difficult that is. That number shrinks to $6.8 trillion, half of its level just a few months ago, according to data from J.P. Morgan Chase & Co.



Note: Inflation data are annualized
Sources: Tradeweb (nominal yields); government statistics (CPI)
THE WALL STREET JOURNAL.

It is perhaps the clearest sign of the intense difficulty that central banks are encountering in their extraordinary efforts to stimulate slumping economies — even as interest rates plunge to fresh lows.

The **10-year U.S. Treasury yield on Friday tumbled to 1.639%,** its **lowest close since May 2013**, and yields on comparable bonds in **Germany** and **Japan** hit fresh **all-time lows**, with 10-year rates in Germany on the verge of closing below zero for the first time.

But falling rates promise limited relief for consumers and businesses in many places, because in recent months **inflation** there has been **tumbling**, **too**. For many across Europe and Japan, even record-low interest rates don't translate into easier borrowing terms on a real, or inflation-adjusted, basis. For investors, it is likely another sign that ultralow interest rates will be with us for a long while.

"It just shows the **limits that central banks face**," said Alejandra Grindal, senior international economist at Ned Davis Research Inc. "They can push down nominal yields below zero, but they still struggle."

When recession hits or **demand** for **goods** and **services** otherwise **abates**, **central bankers often reduce interest rates**. In part, they aim to push rates into negative territory in inflation-adjusted terms. Doing so **imposes** an **implicit cost** on **holding onto cash** and gives people and businesses an **incentive to spend**

But **that isn't easy to do when inflation is falling faster than nominal bond yields**. Take Japan, said Jigar Vakharia, a J.P. Morgan analyst who generated the real-yield data, which was calculated as of Monday.

Trillions of dollars worth of Japanese government bonds left the pool of negative-yielding debt after inflation data released earlier this month fell further into negative territory.

To calculate real yields, economists **subtract** the **inflation rate from** a **nominal yield**. For example, the 10-year Japanese government bond yielded negative 0.16% Friday. With the latest consumer-price-index reading showing a 0.3% decline from a year earlier, the real yield was positive 0.14% at 10 years, a key rate for many consumer and business loans.

The move signals that the Bank of Japan isn't having much luck getting the economy going, even after it pushed benchmark rates into negative territory early this year. The global pool of government bonds with negative real yields hit nearly $14 trillion in February but has since shrunk by more than half, reflecting the free fall of inflation.

Many analysts say the apparent failure of low- and negative-rate policies amounts to an indictment of fiscal policies across the developed world. Economic growth is being stunted, they say, by governments' failures to enact policies addressing the **challenges of employment, aging and infrastructure** spending in a holistic way.

"I think we have reached the limit of what monetary policy can do,'' said Torsten Slok, chief international economist at Deutsche Bank. "The real case against negative interest rates is the folly of relying on monetary policy alone to rescue economies from depressed conditions."

Though the Federal Reserve hasn't enacted negative rates, it too is being buffeted by soft economic conditions. When the central bank's policy-setting board meets in the coming week, few analysts expect it to raise rates, reflecting low inflation and slackening jobs growth.

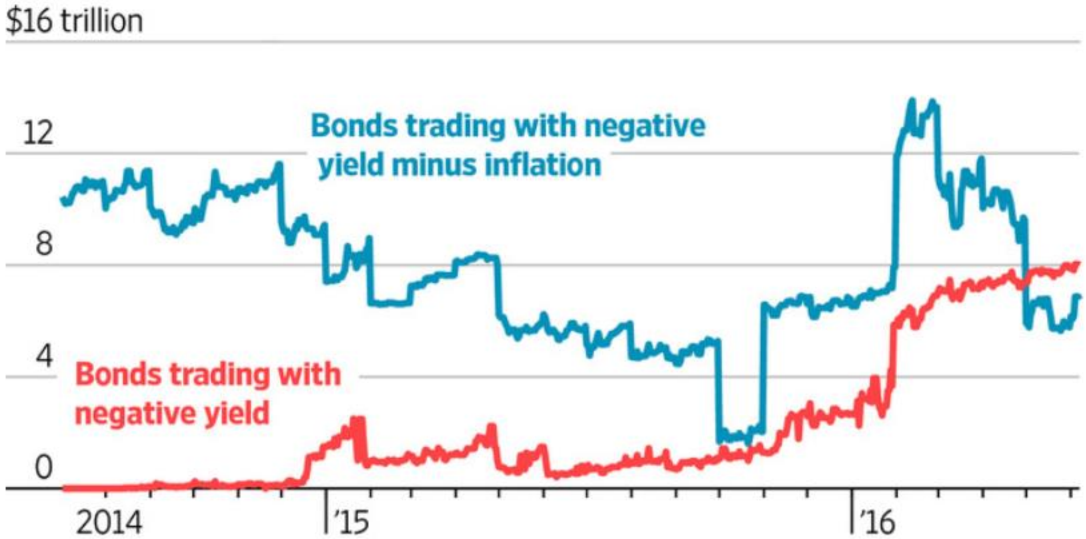
European central bankers are also struggling to keep real rates negative. By lowering interest rates below zero, the European Central Bank has broadly managed to ease the cost of credit for households and businesses. But new lending remains only about 17% of what it was in 2006, according to ECB figures.

Negative rates don't appear to have helped boost inflation in Europe, either. It is currently at minus 0.1%. When the effects of oil and food are stripped out, price growth has mostly hovered below 1%, a sign that **economic activity in the euro-zone has been weak**. Five years ago, inflation in the euro-zone hit 3%.

Real rates in the euro-zone are also much higher now than they were between 2011 and 2013, when they went as low as negative 2%.

Wrong Direction

More government bonds are trading at negative rates. But subtract inflation and 'real rates' are in many cases higher, reflecting central banks' struggles to lift price trends.



Notes: Based on the J.P. Morgan Global Government Bond Index; converted to U.S. dollars at the current rate; all figures as of June 6
Source: J.P. Morgan Chase THE WALL STREET JOURNAL.

ECB President Mario Draghi recently pointed to real rates in order to defend ultra-loose monetary policy against criticisms that it is hurting savers in core European countries such as Germany.

"Real rates today are higher than they were about 20, 30 years ago," Mr. Draghi said during a press conference in April. "But I am aware that to explain real rates to savers may be difficult."

One sign of how low inflation is undoing many of the central bankers' efforts: Interest rates are currently higher in the euro-zone than they are in the U.S. when the effect of changes in prices is taken into account. Real rates based on overnight interbank borrowing, which is closely linked to central-bank policy, stand at negative 0.73% in the U.S., lower than the euro-zone's negative 0.23%.

Other central bankers have had more success. In **Switzerland**, inflation has also been pervasively negative, but its ultra-depressed interbank rate — it hovers around minus 0.73%, the world's lowest — allows real rates to remain significantly negative as well.

Mark Dowding, senior fixed-income manager at BlueBay Asset Management, which had $58 billion under management at the end of April 2016, said higher inflation in the U.S. saps his appetite for U.S. Treasury bonds. Unlike many of his peers who fled German bonds and embraced Treasurys, he favors German bunds over Treasury debt.

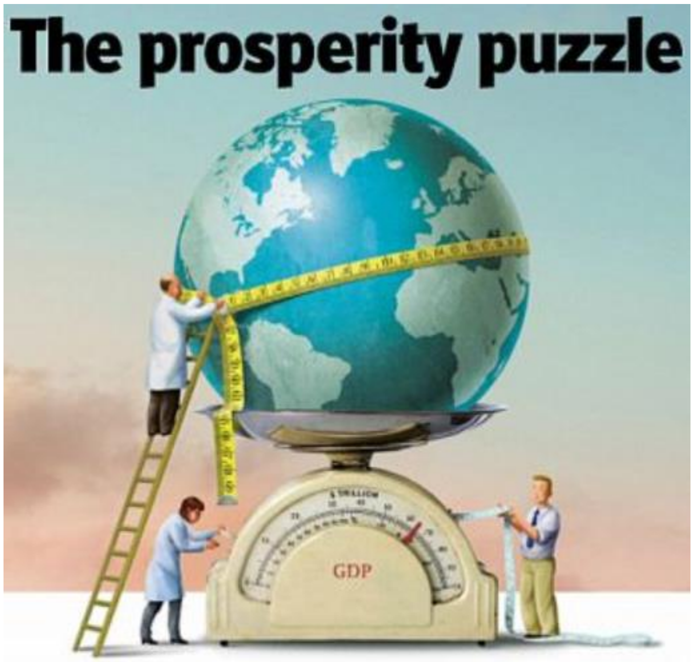
That is a concern because investors pouring into **negative-yielding debt will collect less money** than they put in if they hold the bonds to maturity, **and** they **could suffer heavy losses if interest rates unexpectedly rise**.

The biggest **danger** is that **expansive policy could fuel large-scale distortions in markets**, said Thomas Roth, executive director in the U.S. government-bond trading group at Mitsubishi UFJ Securities (USA) Inc. “Central banks have a history of sticking with the economic policy of the day and not listening to what the results are,” he said.

The Economist

The Strange Case of the Missing Baby

The Economist — Apr. 30, 2016 — 419.8987 p55 (US)
Gale Document Number: GALE|A451181876 — *Business Collection*. Web



As the financial crisis hit, birth rates fell in rich countries, as expected. **But a persistent baby bust is a real puzzle**.

HE IS not exactly leading by example, but Pope Francis wants more babies. "The great challenge of Europe is to return to being mother **Europe**," he said last year, while suggesting that young people might be having too few children because they preferred holidays. **Europe** certainly lacks young souls, particularly in Catholic countries such as Italy and Spain. But the baby shortage is broader: mother America and mother **Australia** have gone missing, too.

They were certainly present **a decade ago**. Although birth rates were low in the former communist countries of eastern Europe, and in traditionalist places where it is hard to combine work with motherhood — think Japan, South Korea and southern Europe — many countries were having a baby boom. In the decade to 2008, the total **fertility rate** (the **number of children a woman can expect to have in her lifetime based on present patterns**) rose in much of the rich world. In Britain it went up from 1.68 to 1.91 (see chart 1); in Australia from 1.76 to 2.02; and in Sweden from 1.5 to 1.91. **America** even **managed** to reach the "**replacement rate**" of **2.1,** meaning its **population** was **sustaining itself**, **without taking migration into account**.

There were two reasons, says Tomas Sobotka of the Vienna Institute of Demography. First, women who had delayed having children while they studied and started careers hurried to the maternity wards while they still could. Births to women in their 30s, which had been rising gently for years, went up further in Norway and elsewhere (see chart 2). Second, fertility among women in their 20s stopped falling.

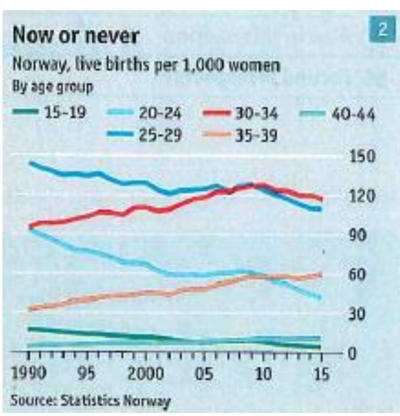
The **financial crisis abruptly turned the boom to bust**. Countries in the **European Union delivered** 5,469,000 **babies** in 2008 but only 5,075,000 in 2013 — a **drop of over 7%.** That was too much for Kimberly-Clark, the maker of Huggies nappies, which announced in 2012 that it would pull out of most of Europe. In America the fertility rate fell from a peak of 2.12 in 2007 to 1.86 in 2014. Ken Johnson, a demographer at the University of New Hampshire, estimated that **America was missing 2.3m babies**.

The crunch was unsurprising: anxiety about jobs and money puts people off children. But a rich-world baby bust that began predictably turned into a puzzle.

Fertility rates have fallen in countries with woeful economies, such as Greece and Italy. But they have also fallen in countries that sailed through the financial crisis, such as Australia and Norway. **Although the American baby bust was expected**, the **lack of recovery after seven years seems odd**. "I was fairly confident that women were just delaying births, and that we would see a rebound," says Mr Johnson. "I'm beginning to wonder now." In Britain the drop came late: the fertility rate fell from 1.92 to 1.81 between 2012 and 2014. Then there is France, where couples looked at the economic slump and shrugged. The fertility rate there has barely moved.

If some of the international trends are hard to fathom, so is the strange uniformity within countries. Trude Lappegard, a Norwegian demographer, says that her country's baby bust, which has been going on for six years, might be easy to explain if it had hit one group especially hard. Instead, **women of all ages and all levels of education are having fewer children**.

One possible explanation is that immigrants are not boosting birth rates much these days, and might even be dragging them down (see "Immigrant fertility: Fecund foreigners?"). Some demographers suggest that cuts to welfare might have made poor mothers warier of having children. But that does not explain the behavior of middle-class women. And family support has actually become more generous in some countries with falling fertility.



Ann Berrington of Southampton University points to housing. Young and even not-so-young couples find it hard to buy property in England and Wales: 46% of 25- to 34-year-olds lived in private rented accommodation in 2014-15, up from 24% a decade earlier. **Four in ten 24-year-olds still live with their parents**. Home-ownership rates have fallen in America and Australia, too. The rate is rising in France, where fertility has held steady--though that might be thanks to strong pro-natalist policies.

You can have a baby in a rented flat, of course. But in a country like Britain, where earlier generations found it easy to buy homes, that seems to flout a psychological rule for some. In the 1960s Richard Easterlin, an American economist, suggested that people would avoid having children if they felt unable to bring them up in a style that at least matched the way they were raised. It might be time to dust off that idea.

Some couples could be delaying having babies not because they cannot afford them, but because of a vague feeling that family life is harder than it used to be. A Pew poll of 11 rich countries last year found that 64% believe that today's children will be worse off than their parents. Perhaps the gloom has spread even to countries with strong economies. Mr Sobotka suggests that Scandinavians could have overreacted to repeated news reports about hard times elsewhere in Europe. "It gets below people's skins," he says.

In this, childbirth might be a little like politics. When a surly, anti-politics mood first took hold in Europe and America after the financial crisis, it was tempting to think it would dissipate as economic growth returned. Today Donald Trump is the probable Republican presidential nominee in America, the National Front is rampant in France and the British government is fighting both Scottish separatism and Europhobia. Bad moods can linger.

Whether and when birth rates bounce back, and how high, has broad consequences. **America's Census Bureau** simply **assumes that current fertility rates will persist**. **Since 2008 it has slashed its prediction for the country's population in 2050 from 439m to 398m**. If lower fertility lasts, it would help balance government accounts in the short term, because there would be fewer children to educate, but hurt in the long term. **A fertility rate of 1.8 would mean twice as large an annual social-security deficit by 2089 as one of 2.2, as a percentage of the social-security tax base**.

A persistent slump would also be bad news for nappy-makers. But the overall effect on the market for baby gear might be surprisingly slight. Marcus Tagesson, the boss of Babyshop, a Stockholm-based retailer, says that the important thing is that couples have at least one child. The first baby is the most profitable, he explains. Parents want everything to be new and perfect; besides, they make mistakes with their first-born that they do not repeat. Such as? "White clothes," says Mr Tagesson, a little ruefully.

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The Economist

Fecund Foreigners? Immigrant Fertility.

The Economist — Apr. 30, 2016 — 419.8987 p56 (US)
Gale Document Number: GALE|A451181876
Business Collection. Web

Immigrants do less to raise birth rates than is generally believed

FOR a Turkish woman ready to start a household, Weseler Strasse in Duisburg is a one-stop shop. There, in the shadow of an enormous steel works, are dozens of stores selling wedding dresses and glitzy tuxedos; jewelry and home furnishings. What this stretch of Weseler Strasse does not contain is a baby shop.

In the early 1980s women with foreign passports in Duisburg had a birth rate much higher than native Germans (see chart). Most of the foreigners were Turks, who had settled in this Ruhr Valley city for its industrial jobs and brought their big-family culture with them. But then came an astonishing drop. **Today foreigners are actually slightly less fertile than natives**. That is saying something: **German women** in Duisburg, and **in Germany as a whole, do not have nearly enough babies to keep the population ticking over naturally**.

Xenophobes and xenophiles share a belief in the fecundity of newcomers. "Immigrants are more fertile," explained **Jeb Bush**, an erstwhile American presidential candidate (and xenophile) in 2013. "They love families and they have more intact families, and they bring a younger population." That is still just about true in America, but the gap is vanishing.

Between 2006 and 2013 the fertility rate among Mexicans in America fell by 35%, compared with a drop of 3% among non-Hispanic whites. In the Netherlands, the immigrant fertility rate is now almost exactly the same as the native one. Even in Britain, where a quarter of births are to immigrants, statisticians reckon that immigration has raised overall fertility by a mere 0.08 children per woman.

The **fertile immigrant is partly an illusion**. Women tend not to move country with babies in tow, explains Gunnar Andersson of Stockholm University: they travel first and then have a child quickly. That makes them seem keener on babies than they really are. Partly, too, the countries that send migrants to the rich world have changed, points out Michael Teitelbaum, a demographer at Harvard Law School. **Fertility rates have plunged in both Mexico and Turkey, from more than six children per woman in 1960 to less than three today**. Grandma in Oaxaca is probably no longer pushing her emigrant daughter to have a third.

But the big reason **immigrants'** birth rates are falling is that they **tend to adopt the ways of the host communities**. This happens fast: some studies suggest that a girl who migrates before her teens behaves much like a native. Acculturation is so powerful that it can boost birth rates as well as cut them. In England, migrants from high-fertility countries like Nigeria and Somalia have fewer babies than compatriots who stay put. Those from low-fertility countries such as Lithuania and Poland have more.

Christine Bleks, who runs a children's charity near Weseler Strasse, points to the front gardens of houses around Duisburg's large mosque. They are small and orderly, with neat hedges and kitsch ornaments. The style is stereotypically German, she says. But the owners are mostly Turkish. As with gardens, so with families: **immigrants have gone native**.

World Bank Cuts Global-Growth Outlook

by Ian Talley — WSJ — Jun. 7, 2016

The global economy will growth 2.4% this year, the bank predicts, amid troubles in both emerging markets and developed nations

The **global economy is increasingly vulnerable to a sharp slowdown as troubles in emerging markets mount and as advanced economies struggle to grow, the World Bank warned Tuesday**.

The **bank's latest projection pegs global growth at 2.4%, down from the 2.9% forecast in January and slower than last year's weak pace**. **The bank also cut its forecast for growth in 2017 to 2.8% from 3.1%.**

"The global outlook faces **pronounced risks of another stretch of muted growth**," said World Bank chief economist Kaushik Basu. " A wide range of risks threaten to derail the recovery."

Commodity exporters such as Brazil, Russia, Nigeria and Angola suffered some of the largest downward revisions. Governments have been forced to cut spending due to the price collapse in metals, energy and other commodities. Weakening currencies also are forcing central banks to raise interest rates to curb rampant inflation. And higher borrowing costs are weighing on investment and putting many company balance sheets deep into the red.

The **bank pared its projections** for the world's largest economy, the **USA** wounded energy sector, strong dollar and anemic international demand contributed to a **0.8-percentage-point cut in growth expectations—to 1.9%—for the year**.

Japan, the world's third-largest economy, isn't gaining traction despite the Bank of Japan 8301 0.13 % 's charge into negative-rate territory. The World Bank said Japan will grow by 0.5% this year, nearly a full percentage point lower than expected in January.

The bank fears emerging-market growth could decelerate further. The bank kept its forecast for a 6.7% expansion in China, the world's No. 2 economy, as Beijing juices output with more stimulus. But the World Bank warned of building financial risks that could trigger a deep slide in growth.

Bank economists are also concerned the Federal Reserve could tighten faster than markets expect, causing a jump in borrowing costs that could spark financial turmoil around the world. Volatility in capital flows also could flare up again if jittery investors pull out of emerging-market equity, currency and bond markets, they said.

The economists cited political risks as a threat to future growth. A U.K. exit from the European Union could severely damp investment as uncertainty weighs on markets, they said.

In the U.S., many economists are also pointing to uncertainty in the presidential election as suppressing activity. Governments from Brazil to South Africa to Indonesia also are facing deepening political turbulence, on top of persistent risks from wars in the Middle East and geopolitical tensions in the South China Sea.

"If we have a major shock, it can translate into a very sharp slowdown for the global economy," said Ayhan Kose, the chief author of the bank's Global Economic Prospects report.

Policy makers' room to maneuver is shrinking. Although debt levels have moderated in many advanced economies, central banks are starting to run out of monetary-policy options. And politicians are reluctant to use government balance sheets to fund major injections of stimulus.

Options are even fewer among emerging-market exporters. Debt levels are rising, budget deficits are deepening and central banks are having to raise rates instead of cutting them to temper rising prices as their currencies weaken. Those countries, such as Angola, Kazakhstan, Malaysia, South Africa and Venezuela, are running average budget deficits of 5% of gross domestic product.

One major indicator of global weakness — trade growth — remains muted at 3.1%, well below pre-crisis trends.

"Persistently low growth could intensify protectionist tendencies that would further weaken growth prospects," the bank said.

That attitude can be seen in the **antitrade rhetoric gathering strength** in the U.S. presidential election, but it isn't isolated to North America. **Around the world**, discriminatory practices that act as a barrier to international trade outpace liberalization efforts by more than two-to-one, the bank said.

One bright note in the outlook: Emerging-market importers aren't suffering the same downturn as exporters. In countries such as India, Hungary, Thailand and Vietnam, government deficits are actually lower than the bank forecast two years ago and debt levels as a share of economic output are falling.

U.S. Durable-Goods Orders Fell 2.2% in May

by Ben Leubsdorf — WSJ — Jun. 24, 2016

Drop led by a 34.1% decline in military-aircraft orders

American businesses were **pulling back on purchases of new equipment** even before the U.K. vote to exit the European Union rocked global financial markets, a sign of **corporate caution** that will likely continue to act as a brake on the economy.

Overall U.S. economic growth picked up in the second quarter, boosted by stronger consumer spending. But surprisingly weak business investment has remained a concern for Federal Reserve Chairwoman Janet Yellen and others. That weakness could be exacerbated in the coming months by "Brexit"-fueled uncertainty and dollar strength.

" 'Brexit' will not likely help matters," said Steve Blitz, chief economist at M Science LLC, in a note to clients.

The U.S. Commerce Department on Friday reported that **new orders for durable goods** — airplanes, industrial machinery and other products that are designed to last at least three years — **decreased** a seasonally adjusted 2.2% in May from the prior month. That was a sharper fall than the 0.4% decline that economists had expected.

Last month's drop was led by a 34.1% decline in military-aircraft orders. But orders were **down across almost every category** in May. Orders for durable goods excluding the transportation category fell 0.3% from April, and orders excluding defense fell 0.9%.

Friday's report showed "**broad-based and persistent softness across the U.S. manufacturing sector**," Barclays economist Jesse Hurwitz said in a note to clients.

A closely watched proxy for business investment in equipment, new orders for nondefense capital goods excluding aircraft, fell 0.7% in May from April. Orders in the category were down 3.5% in the first five months of the year compared with the same period in 2015.

"While the pace of decline has moderated...orders growth remains negative, suggesting **continued weakness in business investment**," BNP Paribas economist Laura Rosner said in a note to clients.

Data on durable-goods orders can be volatile from month to month and are subject to later revisions. The overall trend has remained weak, though bolstered by robust growth this year in orders for military equipment and civilian aircraft. Total durable-goods orders rose 1.7% in the first five months of 2016 compared with the same period a year earlier.

The manufacturing sector has faced pressure since late 2014 from falling oil prices, which squeezed domestic energy production, and **lackluster demand for U.S. exports**, partly reflecting a **strong dollar**.

Those headwinds had been expected to fade. Oil prices have moved higher in recent months and the dollar had largely stabilized. But following Thursday's vote in the U.K. to pull out of the EU, the dollar strengthened and oil prices dropped. The decision also generated **uncertainty** that could weigh on business executives and consumers around the world.

However events evolve in the coming weeks and months, U.S. firms already were pulling back on their capital expenditures.

Orders for nondefense capital goods excluding aircraft began sharp declines in late 2000, ahead of the 2001 recession, and in 2008, during the 2007-2009 recession. Orders in the category have been declining—at a gentler pace — since the fall of 2014.

Over time, the metric has tracked a broader measure of business spending, private fixed nonresidential investment, which declined in the fourth quarter of 2015 and the first quarter of 2016, according to Commerce Department data. That was the first back-to-back quarterly decline in the category since the end of 2009.

Ms. Yellen told lawmakers this week that soft business investment since the recession might reflect broader trends. With slower growth in the workforce, she said, there has been less need for businesses to buy new equipment.

Plus, she told the Senate Banking Committee on Tuesday, “sales growth has been slow and many firms have found they actually don’t need to invest very much in order to satisfy the demand growth that they’re seeing.”

But she also described recent readings on business investment outside the energy sector as “surprisingly weak,” highlighting the issue as a worry for the U.S. central bank. The Fed has described business investment as “soft” in its last three policy statements, most recently in mid-June.

Over time, weak spending on computers, machinery and other equipment could reinforce the sluggish recent trend for U.S. worker productivity and broader economic growth.

Grand Rapids, Mich.-based furniture maker Steelcase Inc. this week reported that its sales in the Americas were nearly flat and orders were down compared with a year earlier in the quarter ended May 27, including a sharp decline in orders from energy-sector clients.

“Given the ongoing uncertainty in the broader economy and political landscape, it is not surprising that orders have remained soft over the last couple of quarters,” Chief Financial Officer David Sylvester told analysts on Thursday.

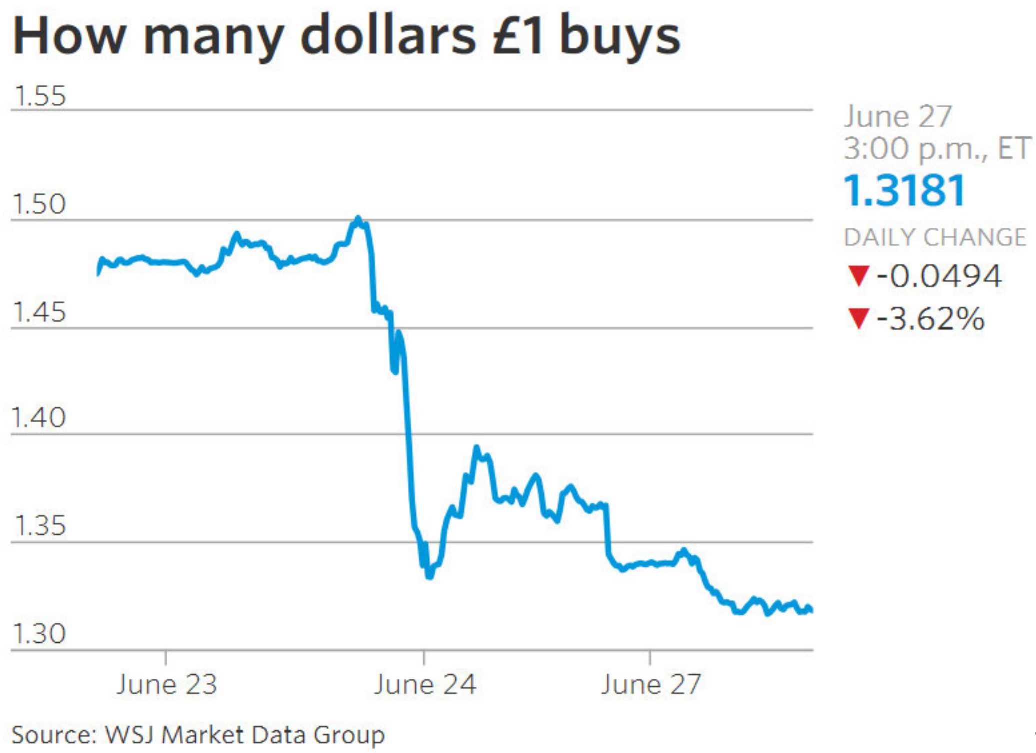
But looking forward, he said the “pipeline of projected project revenue over the next four quarters has meaningfully strengthened” since earlier in 2016.

Speaking ahead of the U.K. referendum, Ms. Yellen this week told lawmakers that the U.S. economy was expected to continue growing despite various headwinds and risks. “I think the odds of recession are low,” she said.

Battered Again by "Brexit"

by Riva Gold, and Aaron Kuriloff — WSJ — Jun. 27, 2016

Britain's decision shifts EU's course, poses test for other EU leaders grappling with populist discontent. U.K. gilts yield below 1% for first time, U.S. 10-year note yield approaches record low.



The rout in

The British pound fell to a three-decade low and investors sold financial shares on both sides of the Atlantic. Government bonds and gold rallied.

Major U.S. stock indexes that recently were approaching record highs have erased weeks of gains in the past two sessions. Questions about the impact of the U. K.'s departure added to persistent concerns about the world's economy and the ability of policy makers to stoke growth and inflation.

Investors and analysts said the **fallout could include lower growth, lower interest rates and a stronger dollar that could pressure exporters**' profits. Some have slashed near-term forecasts for U.K. and euro-zone growth ahead of what several said could be a prolonged period of political and economic ambiguity.

"There's no playbook for this," said Bill Nichols, head of U.S. equities at Cantor Fitzgerald.

The Dow Jones Industrial Average declined 280 points, or 1.6%, while the S&P 500 dropped 1.9% and the Nasdaq Composite fell 2.4%.

The Stoxx Europe 600 slid 4.1%, to its lowest close since February.

The British pound fell 3.7% against the dollar to as low as $1.3121, its weakest since 1985, even after British Chancellor of the Exchequer George Osborne issued a statement reassuring investors that the U.K. economy remained resilient and its banks and financial system were healthy.

Investors face a range of question marks following the vote, including the makeup of Britain's political leadership, the country's future relationship with the EU, the long-term impact on business confidence and investment in Europe, and the response it will prompt from politicians and central banks around the world.

"There are just so many moving bits…it's a highly **uncertain future**," said Mark Harris, head of multiasset at City Financial in London. "To say that I'm stunned is an understatement," he added.

Bank shares were hard hit Monday amid concerns that the U.K.'s exit could hurt lenders operating in the region and lengthen a period of ultralow interest rates that has pressured bank profits. Expectations for the Federal Reserve to raise interest rates this year have fallen sharply.

Financial shares in the S&P 500 fell 2.7%, while the KBW Nasdaq Bank index of large U.S. commercial lenders fell 4.4%. Bank of America fell 6.4%, Citigroup lost 4.2% and Morgan Stanley shed 3.5%.

The Stoxx Europe 600 Banks index fell 7.7% to its lowest close since 2011 as shares of Barclays PLC declined more than 17%, and the Royal Bank of Scotland Group PLC fell 15%.

Investors sought safety in government debt and other havens. **Yields on 10-year U.K. government bonds fell below 1% for the first time on record**, according to data from Tradeweb.

The yield on the 10-year U.S. Treasury fell to 1.462%, from 1.577% Friday. The yield's record-low close was 1.404%, set in July 2012. Yields move inversely to prices.

The **only two sectors to rise in the S&P 500 were utilities and telecom**, which are **often used as a proxy for bonds**. **Investors have poured into the relative safety of such dividend-paying stocks, sending utility shares up 17% in 2016 and telecom shares up 18%.**

The euro fell 0.9% against the dollar to $1.1018, while the dollar fell 0.2% against the yen to ¥101.9790.

Last week's rally ahead of the results intensified the pace of stock market declines, said Bruce Bittles, chief investment strategist at Robert W. Baird & Co. Despite worries about valuations and the impact of a strengthening dollar on exporters' profits, low yields in the bond market leave few alternatives for investors outside of equities.

The aftershocks of the U.K.'s vote to leave the European Union continued to ripple through financial markets Monday, WSJ's Riva Gold reports.

"Stocks don't have much competition," he said. "Very low rates, very low inflation and a friendly monetary policy backdrop is going to drive the market."

Asian shares had a modest rebound following heavy losses on Friday.
The Nikkei Stock Average gained 2.4% after an adviser to Prime Minister Shinzo Abe

said Monday that Japan now has a “little more ground” to rationalize intervening in the currency markets.

The Shanghai Composite Index added 1.5% after the People’s Bank of China weakened the yuan by the most since August, while shares in Hong Kong edged down 0.2%.

In commodities, U.S. crude oil fell 2.8% to settle at $46.33 a barrel, while gold rose 0.2% to settle at $1,324.70 an ounce, following its biggest one-day gain since 2013.

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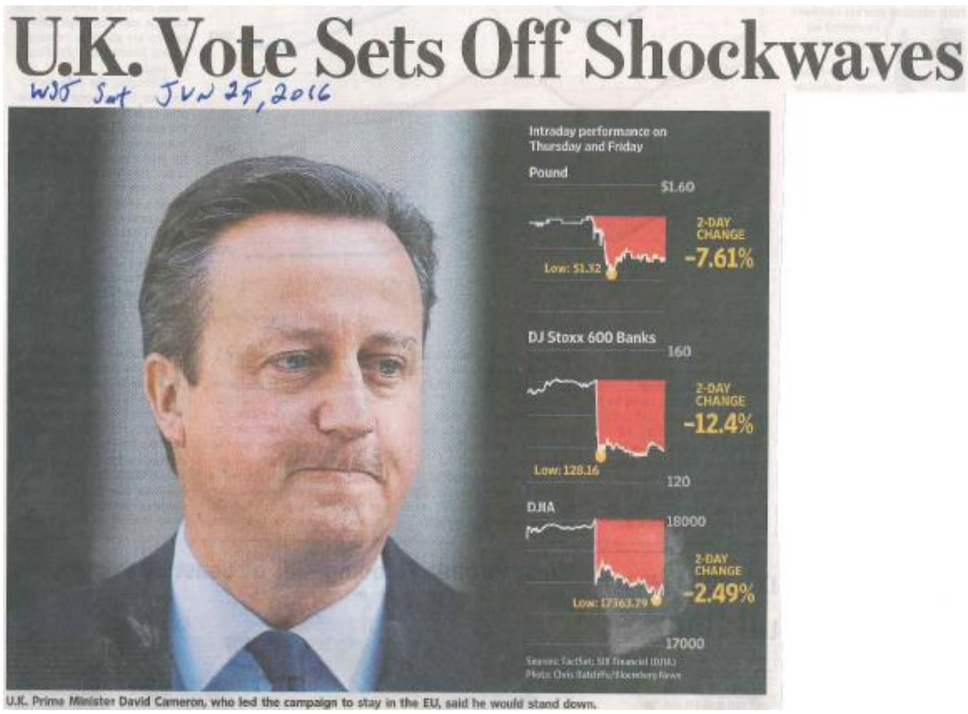


Friday, Jun. 24, 2016 Market Reaction to Brexit

Productivity Slowdown

The Oregonian — Source: Bureau of Labor Statistics — Jun. 25, 2016

Losing Steam

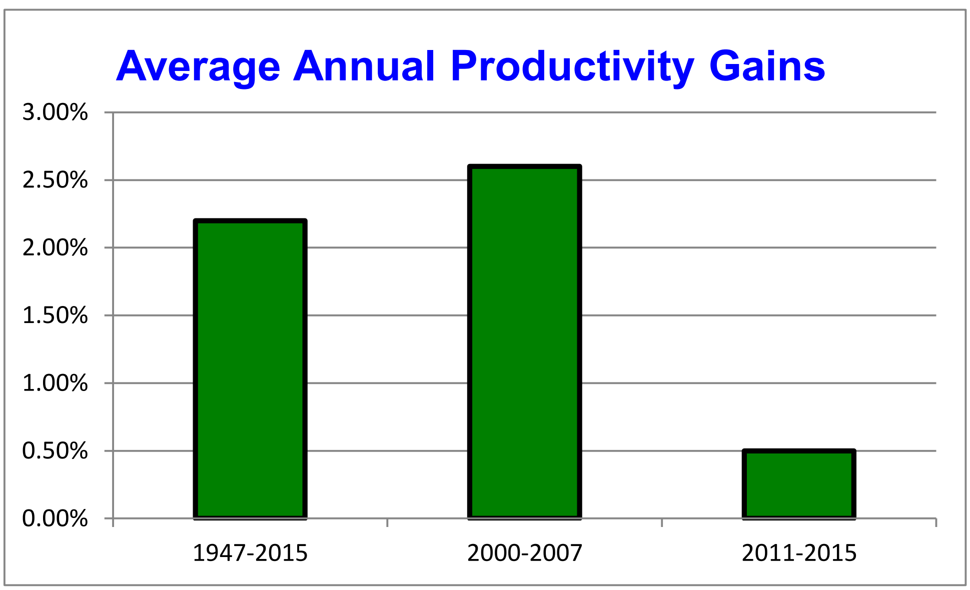
Meager productivity Gains in recent years could spell trouble for the U.S. Economy.

Productivity, the amount of output per hour of work, is the **key factor that determines how fast living standards can risk**. It allows a company to pay its workers higher wages without having to raise prices, though in recent years pay gains for most Americans haven't kept up with productivity.

The **trouble is that productivity growth recently has been terrible, averaging annual gains of just 0.5 percent over the past five years**. That **compares to average productivity growth of 2.6 percent in the eight years before the Great Recession** started in late 2007 and an annual average of **2.2 percent in the seven decades since 1947**.

Federal Reserve Chair Janet Yellen says the productivity slowdown is a big economic uncertainty. Some worry that productivity gains through computers and the internet have already hit their peak. But optimists argue that newer technology could still boost productivity. Economists at Goldman Sachs are forecasting productivity will rebound at 1.5 percent growth rates in future years. Yellen says she is "cautiously optimistic."

	Average Annual Productivity Gains
1947-2015	2.20%
2000-2007	2.60%
2011-2015	0.50%

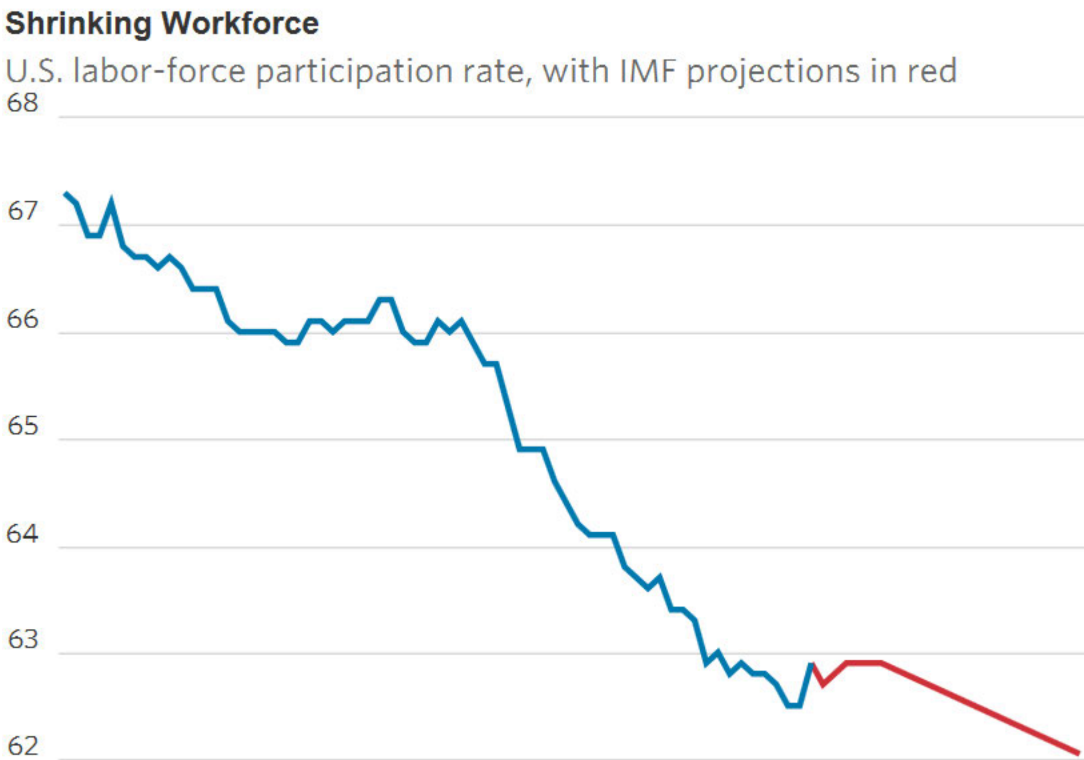


The IMF's Grim Long-Term U.S. Outlook in Six Charts
by Ian Talley — WSJ — Jun. 28, 2016

The agency cited weak energy sector, strong dollar and overseas turmoil

The **International Monetary Fund** recently **cut its U.S. economic forecast** the **U.S., painting a bleak growth picture ahead without a major overhaul of the American economy**.

Here are six charts that detail why the fund is so concerned, and the IMF's prescriptions.

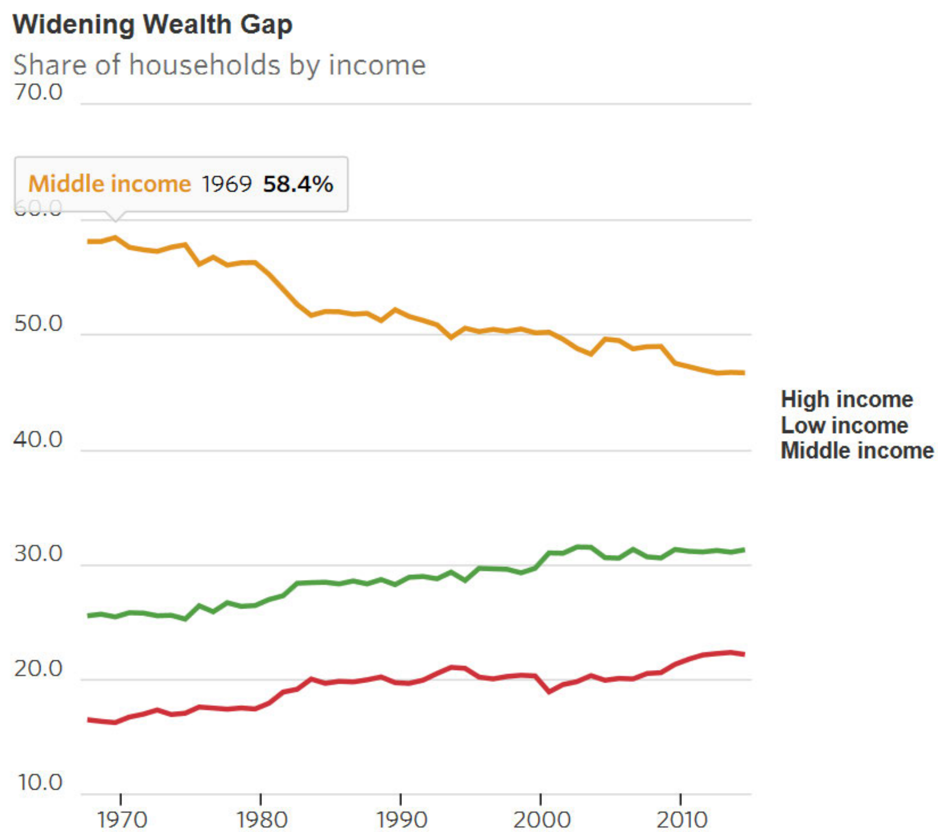


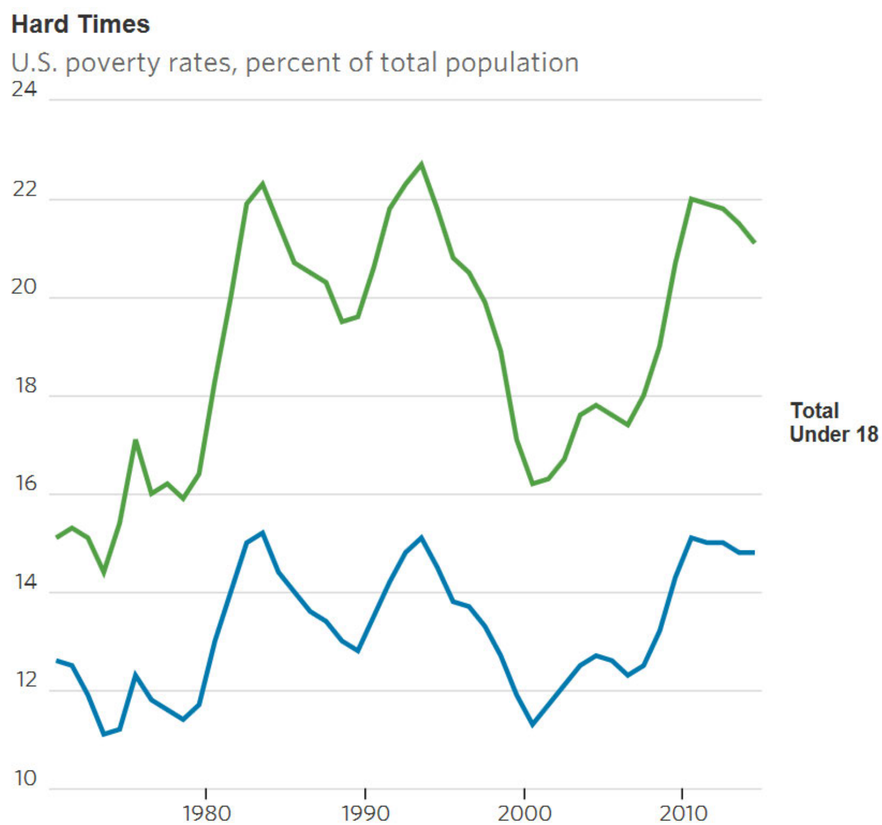
A rising share of the workforce is retiring, squeezing the capacity of the economy to grow.

The IMF recommends the U.S. move forward with immigration reform, expand the earned-income tax credit and provide greater childcare benefits to encourage more women in the workforce.

Meanwhile, the disparity between the rich and the poor appears to be building.

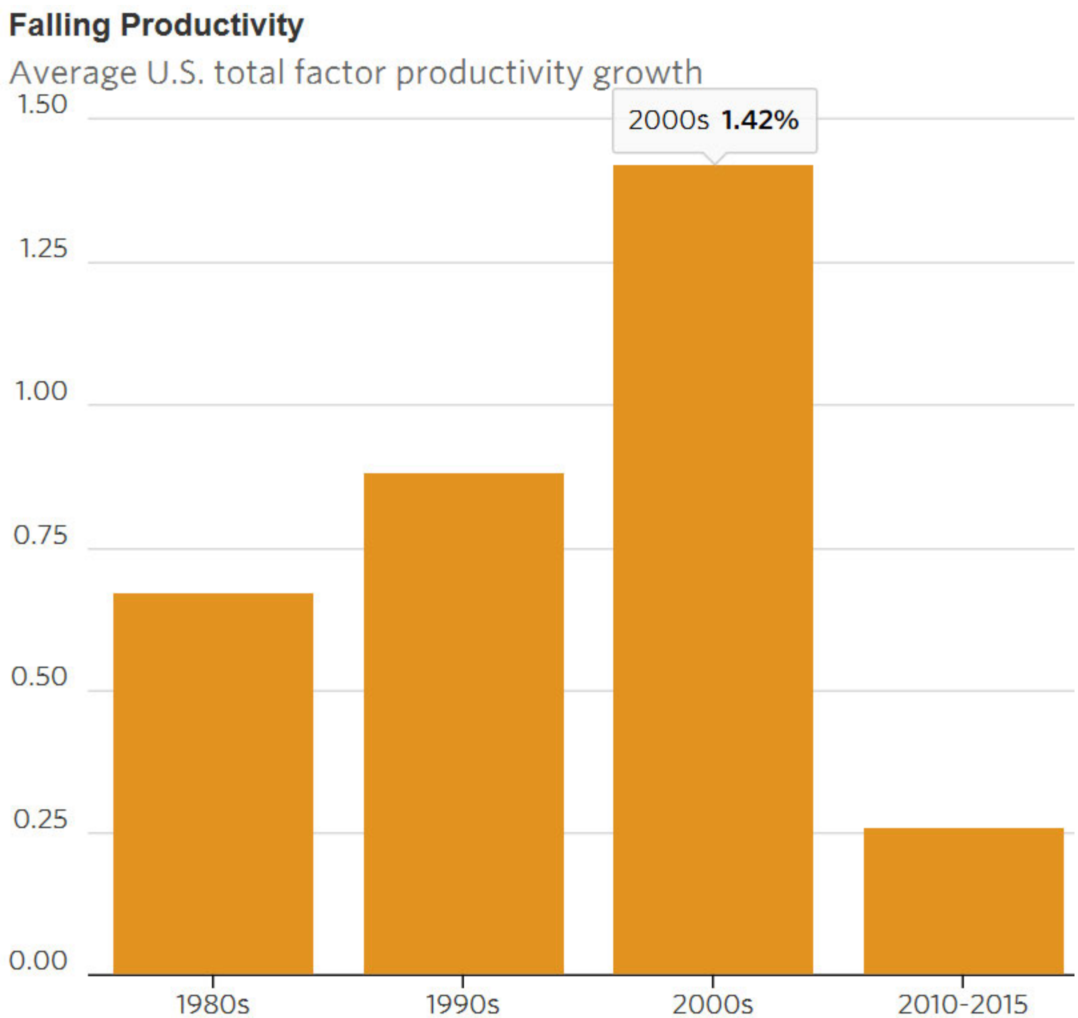
And poverty is rising.


Widening Wealth Gap
Share of households by income
Middle income 1969 58.4%
70.0
60.0
50.0
40.0
30.0
20.0
10.0
1970
1980
1990
2000
2010
High income
Low income
Middle income


Hard Times
U.S. poverty rates, percent of total population
24
22
20
18
16
14
12
10
1980
1990
2000
2010
Total
Under 18

"Income polarization itself can prevent productivity-improving investments in education by poorer households, lessen social mobility, add to economic insecurity, and limit consumption prospects," the IMF said.

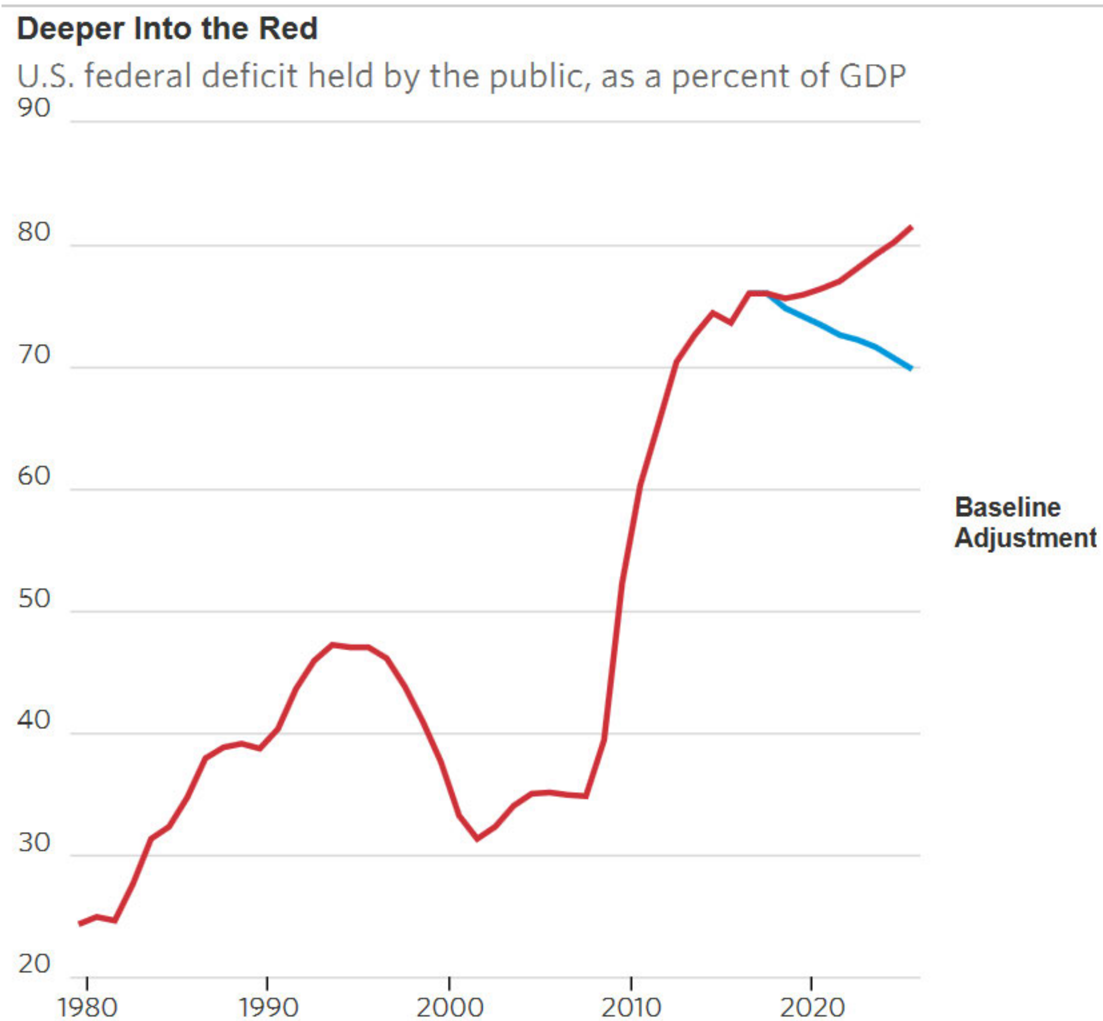
Businesses are on average becoming less dynamic, and improvements in productivity and efficiency are slowing, the IMF warns.

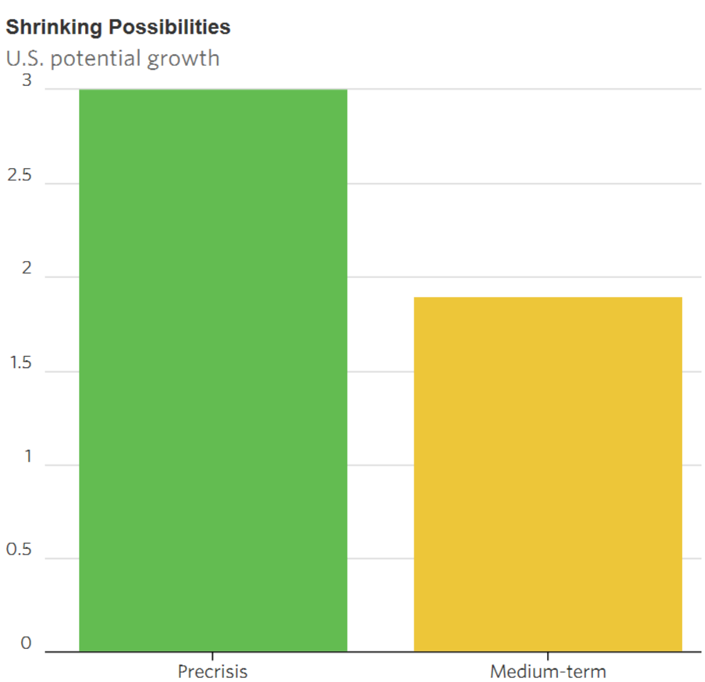


If left unchecked, these forces will continue to drag down both potential and actual growth, diminish gains in living standards, and worsen poverty," the IMF said.

To counter those forces, the IMF says the government must invest more in infrastructure, boost spending on education and workforce training and raise the minimum wage to aid the poor.

But mounting government debt will constrain the government's ability to address those issues without an overhaul of entitlement programs such as social security and healthcare and a comprehensive revamp of the tax code.



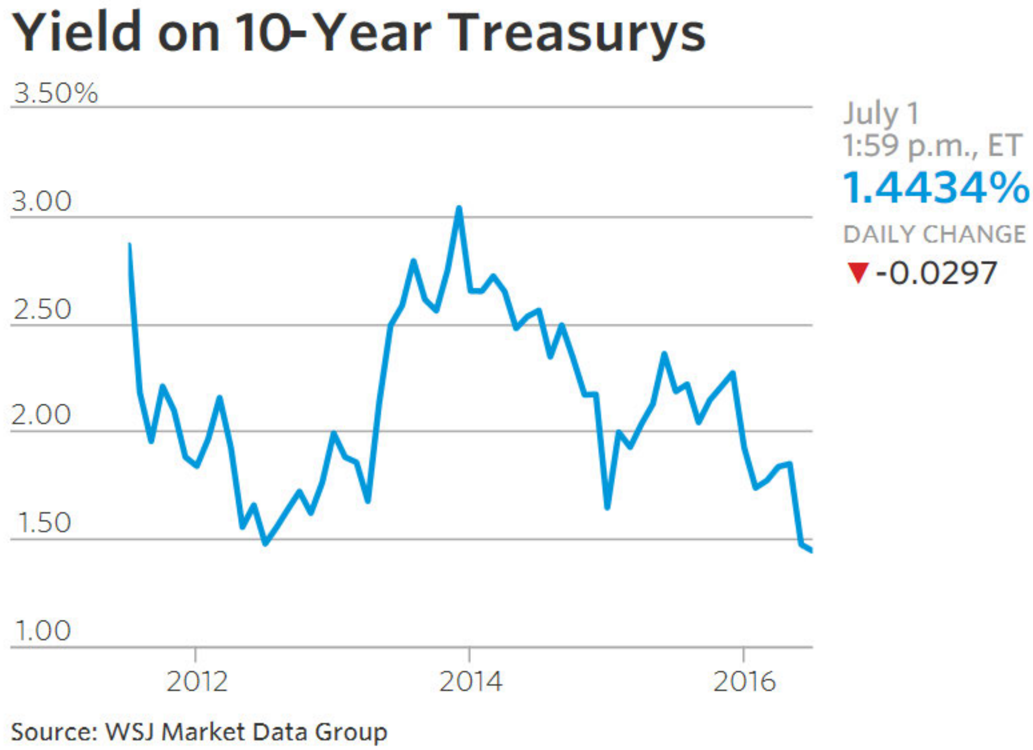


Without such actions — efforts that have thus far exceeded the ability of Congress to resolve — the ability of the economy to expand will remain far short of its pre-crisis levels.

U.S. Treasury Yields Plunge

as Investors Expect Central Banks to Support Growth
by Min Zeng, Christopher Whittall and Sam Goldfarb

Yields on U.K. government bonds also fall to fresh lows



Yields on U.S. government bonds touched new lows Friday, the latest records set during this year's rally in sovereign debt, as investors continue to grapple with **slow global growth, ultraloose central bank policies** and the **aftershocks** of the **U.K.'s vote to leave the European Union**.

The bid yield on the benchmark 10-year Treasury note fell to 1.385% during European morning trading, according to Tradeweb, breaking its previous intraday low of 1.389% set on July 24, 2012, when it also set a record closing low of 1.404%.

Bond yields didn't last long at those levels, rising later in the morning as investors favored riskier assets, such as stocks, as a new report on U.S. manufacturing activity showed signs of strength in the U.S. economy.

The yield on the 10-year note closed at 1.446% in a shortened session ahead of Monday's Independence Day holiday, compared with 1.492% Thursday. However, the **yield on the 30-year bond** still **closed** at **record low of 2.226%,** beating out the previous record of 2.25%.

Yields on U.K. government bonds also fell to fresh lows on Friday, with the yield on the **10-year gilt settling at 0.860%,** according to Tradeweb.

The sharp overnight drop in U.S. bond yields roughly coincided with a news report that suggested the European Central Bank would be cautious in loosening certain rules governing its quantitative-easing bond-buying program. A loosening would make it easier for it to buy the debt of peripheral European countries.

The report appeared to lead some investors back into German and U.S. bonds after an earlier report that the ECB was considering such changes had led to a rally in Italian and Spanish government bonds, analysts said.

Bond yields have fallen broadly this year, reflecting investors' concerns about the global economy and low inflation. Negative interest rates in Japan and Europe, and central banks' purchases of government bonds, have also pushed down yields.

The rally has intensified since Britain voted to leave the European Union last week, heightening concerns about the global economy and driving investors to safe assets such as government bonds.

Traders say lower global bond yields partly reflect **growing expectations that major central banks will need to take fresh action to spur growth, and that the Federal Reserve may not be able to raise interest rates this year**. Rising rates tend to hurt the value of bonds.

Reinforcing that view, **Bank of England Gov. Mark Carney signaled Thursday** that the **central bank will likely need to cut interest rates** and take other measures to combat a weakening economy in the aftermath of the so-called Brexit vote. The International Monetary Fund also warned on Thursday that Brexit is likely to damp global growth outlook.

The overarching reason why government bond yields are pushing lower is that "monetary policy is still very, very supportive for government bonds," said **Seamus Mac Gorain**, a **government bonds fund manager at J.P. Morgan Asset Management**.

Yields on U.S. Treasury debt and other government bonds have fallen broadly this year, reflecting investors' concerns about soft global growth and low inflation. Left, the U.S. Treasury building.

Mr. Mac Gorain said the BOE, Bank of Japan and the ECB will all ease policy this year, while the Federal Reserve is now unlikely to raise interest rates. Mr. Mac Gorain has bought up U.K and U.S. government bonds, adding the 10-year Treasury yield could fall as low as 1.25%.

The yield on a two-year U.K. government bond dropped below zero briefly in late European trading Thursday for the first time ever, momentarily bringing the U.K. into the ever growing club of countries with negative-yielding debt.

Even as questions were raised about changes to ECB policy, Spanish and Italian bond yields also neared record lows. The yield on the 10-year Spanish bond dropped to around 1.15% from 1.22% Thursday, while the yield on the 10-year Italian bond fell to 1.14% from 1.25%.

The **global stock of negative-yielding bonds jumped by nearly $1 trillion to almost $11 trillion following the Brexit vote**, according to a report from Bank of America Merrill Lynch strategists published Wednesday.

That means **even though U.S. yields are at historic lows, they have still tempted foreign investors, further pushing Treasury bond yields lower**.

The resilience of the U.S. bond market has wrong-footed many interest-rate strategists and traders. Bond bears had predicted that yields would reverse the declines as the Fed started to normalize interest-rate policy and the U.S. economy recovered from the financial crisis.

"The U.S. has been doing fine, but it's looking increasingly isolated. Meanwhile, the yields on offer in the U.S. look appealing by comparison," said Charlie Diebel, head of interest rates at Aviva Investors.

Still, skinny yields mean investors face diminished returns from the bond market. Even just a moderate rise in yields will wipe out the slim income earned from bonds. Investors are particularly vulnerable to potentially large losses by piling into long-term government debt as their prices will post a sharper drop than short-term debt in response to a given rise in yields.

Investors remember the "taper tantrum" episode when the 10-year Treasury yield posted one of the biggest increases on record during the summer of 2013. Worries over a cut in the Fed's bond-buying program spooked bond investors, generated a record pace of outflows from bond mutual funds and left many investors with capital losses.

Goldman Sachs Group Inc. warned in a report earlier in June that a **1 percentage point** "**upward shock to interest rates would translate into over $1 trillion in capital losses**" **to investors** holding U.S. Treasury and other fixed-income debt.

Some investors say they are concerned about a sharp reversal, similar to what happened last year when the 10-year bund yield spiked to 1% in less than two months after falling to near zero.

Utilities Log Fat Gains Amid Market Turmoil

by Aaron Kuriloff — WSJ — Jul. 1, 2016

Relatively high dividends and lower risk draw investors to a sector regarded as a haven.

The price of security in financial markets keeps rising, and many investors are still paying up.

As investors have flooded into government bonds in recent weeks, pushing yields on the 10-year Treasury note to record intraday lows, they also bought shares of **utility companies**. Known as **bond proxies** because they pay relatively **high dividends** and are considered **less risky than other S&P 500 sectors**, **shares of U.S. power and water providers have climbed 21% in 2016, gaining along with other haven assets like gold**.

The **run-up has made utility shares more expensive than usual** compared with their last 12 months of earnings. The **price-to-earnings ratio for utility stocks was roughly 21 on Thursday**, compared with a **10-year average of 15** and higher than the S&P 500's P/E ratio of 18.

It is a reflection of investors' continued jitters about slowing global growth and the political and economic fallout from the **U.K.'s vote to leave the European Union**. **Utilities were the only S&P 500 sector to rise** in the meltdown **immediately following the result.**

Because **utility companies** provide critical services to **U.S.-based customers**, their stocks are **relatively isolated from the turmoil overseas**, while the recent fall in already-low **government bond yields** has also **made** such **dividend-paying stocks more attractive in comparison**, several analysts and investors said.

A wave of **fear** in the **aftermath of the Brexit vote** and an extended period of economic anxiety in 2016 have been more than enough to **overwhelm concerns** that the stocks are overpriced and suffering from **diminishing returns**.

"All of those components together lead to a **favorable environment for utilities**," said **Erik Davidson**, **chief investment officer at Wells Fargo Private Bank**. "And yes, valuations are stretched, but if you look at global bonds, valuations are even more stretched."

Last year, the sector lagged behind the broader market, falling 8.4% in 2015 as the S&P 500 lost 0.7%.

Utility stocks in the S&P 500 offer a dividend yield of 3.4% according to FactSet, behind only **telecommunication stocks**. That compares with a yield of 1.492% on the 10-year Treasury note on Thursday.

Government bond yields hit record lows in countries including Germany and Japan after the U.K. vote. Investors' expectations for a rate increase from the Federal Reserve have fallen precipitously, increasing the appeal of dividend-paying stocks.

Some of the better-performing utility companies this year include American Water Works Co., Inc., which has gained 40%, NiSource Inc., a natural gas and electrical provider that is up 36%, and CenterPoint Energy, which has risen 31%.

There is **relative certainty about utilities' performance and ability to pay dividends**, said **Mike Barclay**, **senior equity portfolio manager at Columbia Threadneedle Investments**. "When people are looking for yield in a low-rate environment, that's very attractive. You can sleep a bit at night."

Other haven assets have also gained considerably this year. Gold is up 25%. Yields on municipal bonds hit historic lows in June. Yields fall as prices rise.

Some investors said that even as low bond yields demonstrate the appeal of relatively safe, income-producing investments, **utility stocks have grown very expensive**, underscoring the risk of sinking money into stocks that have already shown big gains.

Other assets favored because of their dividends have taken a hit recently. These includes **bank stocks**, which have fallen amid concerns that **low rates** will pressure their profits, and energy-focused master limited partnerships, which suffered when oil prices fell.

"Don't chase income and especially don't chase it after everyone else has started chasing it," said Allan Roth, a financial adviser at Wealth Logic in Colorado Springs. "The fact that utilities have gone up so much means it's an especially poor time to do it."

While expectations for rising rates have dwindled, utility stocks are expected to suffer if bond yields rise, making debt more competitive with the shares because investors have less need for utilities' income. Economic growth could also cause investors to rotate to faster-growing sectors, leaving utilities behind.

"If we see growth prevail, we suspect they'll be less rewarded than other spaces," said Eric Wiegand, senior portfolio manager at U.S. Bank's Private Client Reserve.

Still, some investors and analysts said it makes sense to stick with the stocks because there are **few alternatives**.

"**People** come in, **they hit** the **switch** and they **expect** the **lights** to **go on**," said Jack Caffrey, equity portfolio manager at J.P. Morgan Private Bank. He has **trimmed** his utility exposure, **but** the run-up means he's **still overweight** the sector. "You're **not worrying about how a plebiscite in a country 12 hours away is going to do to demand for electricity."**

CASE: UG 305
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 210

Pensions Overview

Exhibits in Support
of Opening Testimony

August 11, 2016

Pensions and Post-Retirement Benefits

by Brian Bahr — OPUC Staff
edited by Matt Muldoon — OPUC Staff

Definitions:

Accounting Standards Codification 715 (**ASC 715**) – accounting guidance regarding pension and post-retirement benefits.

Accrued Pension Liability (**APL**) – the opposite of a prepaid pension asset — sometimes referred to as a Negative PPA. A company shows an APL if it has recorded more cumulative FAS 87 expense than cumulative cash contributions.

Cash Contribution – is a payment from the company into its pension plan. Cash contributions increase the pension asset.

Defined Benefit Plan – a type of pension plan in which a company guarantees an employee a defined amount of money upon retirement. Conversely to a defined contribution plan, in which the company guarantees the amount of money paid into the fund but not the amount paid out, the risk to achieve adequate returns in the market lie solely on the company. For this reason, defined benefit plans are now considered risky, and companies are more likely not to offer them.

Expected Return on Assets (**EROA**) – determined by an actuary, based on a company's pension asset investment strategy, and used for calculating a company's FAS 87 and FAS 106 expenses.

Financial Accounting Standard 106 (**FAS 106**) – accounting guidance regarding post-retirement benefits. A company's post-retirement benefits costs are sometimes referred to as the FAS 106 expense.

Financial Accounting Standard 87 (**FAS 87**) – accounting guidance regarding pension costs. A company's pension costs are sometimes referred to as the FAS 87 expense.

Funded Percentage – the ratio of the pension asset to the pension obligation.

Moving Ahead for Progress in the 21st Century Act (**MAP 21**) – regulation passed in 2012 that eases the stringency of regulations passed in the Pension Protection Act.

Pension Asset – the amount of money a company has to pay its pension obligation. A pension asset can increase through cash contributions from the company or through returns on investing the pension asset in the market.

Pension Obligation – the amount of money a company expects to owe to participants of its pension plan over the remaining life of the plan. The pension obligation is affected by life expectancy of plan participants, number of participants, retirement age of participants, and other factors.

Prepaid Pension Asset (**PPA**) – at a given point in time, is the difference between the cumulative amount of cash contributions made by a company to its pension fund and the cumulative amount of annual FAS 87 expenses. A PPA can be thought of as a balance that tracks the difference between money paid by a company for its pension costs and the amount it has actually recorded as costs for purposes of financial statements and regulation.

Pension Protection Act (**PPA-of-2006**) – regulations passed in 2006, effective in 2008, that increase stringency of funding requirements for pension funds.

Abbreviations:

APL .... Accrued Pension Liability

ASC 715 .... Accounting Standard Codification 715

AVA .... Avista Corporation

CNG .... Cascade Natural Gas Co., division of MDU Resources Group, Inc.

EROA .... Expected Return on Assets

FAS 87 .... Financial Accounting Standard 87

FAS 106 .... Financial Accounting Standard 106

IPC .... Idaho Power Company, primary subsidiary of IdaCorp, Inc.

MAP 21 .... Moving Ahead for Progress in the 21st Century Act

NWN .... Northwest Natural Gas Company

PAC .... PacifiCorp

PGE .... Portland General Electric Company

PPA-of-2006 .... Pension Protection Act, not to be confused with PPA

PPA .... Prepaid Pension Asset, not to be confused with PPA-of-2006

Other:

Based on information collected from SEC 10k reports found online, tables on the next page show the discount rates and EROAs used in calculating FAS 87 expense for the regulated Oregon utilities abbreviated above

Oregon Jurisdictional EROAs and Discount Rates

Table 1 – Expected Return on Assets

(Net Periodic Benefit Cost)

Utility	*2013*	Difference from Avg.	*2014*	Difference from Avg.	*2015*	Difference from Avg.
AVA	6.60	**-13%**	6.60	-9%	5.30	**-31%**
CNG	7.00	-6%	7.00	-3%	7.00	1%
IPC	7.75	4%	7.75	7%	7.50	7%
NWN	7.50	1%	7.50	4%	7.50	7%
PAC	7.50	1%	6.86	-5%	6.88	-1%
PGE	8.25	**10%**	7.50	4%	7.50	7%
Average:	**7.43**		**7.20**		**6.95**	

Table 2 – Discount Rate

(Net Periodic Benefit Cost)

Utility	*2013*	Difference from Avg.	*2014*	Difference from Avg.	*2015*	Difference from Avg.
AVA	4.15	3%	5.10	5%	4.21	5%
CNG	3.65	**-10%**	4.53	-7%	3.70	-8%
IPC	4.20	4%	5.20	6%	4.25	6%
NWN	3.84	-5%	4.71	-3%	3.82	-5%
PAC	4.03	0%	4.81	-1%	4.00	0%
PGE	4.24	5%	4.84	-1%	4.02	0%
Average:	**4.02**		**4.87**		**4.00**	

CASE: UG 305
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Load Forecast, Sales and Transportation Revenues & Weather Normalization, Other Operating Revenues, Conservation Alliance Plan & Decoupling, and Public Purpose Cost Reallocation

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Max St. Brown. I am a Senior Utility Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High St. SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. Did you include any other exhibits for this testimony?

A. Yes. I have included the following exhibits:

- Exhibit Staff/302: Cascade's supplemental response to Staff DR No. 132 and response to Staff DR Nos164, 260, and 259.
- Exhibit Staff/303: Pages 352-353 of *Introductory Econometrics: A Modern Approach* by Jeffrey M. Wooldridge.
- Exhibit Staff/304: A description of the data used in Staff's load forecasts.
- Exhibit Staff/305: Staff's load forecasting models in equation form.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Load Forecast 3
Issue 2. Sales and Transportation Revenues & Weather Normalization... 15
Issue 3. Other operating revenues.. 18
Issue 4. Conservation Alliance Plan & Decoupling 22
Issue 5. Public Purpose Cost Reallocation 26

Q. Please summarize your recommendations.

A. The Table below provides a summary of my adjustments:

Table 1. Summary of Adjustments

Table 1			
Description	Company Filing – OR Allocated	Staff – OR Allocated	Adjustment
Load Forecast and Sales revenues (000's of Dollars)	$29,640[1]	$29,953	$313
Other operating revenues (000's of Dollars)	$260[2]	$272	$11

[1] Margin revenue presented on CNGC/401, Archer/5.
[2] CNGC/201, Parvinen/1, line 3.

ISSUE 1. LOAD FORECAST

Q. Please summarize the Company's load forecast.

A. The Company uses weather and demand data from 2010 to 2015 in order to perform a linear regression analysis by gate station. The Company then makes outboard adjustments to the regression outputs to account for expected growth over the test period.[3]

Q. How does the Company use its load forecast?

A. The load forecast outputs are inputs into Company witness Archer's revenue proof. For example, Exhibit CNGC/401, Archer/1 indicates that the Company forecasts to sell 39,969,509 therms of gas to residential customers if there is normal weather during the test year. The revenue requirement impact of the load forecast is discussed in the next section.

Q. Has the Company made any changes to its load forecasting methodology since it produced forecasts in the UG 287 rate case?

A. Yes, the Company's load forecast outputs are now prepared on a per-customer basis. This conforms to Staff's recommendation in the UG 287 rate case.[4] Additionally, the Company updated the time period of its data inputs.

Q. Has the Company indicated that they are planning to make any other changes?

A. Yes, the Company states, "Cascade is currently analyzing and implementing a change to model each rate class individually."[5]

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[3] Staff/302, St. Brown/3.
[4] See UG 287 Staff/200, Bhattacharya/17-18.

Q. Does Staff support this upcoming change?

A. Yes. In Cascade's 2014 IRP, Staff recommended that "Cascade work with Staff and other interested parties to … formulate alternative regression models…" Additionally, Cascade "express[ed] agreement with Staff's Demand Forecast recommendations."[6]

1.1. RECOMMENDATIONS FOR CASCADE'S LOAD FORECAST

Q. Do you make recommendations for formulating alternative regression models?

A. Yes. I recommend four changes to Cascade's existing load forecast models.

1. Model each rate class individually.
2. Allow for non-linear weather effects on natural gas usage.
3. Eliminate outboard adjustments by including greater relevant data in the regression equations.
4. Address potential serial correlation problems in the regression equations.

Q. Why do you recommend modeling each rate class individually?

A. Cascade currently models the aggregate load of all firm delivery rate classes by city gate. This approach restricts the model to assume that the determinants of gas usage per customer affect all rate classes identically at each city gate. However, Cascade acknowledges that "intuitively, the three

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[5] Staff/302, St. Brown/19 (Cascade response to Staff DR No. 164).
[6] LC 59, Order No. 16-054 at 9 (Feb. 9, 2016).

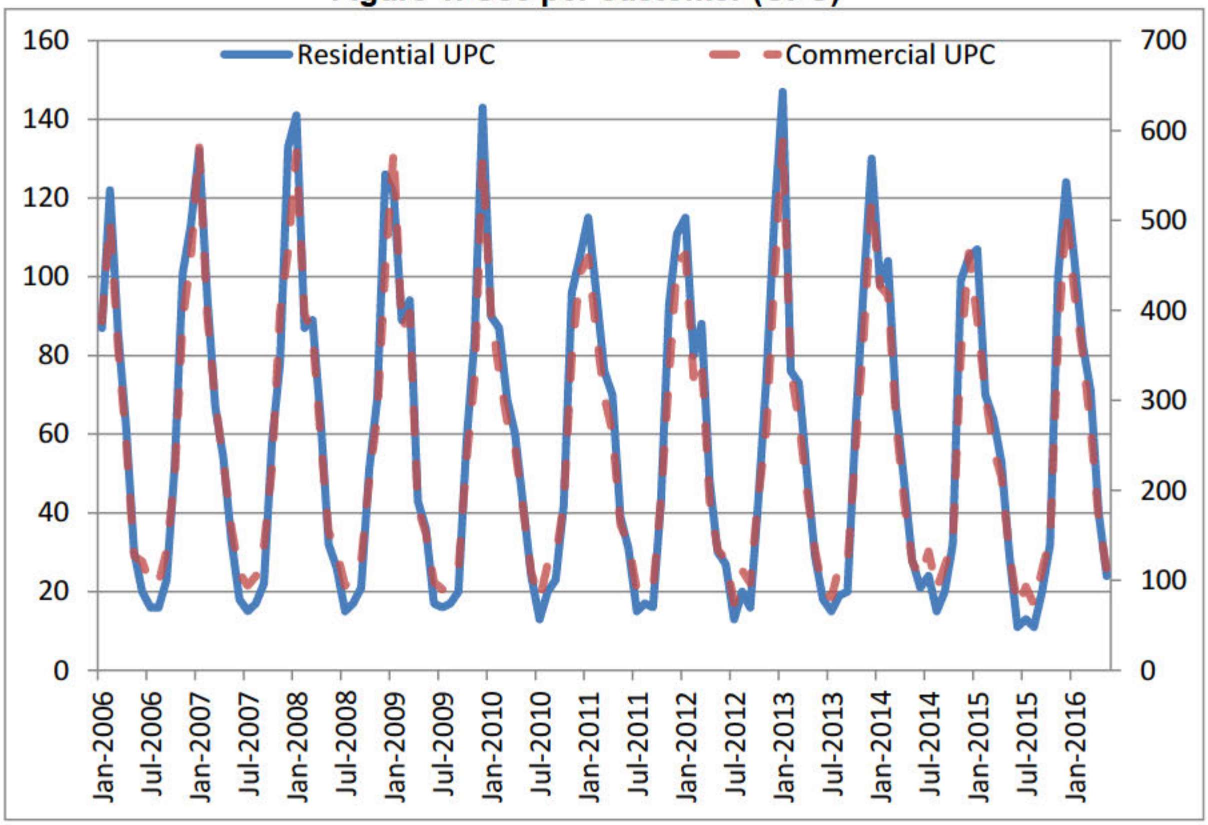
types of core customers that Cascade serves--residential, commercial and industrial--all react to weather differently."[7]

If each rate class is modeled individually, the distinct weather sensitivity of each rate class can be incorporated into the load forecast.

Q. Can you provide an example and describe the implication?

A. Yes, Figure 1 below shows use-per-customer (UPC) for residential and commercial customers.

Figure 1. Use per customer (UPC)



In the figure above, the UPC of residential customers is visually more peaky than the UPC of commercial customers. Additionally, the coefficient of variation

[7] Staff/302, St. Brown/20(Cascade response to Staff DR No. 260).

for residential UPC, at 65%, exceeds the value for commercial UPC, at 58%. The coefficient of variation is a measure of the dispersion of data and is computed as the standard deviation to the mean. Thus, a modeling approach that allows weather to affect residential gas usage differently than commercial gas usage is expected to be more accurate.

Q. What is Cascade's timeline to model each rate class individually?

A. Cascade reports that "it does not seem likely it will be fully implemented and tested during the UG 305 rate case timeline."[8]

Q. Turning to the second recommendation listed above, why do you recommend allowing for non-linear weather effects on natural gas usage?

A. Customers' sensitivity to weather varies based on the weather; having the model allow for non-linear weather effects on usage can better capture this relationship. Additionally, this aligns with the approach of Oregon's other LDCs.[9]

Q. Why do you recommend eliminating outboard adjustments by including greater relevant data in the regression equations, which is your third recommendation?

A. Outboard adjustments are an imprecise mechanism. For example, Cascade determines customer growth with an outboard adjustment, reporting that it "assumes a 1% growth in population translates to a 1% increase in

[8] Staff/302, St. Brown/21 (Cascade response to Staff DR No. 259).
[9] Avista and NWN use non-linear approaches: HDDs are squared in UG 288 (Avista) and a piecewise function is used in NWN's 2016 IRP.

customer growth."[10] Including population directly in the regression equations is a preferred approach because it allows a one percent increase in population to translate into an increase in customer growth other than one percent. The exact percent is determined by the data itself, rather than assumed through the use of an outboard adjustment. Further, Staff recommended against outboard adjustments in UE 294 (PGE) and found that standard industry practice is to include data in the regression equations directly.[11]

Q. Why do you recommend addressing potential serial correlation in the regression equations, which is your last recommendation regarding Cascade's load forecast methodology?

A. *Introductory Econometrics: A Modern Approach* by Wooldridge states that serial correlation is "a potential problem for regressions with time series data."[12] Serial correlation occurs when the regression model errors from adjacent time periods are correlated. Adapting Wooldridge's example to the load forecast: if the number of customers is unexpectedly high in a particular month, then the number of customers is likely to be above average for (given economic conditions) for the next month.

Wooldridge further describes that OLS regression models performed on data suffering from serial correlation violate the assumptions for an ordinary

[10] Staff/302, St. Brown/5 (Cascade Supplemental Response to Staff DR No. 132).
[11] See UE 294 Staff/400, Bhattacharya/13, lines 11-16.
[12] Staff/302, St. Brown/22-23(Wooldridge, Jeffrey M. *Introductory Econometrics: A Modern Approach*, Thomson South-Western, 2006, pp. 352-353).

least squares (OLS) model to be the best linear unbiased estimator. Thus Cascade's OLS models might be outperformed by an alternative model.

Q. How can a forecasting model be tested for serial correlation?

A. *Introductory Econometrics: A Modern Approach* indicates that the Durbin-Watson test is a test for autoregressive process of order one (AR(1)) serial correlation.[13]

Q. Does the Durbin-Watson test reject the null hypothesis of no AR(1) serial correlation for any potential models involving Cascade's load data?

A. Yes. For example, the output below shows that the Durbin-Watson test indicates potential autocorrelation in an OLS model with the number of commercial customers in Milton-Freewater, OR as the dependent variable and Woods and Poole's economic growth as the explanatory variable.

```
        Durbin-Watson test

data:  Milton.Freewater$customers.commercial ~ Milton.Freewater$WP.economic
DW = 1.856, p-value = 0.2443
alternative hypothesis: true autocorrelation is greater than 0
```

While neither the Company nor I used this OLS model, the Durbin-Watson test indicates that it is appropriate to address potential serial correlation.

Q. How does Avista, another natural gas utility providing service in Oregon, address potential serial correlation in their regression models?

[13] *Id.*

A. In UG 288, Avista addressed potential serial correlation by using an autoregressive integrated moving average (ARIMA) model with explanatory variables. A defining characteristic of the ARIMA models is that they use past observations of the dependent variable itself as explanatory variables.

Q. What do you recommend for each of the Company's regression models?

A. For future rate cases, I recommend that Cascade work with Staff and parties to discuss and design changes to Cascade's existing load forecast models to address the four issues described above. For this rate case, I have made these four changes and re-forecasted Cascade's loads.

1.2. STAFF'S LOAD FORECAST

Q. What methodology did you use to re-forecast Cascade's loads reflecting your four recommended changes?

A. I used autoregressive integrated moving average (ARIMA) models with explanatory variables. Cascade's confidential response to Staff DR No. 129 and response to Staff DR No. 301 provided monthly billing data and customer counts by rate schedule and weather station, which were used as the dependent variables in the models. Weather, as measured by heating degree days (HDDs), was used as the explanatory variables in the use-per-customer (UPC) models. Including both HDDs and HDDs^2 allowed non-linear weather impacts. Woods and Poole's economic indicator variables were used as the explanatory variables in the customer count models.[14] Additionally, all models included variables to control for monthly variations. The data I used are described in Exhibit Staff/304. The models are provided in equation form in Exhibit Staff/305. I used the *R* statistical software package and have prepared the *R* project file as a workpaper so that parties can replicate my forecasts.

Q. Does any actual weather normalized load data exist for the test year?

A. Yes. While Cascade only provided data up to December 2015, in response to Staff Data Request No. 301, which asked for billed therms per month for the most recent data available, Cascade's response to Staff DR No. 331 (actual monthly usage per customer) combined with the response to Staff DR No. 301 provided actual weather normalized therms for Schedules 101(Residential) and 104 (Commercial) from January to April 2016. Staff DR No. 170 asked for the most recent Schedule 900 (Special Contracts) monthly load data available and the Company responded with data up to December 2015.

Q. Did you use the actual weather normalized load data for the test year?

A. Yes, after converting the Staff DR No. 331 response data so that it is comparable to the Staff DR No. 301 response data, I used the actual weather normalized loads provided by the Company. I computed the ratio of the DR 301 response data versus the DR 331 response data and multiplied that by the DR 331 weather normalized actuals in order to make them comparable to the DR 301 response data. Proceeding without making this conversion would greatly

[14] Except for Baker County where population was substituted for the Woods and Poole variable because the Woods and Poole variable did not vary over time.

decrease the Company's revenue requirement. Thus, I only needed to re-forecast the Schedule 101 and 104 loads for May to December 2016. The table below shows the time interval for the loads I re-forecasted.

Table 2. Time Intervals

Schedule 101	May – Dec 2016
Schedule 104	May – Dec 2016
Schedule 105	Jan – Dec 2016
Schedule 900, Hermiston Generating Plant	Jan – Dec 2016

Q. How does the Company forecast loads for its large volume customers?

A. The Company annually surveys its large volume customer base and annually meets face to face with many of its largest volume accounts.[15] The Company forecasts its Special Contract 900 2016 loads by either applying a 1% increase to its 2014 actuals, using its 2015 actuals, or by applying growth factors based on internal knowledge.[16]

Q. Do you find this approach reasonable?

A. In general yes, because the Company has considerable internal knowledge about its large volume customers. However, I recommend the use of an econometric model that takes into account explanatory variables for forecasting the load of Cascade's largest customer, the Hermiston Generating Plant. CNGC/401, Archer/1-5 indicates that in the test year the Company sold more therms to the Hermiston Generating Plant than to all of its residential and commercial customers combined.

[15] Cascade Response to Staff DR No. 172.
[16] Cascade Response to Staff DR No. 284.

Q. How does the Company forecast its test-year therms sales to the Hermiston Generating Plant?

A. The Company added one percent to 2014's sales in order to forecast June 2016 to December 2016.[17]

Q. Why is this problematic?

A. The Company has used actual rather than weather-adjusted 2014 values. Also, adding 1% to prior year's sales does not incorporate available data on economic growth.

Q. What do you recommend?

A. I recommend that Cascade use an econometric model including weather and economic variables to forecast the Hermiston Generating Plant's load.

Q. Please provide the results of your four recommended changes.

A. The table below presents the Company's load forecasts for Schedule 101 (Residential), Schedule 104 (Commercial), Schedule 105 (Industrial), and Schedule 900 (Special Contracts) versus Staff's load forecasts. The revenue requirement effects are presented in the next section.

Table 3. Load Forecast Comparison[18]

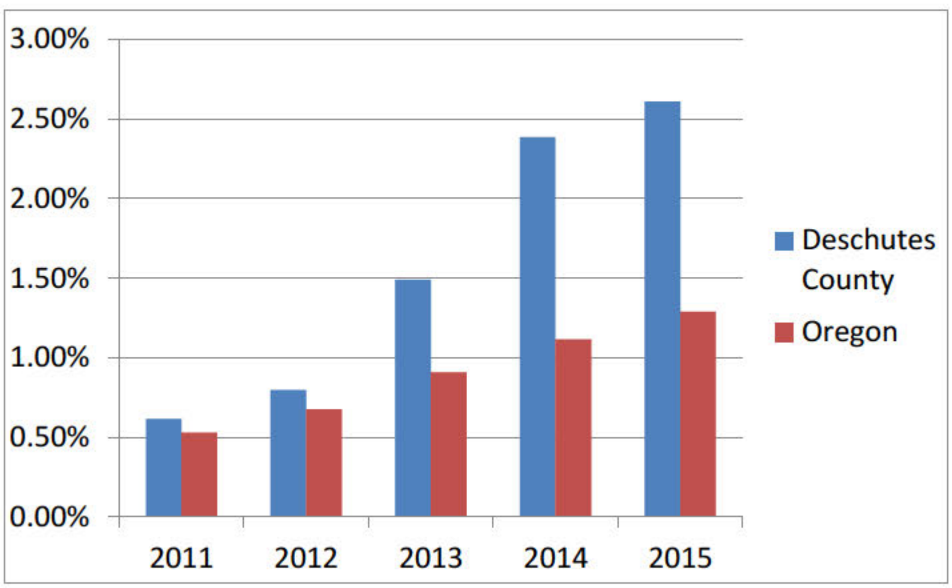
[17] Cascade Response to Staff DR No. 285, Cell B91:B97.
[18] The customer counts are summed across 12 months. Dividing by 12 would provide the average number of customers.

	Staff	Company	Difference
Schedule 101 customers	719,171	727,940	(8,769)
Schedule 101 therms	40,800,204	39,969,509	830,695
Schedule 104 customers	117,275	118,811	(1,536)
Schedule 104 therms	27,756,595	28,117,840	(361,245)
Schedule 105 customers	1,659	1,534	125
Schedule 105 therms	2,906,973	2,543,274	363,699
Schedule 900 HGP therms	218,979,558	178,932,927	40,046,631

Q. What are potential drivers of this result?

A. Some of the largest cities served by Cascade have had considerable population growth in the past five years. For example, Bend and Redmond are in Deschutes County, the population growth of which is charted versus that of Oregon below.

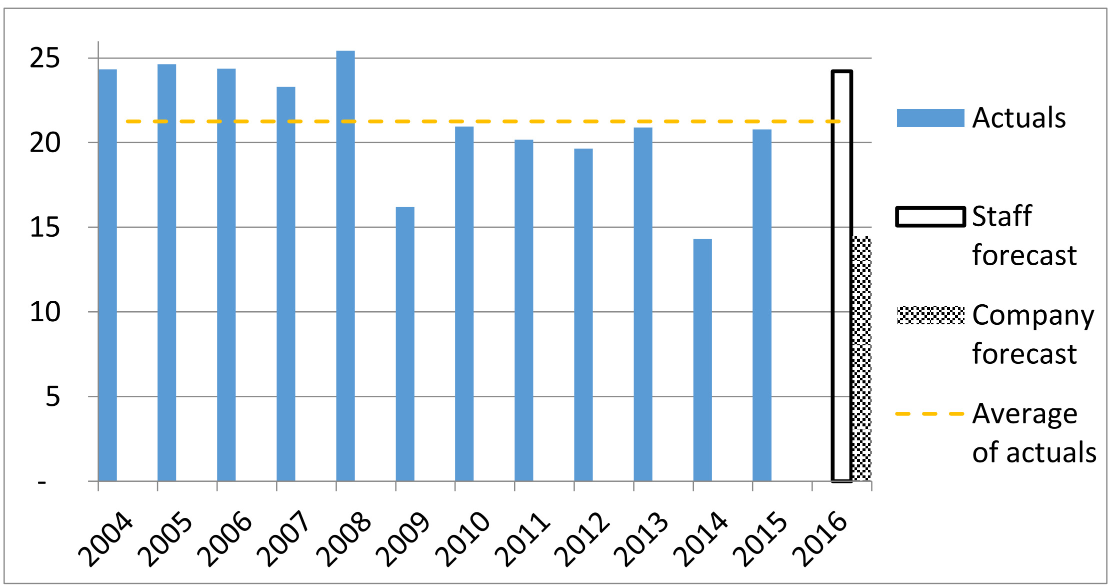
Figure 2. Percent Population Growth[19]



[19] July 1 population estimate versus prior year. Data source: 2010-2015 Certified Population Estimates from the Population Research Center at Portland State University's College of Urban & Public Affairs.

Further, as described above, Cascade increased 2014 actuals by 1% in order to forecast some of the 2016 load of its largest customer, the Hermiston Generating Plant. December 2014, on which the Company's forecasts are based, is the lowest usage month out of all of the years of December data the Company provided. The figure below shows historical actual December usage versus Staff and the Company's forecast.

Figure 3. Hermiston Generating Plant, December load (millions of therms)



The load of the Hermiston Generating Plant is weather sensitive because it provides electricity for nearly 500,000 households.[20]

Q. Are there any other benefits of your proposed forecasting methodology?

A. Yes, as indicated above, my proposed forecasting methodology can be readily reproduced by any interested party.

[20] See: Perennial Power, "Hermiston Generating Plant," 2014. Available at: http://www.perennialpower.net/Portfolio/Hermiston-Generation-Plant/

ISSUE 2. SALES AND TRANSPORTATION REVENUES & WEATHER NORMALIZATION

Q. Please describe the Company's approach to weather normalization.

A. "The 'normal', or expected, HDDs used to compute the base forecast are calculated by finding the average HDD over the 30 years prior to the first forecasted year."[21]

Q. Has Staff made recommendations about weather normalization in past rate cases?

A. Yes, in Cascade's UG 287 rate case, Staff recommended that the Company consider different average values such as 25- or 20-year daily averages to represent normal HDD values, stating that "this approach will help capture the effect of warmer weather in this region at a much granular level."[22] Further, in the UG 288 rate case, Avista's witness described why a 20-year weather average was used and stated, "recent climate research from NASA's Goddard Institute for Space Studies … shows that summer temperatures in the Northern Hemisphere have increased about 1° F above the 1951-1980 reference period, and the increase started roughly 20 years ago in the 1981-1991 period."[23]

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[21] Staff/302, St. Brown/16, Cascade Supplemental Response to Staff DR No. 132.
[22] UG 287 Staff/200, Bhattacharya/11, lines 10-13.
[23] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html; as cited in UG 288, Avista/700, Forsyth/11-12, lines 23 and 3-5.

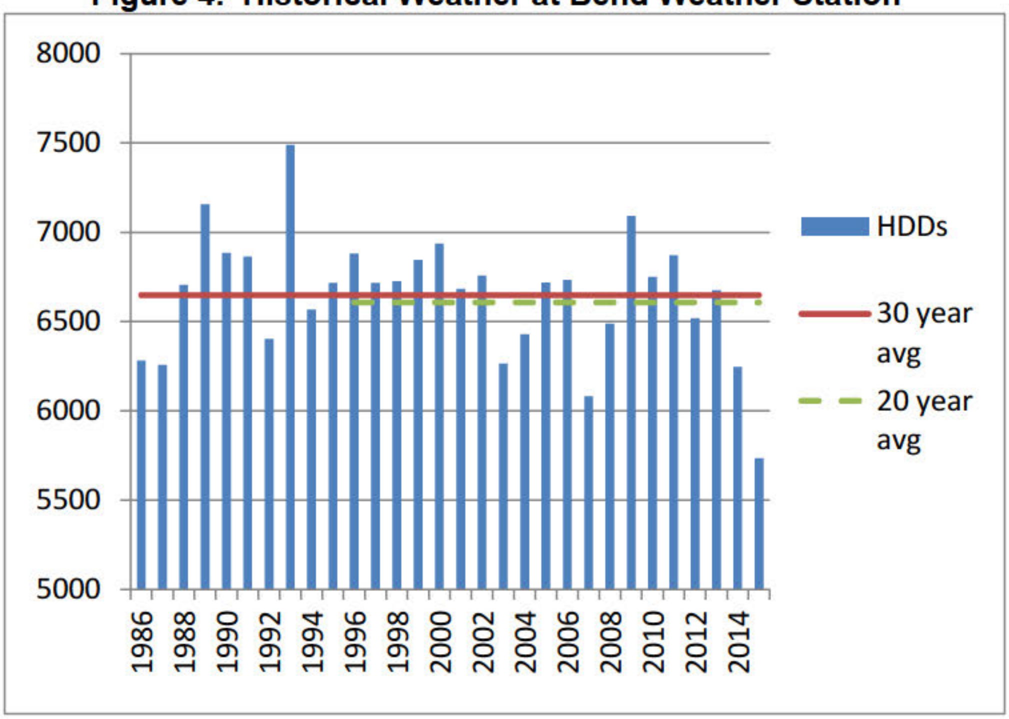
Q. What is your recommendation regarding weather normalization?

A. I support Cascade using a consistent weather time period across its IRP and rate cases. Because the Company uses a 30-year weather time period in its IRP, I do not dispute its use of 30-year average weather for this rate case. However, I recommend that the Company also consider different averages including 20 years and 25 years.

Q. What would be the revenue requirement impacts of switching to a 20 year normal weather definition?

A. On average, the last 20 years have been warmer than the last 30 years in some of Cascade's service area. For example, the chart below shows historical weather at the Bend weather station from NOAA.

Figure 4. Historical Weather at Bend Weather Station



Thus switching to a 20-year normal weather definition might lower Cascade's forecasted loads (and revenues) and increase the Company's revenue requirement.

Q. How did you compute the revenue requirement effects of your load forecasts?

A. I multiplied the difference in my proposed load forecast versus the Company's load forecast versus the rates for each respective schedule as shown in the table below.

Table 4. Rev. Req. Comparison[24]

	Staff	Company	Difference	Rate	Adjustment
Schedule 101 customers	719,171	727,940	(8,769)	$ 3.00	$ (26,308)
Schedule 101 therms	40,800,204	39,969,509	830,695	$ 0.36884	$ 306,394
Schedule 104 customers	117,275	118,811	(1,536)	$ 3.00	$ (4,608)
Schedule 104 therms	27,756,595	28,117,840	(361,245)	$ 0.26263	$ (94,874)
Schedule 105 customers	1,659	1,534	125	$ 12.00	$ 1,497
Schedule 105 therms	2,906,973	2,543,274	363,699	$ 0.19152	$ 69,656
Schedule 900 HGP therms	218,979,558	178,932,927	40,046,631	$0.0015259	$ 61,107
				Adjustment	**$ 312,864**

Q. What is your load forecast adjustment to Cascade's revenue requirement?

A. I recommend a $312,864 decrease to Cascade's revenue requirement due to increased sales forecast. I forecasted that at current rates Cascade will earn greater margin revenue from sales and transportation revenues and thus does not need as great a rate increase.

[24] The customer counts are summed across 12 months. Dividing by 12 would provide the average number of customers.

ISSUE 3. OTHER OPERATING REVENUES

Q. Please describe Cascade's other operating revenues.

A. In its original filing the Company represents that it had $260,460 in other operating revenues in the base year, 2015.[25] The Company calculates other operating revenue as the sum of: miscellaneous service revenue, service line modification, rent from gas property, interdepartmental rents, and other gas revenue.[26] Miscellaneous service revenue represented 71% of the total base year other operating revenues. Miscellaneous service revenue includes revenue from the miscellaneous charges listed in Rate Schedule No. 200 in the Company's tariff. Examples include reconnection charges, late payment charges, and returned check charges.

Q. What does Cascade include in the test year for other operating revenues?

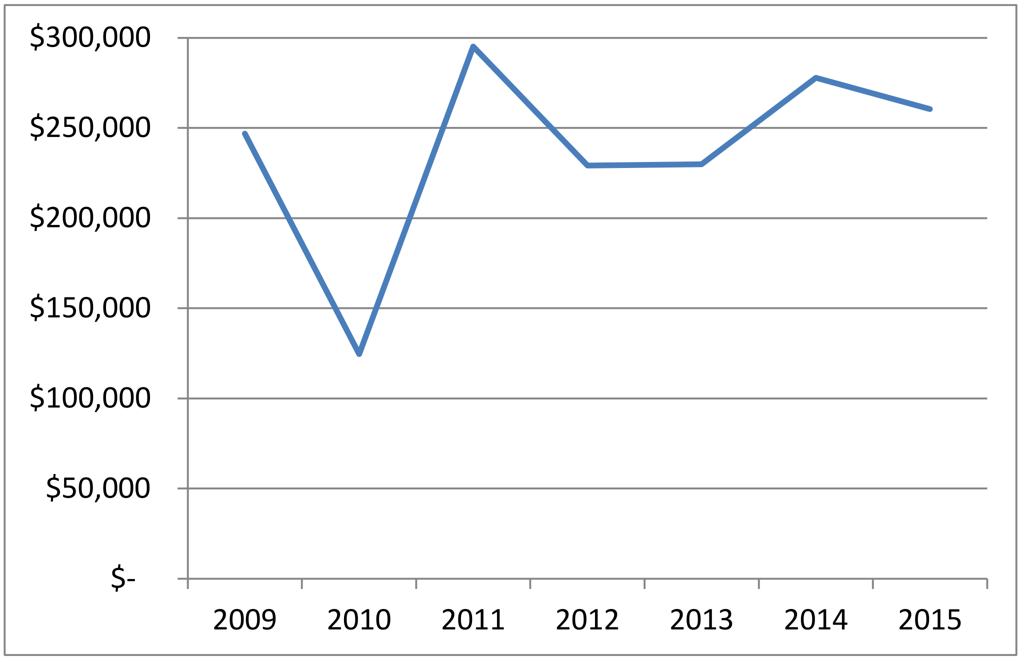
A. For test year other operating revenues, the Company proposes to use the same value as the base year.

Q. What are the historical values of other operating revenues?

A. Other operating revenues from 2009 to 2015 are graphed below:

[25] CNGC/201, Parvinen/1, line 3.
[26] Cascade Response to Staff DR No. 138.

Figure 5. Misc. Other Operating Revenues 2009-2015



The unusually low value in 2010 is due partly to three large negative journal entries for miscellaneous service revenue. In response to a Staff Data Request in the UG 287 rate case, Cascade indicated that they did not have data available prior to 2009.

Q. What was the treatment of other operating revenues in the UG 288 (Avista) rate case?

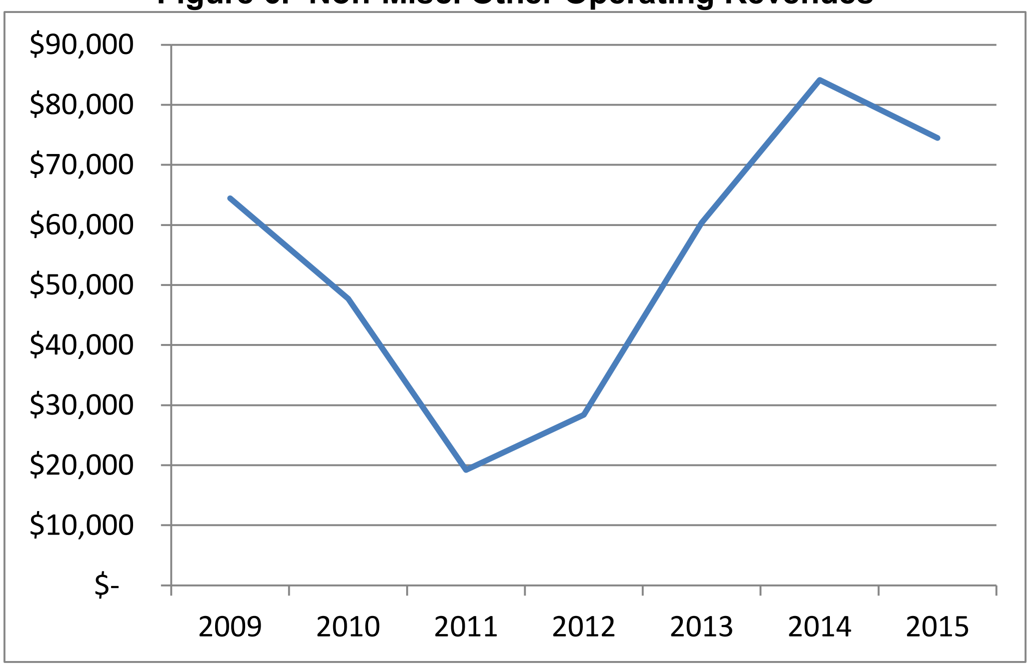
A. Staff argued that miscellaneous service revenues are customer driven and Staff proposed to increase test year miscellaneous service revenues based on the increase in residential customers. In the partial stipulation, parties agreed to adjust the Company's other revenues to an agreed-upon level.[27]

[27] See UG 288, Order No. 16-076 at 5 (Feb. 29, 2016).

Q. Please describe your proposed adjustments to Cascade's test year other operating revenues.

A. Dividing miscellaneous service revenue by the number of residential customers in each of the years 2009 – 2015 provides an average of $3.28. The Company forecasts an additional 914 residential customers in the test year.[28] Thus I scale miscellaneous service revenues up by $3,009 ($3.28 * 914) due to the increased number of customers. Revenue from all other components of miscellaneous operating revenues are graphed below:

Figure 6. Non-Misc. Other Operating Revenues



The Company has had revenue from interdepartmental rents in each of the last three years, thus I propose to apply the yearly growth rate between 2013 and 2015 values to the test year. Revenue from all other components of miscellaneous operating revenues increased from 2013's value to 2015's value

[28] CNGC/401, Archer/1.

by a yearly rate of 11%. Multiplying the test year's value by 11% results in an $8,246 revenue increase. Summing, I propose an $11,255 increase to miscellaneous operating revenues for the test year.

ISSUE 4. CONSERVATION ALLIANCE PLAN & DECOUPLING

Q. Cascade's Conservation Alliance Plan was a significant issue in the UG 287 rate case, please describe its resolution.

A. In UG 287, the parties agreed to continue Cascade's current decoupling mechanism. They further agreed that Staff and CUB will organize a decoupling workshop for September 2016 to explore whether and how Cascade may implement a real-time weather adjustment. They agreed to initiate full review of the mechanism on September 30, 2019, with any proposed changes to be effective January 1, 2020.[29]

Q. Does Staff have any refinements of the decoupling mechanism to propose at this time?

A. Yes, I recommend that the Company explore adding non-linear weather effects to its methodology used to compute its weather coefficient. The weather coefficient is used to produce the decoupling mechanism's monthly commodity margin per customer.

Q. How is the monthly commodity margin per customer used?

A. Cascade's Conservation Alliance Plan tariff reflects that the Company uses historical weather and load data to compute monthly commodity margin per customer. For example, Cascade has computed the margin per residential customer in December 2016 at $45.93.[30] If actual usage per customer is less than this expected value, the mechanism allows the company to defer with

[29] See UG 287, Order No. 15-412 at 5 (Dec. 28, 2015).
[30] See CNGC/206, Parvinen/1.

interest the difference for recovery in the subsequent year's rates. Likewise, if actual usage exceeds this margin, then customers will receive rate relief in the following year.

Q. What methodology does the Company use to compute commodity margin per customer?

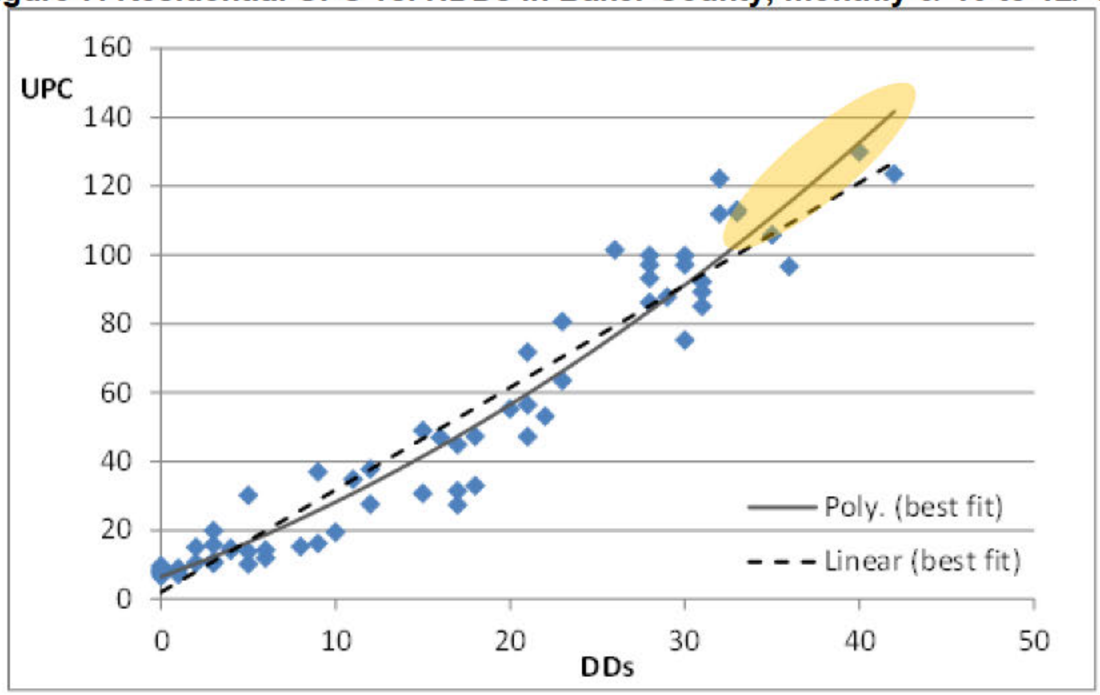
A. The Company computes a weather coefficient by rate schedule and by month using historical usage and weather data. Cascade's *Non Gas Costs Worksheets.xlsx* worksheet in their UG 299 PGA indicates their weather coefficient is multiplied by the number of customers and by the number of degree days (DDs) versus average DDs in order to arrive at the weather normalization adjustment.

Q. What is Staff's recommendation?

A. In this testimony I have recommended that the Company allow for a non-linear relationship between weather and load. I also recommend that the Company explore adding non-linear weather effects to its decoupling mechanism because it can improve the accuracy of the model's description of normal weather. The non-linear relationship better describes (as measured by the adjusted R square statistic of the model) the true pattern of UPCs. This might be especially true on very cold days.

In the Company's data, customers appear to be more sensitive to weather at lower temperatures. Thus the Company's current approach of explaining the variation in UPC based on variation in heating degree days might tend to under-predict the increase in UPC on very cold days. An example of how this might occur is shown with the linear and non-linear best fit lines below.

Figure 7. Residential UPC vs. HDDs in Baker County, monthly 6/'10 to 12/'15



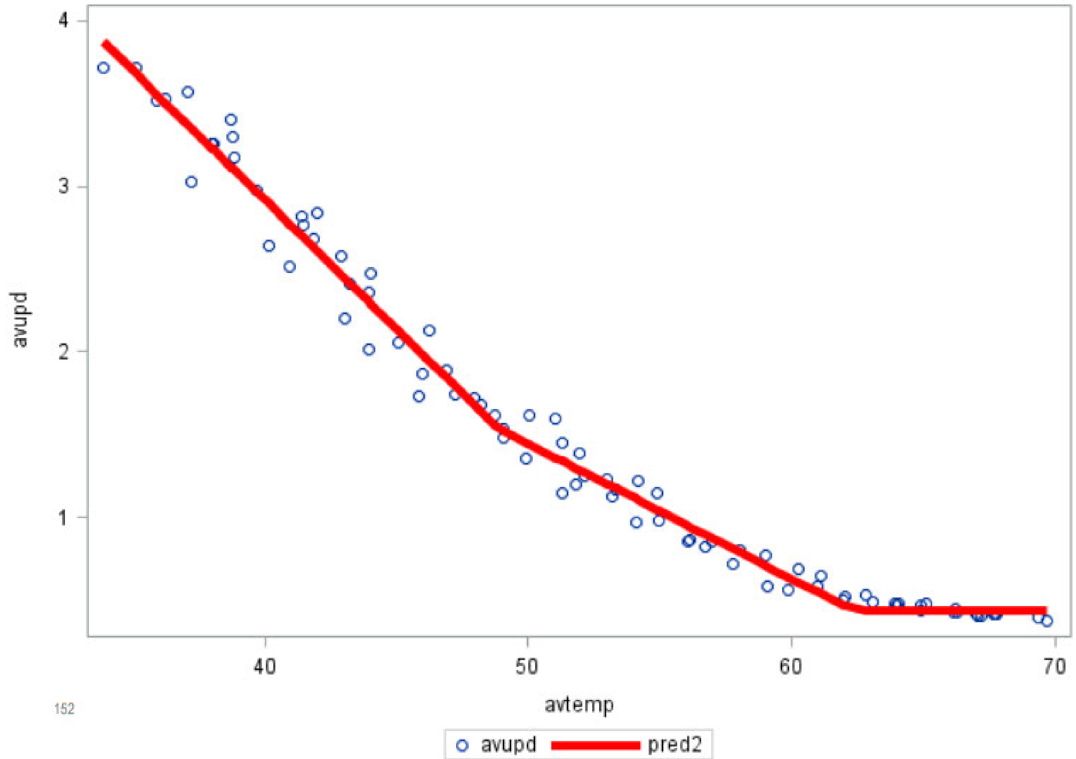
The highlighted oval depicts that, on very cold days, the linear best fit line tends to predict UPC values below those predicted by a non-linear best fit line.

Q. Can you provide further evidence that non-linear weather effects more accurately describe the variation in UPC?

A. Yes, the figure below is reproduced from Appendix 2 of Northwest Natural's draft 2016 IRP.[31]

[31] See NW Natural 2016 Integrated Resource Plan, LC-64: Draft for Public Comment at 2A-42. Available at: https://www.nwnatural.com/uploadedFiles/2016%20Draft%20IRP%20as%20of%20July%2015.pdf

Figure 8. NW Natural IRP Excerpt



In the figure above, average use per day (avupd) appears to have a strong non-linear relationship with average temperature per day (avtemp) such that temperature affects usage more on cold days than on warm days.

ISSUE 5. PUBLIC PURPOSE COST REALLOCATION

Q. Please summarize Cascade's public purpose cost reallocation.

A. Cascade uses the services of the Energy Trust of Oregon (Energy Trust) to administer energy efficiency programs. Prior to the UG 287 rate case, the Company financed the program through two measures. Cascade collected funds from ratepayers through a public purpose charge based on the Energy Trust's program budget. The Commission also approved Cascade use of deferred accounting, as is the case with other Oregon-regulated utilities, along with a balancing account. In addition, Cascade collected an additional 0.75 percent of its revenues from residential and commercial customers as additional funding to the Energy Trust.

In Docket No. UG 287, the Commission adopted a stipulation under which Cascade no longer collects a portion of public purposes funds through general rates charged to residential and commercial customers, but collects all public purpose funds through the public purpose charge. Because this reallocation occurred in 2015, the treatment of these costs differs between the base year and the test year.

Cascade proposes to collect 3.15% of current revenues from rate Schedules 101, 104, 105, 111, and 170 to support public purposes, including energy efficiency programs administered by the Energy Trust of Oregon and weatherization and bill assistance programs for low-income customers administered by Cascade.

Q. Please describe the revenue impact of Cascade's public purpose cost reallocation.

A. There is no revenue impact. Staff confirmed that the Company has correctly avoided double collecting public purpose funds and has properly adjusted for these expenses from the base year to the test year. Post UG 287, the Company is not collecting the funds through specific customer tariffs on a forward going basis.

The testimony of Staff witness JP Batmale further explores the Company's funding of the Energy Trust in an effort to acquire all cost effective energy efficiency.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 305
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS TWENTY YEAR DEMAND STUDY

UG 305 Supporting Document

Abstract

This document contains the forecast methodology and supporting documentation for the 20 year demand forecast results generated as part of the combined demand study.

MRE Consulting, Ltd
Gelber & Associates Corp

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I. Overview

Cascade will discuss the forecast model and methodology within the Demand Study document. Cascade will describe in detail the methodology to data aggregation, linear regression analysis, growth factors, and weather.

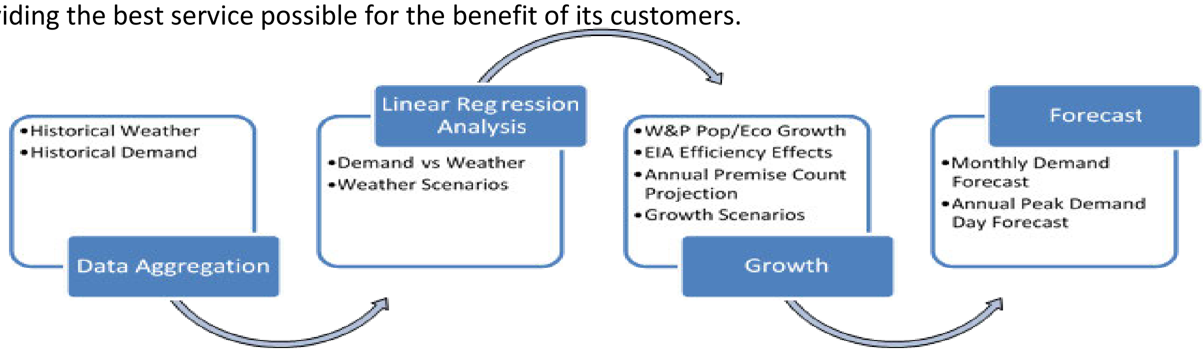
II. Methodology

a. Introduction

The Cascade demand forecast developed for the IRP is an estimate of gas demand sales and peak demand over a 20-year period for core customers at each CityGate[1] or Demand Loop[2]. Cascade core load consists mostly of residential and commercial customers along with some industrial customers. The provided forecasts are designed for use in long-term planning for resources and delivery systems. The 20-year horizon helps Cascade anticipate needs and develop timely responses.

This document defines the assumptions and methods employed in generating the forecast as well as providing the definition of terms where appropriate. The past 30 years of weather data and 4 ½ years of demand data were analyzed to generate the forecast projection for the next 20 years.

Cascade has employed a methodology designed to identify and minimize uncertainties, and to increase transparency and accuracy of the forecast. This forecast, along with the rest of the IRP, assists Cascade in providing the best service possible for the benefit of its customers.



[1] CityGate marks the point where the gas utility, Cascade, delivers gas from the gas pipeline company to a large group of customers. This report forecasts gas demand from Cascade's 76 CityGates.
[2] Demand loop is a grouping of CityGates that service a similar area.

b. EIA Efficiency Effects

Future gas demand is projected to be impacted by efficiency gains due to technology advances that allow customers to reduce natural gas consumption. A 20 year forecast of efficiency gains can be derived from the demand forecast provided by the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2014* that has projections to 2040.

The EIA Energy Outlook report gives data based on region (census division). Cascade uses the 2014 EIA Outlook data for the entire U.S. While Cascade considered using forecast data for the Pacific Region, a region that contains both Washington and Oregon, this region is too heavily influenced by California and its high population which Cascade does not serve. Cascade uses figures from EIA's reference or base case forecast which projects annual natural gas consumption for both residential and commercial customers along with expected HDDs[3] and population. Residential and commercial numbers are combined to create a single natural gas demand number for each year. A demand per population per HDD figure is calculated by dividing demand by the population and HDDs given for each year of the EIA forecast. The demand per population per HDD figure is normalized by dividing each year's calculation by year one (in this case 2014) results and is then converted to a percentage. This produces an efficiency growth[4] rate for each of the next 20 years. Currently, Cascade does not use this factor as it was determined it may be double counting with conservations analysis.

EIA Efficiency was calculated utilizing the equations defined below:

$TD_{[Yr]} = RD_{[Yr]} + CD_{[Yr]}$

$EIA\_E_{[Yr]} = TD_{[Yr]} / US\_POP_{[Yr]} / US\_HDD_{[Yr]}$

Definitions:

- $RD_{[Yr]}$: Residential demand from EIA's *Annual Energy Outlook 2014* by [Yr] year
- $CD_{[Yr]}$: Commercial demand from EIA's *Annual Energy Outlook 2014* by [Yr] year
- $TD_{[Yr]}$: Total natural gas demand is the summation of the residential and commercial natural gas demand for a given year
- $US\_POP_{[Yr]}$: United States population forecasted by the EIA
- $US\_HDD_{[Yr]}$: Total Heating Degree Days for the United States as forecasted by the EIA

[3] HDD or Heating Degree Day is a measure of coldness derived from the daily high and low temperature in degrees Fahrenheit. More information is provided in the weather segment of section II d. of this report.
[4] In this case, efficiency gains make for negative growth.

- $EIA\_E_{[Yr]}$: Efficiency rate created using data from the EIA's *Annual Energy Outlook 2014*. This figure is normalized and converted to a percent rate.

c. Regional Economic Demographics (W&P)

Cascade uses regional economic demographics data formulated by Woods and Poole to derive a projected customer growth by town and year. Woods and Poole employment, income, population, and housing demographics were reviewed. Cascade derived population and economic growth factors formulated from Woods and Poole's forecasted population growth and farm, manufacturing, and construction earnings.

Population Growth

Cascade uses population growth data formulated by Woods and Poole to derive a projected customer growth by CityGate and year. The Woods and Poole population growth forecast is provided by county and year and directly assigned to a CityGate. Cascade assumes a 1% growth in population translates to a 1% increase in customer growth.

W&P Growth by CityGate was calculated utilizing the equations defined below:

$WP\_P_{[CityGate,Yr]} = \sum WP\_P_{[County,Yr]}$

$WP\_G_{[CityGate,Yr]} = (WP\_P_{[CityGate,Yr-1]} - WP\_P_{[CityGate,Yr]}) / WP\_P_{[CityGate,Yr]}$

Definitions:

- $WP\_P_{[Yr,\ County]}$: Woods and Poole annual population forecast based on numerous demographic factors by county and by year
- $WP\_P_{[CityGate,Yr]}$: Sum of all Woods and Poole annual population figures for all counties assigned to a CityGate
- $WP\_G_{[CityGate,Yr]}$: Woods and Poole growth factor percentage calculated from Woods and Poole population forecast by CityGate and year

Economic Growth

To create an economic growth figure, Woods and Poole's construction, manufacturing, and farming earnings were combined for each county and year (2015-2050) to produce a total earnings number. These three industries were chosen because they describe the majority of industrial gas users in Cascade's service areas. The total economic earnings figure is divided by Woods & Poole's inflation forecast to calculate raw earnings growth. The sum of all raw earnings growth figures assigned to a CityGate was used to calculate the Economic Growth by year for each CityGate.

W&P Economic Growth by citygate was calculated utilizing the equations defined below:

$WP\_TE_{[County,\ Yr]} = (WP\_CE_{[County,\ Yr]} + WP\_ME_{[County,\ Yr]} + WP\_FE_{[County,\ Yr]})$

$WP\_TE_{[CityGate,\ Yr]} = \sum WP\_TE_{[County,\ Yr]}$

$WP\_EG_{[CG,\ Yr]} = (WP\_TE_{[CityGate,\ Yr-1]} - WP\_TE_{[CityGate,\ Yr]})/ WP\_TE_{[County,\ Yr]}$

Definitions:

- $WP\_TE_{[County,\ Yr]}$: Woods and Poole total earnings from farming, manufacturing, and construction forecast by county and by year
- $WP\_TE_{[CityGate,\ Yr]}$: Sum of all total earning from farming, manufacturing, and construction forecast by county and by year allocated to a CityGate
- $WP\_EG_{[CG,\ Yr]}$: Woods and Poole economic growth percentage by CityGate and year

d. Demand Study (In House Models)

Historical Demand

Historical core monthly demand by CityGate was derived from the amalgamation and analysis of demand pulled from three sources:

- Customer Care and Billing System (CC&B) provided billing demand by town, tariff, year, and month;
- Gas Management System (GMS) provided non-core demand by CityGate, year, and month;
- Pipeline Flow Data System (EBB[5]) provided demand by CityGate, year, and month.

Cascade core demand is comprised of residential, commercial, and industrial customers assigned to core bundled gas services as defined by tariff[6]. Cascade calculates core demand by using pipeline flow data for each CityGate, which represents total gas flow for both core and non-core customers, and subtracting Cascade's non-core data by CityGate. Non-core data comes from Cascade's own Gas Management System (GMS) which tracks non-core data demand by individual customers behind each CityGate.

Core demand is improved further by a Cascade analyst who removes data that is clearly non-weather related and is atypical of Cascade's core deliveries. A review of CC&B premise counts and demand by tariff assists in identifying this data (NOTE: In the final document we will include example of how this CC&B data actually helps to identify non-weather data). The removed data is later reinserted into the forecast but only after the weather regressions are performed. Removing the data prior to performing the regressions improves the quality of the weather modeling[7]. Core demand by year, month, and CityGate is the primary unit of information upon which this forecast is constructed.

Core Demand by CityGate was calculated utilizing the equation defined below:

$CD_{[CG,Yr,Mth]} = A\_P\_D_{[CG,Yr,Mth]} – NC\_GMS\_D_{[CG, Yr, Mth]} – NWD\_CD_{[CG, Yr, Mth]}$

Definitions:

- A_P_D: Actual Pipeline Demand by CityGate, year, and month.
- NC_GMS_D: Non-Core GMS Demand by CityGate, year, and month
- $CD_{[CG, Yr, Mth]}$: Core demand by CityGate, year, month
- NWD_CD: Non Weather dependent core demand, as determined by Cascade's review of C_CCB_D_A and NC_CCB_D_A (see next calculation on CC&B data)

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[5] EBB or Energy Bulletin Board is system in which pipeline companies post pipeline volumes for the benefit of buyers and sellers of natural gas.

[6] Tariff is a customer classification code

[7] See regression section of the report for more information

- WD_CD: Calculated weather dependent core demand by CityGate, month, and year.

Core demand data can also be generated by using CC&B demand figures. However, CC&B derived demand figures were found to not be consistent enough for use in the forecast model (NOTE: In the final document we will include samples of the supporting analysis). Instead, the data is used only as analytical support such as helping to identifying atypical, non-weather related data. CC&B demand was allocated by town to each CityGate to determine total allocated CityGate demand by billing year and month. Analysis of the CC&B data determined that billed non-core load minus one month was equivalent to non-core physical flow, due to billing operations scheduled for the last day of the month. CC&B core demand was determined to not be equivalent to physical gas flow because of differences between the billing cycle and physical gas flow.

CC&B Demand data by CityGate was calculated utilizing the equations defined below:

$D\_A\_CCB_{[CG,\ Tarriff,Yr,Mth]} = D\_CCB_{[Tariff,Town,Yr,Mth]} \times TGA_{[Town,\ CG]}$

$C\_CCB\_D\_A_{[CG,Yr,Mth]} = \sum D\_A\_CCB_{[CG,Tariff,Yr,Mth]}$

$NC\_CCB\_D\_A_{[CG,Yr,Mth]} = \sum D\_A\_CCB_{[CG,Tarrif,Yr,Mth]}$

Definitions:

- D_CCB: Raw CC&B Demand data by billing Year, Month -1, Town, and Tariff
- D_A_CCB: calculated demand where CC&B demand is allocated to each CityGate$_{CG}$ based upon the TGA
- TGA: Town to Gate Allocation (TGA) where 100 % of a town's billed volume is allocated to one or more CityGates
- C_CCB_D_A: Sum of Core CC&B Demand Allocated to the CityGate by year and month
- NC_CCB_D_A: Sum of Non-Core CC&B Demand Allocated to the CityGate by year and month

Weather

Weather Information Gathering

Historical weather is pulled from the Schneider Electric weather service for all weather related analysis. Weather used represents the minimum (Min) and maximum (Max) temperatures per weather station and day. Schneider uses both official and unofficial sources for their weather temperatures. The official source is the National Weather Service (NWS). The unofficial sources includes observations from federal, state, and local government agencies other than the NWS, as well as corporate weather networks, and even home users. Since Cascade serves mostly rural area's it is significant to have observed weather data from a variety of sources.

Average Weather by Weather Station was calculated utilizing the equations defined below:

$AVG\_WS_{[WS, WD]} = \mathit{Average}(MinOfTemperature_{[WS, WD]}, MaxOfTemperature_{[WS, WD]})$

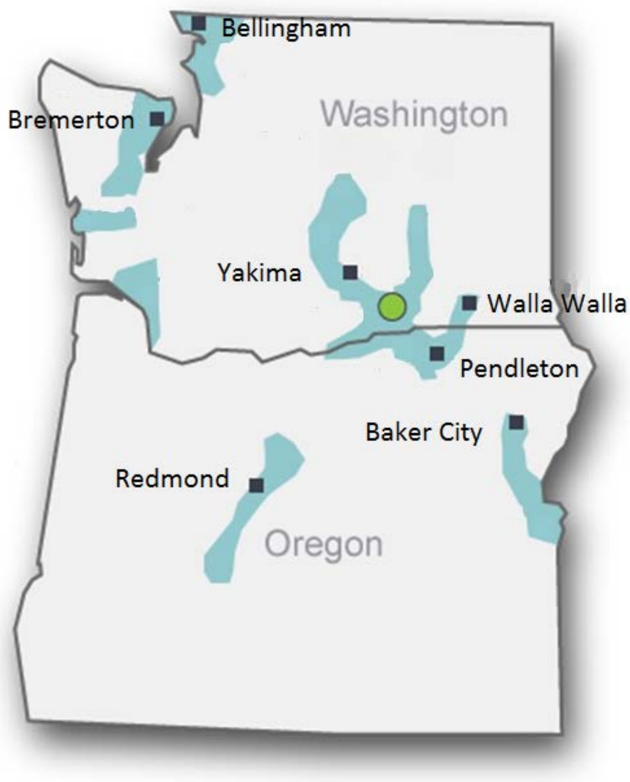
Definitions:

- $AVG\_WS_{[WS, WD]}$: calculated average temperature by $WeatherStation_{WS}$ and $WeatherDay_{WD}$
- $MinOfTemperature_{[WS, WD]}$: minimum temperature from Schneider Electric weather service by [WS] weather station and [WD] weather day
- $MaxOfTemperature_{[WS, WD]}$: maximum temperature from Schneider Electric weather service by [WS] weather station and [WD] weather day

Cascade assigns a particular weather station to represent each CityGate or demand loop it defines as a forecasting location. Seven weather stations were determined to best fit the Cascade geographic network and are located in the cities of Bellingham, Yakima, Walla Walla, Pendleton, Redmond, Baker City, and Bremerton. Considerations for selecting the weather stations are:

- Proximity of the CityGate to the weather station;
- Quality of the data available at the weather station; and
- Geographical impediments between the weather station and the CityGate.

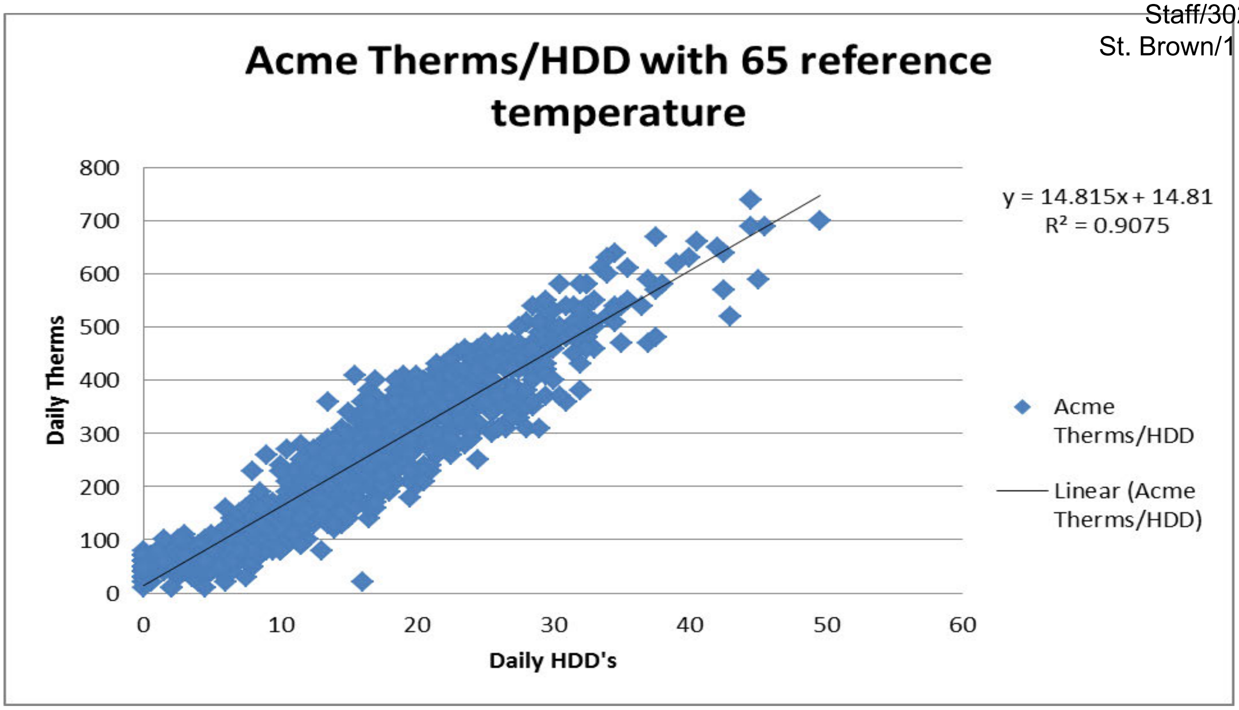
The map below shows the weather locations as well as Cascade's related customer locations (shaded in aqua).

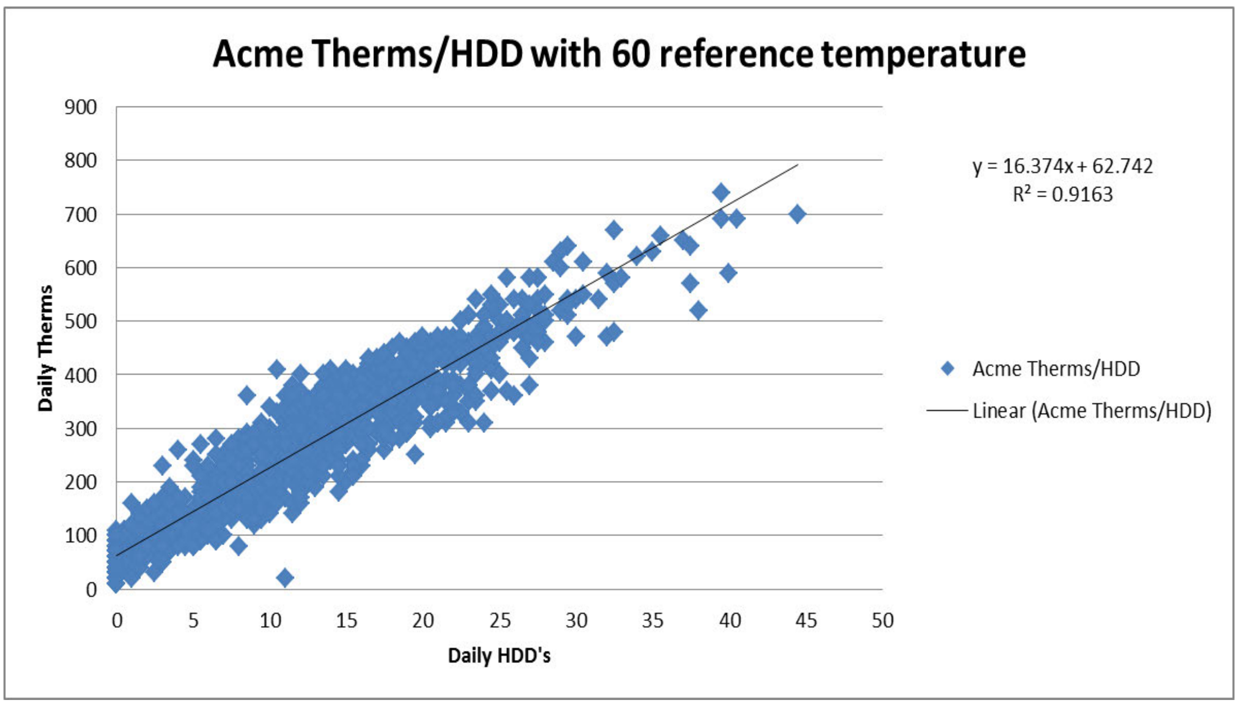


Average weather by weather station is converted into Heating Degree Days (HDD) which becomes the unit of measure for the weather upon which this report is based. With weather quantified in terms of HDDs, Cascade can forecast demand scenarios based on an average year, a cold year, or a mild year. In addition, Cascade can forecast demand on peak demand days when gas loads are at their highest. These concepts enable Cascade to service its clientele during varying demand levels.

Heating Degree Days

Heating Degree Day (HDD) values are calculated by beginning with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 65°F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to notably rise. The historical threshold for calculating HDD has been 65 °F. However, when modeling gas demand based on weather, Cascade has determined that lowering the threshold to 60 °F produces better results. The graph below shows why the lower threshold is preferable. It shows that heating demand does not begin to increase significantly until a HDD of five (65 °F minus 60 °F) if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold thus gives a better measure of the relation between HDD and therms (measurement of heat usage).





Cascade's analysis has optimized the HDD threshold for each city gate by lowering the HDD threshold. A lower HDD threshold of 60 is used for modeling all CityGates.

Historical Premise Count

The historical premise count by year and CityGate was derived from the analysis of monthly premise counts by town and tariff pulled from the Customer Care and Billing (CC&B) system. Monthly premise counts by town, tariff, and year were allocated by town to each CityGate to determine total allocated CityGate premise count by tariff, year, and month.

Historical Premise Count by CityGate were calculated utilizing the equations defined below:

$P\_A\_CCB_{[CG, Yr, Mth, Tariff]} = P\_CCB_{[Town,Tariff,Yr,Mth-1]} \times TGA_{[Town, CG]}$

$CCB\_AAP_{[CG, Yr, Tariff]} = \text{Average}(P\_A\_CCB_{[CG, Yr, Mth, Tariff]})$

Definitions:

- P_CCB: Raw CCB premise count data by billing Year, Month -1_{Mth}, Town, and Tariff
- P_A_CCB: calculated premise count where monthly CC&B premise count by tariff is allocated to each CityGate based upon the TGA
- TGA: Town to gate allocation (TGA) where 100 % of a towns billed volume is allocated to one or more CityGates
- CCB_AAP: CC&B Average annual premise count by CityGate, tariff, and year

Growth

Growth is a calculated value which is determined based upon Woods and Poole Growth, Economic, Mixed, or a manually assigned Cascade growth adjustment plus an EIA efficiency factor. Cascade utilizes a manual growth adjustment when it determines the Woods and Poole growth figure does not best project the growth of a CityGate for a period of time. Manually assigned growth factors are based on supporting analytics related to premise growth, engineering estimates, and internal customer projections.

Growth effects are cumulative, which means that growth effects from one year carry over into the next year. However, there can occasionally be predictable events that impact demand for a specific time period but in a manner such that normal demand resumes when the event is over. For example, a factory may shut down for several months but return to full gas usage after the shutdown. This in turn would reduce CityGate demand for those months but would not affect demand thereafter. Cascade incorporates these non-cumulative events in its forecast as a manual assumption.

Forecast Adjustment Factor by CityGate and year was calculated utilizing the equations defined below:

$WP\_M_{[GC,Yr]} = [WP\_E_{[CG,Yr]} * (1- WC_{[CG]})] + [WP\_P_{[CG,Yr]} * WC_{[CG]}]$

$A\_GR_{[CG,Yr]} = \text{Select}\ (WP\_M_{[CG,Yr],} WP\_E_{[CG,Yr]}, WP\_P_{[CG,Yr]}, MAG_{[GC,Yr]})$

$SA\_GR_{[CG,Yr]} = A\_GR_{[CG,Yr]} \text{ x } (GS_{[Avg,High,Low]} +1)$[8]

$SEC\_GF_{[CG,Yr]} = SEC\_GF_{[CG,Yr-1]} *(1 + S\_GF_{[Yr,CG]} + EIA\_E_{[GC,YR]})$

$SEC\_GR_{[CG,Yr]} = (SEC\_GF_{[CG,Yr]} – 1) /1$

$FAF_{[CG,YR,Mth]} = (SEC\_GR_{[CG,Yr]} + MA_{[Yr]}+ MA_{[Yr,Mth]} + MA_{[Mth]})$

Definitions:

- $WC_{[CG]}$: Weather correlation R^2 coefficient for a CityGate
- $A\_GR_{[CG,Yr]}$: The Assigned Annual Growth Rate, represents growth by CityGate and year (This defaults to the Woods and Poole Growth rate for the CityGate and year unless a Manually Assigned Growth rate is provided)
- $WP\_P_{[GC,Yr]}$: Woods and Poole Population Growth by CityGate and year
- $WP\_E_{[GC,Yr]}$: Woods and Poole Economic Growth by CityGate and year
- $WP\_M_{[GC,Yr]}$: Mixed Woods and Poole Population and Economic Growth factors by CityGate and year
- $MAG_{[GC,Yr]}$: Manually Assigned Growth by CityGate and year
- $SA\_GR_{[CG,Yr]}$: The Assigned Scenario Growth Rate, represents A_GR impacted by the selected growth scenario
- $GS_{[Avg,High,Low]}$: Growth Scenario Impact for average, high, and low growth given in percent terms
- $EIA\_E_{[GC,Yr]}$: EIA Efficiency factor by year
- $SEC\_GF_{[CG,Yr]}$: Applied Annual Growth Factor (With EIA Efficiency), by CityGate and year that is compounded
- $SEC\_GR_{[CG,Yr]}$: Applied Annual Growth modified from a factor to percent rate
- $FAF_{[CG,Yr,Mth]}$: Final Forecast Adjustment Factor by CityGate, year, and month
- $MA_{[Yr]}$: A Manual Forecast Adjustment Factor that affects a given year
- $MA_{[Yr,Mth]}$: A Manual Forecast Adjustment Factor that affects a given month in a given year
- $MA_{[Mth]}$: A Manual Forecast Adjustment Factor that affects a given month for all years

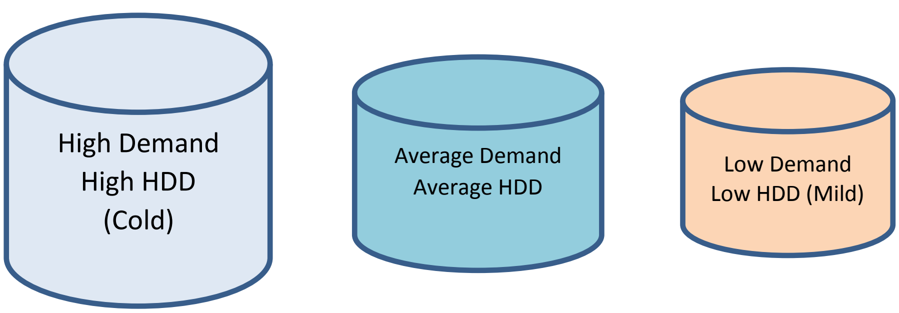
[8] This formula changes depending on whether the assigned growth rate is positive or negative and the growth scenario (high or low). See growth scenario section for more details.

Weather Scenarios

To determine the average (medium) weather case scenario, the average HDD of each month is taken from a specified range of years for each of the seven weather locations. This forecast uses a 30 year range of weather history from the years 1986 through 2015 for each of the three scenarios. To determine the high case HDD weather scenario, Cascade selects the years representing the six coldest years (20% of the coldest years out of 30). These are the particular years with the highest system HDD. Finding the system HDD involves considering HDDs from all seven weather stations and giving appropriate weight to the weather stations that have greater impact on system wide demand. The weighting factor is determined by adding the coefficients or factors (derived from the regression[9]) for each weather station, and by then dividing the sum of the coefficients by the total value of the coefficients from all of the weather stations. Thus the system weighted HDD is the summation of HDDs from each weather station multiplied by its weighting factor. The system calculated HDDs are used to rank the years from warmest to coldest.

To determine the high case HDD weather scenario, Cascade selects the years representing the six coldest years (20% of the coldest years out of 30). These are the particular years with the highest system wide HDD. To determine the low case HDD weather scenario, Cascade selects the years representing the six warmest years (20% of the warmest years out of 30). These are the particular years with the lowest system wide HDD. For both the high and low case HDD weather scenarios, for each particular month of a given projected future year, the HDD from these six years average to provide the appropriate scenario.

Weather Scenarios



[9] Refer to regression section of this report for more information.

The “normal”, or expected, HDDs used to compute the base forecast are calculated by finding the average HDD over the 30 years prior to the first forecasted year.

1985-2014 Normals												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Baker City	1032	883	639	469	254	95	10	16	125	428	790	1026
Bellingham	617	572	466	333	175	61	11	8	80	277	493	636
Bremerton	624	591	480	370	201	83	15	11	73	278	519	656
Pendleton	766	671	459	298	127	25	1	1	32	250	576	801
Redmond	795	750	585	458	266	104	17	18	113	358	656	848
Walla Walla	735	632	398	235	87	14	0	0	16	198	536	773
Yakima	876	721	504	314	123	29	2	3	53	310	667	924
System Weighted	717	644	485	341	171	58	9	8	69	284	564	751

Cascade Weather Scenario Impact

Weather Scenario Impact by Weather Station was calculated utilizing the equations defined below:

$AWS_{[Avg, Mth]} = Average(HDD_{[All\ Weather\ YRS, Mth]})$

$HWS_{[High, Mth]} = Average(HDD_{[Top\ X\ YRS, Mth]})$

$LWS_{[Low, Mth]} = Average(HDD_{[Bottom\ Y\ YRS, Mth]})$

Definitions:

- $AWS_{[Avg, Mth]}$: Average HDD by month for all weather years
- $HWS_{[High, Mth]}$: Average HDD by month for the X years with the highest HDD values (coldest), where X is the number of weather years multiplied by the weather range, e.g. 30 years * 20% = 6 years
- $LWS_{[Low, Mth]}$: Average HDD by month for the Y years with the lowest HDD values (warmest), where Y is the number of weather years multiplied by the weather range, e.g. 30 years * 20% = 6 years

Growth Scenarios

Cascade has defined three growth scenarios to adjust expected demand:

- Expected growth: is the calculated Annual Cascade Assigned Scenario Impact growth projection
- High Growth: is the High Cascade Assigned Scenario Impact
- Low Growth: is the Low Cascade Assigned Scenario Impact

Each scenario calculates a single growth factor to increase or decrease demand at a given CityGate in a given year over the projected 20 year period.

Cascade Growth Scenario Impact

High and low growth scenarios are defined by a banded +/- ranged based upon the average assigned scenario growth defined.

Growth Scenario Impact by CityGate and Year was calculated utilizing the equations defined below:

$SA\_GR_{[AVG, CG, Yr]} = SA\_GR_{[YR,CG]}$

$SA\_GR_{[High]}$ = If $A\_GR_{[YR,CG]} > 0$, THEN = $A\_GR_{[YR,CG]} * (1+GS_{[High]})$, ELSE = $A\_GR_{[YR,CG]} * (1-GS_{[High]})$

$SA\_GR_{[Low]}$ = If $A\_GR_{[YR, CG]} > 0$, THEN = $A\_GR_{[YR,CG]} * (1-GS_{[High]})$, ELSE = $A\_GR_{[YR, CG]} * (1+GS_{[Low]})$

Definitions:

- $GS_{[Avg, High, Low]}$: Growth based upon scenario Avg, High, or Low
- $A\_GR_{[CG, Yr]}$: The Assigned Annual Growth Rate, represents growth by CityGate and Year (This is the Population/Economic/Mixed Woods and Poole Growth factor for the CityGate and Year unless a Manually Assigned Growth factor is provided)
- $GS_{[High]}$: High Growth Range Adjustment is a model variable represented as %
- $GS_{[Low]}$: Low Growth Range Adjustment is a model variable represented as %

Regression Analysis

The majority of Cascade's core natural gas demand is used for heating purposes and is highly dependent on the weather. The colder the weather, the greater the demand. To forecast weather dependent load which accounts for weather differences, Cascade conducted a linear regression[10] analysis to develop a regression coefficient and constant for each CityGate. Cascade preformed a regression analysis of weather dependent monthly gas demand in comparison with monthly heating degree days at each CityGate for Historical Demand. The regression analysis calculated the coefficient ***b*** and constant ***C*** that best minimizes the error. This forecast uses a linear regression, no exponents were used.

Regression analysis calculates the best coefficient *b* and constant *C* values for each CityGate *utilizing the equations defined below*:

$$\boldsymbol{Demand = b \times HDD \times Customers + C}$$

Definitions:

- Demand = Core Weather Dependent Gas Demand (Daily Average for a given month in dekatherms)
- HDD = Average Heating Degree Day Per month
- b = coefficient that gives gas demand (dekatherms) per HDD per Customer
- C = constant, base level of gas demand (dekatherms) that remains the same regardless of weather

The coefficient ***b*** is the central figure in the model when calculating weather dependent demand. It best describes the impact that weather and customers has on gas demand. The larger the ***b*** coefficient, the greater the gas demand per unit of weather per customer. The constant ***C*** is the base level of gas demand (dekatherms) that remains the same regardless of weather.

In addition to finding the coefficient ***b*** and the constant ***C***, another product of the regression analysis is the production of the correlation coefficient, *R*. This figure is typically squared to form R^2. R^2 measures the strength of the relationship between two variables. R^2 values can range from zero to one. A regression with an R^2 of 1 means it has been a perfect predictor of demand, and therefore, would be an ideal regression to use. An R^2 of 1 does not guarantee a future HDD will predict the exact demand. Generally, a low R^2 value shows that it has not been a good predictor, and therefore, would not be an ideal regression to use.

[10] Regression analysis is a statistical process used to study the relationship between variables – in this case weather and demand.

For the purposes of this forecast, Cascade did not require the use of a Monte Carlo[11] model to calculate weather. There was sufficient historical weather data to produce high, low, and medium cases without utilizing a Monte Carlo simulation.

e. Demand Study (Calculation)

Monthly Demand Forecast

The Monthly Demand Forecast by CityGate, year, and month is based upon the calculated forecast for weather dependent core load plus the most recent year's (2015) non weather dependent core load where a single forecast adjustment was applied which included growth and Cascade assumptions.

Weather dependent core load was forecasted by CityGate utilizing the Weather Dependent Model equation, unless the R^2 of a CityGates linear regression was below a certain 80% threshold, meaning HDD is not a good predictor of demand.

Forecast Demand by CityGate, Year, and Month was calculated utilizing the equations defined below:

$WDD_{[CG,YR,Mth]} = (b_{[CG]} \times HDD_{[High,\ Ave,\ Low,\ CG,Mth]} + C_{[CG]}) * DAYS_{[Yr,Mth]} + NWDDV_{[CG,YR,Mth]}$

$MDF_{[CG,YR,Mth]} = Or(WDD_{[CG,YR,Mth]}, DDV_{[CG,YR,Mth]}) * (1+FAF_{[YR,Mth,CG]})$

Definitions:

- WDD: Weather & Customer based demand for a given weather scenario for a given CityGate and month
- b: coefficient that gives gas demand (dekatherms) per HDD per Customer for a given CityGate
- C: constant, base level of gas demand (dekatherms) that remains the same regardless of weather
- DAYS: Number of days in forecast year and month
- NWDDV: Non Weather Dependent Default Demand Value based upon forecast month
- DDV: Default demand value per CityGate based upon forecast month
- MDF: Monthly demand forecast per CityGate
- FAF: Forecast Adjustment Factor by CityGate, year, and month (Includes growth, assumptions, and scenario impact)

[11] Monte Carlo model is a statistical method used to estimate solutions for complex equations that cannot be solved for implicitly. The technique typically involves averaging the results of multiple trials using random input figures. For this forecast, the primary inputs, including weather, were defined well enough that the use of Monte Carlo is not necessary.

System Peak Forecast

The purpose of finding the peak demand day is to ensure that Cascade can continue to provide adequate heating to its customers even under extreme conditions which are far colder than the norm. There are 3 scenarios that are analyzed in the forecast model:

- Expected peak day;
- System wide max peak day;
- Max CityGate peak day.

Expected peak day demand in a given year, in contrast with the highest case scenario peak day demand, is calculated by Cascade based on the average of the peak demand days for each of the last 30 years. Initially, the system-weighted peak day, which is later explained, is found for each year for the last thirty years. The actual HDD from each of those 30 peak days is averaged for each weather station resulting in an average peak HDD. Applying the associated average peak HDD to the forecast model for each CityGate yields an expected peak demand for each CityGate. Cascade calculates the expected peak demand for each CityGate for each future year of the forecast by then applying appropriate growth factors.

Cascade determines the system wide max peak demand day by first selecting the system wide single coldest day recorded in the past 30 years. To determine the system wide max peak demand day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations having the greater impact on system wide demand. This same method is used in the weather scenario section of this report in order to find the coldest and warmest years. The calculation of the system weighted HDD is applied to the previous 30 years of weather data to determine the highest HDD of all. Cascade has found December 21, 1990 to be the highest system weighted HDD for this period.

The peak demand day is then derived from the highest HDD by applying the actual HDD from the peak day for the 30 year period to the monthly linear regression equation for each CityGate[12].Thus, all CityGates associated with the Bellingham weather station, for example, use the HDD calculated for Bellingham for December 21, 1990 and similarly for all the other weather stations and CityGates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for each CityGate. To determine the peak demand day for a given projected year, growth factors (see below) are applied to the peak demand day for the thirty year period. Peak day demand is in turn calculated for each CityGate for each year of the twenty year forecast.

[12] See regression section of this report

The max CityGate peak day is determined by finding the coldest HDD for each weather station in the 30 year history and combining those to happen in one day. The difference between the system wide max peak day and the max CityGate peak day is that the system wide max peak day is the historical day that maximized the entire system demand where the max CityGate peak day is a rhetorical scenario where the coldest HDD for each weather station happened on one day.

For CityGates where demand is not weather dependent, the peak demand day cannot be calculated by applying an associated HDD. Instead, peak demand for these CityGates becomes the average daily demand for the month in which the system peak day falls. Cascade applies the calculated Daily Peak Adder (DPA) to the average daily demand number to convert the average day figure to daily peak demand. As with the weather dependent peak days, growth factors are applied to this figure.

PeakDemand by CityGate and year was calculated utilizing the equations defined below:

$DDmax_{[CG,Yr]} = (b_{[CG]} \text{ x } HDDpmax_{[day]} + C_{[CG]})$

$DDavg_{[CG,Yr]} = (b \text{ x } HDDpavg_{[day]} + C)$

$MPDF_{[CG,Yr]} = (DDmax_{[CG,Yr]})*(1+FAF_{[CG,Yr]})$ OR

$(DDV_{[CG,Yr,Mth]})/ DAYS_{[Yr,Mth]})* (1+FAF_{[CG,Yr]})*(1+DPA)$

$EPDF_{[CG,Yr]} =(DDavg_{[CG,Yr]})*(1+FAF_{[CG,Yr]})$ OR

$(DDV_{[CG,Yr,Mth]})/ DAYS_{[Yr,Mth]})* (1+FAF_{[CG,Yr]})*(1+DPA)$

Definitions:

- HDDpmax: HDD of an associated weather station on the historical peak day
- HDDpavg: Average of the weather station's HDDs from the historical peak days of each of the last 30 years
- DDmax: Daily demand based on a max peak HDD
- DDavg: Daily demand based on an average peak HDD
- b: coefficient that gives gas demand (dekatherms) per HDD per Customer
- C: constant, base level of gas demand (dekatherms) that remains the same regardless of weather
- DAYS: Number of days in forecast Year and Month
- DDV: Default monthly demand value per CityGate based upon month of peak demand day
- MPDF: Max peak demand day forecast per CityGate
- EPDF: Expected peak demand day forecast per CityGate
- FAF: Forecast Adjustment Factor by CityGate, Year (Includes Growth, Assumptions, and Scenario Impact)
- DPA: Default peak adder based on user input

Annual Premise Count Trend Forecast

The Annual Premise Count Projection by CityGate and year was based upon a linear trend analysis of the Historical Premise Count data pulled from CC&B for a CityGate, tariff, and year. Historical Premise Count by CityGate, tariff, and year was used to forward project premise count based upon the trend between premise count and time. This information is used as guide to assist Cascade when forecasting customer growth.

Premise Trends by CityGate where calculated utilizing the equations defined below:

$FPC_{[CG,Tariff,Yr]} = Trend(CCB\_AAP_{[CG,Tariff,Yr]}, Time_{[Yr]})$

Definitions:

- CCB_AAP: CCB Average Annual Premise count by CityGate, tariff, and year.
- Time: Years Raw CCB premise count data was provided
- FPC: Forward projection of annual premise count by CityGate, tariff, and year.

f. Assumptions (NOTE: All model assumptions will be included in final document)

Weather

- Forecast is based off of core data
- Core data is sourced from the pipeline company and from Cascade GMS (Gas Management System)
- Weather at each CityGate is represented by weather at one of the seven weather locations.
- HDDs, on a 60 F threshold, are used to measure unit of coldness
- The time period for finding historical weather is the past 30 years (1986-2015).
- The average weather case scenario is based on normal weather- the average monthly HDD of a historical time period of 30 years.
- The high case weather scenario uses the monthly average from the six coldest system wide years out of 30.
- The low case weather scenario uses the monthly average from the six warmest system wide years out of 30.

Linear Regression Model

- A linear regression model is used to model demand based on weather.
- Cascade refers to the most recent year (2015) for CityGates that have regressions (R^2) less than a certain value assigned by Cascade (80%).

Growth

- The forecast uses outside consulting firm Woods & Poole's forecast for population growth.
- The forecast model assumes that 1% increase in population translates to a 1% increase in gas demand, before accounting for any efficiency gains.
- The EIA efficiency factor is derived from the 2014 EIA Annual Energy Outlook.

III. Glossary of Terms and Assumptions

Core Customers – These are full service customers of Cascade that pay a delivered price of gas. These are typically residual and commercial customer users.

Non-Core Customers – These customers pay Cascade the cost of transporting the gas to Cascade and purchase the gas from another source.

Premise Count – Customer count.

NOAA – National Oceanic Administration Association, the federal agency that is the primary weather data holder for the United States.

Regression – A method of comparing two different data sets in which factors are calculated to predict one data set to the other. The closer the predicted set to the actual set the better the regression.

Correlation – A measure of the regression of between two data sets. The higher the regression or relation between two data sets the higher the correlation. Correlation figures range from zero to one.

HDD – Heating Degree Day – A unit to describe unit of coldness.

CityGate – This marks the point where the gas utility, Cascade, deliveries gas from the gas pipeline company to a large group of customers.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 164

Date prepared: 6/7/2016

Preparer: Brian Robertson

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 164

Please refer to the "RegressionAnalysis" tab of the Excel file *CONFIDENTIAL CNGCForcastModel2016-2035.xlsx* provided in response to Staff IR 130. Please describe how the effect of weather on customers' demand is modeled. Please describe the modeled effect of weather on residential, commercial, and industrial demand.

Response:

Cascade uses a linear regressions y = a*(HDD/customer) + c*(customers) to analyze the effect of weather on customers' demand. This can be seen on the "RegressionAnalysis" tab of the Excel file *CONFIDENTIAL CNGCForcastModel2016-2035.xlsx* in columns N and O. Column O is the constant (c) coefficient therms/customer. The constant is the baseload that doesn't depend on weather. Column N is the slope coefficient (a) therms/HDD/customer. This coefficient increases by the slope (a) when the HDD increases by 1. Using this formula, Cascade applies the normal HDD and expected customers to the regression and solves for therms (y). Cascade modeled residential, commercial, and industrial demand together within a CityGate for this forecast. Cascade is currently analyzing and implementing a change to model each rate class individually.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 260

Date prepared: 6/24/2016

Preparer: Brian Robertson

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 260

Please refer to Cascade's response to Staff DR 164. Please describe the results of Cascade's analysis so far to implement the change to model each rate classes' load forecast individually. Please describe why Cascade is making this change.

Response:

Cascade is still implementing the changes to the forecast model so there are no results to discuss so far. Intuitively, the 3 types of core customers that Cascade serves--residential, commercial and industrial--all react to weather differently.

CASE: UG 305
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS TWENTY YEAR DEMAND STUDY

UG 305 Supporting Document

Abstract
This document contains the forecast methodology and supporting documentation for the 20 year demand forecast results generated as part of the combined demand study.

MRE Consulting, Ltd
Gelber & Associates Corp

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I. Overview

Cascade will discuss the forecast model and methodology within the Demand Study document. Cascade will describe in detail the methodology to data aggregation, linear regression analysis, growth factors, and weather.

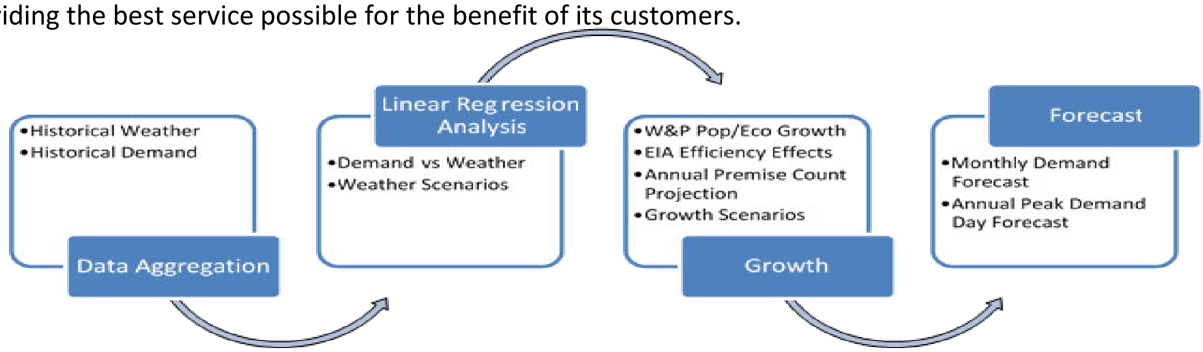
II. Methodology

a. Introduction

The Cascade demand forecast developed for the IRP is an estimate of gas demand sales and peak demand over a 20-year period for core customers at each CityGate[1] or Demand Loop[2]. Cascade core load consists mostly of residential and commercial customers along with some industrial customers. The provided forecasts are designed for use in long-term planning for resources and delivery systems. The 20-year horizon helps Cascade anticipate needs and develop timely responses.

This document defines the assumptions and methods employed in generating the forecast as well as providing the definition of terms where appropriate. The past 30 years of weather data and 4 ½ years of demand data were analyzed to generate the forecast projection for the next 20 years.

Cascade has employed a methodology designed to identify and minimize uncertainties, and to increase transparency and accuracy of the forecast. This forecast, along with the rest of the IRP, assists Cascade in providing the best service possible for the benefit of its customers.



[1] CityGate marks the point where the gas utility, Cascade, delivers gas from the gas pipeline company to a large group of customers. This report forecasts gas demand from Cascade's 76 CityGates.
[2] Demand loop is a grouping of CityGates that service a similar area.

b. EIA Efficiency Effects

Future gas demand is projected to be impacted by efficiency gains due to technology advances that allow customers to reduce natural gas consumption. A 20 year forecast of efficiency gains can be derived from the demand forecast provided by the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2014* that has projections to 2040.

The EIA Energy Outlook report gives data based on region (census division). Cascade uses the 2014 EIA Outlook data for the entire U.S. While Cascade considered using forecast data for the Pacific Region, a region that contains both Washington and Oregon, this region is too heavily influenced by California and its high population which Cascade does not serve. Cascade uses figures from EIA's reference or base case forecast which projects annual natural gas consumption for both residential and commercial customers along with expected HDDs[3] and population. Residential and commercial numbers are combined to create a single natural gas demand number for each year. A demand per population per HDD figure is calculated by dividing demand by the population and HDDs given for each year of the EIA forecast. The demand per population per HDD figure is normalized by dividing each year's calculation by year one (in this case 2014) results and is then converted to a percentage. This produces an efficiency growth[4] rate for each of the next 20 years. Currently, Cascade does not use this factor as it was determined it may be double counting with conservations analysis.

EIA Efficiency was calculated utilizing the equations defined below:

$TD_{[Yr]} = RD_{[Yr]} + CD_{[Yr]}$

$EIA\_E_{[Yr]} = TD_{[Yr]} / US\_POP_{[Yr]} / US\_HDD_{[Yr]}$

Definitions:

- $RD_{[Yr]}$: Residential demand from EIA's *Annual Energy Outlook 2014* by [Yr] year
- $CD_{[Yr]}$: Commercial demand from EIA's *Annual Energy Outlook 2014* by [Yr] year
- $TD_{[Yr]}$: Total natural gas demand is the summation of the residential and commercial natural gas demand for a given year
- $US\_POP_{[Yr]}$: United States population forecasted by the EIA
- $US\_HDD_{[Yr]}$: Total Heating Degree Days for the United States as forecasted by the EIA

[3] HDD or Heating Degree Day is a measure of coldness derived from the daily high and low temperature in degrees Fahrenheit. More information is provided in the weather segment of section II d. of this report.
[4] In this case, efficiency gains make for negative growth.

- $EIA\_E_{[Yr]}$: Efficiency rate created using data from the EIA's *Annual Energy Outlook 2014.* This figure is normalized and converted to a percent rate.

c. Regional Economic Demographics (W&P)

Cascade uses regional economic demographics data formulated by Woods and Poole to derive a projected customer growth by town and year. Woods and Poole employment, income, population, and housing demographics were reviewed. Cascade derived population and economic growth factors formulated from Woods and Poole's forecasted population growth and farm, manufacturing, and construction earnings.

Population Growth

Cascade uses population growth data formulated by Woods and Poole to derive a projected customer growth by CityGate and year. The Woods and Poole population growth forecast is provided by county and year and directly assigned to a CityGate. Cascade assumes a 1% growth in population translates to a 1% increase in customer growth.

W&P Growth by CityGate was calculated utilizing the equations defined below:

$WP\_P_{[CityGate,Yr]} = \sum WP\_P_{[County,Yr]}$

$WP\_G_{[CityGate,Yr]} = (WP\_P_{[CityGate,Yr-1]} - WP\_P_{[CityGate,Yr]}) / WP\_P_{[CityGate,Yr]}$

Definitions:

- $WP\_P_{[Yr,\ County]}$: Woods and Poole annual population forecast based on numerous demographic factors by county and by year
- $WP\_P_{[CityGate,Yr]}$: Sum of all Woods and Poole annual population figures for all counties assigned to a CityGate
- $WP\_G_{[CityGate,Yr]}$: Woods and Poole growth factor percentage calculated from Woods and Poole population forecast by CityGate and year

Economic Growth

To create an economic growth figure, Woods and Poole's construction, manufacturing, and farming earnings were combined for each county and year (2015-2050) to produce a total earnings number. These three industries were chosen because they describe the majority of industrial gas users in Cascade's service areas. The total economic earnings figure is divided by Woods & Poole's inflation forecast to calculate raw earnings growth. The sum of all raw earnings growth figures assigned to a CityGate was used to calculate the Economic Growth by year for each CityGate.

W&P Economic Growth by citygate was calculated utilizing the equations defined below:

$WP\_TE_{[County,\ Yr]} = (WP\_CE_{[County,\ Yr]} + WP\_ME_{[County,\ Yr]} + WP\_FE_{[County,\ Yr]})$

$WP\_TE_{[CityGate,\ Yr]} = \sum WP\_TE_{[County,\ Yr]}$

$WP\_EG_{[CG,\ Yr]} = (WP\_TE_{[CityGate,\ Yr-1]} - WP\_TE_{[CityGate,\ Yr]}) / WP\_TE_{[County,\ Yr]}$

Definitions:

- $WP\_TE_{[County,\ Yr]}$: Woods and Poole total earnings from farming, manufacturing, and construction forecast by county and by year
- $WP\_TE_{[CityGate,\ Yr]}$: Sum of all total earning from farming, manufacturing, and construction forecast by county and by year allocated to a CityGate
- $WP\_EG_{[CG,\ Yr]}$: Woods and Poole economic growth percentage by CityGate and year

d. Demand Study (In House Models)

Historical Demand

Historical core monthly demand by CityGate was derived from the amalgamation and analysis of demand pulled from three sources:

- Customer Care and Billing System (CC&B) provided billing demand by town, tariff, year, and month;
- Gas Management System (GMS) provided non-core demand by CityGate, year, and month;
- Pipeline Flow Data System (EBB[5]) provided demand by CityGate, year, and month.

Cascade core demand is comprised of residential, commercial, and industrial customers assigned to core bundled gas services as defined by tariff[6]. Cascade calculates core demand by using pipeline flow data for each CityGate, which represents total gas flow for both core and non-core customers, and subtracting Cascade's non-core data by CityGate. Non-core data comes from Cascade's own Gas Management System (GMS) which tracks non-core data demand by individual customers behind each CityGate.

Core demand is improved further by a Cascade analyst who removes data that is clearly non-weather related and is atypical of Cascade's core deliveries. A review of CC&B premise counts and demand by tariff assists in identifying this data (NOTE: In the final document we will include example of how this CC&B data actually helps to identify non-weather data). The removed data is later reinserted into the forecast but only after the weather regressions are performed. Removing the data prior to performing the regressions improves the quality of the weather modeling[7]. Core demand by year, month, and CityGate is the primary unit of information upon which this forecast is constructed.

Core Demand by CityGate was calculated utilizing the equation defined below:

$CD_{[CG,Yr,Mth]} = A\_P\_D_{[CG,Yr,Mth]} – NC\_GMS\_D_{[CG, Yr, Mth]} – NWD\_CD_{[CG, Yr, Mth]}$

Definitions:

- A_P_D: Actual Pipeline Demand by CityGate, year, and month.
- NC_GMS_D: Non-Core GMS Demand by CityGate, year, and month
- $CD_{[CG, Yr, Mth]}$: Core demand by CityGate, year, month
- NWD_CD: Non Weather dependent core demand, as determined by Cascade's review of C_CCB_D_A and NC_CCB_D_A (see next calculation on CC&B data)

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[5] EBB or Energy Bulletin Board is system in which pipeline companies post pipeline volumes for the benefit of buyers and sellers of natural gas.
[6] Tariff is a customer classification code
[7] See regression section of the report for more information

- WD_CD: Calculated weather dependent core demand by CityGate, month, and year.

Core demand data can also be generated by using CC&B demand figures. However, CC&B derived demand figures were found to not be consistent enough for use in the forecast model (NOTE: In the final document we will include samples of the supporting analysis). Instead, the data is used only as analytical support such as helping to identifying atypical, non-weather related data. CC&B demand was allocated by town to each CityGate to determine total allocated CityGate demand by billing year and month. Analysis of the CC&B data determined that billed non-core load minus one month was equivalent to non-core physical flow, due to billing operations scheduled for the last day of the month. CC&B core demand was determined to not be equivalent to physical gas flow because of differences between the billing cycle and physical gas flow.

CC&B Demand data by CityGate was calculated utilizing the equations defined below:

$D\_A\_CCB_{[CG,\ Tarriff,Yr,Mth]} = D\_CCB_{[Tariff,Town,Yr,Mth]} \times TGA_{[Town,\ CG]}$

$C\_CCB\_D\_A_{[CG,Yr,Mth]} = \sum D\_A\_CCB_{[CG,Tariff,Yr,Mth]}$

$NC\_CCB\_D\_A_{[CG,Yr,Mth]} = \sum D\_A\_CCB_{[CG,Tarrif,Yr,Mth]}$

Definitions:

- D_CCB: Raw CC&B Demand data by billing Year, Month -1, Town, and Tariff
- D_A_CCB: calculated demand where CC&B demand is allocated to each CityGate$_{CG}$ based upon the TGA
- TGA: Town to Gate Allocation (TGA) where 100 % of a town's billed volume is allocated to one or more CityGates
- C_CCB_D_A: Sum of Core CC&B Demand Allocated to the CityGate by year and month
- NC_CCB_D_A: Sum of Non-Core CC&B Demand Allocated to the CityGate by year and month

Weather

Weather Information Gathering

Historical weather is pulled from the Schneider Electric weather service for all weather related analysis. Weather used represents the minimum (Min) and maximum (Max) temperatures per weather station and day. Schneider uses both official and unofficial sources for their weather temperatures. The official source is the National Weather Service (NWS). The unofficial sources includes observations from federal, state, and local government agencies other than the NWS, as well as corporate weather networks, and even home users. Since Cascade serves mostly rural area's it is significant to have observed weather data from a variety of sources.

Average Weather by Weather Station was calculated utilizing the equations defined below:

$AVG\_WS_{[WS,\ WD]} = \mathit{Average}(MinOfTemperature_{[WS,\ WD]}, MaxOfTemperature_{[WS,\ WD]})$

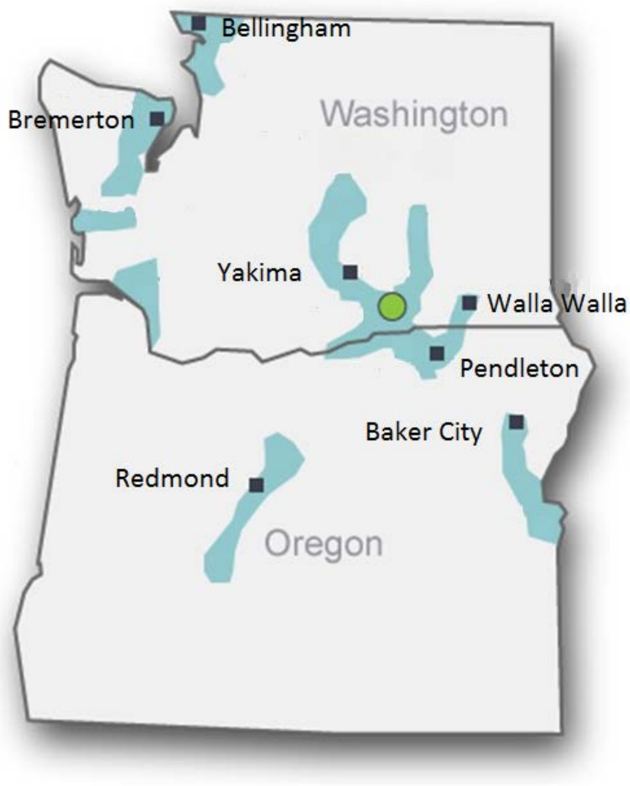
Definitions:

- $AVG\_WS_{[WS,\ WD]}$: calculated average temperature by $WeatherStation_{WS}$ and $WeatherDay_{WD}$
- $MinOfTemperature_{[WS,\ WD]}$: minimum temperature from Schneider Electric weather service by [WS] weather station and [WD] weather day
- $MaxOfTemperature_{[WS,\ WD]}$: maximum temperature from Schneider Electric weather service by [WS] weather station and [WD] weather day

Cascade assigns a particular weather station to represent each CityGate or demand loop it defines as a forecasting location. Seven weather stations were determined to best fit the Cascade geographic network and are located in the cities of Bellingham, Yakima, Walla Walla, Pendleton, Redmond, Baker City, and Bremerton. Considerations for selecting the weather stations are:

- Proximity of the CityGate to the weather station;
- Quality of the data available at the weather station; and
- Geographical impediments between the weather station and the CityGate.

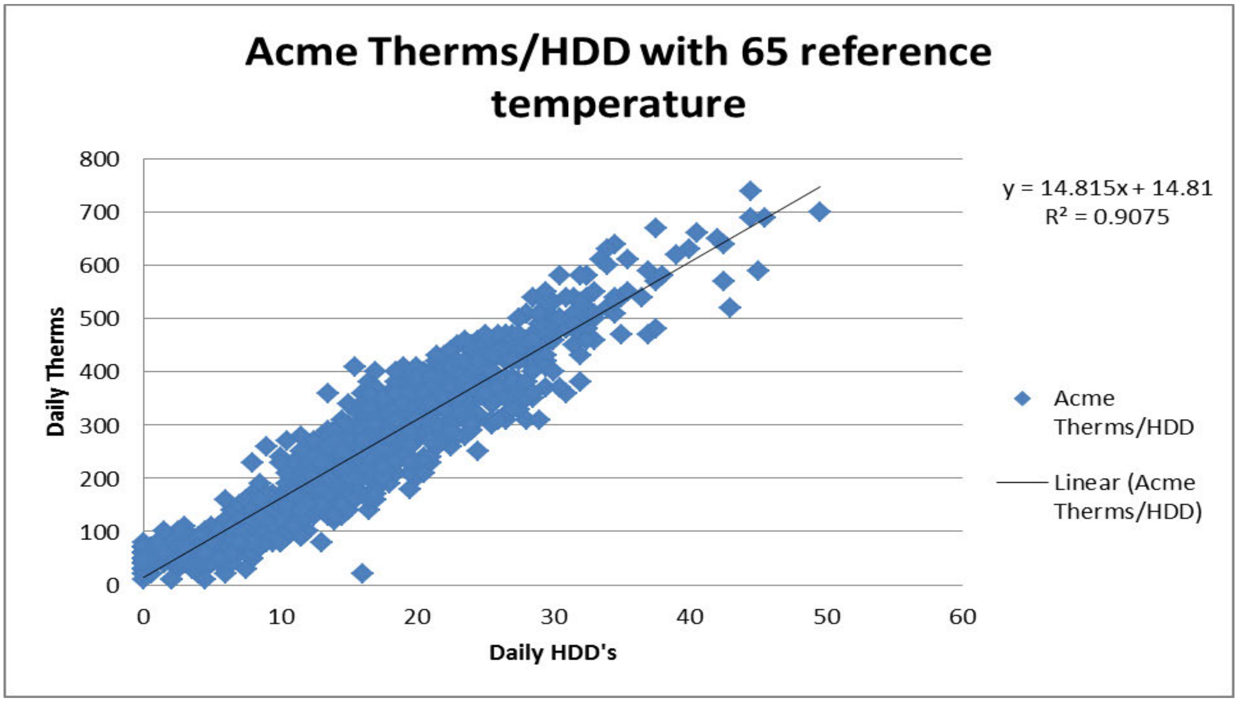
The map below shows the weather locations as well as Cascade's related customer locations (shaded in aqua).

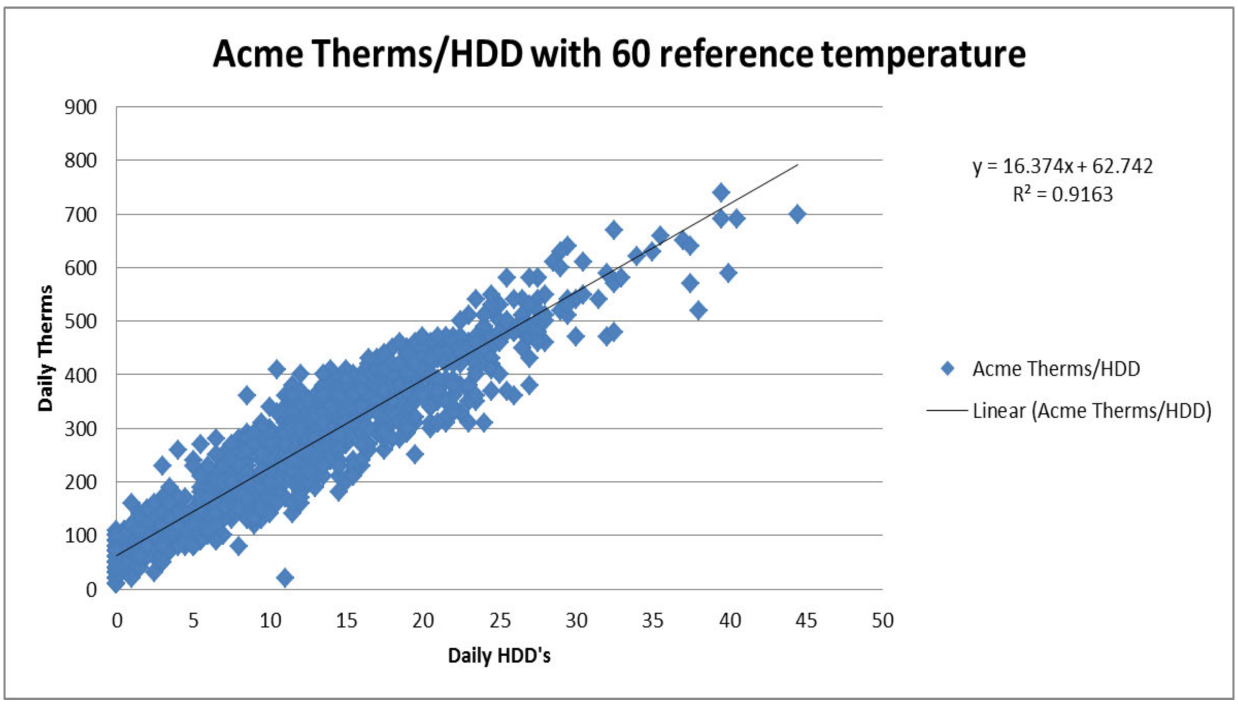


Average weather by weather station is converted into Heating Degree Days (HDD) which becomes the unit of measure for the weather upon which this report is based. With weather quantified in terms of HDDs, Cascade can forecast demand scenarios based on an average year, a cold year, or a mild year. In addition, Cascade can forecast demand on peak demand days when gas loads are at their highest. These concepts enable Cascade to service its clientele during varying demand levels.

Heating Degree Days

Heating Degree Day (HDD) values are calculated by beginning with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 65°F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to notably rise. The historical threshold for calculating HDD has been 65 °F. However, when modeling gas demand based on weather, Cascade has determined that lowering the threshold to 60 °F produces better results. The graph below shows why the lower threshold is preferable. It shows that heating demand does not begin to increase significantly until a HDD of five (65 °F minus 60 °F) if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold thus gives a better measure of the relation between HDD and therms (measurement of heat usage).





Cascade's analysis has optimized the HDD threshold for each city gate by lowering the HDD threshold. A lower HDD threshold of 60 is used for modeling all CityGates.

Historical Premise Count

The historical premise count by year and CityGate was derived from the analysis of monthly premise counts by town and tariff pulled from the Customer Care and Billing (CC&B) system. Monthly premise counts by town, tariff, and year were allocated by town to each CityGate to determine total allocated CityGate premise count by tariff, year, and month.

Historical Premise Count by CityGate were calculated utilizing the equations defined below:

$P\_A\_CCB_{[CG, Yr, Mth, Tariff]} = P\_CCB_{[Town,Tariff,Yr,Mth-1]} \times TGA_{[Town, CG]}$

$CCB\_AAP_{[CG, Yr, Tariff]} = Average(P\_A\_CCB_{[CG, Yr, Mth, Tariff]})$

Definitions:

- P_CCB: Raw CCB premise count data by billing Year, Month -1_{Mth}, Town, and Tariff
- P_A_CCB: calculated premise count where monthly CC&B premise count by tariff is allocated to each CityGate based upon the TGA
- TGA: Town to gate allocation (TGA) where 100 % of a towns billed volume is allocated to one or more CityGates
- CCB_AAP: CC&B Average annual premise count by CityGate, tariff, and year

Growth

Growth is a calculated value which is determined based upon Woods and Poole Growth, Economic, Mixed, or a manually assigned Cascade growth adjustment plus an EIA efficiency factor. Cascade utilizes a manual growth adjustment when it determines the Woods and Poole growth figure does not best project the growth of a CityGate for a period of time. Manually assigned growth factors are based on supporting analytics related to premise growth, engineering estimates, and internal customer projections.

Growth effects are cumulative, which means that growth effects from one year carry over into the next year. However, there can occasionally be predictable events that impact demand for a specific time period but in a manner such that normal demand resumes when the event is over. For example, a factory may shut down for several months but return to full gas usage after the shutdown. This in turn would reduce CityGate demand for those months but would not affect demand thereafter. Cascade incorporates these non-cumulative events in its forecast as a manual assumption.

Forecast Adjustment Factor by CityGate and year was calculated utilizing the equations defined below:

$WP\_M_{[GC,Yr]} = [WP\_E_{[CG,Yr]} * (1- WC_{[CG]})] + [WP\_P_{[CG,Yr]} * WC_{[CG]}]$

$A\_GR_{[CG,Yr]} = \text{Select}\ (WP\_M_{[CG,Yr],} WP\_E_{[CG,Yr]}, WP\_P_{[CG,Yr]}, MAG_{[GC,Yr]})$

$SA\_GR_{[CG,Yr]} = A\_GR_{[CG,Yr]} \times (GS_{[Avg,High,Low]} +1)$[8]

$SEC\_GF_{[CG,Yr]} = SEC\_GF_{[CG,Yr-1]} *(1 + S\_GF_{[Yr,CG]} + EIA\_E_{[GC,YR]})$

$SEC\_GR_{[CG,Yr]} = (SEC\_GF_{[CG,Yr]} – 1) /1$

$FAF_{[CG,YR,Mth]} = (SEC\_GR_{[CG,Yr]} + MA_{[Yr]} + MA_{[Yr,Mth]} + MA_{[Mth]})$

Definitions:

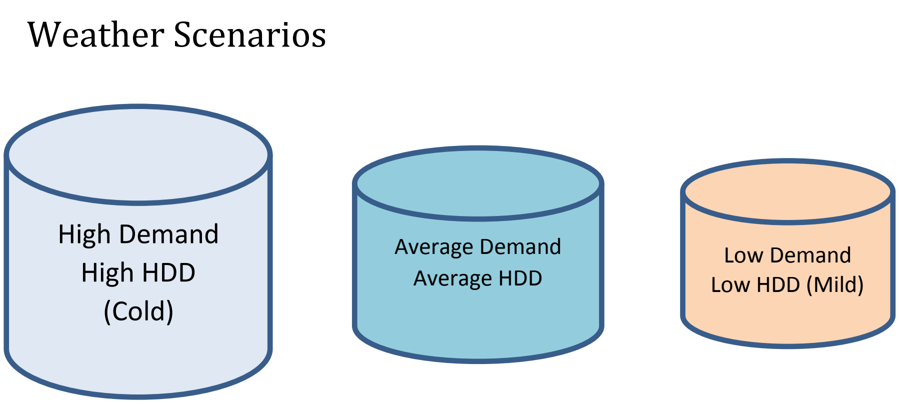
- $WC_{[CG]}$: Weather correlation R^2 coefficient for a CityGate
- $A\_GR_{[CG,Yr]}$: The Assigned Annual Growth Rate, represents growth by CityGate and year (This defaults to the Woods and Poole Growth rate for the CityGate and year unless a Manually Assigned Growth rate is provided)
- $WP\_P_{[GC,Yr]}$: Woods and Poole Population Growth by CityGate and year
- $WP\_E_{[GC,Yr]}$: Woods and Poole Economic Growth by CityGate and year
- $WP\_M_{[GC,Yr]}$: Mixed Woods and Poole Population and Economic Growth factors by CityGate and year
- $MAG_{[GC,Yr]}$: Manually Assigned Growth by CityGate and year
- $SA\_GR_{[CG,Yr]}$: The Assigned Scenario Growth Rate, represents A_GR impacted by the selected growth scenario
- $GS_{[Avg,High,Low]}$: Growth Scenario Impact for average, high, and low growth given in percent terms
- $EIA\_E_{[GC,Yr]}$: EIA Efficiency factor by year
- $SEC\_GF_{[CG,Yr]}$: Applied Annual Growth Factor (With EIA Efficiency), by CityGate and year that is compounded
- $SEC\_GR_{[CG,Yr]}$: Applied Annual Growth modified from a factor to percent rate
- $FAF_{[CG,Yr,Mth]}$: Final Forecast Adjustment Factor by CityGate, year, and month
- $MA_{[Yr]}$: A Manual Forecast Adjustment Factor that affects a given year
- $MA_{[Yr,Mth]}$: A Manual Forecast Adjustment Factor that affects a given month in a given year
- $MA_{[Mth]}$: A Manual Forecast Adjustment Factor that affects a given month for all years

[8] This formula changes depending on whether the assigned growth rate is positive or negative and the growth scenario (high or low). See growth scenario section for more details.

Weather Scenarios

To determine the average (medium) weather case scenario, the average HDD of each month is taken from a specified range of years for each of the seven weather locations. This forecast uses a 30 year range of weather history from the years 1986 through 2015 for each of the three scenarios. To determine the high case HDD weather scenario, Cascade selects the years representing the six coldest years (20% of the coldest years out of 30). These are the particular years with the highest system HDD. Finding the system HDD involves considering HDDs from all seven weather stations and giving appropriate weight to the weather stations that have greater impact on system wide demand. The weighting factor is determined by adding the coefficients or factors (derived from the regression[9]) for each weather station, and by then dividing the sum of the coefficients by the total value of the coefficients from all of the weather stations. Thus the system weighted HDD is the summation of HDDs from each weather station multiplied by its weighting factor. The system calculated HDDs are used to rank the years from warmest to coldest.

To determine the high case HDD weather scenario, Cascade selects the years representing the six coldest years (20% of the coldest years out of 30). These are the particular years with the highest system wide HDD. To determine the low case HDD weather scenario, Cascade selects the years representing the six warmest years (20% of the warmest years out of 30). These are the particular years with the lowest system wide HDD. For both the high and low case HDD weather scenarios, for each particular month of a given projected future year, the HDD from these six years average to provide the appropriate scenario.



[9] Refer to regression section of this report for more information.

The “normal”, or expected, HDDs used to compute the base forecast are calculated by finding the average HDD over the 30 years prior to the first forecasted year.

1985-2014 Normals												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Baker City	1032	883	639	469	254	95	10	16	125	428	790	1026
Bellingham	617	572	466	333	175	61	11	8	80	277	493	636
Bremerton	624	591	480	370	201	83	15	11	73	278	519	656
Pendleton	766	671	459	298	127	25	1	1	32	250	576	801
Redmond	795	750	585	458	266	104	17	18	113	358	656	848
Walla Walla	735	632	398	235	87	14	0	0	16	198	536	773
Yakima	876	721	504	314	123	29	2	3	53	310	667	924
System Weighted	717	644	485	341	171	58	9	8	69	284	564	751

Cascade Weather Scenario Impact

Weather Scenario Impact by Weather Station was calculated utilizing the equations defined below:

$AWS_{[Avg,\ Mth]} = Average(HDD_{[All\ Weather\ YRS,\ Mth]})$

$HWS_{[High,\ Mth]} = Average(HDD_{[Top\ X\ YRS,\ Mth]})$

$LWS_{[Low,\ Mth]} = Average(HDD_{[Bottom\ Y\ YRS,\ Mth]})$

Definitions:

- $AWS_{[Avg,\ Mth]}$: Average HDD by month for all weather years
- $HWS_{[High,\ Mth]}$: Average HDD by month for the X years with the highest HDD values (coldest), where X is the number of weather years multiplied by the weather range, e.g. 30 years * 20% = 6 years
- $LWS_{[Low,\ Mth]}$: Average HDD by month for the Y years with the lowest HDD values (warmest), where Y is the number of weather years multiplied by the weather range, e.g. 30 years * 20% = 6 years

Growth Scenarios

Cascade has defined three growth scenarios to adjust expected demand:

- Expected growth: is the calculated Annual Cascade Assigned Scenario Impact growth projection
- High Growth: is the High Cascade Assigned Scenario Impact
- Low Growth: is the Low Cascade Assigned Scenario Impact

Each scenario calculates a single growth factor to increase or decrease demand at a given CityGate in a given year over the projected 20 year period.

Cascade Growth Scenario Impact

High and low growth scenarios are defined by a banded +/- ranged based upon the average assigned scenario growth defined.

Growth Scenario Impact by CityGate and Year was calculated utilizing the equations defined below:

$SA\_GR_{[AVG, CG, Yr]} = SA\_GR_{[YR,CG]}$

$SA\_GR_{[High]}$ = If $A\_GR_{[YR,CG]} > 0$, THEN = $A\_GR_{[YR,CG]} * (1+GS_{[High]})$, ELSE = $A\_GR_{[YR,CG]} * (1-GS_{[High]})$

$SA\_GR_{[Low]}$ = If $A\_GR_{[YR, CG]} > 0$, THEN = $A\_GR_{[YR,CG]} * (1-GS_{[High]})$, ELSE = $A\_GR_{[YR, CG]} * (1+GS_{[Low]})$

Definitions:

- $GS_{[Avg, High, Low]}$: Growth based upon scenario Avg, High, or Low
- $A\_GR_{[CG, Yr]}$: The Assigned Annual Growth Rate, represents growth by CityGate and Year (This is the Population/Economic/Mixed Woods and Poole Growth factor for the CityGate and Year unless a Manually Assigned Growth factor is provided)
- $GS_{[High]}$: High Growth Range Adjustment is a model variable represented as %
- $GS_{[Low]}$: Low Growth Range Adjustment is a model variable represented as %

Regression Analysis

The majority of Cascade's core natural gas demand is used for heating purposes and is highly dependent on the weather. The colder the weather, the greater the demand. To forecast weather dependent load which accounts for weather differences, Cascade conducted a linear regression[10] analysis to develop a regression coefficient and constant for each CityGate. Cascade preformed a regression analysis of weather dependent monthly gas demand in comparison with monthly heating degree days at each CityGate for Historical Demand. The regression analysis calculated the coefficient ***b*** and constant ***C*** that best minimizes the error. This forecast uses a linear regression, no exponents were used.

Regression analysis calculates the best coefficient *b* and constant *C* values for each CityGate *utilizing the equations defined below*:

$$\boldsymbol{Demand = b \times HDD \times Customers + C}$$

Definitions:

- Demand = Core Weather Dependent Gas Demand (Daily Average for a given month in dekatherms)
- HDD = Average Heating Degree Day Per month
- b = coefficient that gives gas demand (dekatherms) per HDD per Customer
- C = constant, base level of gas demand (dekatherms) that remains the same regardless of weather

The coefficient ***b*** is the central figure in the model when calculating weather dependent demand. It best describes the impact that weather and customers has on gas demand. The larger the ***b*** coefficient, the greater the gas demand per unit of weather per customer. The constant ***C*** is the base level of gas demand (dekatherms) that remains the same regardless of weather.

In addition to finding the coefficient ***b*** and the constant ***C***, another product of the regression analysis is the production of the correlation coefficient, *R*. This figure is typically squared to form R^2. R^2 measures the strength of the relationship between two variables. R^2 values can range from zero to one. A regression with an R^2 of 1 means it has been a perfect predictor of demand, and therefore, would be an ideal regression to use. An R^2 of 1 does not guarantee a future HDD will predict the exact demand. Generally, a low R^2 value shows that it has not been a good predictor, and therefore, would not be an ideal regression to use.

[10] Regression analysis is a statistical process used to study the relationship between variables – in this case weather and demand.

For the purposes of this forecast, Cascade did not require the use of a Monte Carlo[11] model to calculate weather. There was sufficient historical weather data to produce high, low, and medium cases without utilizing a Monte Carlo simulation.

e. Demand Study (Calculation)

Monthly Demand Forecast

The Monthly Demand Forecast by CityGate, year, and month is based upon the calculated forecast for weather dependent core load plus the most recent year's (2015) non weather dependent core load where a single forecast adjustment was applied which included growth and Cascade assumptions.

Weather dependent core load was forecasted by CityGate utilizing the Weather Dependent Model equation, unless the R^2 of a CityGates linear regression was below a certain 80% threshold, meaning HDD is not a good predictor of demand.

Forecast Demand by CityGate, Year, and Month was calculated utilizing the equations defined below:

$WDD_{[CG,YR,Mth]} = (b_{[CG]} \text{ x } HDD_{[High, Ave, Low, CG,Mth]} + C_{[CG]})* DAYS_{[Yr,Mth]} + NWDDV_{[CG,YR,Mth]}$

$MDF_{[CG,YR,Mth]} = Or(WDD_{[CG,YR,Mth]}, DDV_{[CG,YR,Mth]}) * (1+FAF_{[YR,Mth,CG]})$

Definitions:

- WDD: Weather & Customer based demand for a given weather scenario for a given CityGate and month
- b: coefficient that gives gas demand (dekatherms) per HDD per Customer for a given CityGate
- C: constant, base level of gas demand (dekatherms) that remains the same regardless of weather
- DAYS: Number of days in forecast year and month
- NWDDV: Non Weather Dependent Default Demand Value based upon forecast month
- DDV: Default demand value per CityGate based upon forecast month
- MDF: Monthly demand forecast per CityGate
- FAF: Forecast Adjustment Factor by CityGate, year, and month (Includes growth, assumptions, and scenario impact)

[11] Monte Carlo model is a statistical method used to estimate solutions for complex equations that cannot be solved for implicitly. The technique typically involves averaging the results of multiple trials using random input figures. For this forecast, the primary inputs, including weather, were defined well enough that the use of Monte Carlo is not necessary.

System Peak Forecast

The purpose of finding the peak demand day is to ensure that Cascade can continue to provide adequate heating to its customers even under extreme conditions which are far colder than the norm. There are 3 scenarios that are analyzed in the forecast model:

- Expected peak day;
- System wide max peak day;
- Max CityGate peak day.

Expected peak day demand in a given year, in contrast with the highest case scenario peak day demand, is calculated by Cascade based on the average of the peak demand days for each of the last 30 years. Initially, the system-weighted peak day, which is later explained, is found for each year for the last thirty years. The actual HDD from each of those 30 peak days is averaged for each weather station resulting in an average peak HDD. Applying the associated average peak HDD to the forecast model for each CityGate yields an expected peak demand for each CityGate. Cascade calculates the expected peak demand for each CityGate for each future year of the forecast by then applying appropriate growth factors.

Cascade determines the system wide max peak demand day by first selecting the system wide single coldest day recorded in the past 30 years. To determine the system wide max peak demand day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations having the greater impact on system wide demand. This same method is used in the weather scenario section of this report in order to find the coldest and warmest years. The calculation of the system weighted HDD is applied to the previous 30 years of weather data to determine the highest HDD of all. Cascade has found December 21, 1990 to be the highest system weighted HDD for this period.

The peak demand day is then derived from the highest HDD by applying the actual HDD from the peak day for the 30 year period to the monthly linear regression equation for each CityGate[12].Thus, all CityGates associated with the Bellingham weather station, for example, use the HDD calculated for Bellingham for December 21, 1990 and similarly for all the other weather stations and CityGates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for each CityGate. To determine the peak demand day for a given projected year, growth factors (see below) are applied to the peak demand day for the thirty year period. Peak day demand is in turn calculated for each CityGate for each year of the twenty year forecast.

[12] See regression section of this report

The max CityGate peak day is determined by finding the coldest HDD for each weather station in the 30 year history and combining those to happen in one day. The difference between the system wide max peak day and the max CityGate peak day is that the system wide max peak day is the historical day that maximized the entire system demand where the max CityGate peak day is a rhetorical scenario where the coldest HDD for each weather station happened on one day.

For CityGates where demand is not weather dependent, the peak demand day cannot be calculated by applying an associated HDD. Instead, peak demand for these CityGates becomes the average daily demand for the month in which the system peak day falls. Cascade applies the calculated Daily Peak Adder (DPA) to the average daily demand number to convert the average day figure to daily peak demand. As with the weather dependent peak days, growth factors are applied to this figure.

PeakDemand by CityGate and year was calculated utilizing the equations defined below:

$DDmax_{[CG,Yr]} = (b_{[CG]} \text{ x } HDDpmax_{[day]} + C_{[CG]})$

$DDavg_{[CG,Yr]} = (b \text{ x } HDDpavg_{[day]} + C)$

$MPDF_{[CG,Yr]} = (DDmax_{[CG,Yr]})*(1+FAF_{[CG,Yr]})$ OR

$(DDV_{[CG,Yr,Mth]})/ DAYS_{[Yr,Mth]})* (1+FAF_{[CG,Yr]})*(1+DPA)$

$EPDF_{[CG,Yr]} =(DDavg_{[CG,Yr]})*(1+FAF_{[CG,Yr]})$ OR

$(DDV_{[CG,Yr,Mth]})/ DAYS_{[Yr,Mth]})* (1+FAF_{[CG,Yr]})*(1+DPA)$

Definitions:

- HDDpmax: HDD of an associated weather station on the historical peak day
- HDDpavg: Average of the weather station's HDDs from the historical peak days of each of the last 30 years
- DDmax: Daily demand based on a max peak HDD
- DDavg: Daily demand based on an average peak HDD
- b: coefficient that gives gas demand (dekatherms) per HDD per Customer
- C: constant, base level of gas demand (dekatherms) that remains the same regardless of weather
- DAYS: Number of days in forecast Year and Month
- DDV: Default monthly demand value per CityGate based upon month of peak demand day
- MPDF: Max peak demand day forecast per CityGate
- EPDF: Expected peak demand day forecast per CityGate
- FAF: Forecast Adjustment Factor by CityGate, Year (Includes Growth, Assumptions, and Scenario Impact)
- DPA: Default peak adder based on user input

Annual Premise Count Trend Forecast

The Annual Premise Count Projection by CityGate and year was based upon a linear trend analysis of the Historical Premise Count data pulled from CC&B for a CityGate, tariff, and year. Historical Premise Count by CityGate, tariff, and year was used to forward project premise count based upon the trend between premise count and time. This information is used as guide to assist Cascade when forecasting customer growth.

Premise Trends by CityGate where calculated utilizing the equations defined below:

$FPC_{[CG,Tariff,Yr]} = Trend(CCB\_AAP_{[CG,Tariff,Yr]}, Time_{[Yr]})$

Definitions:

- CCB_AAP: CCB Average Annual Premise count by CityGate, tariff, and year.
- Time: Years Raw CCB premise count data was provided
- FPC: Forward projection of annual premise count by CityGate, tariff, and year.

f. Assumptions (NOTE: All model assumptions will be included in final document)

Weather

- Forecast is based off of core data
- Core data is sourced from the pipeline company and from Cascade GMS (Gas Management System)
- Weather at each CityGate is represented by weather at one of the seven weather locations.
- HDDs, on a 60 F threshold, are used to measure unit of coldness
- The time period for finding historical weather is the past 30 years (1986-2015).
- The average weather case scenario is based on normal weather- the average monthly HDD of a historical time period of 30 years.
- The high case weather scenario uses the monthly average from the six coldest system wide years out of 30.
- The low case weather scenario uses the monthly average from the six warmest system wide years out of 30.

Linear Regression Model

- A linear regression model is used to model demand based on weather.
- Cascade refers to the most recent year (2015) for CityGates that have regressions (R^2) less than a certain value assigned by Cascade (80%).

Growth

- The forecast uses outside consulting firm Woods & Poole's forecast for population growth.
- The forecast model assumes that 1% increase in population translates to a 1% increase in gas demand, before accounting for any efficiency gains.
- The EIA efficiency factor is derived from the 2014 EIA Annual Energy Outlook.

III. Glossary of Terms and Assumptions

Core Customers – These are full service customers of Cascade that pay a delivered price of gas. These are typically residual and commercial customer users.

Non-Core Customers – These customers pay Cascade the cost of transporting the gas to Cascade and purchase the gas from another source.

Premise Count – Customer count.

NOAA – National Oceanic Administration Association, the federal agency that is the primary weather data holder for the United States.

Regression – A method of comparing two different data sets in which factors are calculated to predict one data set to the other. The closer the predicted set to the actual set the better the regression.

Correlation – A measure of the regression of between two data sets. The higher the regression or relation between two data sets the higher the correlation. Correlation figures range from zero to one.

HDD – Heating Degree Day – A unit to describe unit of coldness.

CityGate – This marks the point where the gas utility, Cascade, deliveries gas from the gas pipeline company to a large group of customers.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 164

Date prepared: 6/7/2016

Preparer: Brian Robertson

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 164

Please refer to the “RegressionAnalysis” tab of the Excel file *CONFIDENTIAL CNGCForcastModel2016-2035.xlsx* provided in response to Staff IR 130. Please describe how the effect of weather on customers’ demand is modeled. Please describe the modeled effect of weather on residential, commercial, and industrial demand.

Response:

Cascade uses a linear regressions y = a*(HDD/customer) + c*(customers) to analyze the effect of weather on customers’ demand. This can be seen on the “RegressionAnalysis” tab of the Excel file *CONFIDENTIAL CNGCForcastModel2016-2035.xlsx* in columns N and O. Column O is the constant (c) coefficient therms/customer. The constant is the baseload that doesn’t depend on weather. Column N is the slope coefficient (a) therms/HDD/customer. This coefficient increases by the slope (a) when the HDD increases by 1. Using this formula, Cascade applies the normal HDD and expected customers to the regression and solves for therms (y). Cascade modeled residential, commercial, and industrial demand together within a CityGate for this forecast. Cascade is currently analyzing and implementing a change to model each rate class individually.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 260

Date prepared: 6/24/2016

Preparer: Brian Robertson

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 260

Please refer to Cascade's response to Staff DR 164. Please describe the results of Cascade's analysis so far to implement the change to model each rate classes' load forecast individually. Please describe why Cascade is making this change.

Response:

Cascade is still implementing the changes to the forecast model so there are no results to discuss so far. Intuitively, the 3 types of core customers that Cascade serves--residential, commercial and industrial--all react to weather differently.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 259

Date prepared: 6/24/2016

Preparer: Brian Robertson

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 259

Please refer to Cascade's response to Staff DR 164. Please provide the timeline that Cascade will use to implement the change to model each rate classes' load forecast individually. Will this timeline overlap the UG 305 rate case timeline?

Response:

Cascade is working diligently to implement the change to model each rate classes' load forecast individually. However, it does not seem likely it will be fully implemented and tested during the UG 305 rate case timeline.

CASE: UG 305
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

August 11, 2016

be that the variability in interest rates depends on the level of iuflation or relative size of the deficit. This would also violate the homoskedasticity assumption.

When $\text{Var}(u_t|\mathbf{X})$ does depend on $\mathbf{X}$, it often depends on the explanatory variables at time t, $\mathbf{x}_t$. In Chapter 12, we will see that the tests for heteroskedasticity from Chapter 8 can also be used for time series regressions, at least under certain assumptions.

The final Gauss-Markov assumption for time series analysis is new.

Assumption TS.5 (No Serial Correlation)

Conditional on $\mathbf{X}$, the errors in two different time periods are uncorrelated: $\text{Corr}(u_t,u_s|\mathbf{X}) = 0$, for all $t \neq s$.

The easiest way to think of this assumption is to ignore the conditioning on $\mathbf{X}$. Then, Assumption TS.5 is simply

$$\text{Corr}(u_t,u_s) = 0, \text{ for all } t \neq s. \tag{10.12}$$

(This is how the no serial correlatiou assumption is stated when $\mathbf{X}$ is treated as nonrandom.) When considering whether Assumption TS.5 is likely to hold, we focus on equation (10.12) because of its simple iuterpretation.

When (10.12) is false, we say that the errors in (10.8) suffer from **serial correlation**, or **autocorrelation**, because they are correlated across time. Consider the case of errors from adjacent time periods. Suppose that when $u_{t-1} > 0$ then, on average, the error in the next time period, u_t, is also positive. Then, $\text{Corr}(u_t,u_{t-1}) > 0$, and the errors suffer from serial correlation. In equation (10.11), this means that if interest rates are unexpectedly high for this period, then they are likely to be above average (for the given levels of inflation and deficits) for the next period. This turns out to be a reasonable characterization for the error terms in many time series applications, which we will see in Chapter 12. For now, we assume TS.5.

Importantly, Assumption TS.5 assumes nothing about temporal correlation in the *independent* variables. For example, in equation (10.11), inf_t is almost certainly correlated across time. But this has nothing to do with whether TS.5 holds.

A natural question that arises is: In Chapters 3 and 4, why did we not assume that the errors for different cross-sectional observations are uncorrelated? The answer comes from the raudom sampling assumption: under random sampling, u_i and u_h are independent for any two observations i and h. It can also be shown that, under random sampling, the errors for different observations are iudependent conditional on the explanatory variables in the sample. Thus, for our purposes, we cousider serial correlation only to be a potential problem for regressions with times series data. (In Chapters 13 and 14, the serial correlation issue will come up in connection with panel data analysis.)

Assumptions TS.1 through TS.5 are the appropriate Gauss-Markov assumptions for time series applications, but they have other uses as well. Sometimes, TS.1 through TS.5 are satisfied in cross-sectional applications, even when random sampling is not a reasonable assumption, such as when the cross-sectional units are large relative to the population. Suppose that we have a cross-sectional data set at the city level. It might be that correlation exists across cities within the same state in some of the explanatory variables, such as property tax rates or per capita welfare payments. Correlation of the explanatory variables across observations does not cause problems for verifying the Gauss-Markov assumptions, provided the error terms are uncorrelated across cities. However, in this chapter, we are primarily interested in applying the Gauss-Markov assumptions to time series regression problems.

Theorem 10.2 (OLS Sampling Variances)

Under the time series Gauss-Markov Assumptions TS.1 through TS.5, the variance of $\hat{\beta}_j$, conditional on **X**, is

$$\mathrm{Var}(\hat{\beta}_j|\mathbf{X}) = \sigma^2/[\mathrm{SST}_j(1 - R_j^2)], j = 1, \ldots, k, \tag{10.13}$$

where SST_j is the total sum of squares of x_{tj} and R_j^2 is the R-squared from the regression of x_j on the other independent variables.

Equation (10.13) is the same variance we derived in Chapter 3 under the cross-sectional Gauss-Markov assumptions. Because the proof is very similar to the one for Theorem 3.2, we omit it. The discussion from Chapter 3 about the factors causing large variances, including multicollinearity among the explanatory variables, applies immediately to the time series case.

The usual estimator of the error variance is also unbiased under Assumptions TS.1 through TS.5, and the Gauss-Markov Theorem holds.

Theorem 10.3 (Unbiased Estimation of σ^2)

Under Assumptions TS.1 through TS.5, the estimator $\hat{\sigma}^2 = \mathrm{SSR}/df$ is an unbiased estimator of σ^2, where $df = n - k - 1$.

Theorem 10.4 (Gauss-Markov Theorem)

Under Assumptions TS.1 through TS.5, the OLS estimators are the best linear unbiased estimators conditional on **X**.

QUESTION 10.3

In the FDL model $y_t = \alpha_0 + \delta_0 z_t + \delta_1 z_{t-1} + u_t$, explain the nature of any multicollinearity in the explanatory variables.

The bottom line here is that OLS has the same desirable finite sample properties under TS.1 through TS.5 that it has under MLR.1 through MLR.5.

Inference under the Classical Linear Model Assumptions

In order to use the usual OLS standard errors, t statistics, and F statistics, we need to add a final assumption that is analogous to the normality assumption we used for cross-sectional analysis.

Column Headers	Description	
time	time period of observation	
year	year of observation	
month	month of observation	
count101-BakerCity	Schedule 101 customer count for Baker City weather station	
count101-Pendleton	"	Pendleton weather station
count101-Redmond	"	Redmond weather station
count101-WallaWalla	"	Milton Freewater
upc101-BakerCity	Schedule 101 use per customer for Baker City weather station	
upc101-Pendleton	"	Pendleton weather station
upc101-Redmond	"	Redmond weather station
upc101-WallaWalla	"	Milton Freewater
count104-BakerCity	Schedule 104 customer count for Baker City weather station	
count104-Pendleton	"	Pendleton weather station
count104-Redmond	"	Redmond weather station
count104-WallaWalla	"	Milton Freewater
upc104-BakerCity	Schedule 104 use per customer for Baker City weather station	
upc104-Pendleton	"	Pendleton weather station
upc104-Redmond	"	Redmond weather station
upc104-WallaWalla	"	Milton Freewater
count105-Baker	Schedule 105 customer count for Baker City weather station	
count105-Pendleton	"	Pendleton weather station
count105-Redmond	"	Redmond weather station
count105-WallaWalla	"	Milton Freewater
upc105-BakerCity	Schedule 105 use per customer for Baker City weather station	
upc105-Pendleton	"	Pendleton weather station
upc105-Redmond	"	Redmond weather station
upc105-WallaWalla	"	Milton Freewater
s900	Therms usage of the Hermiston Generating Plant (Schedule 900)	
HDD-BakerCity	Average daily HDD over the month for Baker City weather station	
HDD-Pendleton	"	Pendleton weather station
HDD-Redmond	"	Redmond weather station
HDD-WallaWalla	"	Walla Walla weather station
HDD2-BakerCity	Square of average daily HDD for Baker City weather station	
HDD2-Pendleton	"	Pendleton weather station
HDD2-Redmond	"	Redmond weather station
HDD2-WallaWalla	"	Walla Walla weather station

growth-BakerCity2	Yearly population of Baker County	
growth-Pendleton	Woods and Poole’s population economic growth indicator variable for Hermiston-Pendleton	
growth-Redmond	"	Redmond
growth-WallaWalla	"	Walla Walla

Source
calculated variable: 1 = June 2010, 79 = December 2016
Cascade's response to Staff DR 301, tab 1, column A
" column B*
Cascade's response to Staff DR 129, tab 4, column G
"
"
"
Cascade's response to Staff DR 301, tab 1, column E ÷ count101-BakerCity
" count101-Pendleton
" count101-Redmond
" count101-WallaWalla
Cascade's response to Staff DR 129, tab 4, column G
"
"
"
Cascade's response to Staff DR 301, tab 1, column E ÷ count104-BakerCity
" count104-Pendleton
" count104-Redmond
" count104-WallaWalla
Cascade's response to Staff DR 129, tab 4, column G
"
"
"
Cascade's response to Staff DR 301, tab 1, column E ÷ count105-BakerCity
" count105-Pendleton
" count105-Redmond
" count105-WallaWalla
Cascade's response to Staff DR 170, column D
Cascade's response to Staff DR 129, tab 12, columns ID:KR
"
"
"
HDD-BakerCity^2
HDD-Pendleton^2
HDD-Redmond^2
HDD-WallaWalla^2

1. Population Research Center at Portland State University's College of Urban & Public Affairs, "2010-2015 Certified Population Estimates," July 1, 2010 to July 1, 2015, available at: *https://www.pdx.edu/prc/population-reports-estimates* .
2. Annualized growth rate from 2015 to 2020 is applied for 2016: Oregon Office of Economic Analysis, "Oregon's long-term county population forecast, 2010-2050," 2013, available at: *http://www.oregon.gov/das/OEA/Pages/forecastdemographic.aspx* .

Cascade's response to Staff DR 192, tab 1, columns AZ:BF
"
"

*** " indicates text is the same as above**

Column Headers	Description	
time	time period of observation	
year	year of observation	
month	month of observation	
count101-BakerCity	Schedule 101 customer count for Baker City weather station	
count101-Pendleton	"	Pendleton weather station
count101-Redmond	"	Redmond weather station
count101-WallaWalla	"	Milton Freewater
upc101-BakerCity	Schedule 101 use per customer for Baker City weather station	
upc101-Pendleton	"	Pendleton weather station
upc101-Redmond	"	Redmond weather station
upc101-WallaWalla	"	Milton Freewater
count104-BakerCity	Schedule 104 customer count for Baker City weather station	
count104-Pendleton	"	Pendleton weather station
count104-Redmond	"	Redmond weather station
count104-WallaWalla	"	Milton Freewater
upc104-BakerCity	Schedule 104 use per customer for Baker City weather station	
upc104-Pendleton	"	Pendleton weather station
upc104-Redmond	"	Redmond weather station
upc104-WallaWalla	"	Milton Freewater
count105-Baker	Schedule 105 customer count for Baker City weather station	
count105-Pendleton	"	Pendleton weather station
count105-Redmond	"	Redmond weather station
count105-WallaWalla	"	Milton Freewater
upc105-BakerCity	Schedule 105 use per customer for Baker City weather station	
upc105-Pendleton	"	Pendleton weather station
upc105-Redmond	"	Redmond weather station
upc105-WallaWalla	"	Milton Freewater
s900	Therms usage of the Hermiston Generating Plant (Schedule 900)	
HDD-BakerCity	Average daily HDD over the month for Baker City weather station	
HDD-Pendleton	"	Pendleton weather station
HDD-Redmond	"	Redmond weather station
HDD-WallaWalla	"	Walla Walla weather station
HDD2-BakerCity	Square of average daily HDD for Baker City weather station	
HDD2-Pendleton	"	Pendleton weather station
HDD2-Redmond	"	Redmond weather station
HDD2-WallaWalla	"	Walla Walla weather station

growth-BakerCity2	Yearly population of Baker County	
growth-Pendleton	Woods and Poole’s population economic growth indicator variable for Hermiston-Pendleton	
growth-Redmond	"	Redmond
growth-WallaWalla	"	Walla Walla

Source

calculated variable: 1 = June 2010, 79 = December 2016

Cascade's response to Staff DR 301, tab 1, column A

" column B*

Cascade's response to Staff DR 129, tab 4, column G

"

"

"

Cascade's response to Staff DR 301, tab 1, column E ÷ count101-BakerCity

" count101-Pendleton

" count101-Redmond

" count101-WallaWalla

Cascade's response to Staff DR 129, tab 4, column G

"

"

"

Cascade's response to Staff DR 301, tab 1, column E ÷ count104-BakerCity

" count104-Pendleton

" count104-Redmond

" count104-WallaWalla

Cascade's response to Staff DR 129, tab 4, column G

"

"

"

Cascade's response to Staff DR 301, tab 1, column E ÷ count105-BakerCity

" count105-Pendleton

" count105-Redmond

" count105-WallaWalla

Cascade's response to Staff DR 170, column D

Cascade's response to Staff DR 129, tab 12, columns ID:KR

"

"

"

HDD-BakerCity^2

HDD-Pendleton^2

HDD-Redmond^2

HDD-WallaWalla^2

1. Population Research Center at Portland State University's College of Urban & Public Affairs, "2010-2015 Certified Population Estimates," July 1, 2010 to July 1, 2015, available at: *https://www.pdx.edu/prc/population-reports-estimates* .
2. Annualized growth rate from 2015 to 2020 is applied for 2016: Oregon Office of Economic Analysis, "Oregon's long-term county population forecast, 2010-2050," 2013, available at: *http://www.oregon.gov/das/OEA/Pages/forecastdemographic.aspx* .

Cascade's response to Staff DR 192, tab 1, columns AZ:BF

"

"

*** " indicates text is the same as above**

CASE: UG 305
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Exhibits in Support
Of Opening Testimony

August 11, 2016

Exhibit 305

1. Baker City, OR weather station Forecasting Models

The Baker City, OR weather station includes Baker City, Huntington, Nyssa, Ontario, and Vale. The forecasting models for the Baker City weather station region are given below for the residential, commercial, and industrial sectors:

Residential Sector, use per customer (UPC):

$$THM/C_t^{B.r} = \alpha_1 DD_t^B + \alpha_2 (DD_t^B)^2 + \alpha_m I_m + ARIMA\epsilon_t\ (1,1,1)$$

Model notes:
1. *THM/C* is therms per customer.
2. *t* is time period (monthly from June 2010 to December 2016).
3. *B* is Baker City weather station.
4. *r* is residential Schedule 101.
5. *DD* is degree days.
6. *m* is month.
7. *I* is an indicator variable taking on a value of 1 if it is the month indicated and 0 otherwise (February to December).
8. $ARIMA\epsilon_t$ (1,0,0) indicates that the model has 1 autoregressive term, 1 differenced term, and 1 moving average term.

Residential Sector, Customers:

$$C_t^{B.r} = \alpha_0 + \alpha_1 POP_t^B + \alpha_m I_m + ARIMA\epsilon_t\ (1,0,0)$$

Model notes:
1. *POP* is population (Baker County, OR).

Notes:
1. In each time period, therms is the product of therms per customer and number of customers

Commercial Sector, UPC:

$$THM/C_t^{B.c} = \alpha_1 DD_t^B + \alpha_2 (DD_t^B)^2 + \alpha_m I_m + ARIMA\epsilon_t\ (1,1,1)$$

Model notes:
1. *c* is commercial schedule 104.

Commercial Sector, Customers:

$$C_t^{B.c} = \alpha_0 + \alpha_1 POP_t^B + \alpha_m I_m + ARIMA\epsilon_t\ (1,0,0)$$

Industrial Sector, UPC:

$$THM/C_t^{B.i} = \alpha_1 DD_t^B + \alpha_2 (DD_t^B)^2 + \alpha_m I_m + ARIMA\epsilon_t\ (0,1,1)$$

Model notes:
1. *i* is industrial schedule 105.

Industrial Sector, Customers:

$$C_t^{B.i} = \alpha_1 POP_t^B + \alpha_m I_m + ARIMA\epsilon_t\ (0,1,0)$$

2. Pendleton, OR weather station Forecasting Models

The Pendleton, OR weather station includes Athena, Hermiston, Irrigon, Mission tap, Pendleton, Pilot Rock, Stanfield, Umatilla, and Weston. The forecasting models for the Pendleton weather station region are given below for the residential, commercial, and industrial sectors:

Residential Sector, use per customer (UPC):

$$THM/C_t^{P.r} = \alpha_1 DD_t^P + \alpha_2 (DD_t^P)^2 + \alpha_m I_m + ARIMA\epsilon_t \ (1,1,1)$$

Model notes:
1. P is Pendleton weather station.

Residential Sector, Customers:

$$C_t^{P.r} = \alpha_1 WP_t^P + \alpha_m I_m + ARIMA\epsilon_t \ (0,1,0)$$

Model notes:
1. *WP* is Woods and Poole's population economic growth indicator variable (Hermiston – Pendleton, OR).

Commercial Sector, UPC:

$$THM/C_t^{P.c} = \alpha_0 + \alpha_1 DD_t^P + \alpha_2 (DD_t^P)^2 + \alpha_m I_m + ARIMA\epsilon_t \ (1,0,0)$$

Commercial Sector, Customers:

$$C_t^{P.c} = \alpha_1 WP_t^P + \alpha_m I_m + ARIMA\epsilon_t \ (0,1,0)$$

Industrial Sector, UPC:

$$THM/C_t^{P.i} = \alpha_0 + \alpha_1 DD_t^P + \alpha_2 (DD_t^P)^2 + \alpha_m I_m + ARIMA\epsilon_t \ (0,0,0)$$

Industrial Sector, Customers:

$$C_t^{P.i} = \alpha_1 WP_t^P + \alpha_m I_m + ARIMA\epsilon_t \ (0,1,0)$$

Industrial Sector, Therms:

$$THM_t^{P.i900} = \alpha_1 DD_t^P + \alpha_2 (DD_t^P)^2 + \alpha_3 WP_t^P + \alpha_m I_m + ARIMA\epsilon_t \ (0,0,1)$$

Model notes:
1. *i900* is Special Contract Schedule 900: Hermiston Generating Plant.

3. Redmond, OR weather station Forecasting Models

The Redmond, OR weather station includes Bend, Chemult, Crescent, Gilchrist, La Pine, Madras, Metolius, Powell, Butte, Prineville, Redmond, and Sunriver. The forecasting models for the Redmond weather station region are given below for the residential, commercial, and industrial sectors:

Residential Sector, use per customer (UPC):

$$THM/C_t^{R.r} = \alpha_0 + \alpha_1 DD_t^R + \alpha_2 (DD_t^R)^2 + \alpha_m I_m + ARIMA\epsilon_t\ (0,0,1)$$

Model notes:
1. R is Redmond weather station.

Residential Sector, Customers:

$$C_t^{R.r} = \alpha_0 + \alpha_1 WP_t^R + \alpha_m I_m + ARIMA\epsilon_t\ (0,0,4)$$

Commercial Sector, UPC:

$$THM/C_t^{R.c} = \alpha_0 + \alpha_1 DD_t^R + \alpha_2 (DD_t^R)^2 + \alpha_m I_m + ARIMA\epsilon_t\ (1,0,0)$$

Commercial Sector, Customers:

$$C_t^{R.c} = \alpha_0 + \alpha_1 WP_t^R + \alpha_m I_m + ARIMA\epsilon_t\ (1,0,0)$$

Industrial Sector, UPC:

$$THM/C_t^{R.i} = \alpha_1 DD_t^R + \alpha_2 (DD_t^R)^2 + \alpha_m I_m + ARIMA\epsilon_t\ (0,1,1)$$

Industrial Sector, Customers:

$$C_t^{R.i} = \alpha_0 + \alpha_1 WP_t^R + \alpha_m I_m + ARIMA\epsilon_t\ (1,0,0)$$

4. Milton Freewater, OR Forecasting Models

The Milton Freewater, OR forecasts use weather data from the Walla Walla, WA weather station. The forecasting models for Milton Freewater are given below for the residential, commercial, and industrial sectors:

Residential Sector, use per customer (UPC):

$$THM/C_t^{M.r} = \alpha_0 + \alpha_1 DD_t^W + \alpha_2 (DD_t^W)^2 + \alpha_m I_m + ARIMA\epsilon_t \ (0,0,0)$$

Model notes:
1. *M* is Milton Freewater.
2. *W* is Walla Walla weather station.

Residential Sector, Customers:

$$C_t^{M.r} = \alpha_1 WP_t^W + \alpha_m I_m + ARIMA\epsilon_t \ (0,1,0)$$

Commercial Sector, UPC:

$$THM/C_t^{M.c} = \alpha_1 DD_t^W + \alpha_2 (DD_t^W)^2 + \alpha_m I_m + ARIMA\epsilon_t \ (2,1,0)$$

Commercial Sector, Customers:

$$C_t^{M.c} = \alpha_0 + \alpha_1 WP_t^W + \alpha_m I_m + ARIMA\epsilon_t \ (2,0,0)$$

Industrial Sector, UPC:

$$THM/C_t^{M.i} = \alpha_1 DD_t^W + \alpha_2 (DD_t^W)^2 + \alpha_m I_m + ARIMA\epsilon_t \ (0,1,1)$$

Industrial Sector, Customers:

$$C_t^{M.i} = \alpha_1 WP_t^W + \alpha_m I_m + ARIMA\epsilon_t \ (0,1,0)$$

CASE: UG 305
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Erik Colville. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High St. SE, Suite 100, Salem, OR 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I present Staff's recommendations regarding the rate treatment of gas storage in rate base and "other gas supply expense," an issue related to the Integrated Resource Plan (IRP) process, and Cascade's proposed PGA commodity sharing adjustment.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/401 Witness Qualification Statement, Exhibit Staff/402 Other Gas Supply Expense, which details my analysis related to Cascade's other gas supply expense, and Exhibit Staff/403 Data Request Responses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Gas Storage in Rate Base.. 2
Issue 2. Other Gas Supply Expense (FERC Account 813)........................ 5
Issue 3. Underground Storage Expense (FERC Accounts 814-837)......... 9
Issue 4. Purchased Gas Expense... 10
Issue 5. Integrated Resource Plan (IRP) 11
Issue 6. PGA Commodity Sharing Adjustment 13

ISSUE 1. GAS STORAGE IN RATE BASE

Q. Please describe the gas storage costs at issue.

A. Storage gas consists of two components, "cushion gas" and "working gas inventory." Cushion gas is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir.[1] "Working gas inventory" is the gas that flows in and out of the storage reservoir (or liquefied natural gas tank) to serve customer loads.[2] Cascade does not own its own storage facilities and owns no "cushion gas."[3] Accordingly, the only costs for storage gas at issue in this rate case are those for working gas inventory.

Q. Please summarize Cascade's and your proposed rate treatment of Cascade's gas storage costs.

A. Cascade includes $449,172 for gas storage in its rate base. This amount is the 2015 end-of-year balance for Cascade's working gas inventory.[4] Cascade does not adjust the 2015 end-of-year amount.

I propose to adjust the amount Cascade includes in rate base downward by $37,840, so that the amount included in rate base is the average of monthly working gas inventories for 2015, rather than the end-of-year amount.

Q. Please summarize the Commission's historical treatment of gas storage in rate base.

[1] *See, e.g.*, Docket No. UM 1651, Order No. 13-349 (Sept. 30, 2013).
[2] *Id.*
[3] Cascade Response to Staff DR No. 199 (Docket No. UG 287).
[4] CNG/201, Parvinen/1, line 26, Column (1).

A. In Cascade rate case Order No. 77-125, the Commission identified gas in storage as an asset that should be in rate base.[5] In the past, Staff has recommended that working gas inventory costs be recovered through a gas utility's Purchase Gas Adjustment (PGA); however, after investigation, Staff concluded that the benefit obtained by updating the level of working gas inventory each year does not warrant a complicated adjustment to the PGA mechanism.[6] Currently, the Commission has approved stipulations for all three of Oregon's regulated gas utilities that include working gas inventory costs in rate base.[7] Staff does not oppose including the cost of working gas inventory in rate base.

However, the Commission has concluded that the amount included in rate base should be based on the most recent calendar year average,[8] and in Cascade's last rate case, Docket No. UG 287, approved a stipulation that includes in rate base the most recent calendar year average of gas storage costs.

Q. Please summarize your analysis of the amount that should be included in rate base for gas storage.

A. Given the historical treatment of gas storage discussed above, I recommend an amount of gas storage in rate base based upon the most recent

[5] Docket No. UF 3246, Order No. 77-125 (Feb. 22, 1977).
[6] Docket No. UG 287, Staff/400, Colville/2-3 (July 31, 2015).
[7] *See* Docket No. UM 1651, Order No. 13-349 (Sept. 30, 2013); Docket No.UG 287, Order No. 15-412 (Dec. 28, 2015); Docket No.UG 288, Order No. 16-109 (Mar. 15, 2016).
[8] *See* Docket No. UF 3084, UF 3129, Order No. 74-898 (Nov. 21, 1974).

calendar year average. To obtain sufficient information to make this adjustment,

I issued Data Request (DR) No. 142 asking for data supporting the dollar amount of gas in storage that was or is included in rate base, by month, for the years 2005-2015. That data and the calendar year average of that data is calculated and presented in the table below.

Table 1 Gas Storage in Rate Base

		2015
	Jan	$490,752
	Feb	$523,745
	Mar	$344,216
	Apr	$200,054
	May	$240,375
	June	$288,792
	Jul	$381,035
	Aug	$468,191
	Sep	$512,350
	Oct	$511,041
	Nov	$526,263
	Dec	$449,172
Calculated Year Average		**$411,332**

Based on the Staff DR No. 142 response data, the gas storage in rate base, using the average for calendar year 2015, is $411,332.

Q. Please describe your proposed adjustment to gas storage in rate base.

A. I propose to reduce Cascade's gas storage in rate base by $37,840, from $449,172 to $411,332.

ISSUE 2. OTHER GAS SUPPLY EXPENSE (FERC ACCOUNT 813)

Q. What is other gas supply expense?

A. Other gas supply expense is expense recorded in FERC Account 813 and includes the cost of labor, materials used, and expenses incurred in connection with gas supply functions, including research and development expenses, not provided for in any other FERC account for gas expense.[9]

Q. Please summarize Cascade's proposal related to other gas supply expense.

A. Cascade proposes to use its total other gas supply expense for calendar year 2015 for the test year expense. This proposed amount is $8,484, based upon Cascade's response to Staff DR Nos. 144 and 145. Cascade does not adjust the 2015 base year amount.

Q. Please summarize Commission historical treatment of other gas supply expense.

A. I was not able to find a Commission order expressly addressing the ratemaking treatment of "other gas expense" that should be included in revenue requirement.

In Cascade's recent general rate case, Docket No. UG 287, I proposed weighing the previous three years' expense results more heavily than a long-term trend, unless there is a reason not to do so. I apply the same rationale and analysis in this case and conclude that no adjustment to the amount proposed by Cascade is warranted.

---

[9] See 18 C.F.R. FERC Account 813.

Q. Please summarize your analysis.

A. First, I obtained Cascade's actual other gas expense for 2013, 2014, and 2015.[10] I graphed the three years' expense to observe the expense pattern. The pattern is shown with the blue line in Figure 1 below.

Second, as reflected in the graph, other gas expense is higher in 2014 than in 2013 and 2015. In response to Staff DR No. 146, Cascade explained that a change in allocation of software maintenance expense is the likely cause of the expense peak shown in 2014. To eliminate the influence of the change in the expense allocation method in year 2014, Cascade suggests that the pattern represented by the 2013 expenses and 2015 expenses most closely aligns with on-going expenses.

Third, based on Cascade's explanation that 2014 expenses include a change in the software expense allocation method, I adjusted the 2014 expense to reflect the current allocation method.

To make this adjustment, I referred to Cascade's response that stated that $6,089 had been allocated to Oregon for software maintenance in 2014.[11] Cascade's response to Staff DR No. 146 identified that $3,410 in software maintenance expense had been allocated to Oregon in 2015. To account for the atypical software maintenance-related expense peak in 2014, I reduced the 2014 other gas supply expense by $2,679 ($6,089 minus $3,410) for comparison to 2015. Accounting for this adjustment, I re-graphed the expenses to observe the pattern (depicted with the red line in Figure 1 below).

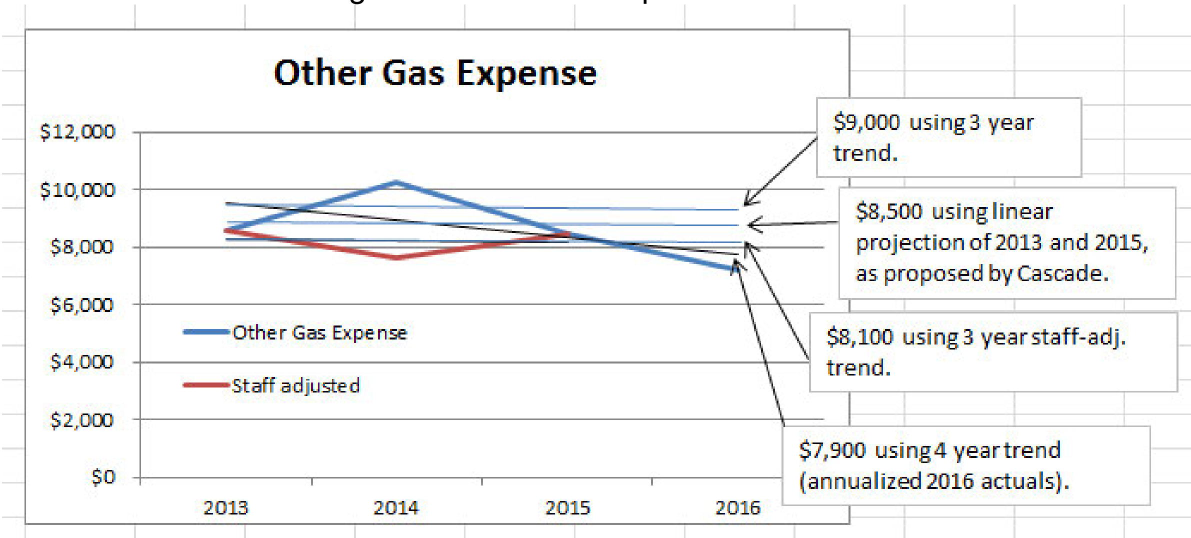
[10] Staff/403,Cascade Response to Staff DR No. 145.
[11] Cascade Response to Staff DR No. 193 (Docket No. UG 287).

As shown in Figure 1 below, the adjustment for the software allocation methodology change in 2014 changed the expense pattern as compared to the actual 2014 expense pattern.

Fourth, as shown in Figure 1 below, the three-year trend line for other gas expenses reported by Cascade project a 2016 expense of $9,000. The linear projection of 2013 and 2015 other gas expense suggests $8,500 for the 2016 expense (which aligns with Cascade's proposal in this rate case of $8,484, rounded up to $8,500). Finally, the three-year trend line for other gas expenses, as adjusted for the change in software maintenance expense allocation, suggests $8,100 for the 2016 expense. For reference, the 4 year trend line for other gas expense, using annualized 2016 year-to-date expenses, suggests $7,900 for the 2016 expense.

Fifth, given the small range in amounts suggested by the different analysis methods described above, I conclude that the $8,484 proposed by Cascade is a reasonable amount to include as Cascade's 2016 test year expense in this rate case.

Figure 1 Other Gas Expense



Q. Please summarize your proposed adjustment to Other Gas Supply Expense.

A. I have no proposed adjustment to other gas supply expense.[12]

[12] See Staff/402 for a detailed description of Staff's analysis.

ISSUE 3. UNDERGROUND STORAGE EXPENSE (FERC ACCOUNTS 814-837)

Q. Please summarize Cascade's proposal related to underground storage expense.

A. No expenses in FERC accounts 814-837 are requested in this rate case.

Q. Please describe your proposed adjustment of underground storage expense.

A. Cascade does not propose an amount for underground storage expense. I have no proposed adjustment.

ISSUE 4. PURCHASED GAS EXPENSE

Q. Please describe your proposed adjustment of purchased gas expense.

A. The actual cost of gas is reconciled with customers each year in the Purchased Gas Adjustment (PGA).[13] Therefore, I have no proposed adjustment for this rate case issue at this time.

[13] Docket No. UM 1286, Order No. 14-238 (June 24, 2014).

ISSUE 5. INTEGRATED RESOURCE PLAN (IRP)

Q. Does Cascade make a proposal related to its IRP in this rate case?

A. No.

Q. Do you have an IRP related concern?

A. Yes. Cascade's staffing approach has created deficiencies in its ability to perform its required regulatory IRP activities. My specific example reflecting these deficiencies comes from the 2014 IRP process. During the IRP preparation process, Cascade requested and was granted three extensions to the filing date for its IRP. These extensions granted an additional eleven months for preparation of the IRP. Even with this additional time to prepare the IRP, Cascade did not file an IRP that satisfied the Commission's criteria. On February 9, 2016, the Commission decided to not acknowledge Cascade's 2014 IRP. The Commission found Cascade had not adequately addressed areas of concern in its 2014 IRP. The Commission also found Cascade's 2014 IRP generally failed to adhere to the IRP Guidelines and relevant Orders put forth by the Commission related to integrated resource planning.

My concern regarding Cascade's staffing is tempered by communications with Cascade at its July 14, 2016 Quarterly Update Meeting where it presented a staffing plan for its 2014 IRP Update and its 2018 IRP, which includes two new IRP analysts and an IRP consultant. In addition, Cascade presented a proposed schedule for its 2014 IRP Update and its 2018 IRP.

Q. Did you have an IRP related concern in Cascade's last general rate case (Docket No. UG 287)?

A. Yes. I also was concerned that Cascade's staffing approach had created deficiencies in its ability to perform its required regulatory IRP activities.

Q. Did you have a proposed adjustment in Docket No. UG 287?

A. Yes. I proposed that Cascade evaluate its staffing approach and changes be made where needed, to ensure that its required regulatory IRP activities are performed on schedule and in compliance with Commission requirements.

Q. Did Cascade have a response to your proposed adjustment in Docket No. UG 287?

A. Yes. In reply testimony filed in Docket No. UG 287, Mike Parvinen testified that Cascade, "now has sufficient personnel to support the IRP process…Cascade has recently filled a new position entitled Supply Resource Analyst. This new position was included in the Labor Addition adjustment and is intended to provide support and backup for the IRP process. Although it will take time for the new individual to be fully-trained in all aspects of the IRP, this hire will certainly help with keeping future IRPs on track."[14]

Q. Do you have a proposal related to Cascade's IRP in this docket?

A. Yes. I propose that Cascade continue to evaluate its staffing approach and changes be made where needed, to ensure that its required regulatory IRP activities are performed on schedule and in compliance with Commission requirements. I do not propose an adjustment in this rate case for Cascade's failure to perform its required regulatory IRP activities related to the 2014 IRP.

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[14] CNG/700 Parvinen/41 (Docket No. UG 287).

ISSUE 6: PGA COMMODITY SHARING ADJUSTMENT

Q. Please summarize Cascade's proposal related to adjusting the PGA commodity sharing.

A. Cascade presents a downward adjustment to operating revenues to reflect a reduction in the amount of PGA commodity sharing due to commodity costs being less than forecasted in the PGA for the 2015-2016 gas year.[15] The adjustment before tax is minus $433,904, while the net adjustment after taxes is minus $260,603.

Q. Please summarize your analysis.

A. I issued Staff DR No. 149 asking Cascade to provide a description of the purpose of the PGA Commodity Sharing Adjustment in column (e) of the Proposed Adjustments to Base Year Results. In Cascade's response to Staff DR No. 149, the Company explains that the 2015 actual gas costs were lower than the commodity rate built into the PGA, therefore, the Company benefited. However, there is then a mismatch between revenues and gas costs associated with the 10 percent that would not exist if no sharing were required. Therefore, an adjustment is required to match the revenues with the associated expenses.

I asked in follow-up Staff DR No. 332 for a spreadsheet detailing the source and calculation of the PGA Commodity Sharing Adjustment, as well as a narrative explanation of the calculation. Cascade's response to Staff DR No. 332 provided monthly spreadsheet reconciliations of actual and embedded

[15] CNGC/200, Parvinen/5; CNGC/204, Parvinen/1.

commodity costs which, when combined, calculate the PGA Commodity Sharing Adjustment. I reviewed the monthly reconciliations for methodology and confirmed the PGA Commodity Sharing Adjustment amount.

Q. Please summarize your proposed adjustment to Other Gas Supply Expense.

A. I confirmed that the PGA Commodity Sharing Adjustment in column (e) of the Proposed Adjustments to Base Year Results was correctly calculated. Therefore, I have no proposed adjustment to that amount.

Q. Does this conclude your testimony?

A. Yes.

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Erik E. Colville, P.E.
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High St. SE, Suite 100 SALEM, OR. 97301
EDUCATION:	Bachelor of Science in Agricultural Engineering Washington State University, Pullman, WA, 1979 Master of Business Administration City University, Seattle, WA, 1989 Licensed Professional Engineer since 1984, and licensed as such in Oregon since 1997
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since June of 2010. I am a Senior Utility Analyst in the Energy Resources and Planning Division of the Utility Program. Current responsibilities include lead analyst for integrated resource planning and resource acquisition, analyst for rate case elements, and other regulated utility matters. I have approximately 36 years of professional engineering experience, including approximately 23 years: • Relating to air, water and soil environmental issues; and • Evaluating, planning, permitting, designing, and supporting construction of energy facilities

CASE: UG 305
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

August 11, 2016

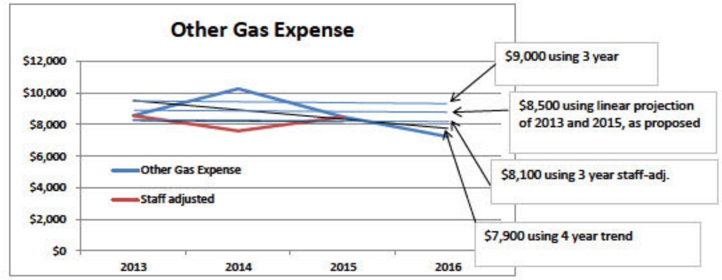
Exhibit Staff/402 Other Gas Supply Expense

From DR58 Response file name "OPUC-58 (b) Revised.xlsx"

	2013	2014	2015	Annualized 2016	YTD Apr 2016
Other Gas Expense	$8,567	$10,273	$8,484	$7,225	$2,408
Staff adjusted	$8,567	$7,594	$8,484	$7,225	

COLVILLE Erik: See below for source/logic of this adjustment.

COLVILLE Erik: From "Paste Special" tab of "OPUC-145 .xlsx"



Response: **See Excel file OPUC-146.xlsx**

Cascade feels that the amounts reported in 2013 & 2015 more accurately reflect the expenditure level in FERC 813 as compared to 2014. The allocation of the software maintenance expenditure between Utility Group companies was changed in 2015 to allocate by meter count. Cascade's total amount of $14,049.93 of which $3,409.92 was allocated to Oregon.

COLVILLE Erik: $3409.92 is 24.27% of $14049.93. Oregon allocation is 24.27% per "PV Table" tab of "OPUC-146 .xlsx"

In Cascade's response to DR 193 (UG 287), it stated that $6,089 had been allocated to Oregon for software maintenance in 2014. Generally, the annual software maintenance expense is relatively equal each year. Therefore, the expense in 2014 would be relatively equal to that in 2015 using the revised allocation method, reducing the 2014 other gas supply expense by $2,679 for comparison to 2015.

CASE: UG 305
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 141

Date prepared: June 2, 2016

Preparer: Michael Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 141

Related to CNGC/204 Parvinen/1, lines 24-32, please state what dollar amount for Gas Storage in Rate Base is requested in this rate case, and how that dollar amount is derived. Provide the dollar amount for Oregon and total company.

Response:

There is no adjustment included in Exhibit CNGC/204 for Gas Storage in Rate Base. Exhibit CNGC/201 Parvinen/Page 1 of 1, line 26, Column (1) includes the end of period amount of $2,287,971 of which $449,172 is Gas Inventory and the remainder is Material and Supplies. Total company end of period amount for Gas Inventory was $3,431,410.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 142

Date prepared: 5/25/2016

Preparer: Brian Hoyle

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 142

Related to CNGC/204 Parvinen/1, lines 24-32, please provide, in spreadsheet form, by month, data supporting the dollar amount of gas in storage that was or is included in Rate Base for the years 2005-2015. If the data is not available by month, then provide it by year. Provide the data by facility and in total, and for Oregon and total company. Include in the data the dollar amount for both cushion gas and working gas separately by storage facility. For spreadsheets, please provide summary hard copies, and electronic files in Excel format with all cells active, all cell references functional, all cell data sources identified, and all abbreviations and terminology defined.

Response: See Excel spreadsheet OPUC-142.xlsx.

Allocations Based on PGA

Tracker 10/01/04		
0.8882	WA	88.82%
0.1118	OR	11.18%
100%		

2005	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
WA	7,104,472	3,747,653	1,508,181	4,483,243	7,102,909	8,435,706	11,614,618	12,723,083	14,624,666	13,061,665	11,572,100	7,897,930
OR	894,258	471,727	189,839	564,317	894,061	1,061,824	1,461,962	1,601,487	1,840,844	1,632,525	1,446,350	987,130
Total Therms	7,998,730	4,219,380	1,698,020	5,047,560	7,996,970	9,497,530	13,076,580	14,324,570	**16,465,510**	14,694,190	13,018,450	8,885,060
WA	$ 4,003,566.57	$ 2,105,512.10	$ 875,176.17	$ 2,856,102.20	$ 4,515,293.66	$ 5,350,515.32	$ 7,136,856.03	$ 7,794,948.41	$ 8,940,151.57	$ 8,022,245.00	$ 7,316,358.93	$ 5,479,625.29
OR	$ 503,939.14	$ 265,026.18	$ 110,160.66	$ 359,504.87	$ 568,351.53	$ 673,483.01	$ 898,334.28	$ 981,170.04	$ 1,125,319.69	$ 1,002,667.81	$ 914,441.98	$ 684,876.11
Total Amount	$ 4,507,505.70	$ 2,370,538.28	$ 985,336.82	$ 3,215,607.07	$ 5,083,645.19	$ 6,023,998.33	$ 8,035,190.30	$ 8,776,118.45	**$ 10,065,471.26**	$ 9,024,912.81	$ 8,230,800.91	$ 6,164,501.40

Allocations Based on PGA

Tracker 10/01/05		
0.8889	WA	88.89%
0.1111	OR	11.11%
100%		

2006	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
WA	4,925,608	1,412,782	1,708,021	133,335	1,896,041	4,570,839	8,401,003	12,850,170	14,636,192	14,010,488	8,602,292	5,732,349
OR	615,632	176,578	213,479	16,665	236,979	571,291	1,050,007	1,606,090	1,829,318	1,719,262	1,055,608	703,431
Total Therms	5,541,240	1,589,360	1,921,500	150,000	2,133,020	5,142,130	9,451,010	14,456,260	**16,465,510**	15,729,750	9,657,900	6,435,780
WA	$ 3,181,787.42	$ 870,515.26	$ 1,147,294.08	$ 81,417.81	$ 1,190,754.56	$ 2,859,006.12	$ 5,303,238.96	$ 8,019,195.32	$ 9,156,353.44	$ 8,777,957.89	$ 5,398,073.86	$ 3,803,150.69
OR	$ 397,678.68	$ 108,802.17	$ 143,395.63	$ 10,176.08	$ 148,827.57	$ 357,335.56	$ 662,830.29	$ 1,002,286.65	$ 1,144,415.42	$ 1,077,164.92	$ 662,410.99	$ 466,694.03
Total Amount	$ 3,579,466.10	$ 979,317.42	$ 1,290,689.71	$ 91,593.89	$ 1,339,582.13	$ 3,216,341.68	$ 5,966,069.25	$ 9,021,481.97	**$ 10,300,768.86**	$ 9,855,122.81	$ 6,060,484.85	$ 4,269,844.72

Allocations Based on PGA

Tracker 10/1/2006		
0.8907	WA	89.07%
0.1093	OR	10.93%
100%		

2007	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
WA	3,758,442	3,312,914	4,240,703	1,580,022	1,821,375	4,593,135	9,469,406	9,807,783	10,747,952	9,076,785	5,579,222	7,938,828
OR	461,208	406,536	520,387	193,888	223,505	563,635	1,162,014	1,203,537	1,318,908	1,113,835	681,828	970,192
Total Therms	4,219,650	3,719,450	4,761,090	1,773,910	2,044,880	5,156,770	10,631,420	11,011,320	12,066,860	10,190,620	6,261,050	**8,909,020**
WA	$ 2,590,340.80	$ 2,425,969.76	$ 3,153,810.94	$ 1,148,215.11	$ 1,309,180.62	$ 3,409,491.19	$ 6,975,240.22	$ 7,214,590.98	$ 7,852,536.57	$ 6,694,754.78	$ 4,145,830.13	$ 6,278,137.75
OR	$ 317,867.13	$ 297,696.75	$ 387,011.94	$ 140,900.32	$ 160,652.79	$ 418,387.10	$ 855,948.98	$ 885,320.30	$ 963,604.18	$ 821,529.92	$ 506,655.71	$ 767,241.84
Total Amount	$ 2,908,207.93	$ 2,723,666.51	$ 3,540,822.88	$ 1,289,115.43	$ 1,469,833.41	$ 3,827,878.29	$ 7,831,189.20	$ 8,099,911.28	$ 8,816,140.75	$ 7,516,284.70	$ 4,652,485.84	**$ 7,045,379.59**

Allocations Based on PGA

Tracker 11/01/07		
0.8911	WA	89.11%
0.1089	OR	10.89%
100%		

2008	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
WA	3,664,444	3,565,166	1,966,426	586,201	1,348,920	4,609,259	6,686,066	9,604,338	11,249,273	9,710,860	9,372,487	8,183,963
OR	447,826	435,694	240,314	71,639	164,850	563,291	817,094	1,173,732	1,374,757	1,186,750	916,773	800,517
Total Therms	4,112,270	4,000,860	2,206,740	657,840	1,513,770	5,172,550	7,503,160	10,778,070	12,624,030	10,897,610	10,289,260	**8,984,480**
WA	$ 2,915,718.96	$ 2,824,246.11	$ 1,492,676.00	$ 432,787.58	$ 1,057,931.31	$ 4,081,614.37	$ 5,866,684.99	$ 8,155,937.44	$ 9,387,576.28	$ 8,075,491.07	$ 7,799,911.75	$ 6,808,472.52
OR	$ 356,325.66	$ 345,146.90	$ 182,417.70	$ 52,890.32	$ 129,288.21	$ 498,808.00	$ 716,958.81	$ 996,724.93	$ 1,147,241.68	$ 986,893.70	$ 762,951.08	$ 665,973.10
Total Amount	$ 3,272,044.62	$ 3,169,393.01	$ 1,675,093.70	$ 485,677.90	$ 1,187,219.52	$ 4,580,422.37	$ 6,583,643.80	$ 9,152,662.37	$ 10,534,817.96	$ 9,062,384.77	$ 8,562,862.83	**$ 7,474,445.62**

Allocations Based on PGA

Tracker 11/01/08		
0.9109	WA	91.09%
0.0891	OR	8.91%
100%		

2009	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
WA	7,620,717	5,918,436	2,604,627	6,683,082	6,093,730	6,888,062	8,775,601	11,101,102	12,083,107	11,473,742	11,157,906	9,140,529
OR	7,620,717	5,918,436	2,604,627	6,683,082	6,093,730	6,888,062	8,775,601	11,101,102	12,083,107	11,473,742	1,133,244	928,351
Total Therms	8,366,140	6,497,350	2,859,400	7,336,790	6,689,790	7,561,820	9,633,990	12,186,960	13,265,020	12,596,050	12,291,150	**10,068,880**
WA	$ 6,386,732.42	$ 4,985,875.06	$ 2,169,959.81	$ 4,932,957.74	$ 4,588,683.77	$ 5,057,446.35	$ 6,236,460.97	$ 7,579,965.14	$ 8,095,800.63	$ 7,835,166.88	$ 7,638,729.94	$ 6,164,930.62
OR	$ 624,720.45	$ 487,695.10	$ 212,255.37	$ 482,518.98	$ 448,843.70	$ 494,695.87	$ 610,021.60	$ 741,436.92	$ 791,893.55	$ 766,399.57	$ 775,821.66	$ 626,136.38
Total Amount	$ 7,011,452.87	$ 5,473,570.16	$ 2,382,215.18	$ 5,415,476.72	$ 5,037,527.47	$ 5,552,142.22	$ 6,846,482.57	$ 8,321,402.06	$ 8,887,694.18	$ 8,601,566.45	$ 8,414,551.60	**$ 6,791,067.00**

Allocations Based on PGA

Tracker 11/01/09		
0.9078	WA	90.78%
0.0922	OR	9.22%
100%		

2010	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
WA	9,506,690	9,393,887	3,092,729	3,712,612	5,142,923	6,709,967	9,567,658	11,794,691	12,738,867	11,785,677	10,587,940	11,685,841
OR	965,540	954,083	314,111	377,068	522,337	681,493	971,732	1,197,919	1,293,813	1,197,003	1,094,660	1,208,169
Total Therms	10,472,230	10,347,970	3,406,840	4,089,680	5,665,260	7,391,460	10,539,390	12,992,610	14,032,680	12,982,680	11,682,600	**12,894,010**
WA	$ 6,435,083.60	$ 6,363,180.51	$ 2,154,203.58	$ 2,483,851.96	$ 3,163,896.88	$ 4,014,478.62	$ 5,565,767.84	$ 6,709,428.40	$ 7,172,581.03	$ 6,582,416.43	$ 5,760,043.82	$ 6,321,616.88
OR	$ 653,574.25	$ 646,271.47	$ 218,790.01	$ 252,270.49	$ 321,338.72	$ 407,727.39	$ 565,282.88	$ 681,437.87	$ 728,477.61	$ 668,538.00	$ 595,515.95	$ 653,575.53
Total Amount	$ 7,088,657.85	$ 7,009,451.98	$ 2,372,993.59	$ 2,736,122.45	$ 3,485,235.60	$ 4,422,206.01	$ 6,131,050.71	$ 7,390,866.27	$ 7,901,058.64	$ 7,250,954.43	$ 6,355,559.77	**$ 6,975,192.41**

Allocations Based on PGA

Tracker 11/01/10		
0.9063	WA	90.63%
0.0937	OR	9.37%
100%		

2011	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
WA	9,335,742	5,891,802	4,985,502	5,872,697	7,752,961	8,675,937	10,884,355	11,938,074	13,301,847	13,301,847	12,515,747	11,941,102
OR	965,198	609,138	515,438	607,163	801,559	896,983	1,125,305	1,234,246	1,375,243	1,375,243	1,361,343	1,298,838
Total Therms	10,300,940	6,500,940	5,500,940	6,479,860	8,554,520	9,572,920	12,009,660	13,172,320	14,677,090	14,677,090	13,877,090	**13,239,940**
WA	$ 5,080,737.04	$ 3,284,144.11	$ 2,821,459.84	$ 3,234,807.41	$ 4,173,202.71	$ 4,583,596.05	$ 5,543,877.17	$ 5,999,872.99	$ 6,597,234.17	$ 6,597,234.17	$ 6,267,589.99	$ 5,898,064.65
OR	$ 525,284.19	$ 339,539.12	$ 291,703.39	$ 334,438.32	$ 431,456.57	$ 473,886.08	$ 573,167.04	$ 620,311.26	$ 682,070.88	$ 682,070.88	$ 647,989.83	$ 641,534.70
Total Amount	$ 5,606,021.23	$ 3,623,683.23	$ 3,113,163.23	$ 3,569,245.73	$ 4,604,659.28	$ 5,057,482.13	$ 6,117,044.21	$ 6,620,184.25	$ 7,279,305.05	$ 7,279,305.05	$ 6,915,579.82	**$ 6,539,599.34**

Allocations Based on PGA

Tracker 11/01/11		
0.9019	WA	90.19%
0.0981	OR	9.81%
100%		

2012	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
WA	11,958,094	12,315,923	11,594,403	10,674,465	10,674,465	10,435,461	12,504,834	13,483,270	16,214,295	14,951,635	14,544,167	13,642,367
OR	1,300,686	1,339,607	1,261,127	1,161,065	1,161,065	1,135,069	1,360,156	1,466,580	1,763,635	1,626,295	1,583,763	1,485,563
Total Therms	13,258,780	13,655,530	12,855,530	11,835,530	11,835,530	11,570,530	13,864,990	14,949,850	17,977,930	16,577,930	16,127,930	**15,127,930**
WA	$ 5,867,208.83	$ 6,003,475.70	$ 5,684,253.60	$ 5,277,245.43	$ 5,277,245.43	$ 5,171,503.11	$ 5,968,653.08	$ 6,345,040.88	$ 7,334,860.62	$ 6,835,985.79	$ 6,680,496.54	$ 6,280,737.62
OR	$ 638,178.50	$ 653,000.29	$ 618,278.39	$ 574,007.96	$ 574,007.96	$ 562,506.33	$ 649,212.63	$ 690,152.47	$ 797,815.53	$ 743,552.73	$ 727,461.48	$ 683,930.40
Total Amount	$ 6,505,387.33	$ 6,656,475.99	$ 6,302,531.99	$ 5,851,253.39	$ 5,851,253.39	$ 5,734,009.44	$ 6,617,865.71	$ 7,035,193.35	$ 8,132,676.15	$ 7,579,538.52	$ 7,407,958.02	**$ 6,964,668.02**

Allocations Based on PGA

Tracker 11/01/12		
0.9018	WA	90.18%
0.0982	OR	9.82%
100%		

2013	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
WA	11,318,275	10,867,375	11,278,596	11,455,042	12,752,002	12,740,315	14,916,151	16,050,327	16,212,497	16,135,520	14,710,419	13,989,070
OR	1,232,485	1,183,385	1,228,164	1,247,378	1,388,608	1,387,335	1,624,269	1,747,773	1,765,433	1,757,050	1,790,331	1,702,540
Total Therms	12,550,760	12,050,760	12,506,760	12,702,420	14,140,610	14,127,650	16,540,420	17,798,100	17,977,930	17,892,570	16,500,750	**15,691,610**
WA	$ 5,277,216.76	$ 5,089,791.16	$ 5,212,157.21	$ 5,287,111.22	$ 5,844,201.51	$ 5,770,962.13	$ 6,598,786.81	$ 7,010,231.27	$ 7,054,128.95	$ 7,010,890.61	$ 6,454,691.80	$ 6,088,854.46
OR	$ 574,653.68	$ 554,244.28	$ 567,569.13	$ 575,731.12	$ 636,394.53	$ 628,419.25	$ 718,563.83	$ 763,367.39	$ 768,147.55	$ 763,439.19	$ 785,568.21	$ 741,043.98
Total Amount	$ 5,851,870.44	$ 5,644,035.44	$ 5,779,726.34	$ 5,862,842.34	$ 6,480,596.04	$ 6,399,381.38	$ 7,317,350.64	$ 7,773,598.66	$ 7,822,276.50	$ 7,774,329.79	$ 7,240,260.01	**$ 6,829,898.44**

Allocations Based on PGA

Tracker 11/01/13		
0.8915	WA	89.15%
0.1085	OR	10.85%
100%		

2014	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
WA	12,351,510	7,828,886	9,239,230	12,134,822	10,075,002	10,075,002	10,994,183	12,572,726	12,572,726	12,649,057	12,083,587	10,972,520
OR	1,503,240	952,814	1,124,460	1,476,868	1,226,178	1,226,178	1,338,047	1,530,164	1,530,164	1,539,453	1,470,633	1,335,410
Total Therms	13,854,750	8,781,700	10,363,690	13,611,690	11,301,180	11,301,180	12,332,230	14,102,890	14,102,890	14,188,510	13,554,220	**12,307,930**
WA	$ 5,570,476.05	$ 3,245,004.99	$ 2,347,897.78	$ 3,584,551.34	$ 4,109,415.13	$ 4,109,415.13	$ 4,530,945.45	$ 5,251,207.17	$ 5,251,207.17	$ 5,290,016.18	$ 5,005,133.95	$ 4,541,103.70
OR	$ 677,954.74	$ 394,933.30	$ 285,750.88	$ 436,257.79	$ 500,136.33	$ 500,136.33	$ 551,438.68	$ 639,098.12	$ 639,098.12	$ 643,821.37	$ 609,149.79	$ 552,674.99
Total Amount	$ 6,248,430.79	$ 3,639,938.29	$ 2,633,648.66	$ 4,020,809.13	$ 4,609,551.46	$ 4,609,551.46	$ 5,082,384.13	$ 5,890,305.29	$ 5,890,305.29	$ 5,933,837.55	$ 5,614,283.74	**$ 5,093,778.69**

Allocations Based on PGA

Tracker 11/01/14		
0.8915	WA	89.15%
0.1085	OR	10.85%
100%		

2015	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
WA	9,803,505	10,606,496	7,017,175	3,915,682	5,059,851	6,336,452	8,760,343	11,189,600	12,397,270	12,373,735	10,754,459	9,206,021
OR	1,193,135	1,290,864	854,025	476,558	615,809	771,178	1,066,177	1,361,830	1,508,810	1,505,945	1,308,871	1,120,419
Total Therms	10,996,640	11,897,360	7,871,200	4,392,240	5,675,660	7,107,630	9,826,520	12,551,430	13,906,080	13,879,680	12,063,330	**10,326,440**
WA	$ 4,032,308.19	$ 4,303,401.93	$ 2,828,281.29	$ 1,643,762.29	$ 1,975,061.98	$ 2,372,885.44	$ 3,130,804.91	$ 3,846,932.60	$ 4,209,767.08	$ 4,199,014.72	$ 3,494,082.74	$ 2,982,238.12
OR	$ 490,752.03	$ 523,745.50	$ 344,215.95	$ 200,054.08	$ 240,374.90	$ 288,792.00	$ 381,034.59	$ 468,190.90	$ 512,349.67	$ 511,041.05	$ 526,263.30	$ 449,171.52
Total Amount	$ 4,523,060.22	$ 4,827,147.42	$ 3,172,497.24	$ 1,843,816.36	$ 2,215,436.88	$ 2,661,677.44	$ 3,511,839.50	$ 4,315,123.50	$ 4,722,116.75	$ 4,710,055.78	$ 4,020,346.04	**$ 3,431,409.65**

Allocations Based on PGA

Tracker 11/01/15		
0.8691	WA	86.91%
0.1309	OR	13.09%
100%		

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 143

Date prepared: May 17, 2016

Preparer: Eric Wood

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 143

Related to CNGC/204 Parvinen/1, please provide a description identifying the gas storage facility volume available to Cascade for each of the years 2005-2015. Provide the volume by facility and in total, and for Oregon and total company.

Response:

Please see attached file Confidential OPUC-143.xlsx.

Pages 5 and 6 of Exhibit 403 are confidential and subject to Protective Order no. 16-141.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 144

Date prepared: May 18, 2016

Preparer: Michael Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 144

Related to CNGC/204 Parvinen/1, lines 10-21, please state what dollar amount for Other Gas Supply Expenses is requested in this rate case, and how that dollar amount is derived.

Response:

Please see response to Staff Data Request 145 for calendar year 2015 for amount requested to be included in this rate request. No adjustment is being proposed to the base year amount for Other Gas Supply Expenses.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 145

Date prepared: 05/18/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 145

Related to Cascade's response to Staff DR 58 for FERC Account 813 Other Gas Supply Expenses. Please provide, in a single electronic spreadsheet, other gas supply expense results for Oregon separately identifying any related labor expense, for each calendar year from 2013 through 2015, and to the extent available monthly through 2016. For spreadsheets, please provide summary hard copies, and electronic files in Excel format with all cells active, all cell references functional, all cell data sources identified, and all abbreviations and terminology defined.

Response: See Excel file OPUC-145.xlsx

Object Account	Sub Account									
		Ledger Type	AA	AA	AA		UO	UO	UO	
		Year	2015	2014	2013		2015	2014	2013	
		Format	YTD	YTD	YTD		YTD	YTD	YTD	
		Period	12	12	12		12	12	12	
		Currency	***	***	***		***	***	***	
		Company	00047	00047	00047		00047	00047	00047	
		Business Unit	*	*	*		*	*	*	
Object Account	Sub Account		**Dec 15**	**Dec 14**	**Dec 13**		**Dec 15**	**Dec 14**	**Dec 13**	
[5110.6999,/5110.5199]	28130	Other Gas Supply Expenses (Non-Labor)	34,958.10	42,277.19	34,897.83		8,484.29	10,273.37	8,567.37	Amounts reported on DR58
[5110.5190,5193]	28130	Other Gas Supply Expenses (Labor only excluding benefits)	410,997.10	370,096.07	339,141.61		99,748.96	89,933.35	83,259.28	Difference between DR58 and FERC Form 2 Oregon Supplement (Labor Expense)
						Ties to FERC Form 2 Oregon Supplement	**108,233.25**	**100,206.72**	**91,826.65**	
[5110.6999,/5191.5192,/5194.5199]	28130	Other Gas Supply Expenses	445,955.20	412,373.26	374,039.44		**108,233.25**	**100,206.72**	**91,826.65**	Amounts reported on FERC Form 2 Oregon Supplement

Object Account	Sub Account							
		Ledger Type	UO	UO	UO	UO	UO	
		Year	2016	2016	2016	2016	2015	
		Format	PER	PER	PER	PER	YTD	
		Period	1	2	3	4	4	
		Currency	***	***	***	***	***	
		Company	00047	00047	00047	00047	00047	
		Business Unit	*	*	*	*	*	
Object Account	Sub Account		**Jan 16**	**Feb 16**	**Mar 16**	**Apr 16**	**YTD-Apr 15**	
[5110.6999,/5110.5199]	28130	Other Gas Supply Expenses (Non-Labor)	17,486.23	2,665.02	700.29	2,668.07	2,408.23	Expenses
[5110.5190,5193]	28130	Other Gas Supply Expenses (Labor only excluding benefits)	8,583.10	7,718.64	8,678.54	7,667.74	32,840.77	Labor Expense
			26,069.33	**10,383.66**	**9,378.83**	**10,335.81**	**35,249.00**	**Total Amounts that would be reported on FERC Form 2 Oregon Supplement**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 146

Date prepared: 05/18/2016

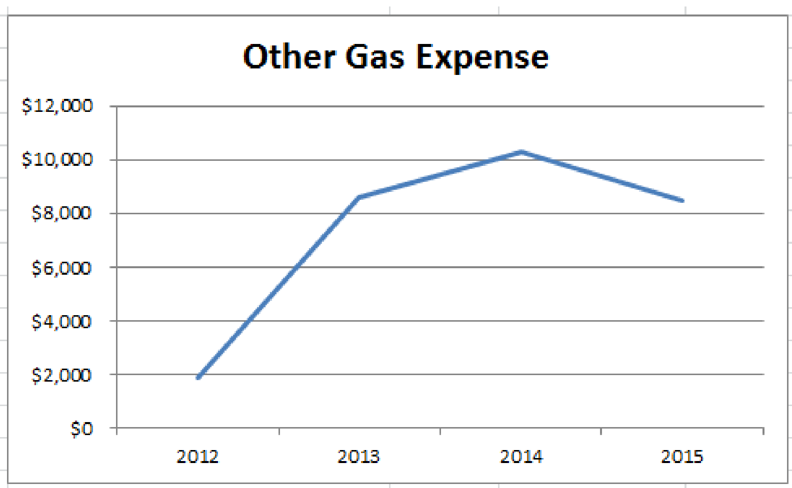
Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 146

Related to CNGC/204 Parvinen/1, lines 10-21 for Operating Expenses, and Cascade's response in Docket Nos. UG 287 and UG 305 to Staff DR 58 for FERC Account 813 Other Gas Supply Expenses. Please provide a description of the events that resulted in a slowing of growth in Other Gas Supply Expenses for the 2014 to 2015 period compared to the 2013 to 2014 period.



Response: See Excel file OPUC-146.xlsx

Cascade feels that the amounts reported in 2013 & 2015 more accurately reflect the expenditure level in FERC 813 as compared to 2014. The allocation of the software maintenance expenditure between Utility Group companies was changed in 2015 to allocate by meter count. Cascade's total amount of $14,049.93 of which $3,409.92 was allocated to Oregon.

Staff/403
Colville/11

CO	BU	OBJ	SUB	SLT	SLN	Explanation 1	Explanation 2	Oregon Allocation 24.27 %	Oregon Situs	Amount	Per	Post	GL Date	Type	Doc Num	Line #	Batch #	Batch Date	Bt Type	Cur	Ex. Rate	Units	Ref 1	Ref 2	Ref 3	Originator	Address #	Invoice #	Invoice Date	PO #	Payment #	Payment Date	Serial Number	Order Type	PO Doc Type
00047	4761200	5400	28130			2011 FORD EXPLORER 4X4		34.95		144.00	9	P	9/30/2015	TE	16491	7	1330357	10/5/2015	T		0	300				CAMPBEDA	0					9/30/2015	/00203023		
00047	4761200	5400	28130			2011 FORD EXPLORER 4X4		1.05		4.32	10	P	10/31/2015	TE	16607	2	1339121	11/4/2015	T		0	9				CAMPBEDA	0					10/31/2015	/00203023		
00047	4761200	5400	28130			2013 FORD ESCAPE 4X4		0.47		1.92	10	P	10/31/2015	TE	16615	5	1339139	11/4/2015	T		0	4				CAMPBEDA	0					10/31/2015	/00217888		
00047	4761200	5400	28130			2013 FORD ESCAPE 4X4		0.47		1.92	12	P	12/31/2015	TE	16772	1	1354763	1/6/2016	T		0	4				CAMPBEDA	0					12/31/2015	/00217888		
00047	4761200	5511	28130			J WHITING 1-15	Flight	67.28		277.20	1	P	1/31/2015	CE	30433	3	1265386	1/29/2015	G		0	0		1618234		DURADOT	0					1/31/2015			
00047	4761200	5511	28130			J WHITING 1-15	Flight	6.07		25.00	1	P	1/31/2015	CE	30433	16	1265386	1/29/2015	G		0	0		1618248		DURADOT	0					1/31/2015			
00047	4761200	5511	28130			J WHITING 2-15	Flight	17.49		72.06	2	P	2/28/2015	CE	30992	2	1272266	2/27/2015	G		0	0		1641597		DURADOT	0					2/28/2015			
00047	4761200	5511	28130			J WHITING 2-15	Flight	65.54		270.05	2	P	2/28/2015	CE	30992	6	1272266	2/27/2015	G		0	0		1641601		DURADOT	0					2/28/2015			
00047	4761200	5511	28130			J WHITING 2-15	Flight Change Fee	1.82		7.50	2	P	2/28/2015	CE	30992	29	1272266	2/27/2015	G		0	0		1641624		DURADOT	0					2/28/2015			
00047	4761200	5511	28130			E WOOD 2-15	Travel	52.47		216.20	2	P	2/28/2015	CE	30993	3	1272266	2/27/2015	G		0	0		1641657		DURADOT	0					2/28/2015			
00047	4761200	5511	28130			E WOOD 2-15	Travel	4.61		19.00	2	P	2/28/2015	CE	30993	5	1272266	2/27/2015	G		0	0		1641659		DURADOT	0					2/28/2015			
00047	4761200	5511	28130			E WOOD 3-15	bagage fee	6.07		25.00	3	P	3/31/2015	CE	31341	5	1280384	4/1/2015	G		0	0				DURADOT	0					3/31/2015			
00047	4761200	5511	28130			E WOOD 3-15	bagage fee	6.07		25.00	3	P	3/31/2015	CE	31341	8	1280384	4/1/2015	G		0	0				DURADOT	0					3/31/2015			
00047	4761200	5511	28130			J WHITING 3-15	Flight	50.17		206.70	3	P	3/31/2015	CE	31456	3	1280390	4/1/2015	G		0	0		1667030		DURADOT	0					3/31/2015			
00047	4761200	5511	28130			J WHITING 3-15	Airfare	68.00		280.20	3	P	3/31/2015	CE	31456	39	1280390	4/1/2015	G		0	0		1667066		DURADOT	0					3/31/2015			
00047	4761200	5511	28130			J WHITING 3-15	Airfare	28.63		117.96	3	P	3/31/2015	CE	31456	40	1280390	4/1/2015	G		0	0		1667067		DURADOT	0					3/31/2015			
00047	4761200	5511	28130			J WHITING 3-15	Airfare	12.38		51.00	3	P	3/31/2015	CE	31456	44	1280390	4/1/2015	G		0	0		1667071		DURADOT	0					3/31/2015			
00047	4761200	5511	28130			J WHITING 3-15	Airfare	9.10		37.50	3	P	3/31/2015	CE	31456	48	1280390	4/1/2015	G		0	0		1667075		DURADOT	0					3/31/2015			
00047	4761200	5511	28130			J WHITING 3-15	Airfare	30.34		125.00	3	P	3/31/2015	CE	31456	60	1280390	4/1/2015	G		0	0		1667087		DURADOT	0					3/31/2015			
00047	4761200	5511	28130			C ROBBINS 4-15	Aifare-Robbins-Denver-PSC	51.60		212.60	4	P	4/30/2015	CE	31743	1	1288260	4/30/2015	G		0	0		1684544		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			C ROBBINS 4-15	Airfare-Wood-Denver-PSC	51.60		212.60	4	P	4/30/2015	CE	31743	2	1288260	4/30/2015	G		0	0		1684545		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			C ROBBINS 4-15	Airfare-Robbins PSC-Denver	81.09		334.10	4	P	4/30/2015	CE	31743	4	1288260	4/30/2015	G		0	0		1684547		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			C ROBBINS 4-15	Airfare-Wood PSC-Denver	81.09		334.10	4	P	4/30/2015	CE	31743	5	1288260	4/30/2015	G		0	0		1684548		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			C ROBBINS 4-15	Airline Baggage Fee	6.07		25.00	4	P	4/30/2015	CE	31743	13	1288260	4/30/2015	G		0	0		1684556		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			J WHITING 4-15	Flight	2.43		10.00	4	P	4/30/2015	CE	31790	5	1288262	4/30/2015	G		0	0		1686132		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			J WHITING 4-15	Flight	35.12		144.70	4	P	4/30/2015	CE	31790	57	1288262	4/30/2015	G		0	0		1686184		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			J WHITING 4-15	Flight Cancelled	(47.74)		(196.70)	4	P	4/30/2015	CE	31790	65	1288262	4/30/2015	G		0	0		1686192		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			C ROBBINS 4-15	Airfare-Roundtrip PSC-PHX	94.46		389.20	4	P	4/30/2015	PV	149461	1	1288243	4/30/2015	V		0	0		1683970		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			E WOOD 4-15	Airline Ticket	68.25		281.20	4	P	4/30/2015	PV	149474	2	1288247	4/30/2015	V		0	0		1686223		DURADOT	0					4/30/2015			
00047	4761200	5511	28130			J WHITING 5-15	Flight Cancellation	30.34		125.00	5	P	5/31/2015	CE	32218	2	1295923	5/29/2015	G		0	0		1706748		DURADOT	0					5/31/2015			
00047	4761200	5511	28130			J WHITING 5-15	Flight	24.22		99.80	5	P	5/31/2015	CE	32218	4	1295923	5/29/2015	G		0	0		1706750		DURADOT	0					5/31/2015			
00047	4761200	5511	28130			J WHITING 5-15	Flight	(24.22)		(99.80)	5	P	5/31/2015	CE	32218	8	1295923	5/29/2015	G		0	0		1706754		DURADOT	0					5/31/2015			
00047	4761200	5511	28130			E WOOD 5-15	Airfare	6.07		25.00	5	P	5/31/2015	CE	32219	1	1295923	5/29/2015	G		0	0		1706790		DURADOT	0					5/31/2015			
00047	4761200	5511	28130			E WOOD 5-15	Airfare	6.07		25.00	5	P	5/31/2015	CE	32219	4	1295923	5/29/2015	G		0	0		1706793		DURADOT	0					5/31/2015			
00047	4761200	5511	28130			J WHITING 8-15	Flight	54.90		226.20	8	P	8/31/2015	CE	33556	12	1320807	8/28/2015	G		0	0		1787070		DURADOT	0					8/31/2015			
00047	4761200	5511	28130			J WHITING 8-15	Flight	16.57		68.28	8	P	8/31/2015	CE	33556	14	1320807	8/28/2015	G		0	0		1787072		DURADOT	0					8/31/2015			
00047	4761200	5511	28130			J WHITING 9-15	Flight Cancellation	30.34		125.00	9	P	9/30/2015	CE	34144	2	1329258	9/30/2015	G		0	0		1818240		DURADOT	0					9/30/2015			
00047	4761200	5511	28130			E WOOD 9-15	Airfare	86.57		356.70	9	P	9/30/2015	CE	34146	1	1329258	9/30/2015	G		0	0		1818266		DURADOT	0					9/30/2015			
00047	4761200	5511	28130			E WOOD 10-15	Baggage Fee	6.07		25.00	10	P	10/31/2015	CE	34474	2	1337367	10/30/2015	G		0	0		1837447		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			E WOOD 10-15	Baggage Fee	6.07		25.00	10	P	10/31/2015	CE	34474	10	1337367	10/30/2015	G		0	0		1837455		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			J WHITING 10-15	Flight	10.62		43.75	10	P	10/31/2015	CE	34585	6	1337373	10/30/2015	G		0	0		1843910		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			J WHITING 10-15	Flight	63.37		261.10	10	P	10/31/2015	CE	34585	21	1337373	10/30/2015	G		0	0		1843925		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			J WHITING 10-15	Flight	86.43		356.10	10	P	10/31/2015	CE	34585	22	1337373	10/30/2015	G		0	0		1843926		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			J WHITING 10-15	Flight	47.96		197.60	10	P	10/31/2015	CE	34585	23	1337373	10/30/2015	G		0	0		1843927		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			J WHITING 10-15	Flight Credit	(86.43)		(356.10)	10	P	10/31/2015	CE	34585	26	1337373	10/30/2015	G		0	0		1843930		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			C ROBBINS 10-15	seat upgrade	3.17		13.05	10	P	10/31/2015	CE	34654	13	1338056	11/2/2015	G		0	0		1846085		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			C ROBBINS 10-15	Airfare PSC-SLC roundtrip	84.99		350.19	10	P	10/31/2015	CE	34654	17	1338056	11/2/2015	G		0	0		1846089		BAYLEJ	0					10/31/2015			
00047	4761200	5511	28130			C ROBBINS 11-15	checked baggage fee	2.73		11.25	11	P	11/30/2015	CE	34887	1	1344685	11/30/2015	G		0	0		1862700		DURADOT	0					11/30/2015			
00047	4761200	5511	28130			C ROBBINS 11-15	checked baggage fee	2.73		11.25	11	P	11/30/2015	CE	34887	23	1344685	11/30/2015	G		0	0		1862722		DURADOT	0					11/30/2015			
00047	4761200	5511	28130			J WHITING 12-15	Flight	89.97		370.70	12	P	12/31/2015	CE	35506	1	1353979	1/4/2016	G		0	0		1893774		DURADOT	0					12/31/2015			
00047	4761200	5511	28130			J WHITING 12-15	Flight	134.87		555.70	12	P	12/31/2015	CE	35506	2	1353979	1/4/2016	G		0	0		1893775		DURADOT	0					12/31/2015			
00047	4761200	5511	28130			J WHITING 12-15	Flight Change	35.68		147.00	12	P	12/31/2015	CE	35506	14	1353979	1/4/2016	G		0	0		1893787		DURADOT	0					12/31/2015			
00047	4761200	5511	28130			J WHITING 12-15	Flight Reimbursement	(100.62)		(414.60)	12	P	12/31/2015	CE	35506	22	1353979	1/4/2016	G		0	0		1893795		DURADOT	0					12/31/2015			
00047	4761200	5514	28130			J WHITING 4-15	Mileage	33.77		139.15	4	P	4/30/2015	PV	149467	1	1288243	4/30/2015	V		0	0		1684026		DURADOT	0					4/30/2015			
00047	4761200	5514	28130			E WOOD 10-15	Personal Vehicle Use	69.08		284.62	10	P	10/31/2015	PV	165010	1	1337351	10/30/2015	V		0	0		1837457		BAYLEJ	0					10/31/2015			
00047	4761200	5514	28130			J WHITING 12-15	Mileage Reimbursement	79.54		327.75	12	P	12/31/2015	PV	170416	1	1353967	1/4/2016	V		0	0		1893798		DURADOT	0					12/31/2015			
00047	4761200	5521	28130			C ROBBINS 1-15	Lunch At Bonefish	16.12		66.40	1	P	1/31/2015	CE	30423	1	1265386	1/29/2015	G		0	0		1618062		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			C ROBBINS 1-15	Lunch At Pho Loa	8.79		36.22	1	P	1/31/2015	CE	30423	2	1265386	1/29/2015	G		0	0		1618063		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 1-15	Meal	21.93		90.36	1	P	1/31/2015	CE	30433	1	1265386	1/29/2015	G		0	0		1618232		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 1-15	Meal	6.87		28.31	1	P	1/31/2015	CE	30433	2	1265386	1/29/2015	G		0	0		1618233		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 1-15	Meal	25.15		103.61	1	P	1/31/2015	CE	30433	4	1265386	1/29/2015	G		0	0		1618235		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 1-15	Meal	26.47		109.05	1	P	1/31/2015	CE	30433	5	1265386	1/29/2015	G		0	0		1618236		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 1-15	Meal	1.33		5.49	1	P	1/31/2015	CE	30433	17	1265386	1/29/2015	G		0	0		1618249		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 1-15	Meal	1.21		4.98	1	P	1/31/2015	CE	30433	19	1265386	1/29/2015	G		0	0		1618251		DURADOT	0					1/31/2015			
00047	4761200	5521	28130			J WHITING 2-15	Meal	0.68		2.79	2	P	2/28/2015	CE	30992	13	1272266	2/27/2015	G		0	0		1641608		DURADOT	0					2/28/2015			
00047	4761200	5521	28130			J WHITING 2-15	Meal	7.95		32.75	2	P	2/28/2015	CE	30992	35	1272266	2/27/2015	G		0	0		1641630		DURADOT	0					2/28/2015			
00047	4761200	5521	28130			C ROBBINS 3-15	travel Meal/Mark	5.76		23.73	3	P	3/31/2015	CE	31294	10	1280382	4/1/2015	G		0	0		1658942		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			E WOOD 3-15	Meals	1.72		7.08	3	P	3/31/2015	CE	31341	6	1280384	4/1/2015	G		0	0		1660212		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			J WHITING 3-15	Meal	11.74		48.38	3	P	3/31/2015	CE	31456	1	1280390	4/1/2015	G		0	0		1667028		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			J WHITING 3-15	Meal	1.17		4.81	3	P	3/31/2015	CE	31456	6	1280390	4/1/2015	G		0	0		1667033		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			J WHITING 3-15	Meal	1.89		7.77	3	P	3/31/2015	CE	31456	10	1280390	4/1/2015	G		0	0		1667037		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			J WHITING 3-15	Meal	2.04		8.41	3	P	3/31/2015	CE	31456	14	1280390	4/1/2015	G		0	0		1667041		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			J WHITING 3-15	Meal	14.34		59.10	3	P	3/31/2015	CE	31456	34	1280390	4/1/2015	G		0	0		1667061		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			J WHITING 3-15	Meal	0.44		1.80	3	P	3/31/2015	CE	31456	68	1280390	4/1/2015	G		0	0		1667095		DURADOT	0					3/31/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	Meal -Employee Recognition	10.33		42.57	4	P	4/30/2015	CE	31743	6	1288260	4/30/2015	G		0	0		1684549		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	GS/GC Meeting Lunch	12.25		50.46	4	P	4/30/2015	CE	31743	9	1288260	4/30/2015	G		0	0		1684552		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	travel Meal	14.11		58.15	4	P	4/30/2015	CE	31743	10	1288260	4/30/2015	G		0	0		1684553		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	travel meal	1.34		5.51	4	P	4/30/2015	CE	31743	12	1288260	4/30/2015	G		0	0		1684555		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	travel Meal	4.49		18.50	4	P	4/30/2015	CE	31743	14	1288260	4/30/2015	G		0	0		1684557		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	travel Meal-Robbins	1.35		5.58	4	P	4/30/2015	CE	31743	16	1288260	4/30/2015	G		0	0		1684559		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	meal -Wood, Robbins	11.64		47.96	4	P	4/30/2015	CE	31743	18	1288260	4/30/2015	G		0	0		1684561		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			C ROBBINS 4-15	meal -Wood, Robbins	16.32		67.24	4	P	4/30/2015	CE	31743	19	1288260	4/30/2015	G		0	0		1684562		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	35.43		145.98	4	P	4/30/2015	CE	31790	1	1288262	4/30/2015	G		0	0		1686128		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	1.73		7.14	4	P	4/30/2015	CE	31790	9	1288262	4/30/2015	G		0	0		1686136		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	1.10		4.52	4	P	4/30/2015	CE	31790	25	1288262	4/30/2015	G		0	0		1686152		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	0.87		3.60	4	P	4/30/2015	CE	31790	29	1288262	4/30/2015	G		0	0		1686156		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	1.99		8.20	4	P	4/30/2015	CE	31790	33	1288262	4/30/2015	G		0	0		1686160		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	0.81		3.35	4	P	4/30/2015	CE	31790	41	1288262	4/30/2015	G		0	0		1686168		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	4.15		17.09	4	P	4/30/2015	CE	31790	45	1288262	4/30/2015	G		0	0		1686172		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	1.55		6.38	4	P	4/30/2015	CE	31790	53	1288262	4/30/2015	G		0	0		1686180		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	1.63		6.71	4	P	4/30/2015	CE	31790	59	1288262	4/30/2015	G		0	0		1686186		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	4.13		17.00	4	P	4/30/2015	CE	31790	61	1288262	4/30/2015	G		0	0		1686188		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	1.27		5.24	4	P	4/30/2015	CE	31790	66	1288262	4/30/2015	G		0	0		1686193		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Meal	2.67		10.99	4	P	4/30/2015	CE	31790	71	1288262	4/30/2015	G		0	0		1686198		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 4-15	Snack	0.50		2.05	4	P	4/30/2015	CE	31790	75	1288262	4/30/2015	G		0	0		1686202		DURADOT	0					4/30/2015			
00047	4761200	5521	28130			J WHITING 5-15	Meal	8.74		36.00	5	P	5/31/2015	CE	32218	1	1295923	5/29/2015	G		0	0		1706747		DURADOT	0					5/31/2015			
00047	4761200	5521	28130			J WHITING 5-15	Meal	19.94		82.16	5	P	5/31/2015	CE	32218	3	1295923	5/29/2015	G		0	0		1706749		DURADOT	0					5/31/2015			
00047	4761200	5521	28130			E WOOD 5-15	Meals	2.13		8.79	5	P	5/31/2015	PV	151766	1	1295912	5/29/2015	V		0	0		1704763		DURADOT	0					5/31/2015			
00047	4761200	5521	28130			E WOOD 5-15	Meals	3.40		14.00	5	P	5/31/2015	PV	151766	3	1295912	5/29/2015	V		0	0		1704765		DURADOT	0					5/31/2015			
00047	4761200	5521	28130			J WHITING 6-15	Meal	46.35		190.97	6	P	6/30/2015	CE	32615	4	1304759	6/30/2015	G		0	0		1729741		DURADOT	0					6/30/2015			
00047	4761200	5521	28130			J WHITING 6-15	Meal	1.46		6.00	6	P	6/30/2015	CE	32615	22	1304759	6/30/2015	G		0	0		1729759		DURADOT	0					6/30/2015			
00047	4761200	5521	28130			J WHITING 6-15	Meal	3.75		15.45	6	P	6/30/2015	CE	32615	24	1304759	6/30/2015	G		0	0		1729761		DURADOT	0					6/30/2015			
00047	4761200	5521	28130			J WHITING 6-15	Meal	3.58		14.75	6	P	6/30/2015	CE	32615	26	1304759	6/30/2015	G		0	0		1729763		DURADOT	0					6/30/2015			

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Colville/12

00047	4761200	5521	28130	J WHITING 7-15	Meal	19.45	80.15	7	P	7/31/2015	CE	33109	1	1312743	7/30/2015	G	0	0	1762725	BAYLEJ	0	7/31/2015
00047	4761200	5521	28130	J WHITING 7-15	Meal	3.10	12.77	7	P	7/31/2015	CE	33109	2	1312743	7/30/2015	G	0	0	1762726	BAYLEJ	0	7/31/2015
00047	4761200	5521	28130	C ROBBINS 8-15	travel meal	3.38	13.93	8	P	8/31/2015	CE	33510	9	1320805	8/28/2015	G	0	0	1784830	DURADOT	0	8/31/2015
00047	4761200	5521	28130	E WOOD 8-15	Meals	13.96	57.50	8	P	8/31/2015	CE	33518	1	1320805	8/28/2015	G	0	0	1784955	DURADOT	0	8/31/2015
00047	4761200	5521	28130	E WOOD 8-15	Meals	2.00	8.25	8	P	8/31/2015	CE	33518	3	1320805	8/28/2015	G	0	0	1784957	DURADOT	0	8/31/2015
00047	4761200	5521	28130	J WHITING 9-15	Lunch	26.62	109.69	9	P	9/30/2015	CE	34144	4	1329258	9/30/2015	G	0	0	1818242	DURADOT	0	9/30/2015
00047	4761200	5521	28130	J WHITING 9-15	Lunch	23.13	95.31	9	P	9/30/2015	CE	34144	13	1329258	9/30/2015	G	0	0	1818251	DURADOT	0	9/30/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	9.26	38.15	10	P	10/31/2015	CE	34474	1	1337367	10/30/2015	G	0	0	1837446	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	4.92	20.26	10	P	10/31/2015	CE	34474	3	1337367	10/30/2015	G	0	0	1837448	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	2.09	8.63	10	P	10/31/2015	CE	34474	4	1337367	10/30/2015	G	0	0	1837449	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	2.03	8.36	10	P	10/31/2015	CE	34474	5	1337367	10/30/2015	G	0	0	1837450	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	13.19	54.34	10	P	10/31/2015	CE	34474	7	1337367	10/30/2015	G	0	0	1837452	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	17.73	73.04	10	P	10/31/2015	CE	34474	8	1337367	10/30/2015	G	0	0	1837453	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	1.69	6.95	10	P	10/31/2015	CE	34474	12	1337367	10/30/2015	G	0	0	1837458	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	E WOOD 10-15	Meals	1.27	5.25	10	P	10/31/2015	CE	34474	13	1337367	10/30/2015	G	0	0	1837459	BAYLEJ	0	10/31/2015
00047	4761200	5521	28130	C ROBBINS 11-15	dinner -travel meal	10.58	43.60	11	P	11/30/2015	CE	34887	5	1344685	11/30/2015	G	0	0	1862704	DURADOT	0	11/30/2015
00047	4761200	5521	28130	C ROBBINS 11-15	lunch-travel meal	1.17	4.84	11	P	11/30/2015	CE	34887	9	1344685	11/30/2015	G	0	0	1862708	DURADOT	0	11/30/2015
00047	4761200	5521	28130	C ROBBINS 11-15	dinner- travel	6.75	27.80	11	P	11/30/2015	CE	34887	15	1344685	11/30/2015	G	0	0	1862714	DURADOT	0	11/30/2015
00047	4761200	5521	28130	C ROBBINS 11-15	Course fees	32.11	132.30	11	P	11/30/2015	CE	34887	19	1344685	11/30/2015	G	0	0	1862718	DURADOT	0	11/30/2015
00047	4761200	5521	28130	C ROBBINS 11-15	breakfast-travel	0.73	3.00	11	P	11/30/2015	CE	34887	27	1344685	11/30/2015	G	0	0	1862726	DURADOT	0	11/30/2015
00047	4761200	5521	28130	C ROBBINS 11-15	travel-breakfast	6.17	25.44	11	P	11/30/2015	CE	34887	31	1344685	11/30/2015	G	0	0	1862730	DURADOT	0	11/30/2015
00047	4761200	5521	28130	C ROBBINS 11-15	travel-breakfast	6.17	25.44	11	P	11/30/2015	CE	34887	35	1344685	11/30/2015	G	0	0	1862734	DURADOT	0	11/30/2015
00047	4761200	5521	28130	J WHITING 11-15	Meal	4.07	16.75	11	P	11/30/2015	CE	35095	2	1345776	12/1/2015	G	0	0	1874744	DURADOT	0	11/30/2015
00047	4761200	5521	28130	J WHITING 11-15	Meal	5.49	22.61	11	P	11/30/2015	CE	35095	3	1345776	12/1/2015	G	0	0	1874745	DURADOT	0	11/30/2015
00047	4761200	5521	28130	J WHITING 11-15	Meal	15.01	61.86	11	P	11/30/2015	CE	35095	4	1345776	12/1/2015	G	0	0	1874746	DURADOT	0	11/30/2015
00047	4761200	5521	28130	J WHITING 11-15	Meal	1.84	7.59	11	P	11/30/2015	CE	35095	5	1345776	12/1/2015	G	0	0	1874747	DURADOT	0	11/30/2015
00047	4761200	5521	28130	J WHITING 11-15	Meal	3.10	12.78	11	P	11/30/2015	CE	35095	6	1345776	12/1/2015	G	0	0	1874748	DURADOT	0	11/30/2015
00047	4761200	5521	28130	J WHITING 11-15	Meal	2.24	9.24	11	P	11/30/2015	CE	35095	8	1345776	12/1/2015	G	0	0	1874750	DURADOT	0	11/30/2015
00047	4761200	5521	28130	COR CE J WHITING 11-15	Meal	(2.64)	(10.89)	11	P	11/30/2015	JE	35140	2	1347071	12/4/2015	G	0	0		RYANC	0	11/30/2015
00047	4761200	5521	28130	J WHITING 12-15	Meal	13.43	55.33	12	P	12/31/2015	CE	35506	12	1353979	1/4/2016	G	0	0	1893785	DURADOT	0	12/31/2015
00047	4761200	5521	28130	J WHITING 12-15	Meal	3.50	14.41	12	P	12/31/2015	CE	35506	13	1353979	1/4/2016	G	0	0	1893786	DURADOT	0	12/31/2015
00047	4761200	5521	28130	J WHITING 12-15	Meal	4.03	16.61	12	P	12/31/2015	CE	35506	18	1353979	1/4/2016	G	0	0	1893791	DURADOT	0	12/31/2015
00047	4761200	5521	28130	J WHITING 12-15	Meal	1.69	6.98	12	P	12/31/2015	CE	35506	19	1353979	1/4/2016	G	0	0	1893792	DURADOT	0	12/31/2015
00047	4761200	5521	28130	J WHITING 12-15	Meal	6.43	26.50	12	P	12/31/2015	CE	35506	20	1353979	1/4/2016	G	0	0	1893793	DURADOT	0	12/31/2015
00047	4761200	5521	28130	J WHITING 12-15	Meal	6.19	25.49	12	P	12/31/2015	CE	35506	24	1353979	1/4/2016	G	0	0	1893797	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 1-15	Parking	2.91	12.00	1	P	1/31/2015	CE	30433	18	1265386	1/29/2015	G	0	0	1618250	DURADOT	0	1/31/2015
00047	4761200	5522	28130	J WHITING 2-15	Taxi	3.68	15.15	2	P	2/28/2015	CE	30992	17	1272266	2/27/2015	G	0	0	1641612	DURADOT	0	2/28/2015
00047	4761200	5522	28130	J WHITING 2-15	Parking	1.64	6.75	2	P	2/28/2015	CE	30992	21	1272266	2/27/2015	G	0	0	1641616	DURADOT	0	2/28/2015
00047	4761200	5522	28130	J WHITING 2-15	Lodging	12.69	52.27	2	P	2/28/2015	CE	30992	25	1272266	2/27/2015	G	0	0	1641620	DURADOT	0	2/28/2015
00047	4761200	5522	28130	E WOOD 2-15	Parking	1.46	6.00	2	P	2/28/2015	CE	30993	10	1272266	2/27/2015	G	0	0	1641664	DURADOT	0	2/28/2015
00047	4761200	5522	28130	C ROBBINS 3-15	Hotel -Santa Fe	54.41	224.19	3	P	3/31/2015	CE	31294	8	1280382	4/1/2015	G	0	0	1658940	DURADOT	0	3/31/2015
00047	4761200	5522	28130	E WOOD 3-15	Parking	2.91	12.00	3	P	3/31/2015	CE	31341	1	1280384	4/1/2015	G	0	0	1660207	DURADOT	0	3/31/2015
00047	4761200	5522	28130	E WOOD 3-15	Transport	18.45	76.00	3	P	3/31/2015	CE	31341	2	1280384	4/1/2015	G	0	0	1660208	DURADOT	0	3/31/2015
00047	4761200	5522	28130	E WOOD 3-15	Ski Rental	(8.13)	(33.50)	3	P	3/31/2015	CE	31341	3	1280384	4/1/2015	G	0	0	1660209	DURADOT	0	3/31/2015
00047	4761200	5522	28130	E WOOD 3-15	Ski Rental	8.13	33.50	3	P	3/31/2015	CE	31341	4	1280384	4/1/2015	G	0	0	1660210	DURADOT	0	3/31/2015
00047	4761200	5522	28130	E WOOD 3-15	parking	8.37	34.50	3	P	3/31/2015	CE	31341	7	1280384	4/1/2015	G	0	0	1660213	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Parking	2.91	12.00	3	P	3/31/2015	CE	31456	2	1280390	4/1/2015	G	0	0	1667029	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Parking	1.31	5.40	3	P	3/31/2015	CE	31456	18	1280390	4/1/2015	G	0	0	1667045	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Hotel	11.37	46.84	3	P	3/31/2015	CE	31456	22	1280390	4/1/2015	G	0	0	1667049	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Shirts Credit -returned Shirt	(7.27)	(29.94)	3	P	3/31/2015	CE	31456	26	1280390	4/1/2015	G	0	0	1667053	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Shirts Debit - shirts resent	7.27	29.94	3	P	3/31/2015	CE	31456	30	1280390	4/1/2015	G	0	0	1667057	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Lodging	11.68	48.11	3	P	3/31/2015	CE	31456	35	1280390	4/1/2015	G	0	0	1667062	DURADOT	0	3/31/2015
00047	4761200	5522	28130	J WHITING 3-15	Taxi	4.37	18.02	3	P	3/31/2015	CE	31456	64	1280390	4/1/2015	G	0	0	1667091	DURADOT	0	3/31/2015
00047	4761200	5522	28130	C ROBBINS 4-15	Hotel-Credit	(54.41)	(224.19)	4	P	4/30/2015	CE	31743	3	1288260	4/30/2015	G	0	0	1684546	DURADOT	0	4/30/2015
00047	4761200	5522	28130	C ROBBINS 4-15	Hotel Deposit -Phoenix	61.89	255.00	4	P	4/30/2015	CE	31743	8	1288260	4/30/2015	G	0	0	1684551	DURADOT	0	4/30/2015
00047	4761200	5522	28130	C ROBBINS 4-15	taxi from DEN-Hotel	16.02	66.00	4	P	4/30/2015	CE	31743	11	1288260	4/30/2015	G	0	0	1684554	DURADOT	0	4/30/2015
00047	4761200	5522	28130	C ROBBINS 4-15	PSC Parking	8.74	36.00	4	P	4/30/2015	CE	31743	15	1288260	4/30/2015	G	0	0	1684558	DURADOT	0	4/30/2015
00047	4761200	5522	28130	C ROBBINS 4-15	hotel room	287.97	1,186.53	4	P	4/30/2015	CE	31743	17	1288260	4/30/2015	G	0	0	1684560	DURADOT	0	4/30/2015
00047	4761200	5522	28130	C ROBBINS 4-15	Hotel -Denver 3 nights	255.42	1,052.43	4	P	4/30/2015	CE	31743	20	1288260	4/30/2015	G	0	0	1684563	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Parking	3.49	14.40	4	P	4/30/2015	CE	31790	13	1288262	4/30/2015	G	0	0	1686140	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Taxi	5.48	22.56	4	P	4/30/2015	CE	31790	17	1288262	4/30/2015	G	0	0	1686144	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Hotel	69.28	285.46	4	P	4/30/2015	CE	31790	21	1288262	4/30/2015	G	0	0	1686148	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Hotel	42.10	173.46	4	P	4/30/2015	CE	31790	37	1288262	4/30/2015	G	0	0	1686164	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Parking	4.37	18.00	4	P	4/30/2015	CE	31790	49	1288262	4/30/2015	G	0	0	1686176	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Parking	3.64	15.00	4	P	4/30/2015	CE	31790	58	1288262	4/30/2015	G	0	0	1686185	DURADOT	0	4/30/2015
00047	4761200	5522	28130	J WHITING 4-15	Lodging	11.83	48.76	4	P	4/30/2015	CE	31790	80	1288262	4/30/2015	G	0	0	1686207	DURADOT	0	4/30/2015
00047	4761200	5522	28130	E WOOD 4-15	Hotel	70.50	290.50	4	P	4/30/2015	CE	31791	2	1288262	4/30/2015	G	0	0	1686214	DURADOT	0	4/30/2015
00047	4761200	5522	28130	E WOOD 4-15	transport	13.35	55.00	4	P	4/30/2015	CE	31791	10	1288262	4/30/2015	G	0	0	1686224	DURADOT	0	4/30/2015
00047	4761200	5522	28130	E WOOD 4-15	Airport Parking	8.74	36.00	4	P	4/30/2015	CE	31791	11	1288262	4/30/2015	G	0	0	1686225	DURADOT	0	4/30/2015
00047	4761200	5522	28130	E WOOD 5-15	Hotel	71.68	295.34	5	P	5/31/2015	CE	32219	2	1295923	5/29/2015	G	0	0	1706791	DURADOT	0	5/31/2015
00047	4761200	5522	28130	E WOOD 5-15	Hotel	70.50	290.50	5	P	5/31/2015	CE	32219	3	1295923	5/29/2015	G	0	0	1706792	DURADOT	0	5/31/2015
00047	4761200	5522	28130	E WOOD 5-15	airport Parking	11.16	46.00	5	P	5/31/2015	CE	32219	5	1295923	5/29/2015	G	0	0	1706794	DURADOT	0	5/31/2015
00047	4761200	5522	28130	E WOOD 5-15	Transport	6.07	25.00	5	P	5/31/2015	PV	151766	2	1295912	5/29/2015	V	0	0	1704764	DURADOT	0	5/31/2015
00047	4761200	5522	28130	E WOOD 5-15	Transport	14.27	58.78	5	P	5/31/2015	PV	151766	4	1295912	5/29/2015	V	0	0	1704766	DURADOT	0	5/31/2015
00047	4761200	5522	28130	J WHITING 6-15	Lodge Fee	1.65	6.80	6	P	6/30/2015	CE	32615	9	1304759	6/30/2015	G	0	0	1729746	DURADOT	0	6/30/2015
00047	4761200	5522	28130	J WHITING 6-15	Travel - BART	2.10	8.65	6	P	6/30/2015	CE	32615	20	1304759	6/30/2015	G	0	0	1729757	DURADOT	0	6/30/2015
00047	4761200	5522	28130	J WHITING 6-15	Travel - BART	2.10	8.65	6	P	6/30/2015	CE	32615	21	1304759	6/30/2015	G	0	0	1729758	DURADOT	0	6/30/2015
00047	4761200	5522	28130	J WHITING 6-15	Hotel	57.84	238.31	6	P	6/30/2015	CE	32615	23	1304759	6/30/2015	G	0	0	1729760	DURADOT	0	6/30/2015
00047	4761200	5522	28130	J WHITING 6-15	Parking	5.82	24.00	6	P	6/30/2015	CE	32615	25	1304759	6/30/2015	G	0	0	1729762	DURADOT	0	6/30/2015
00047	4761200	5522	28130	E WOOD 8-15	Hotel	22.85	94.15	8	P	8/31/2015	CE	33518	2	1320805	8/28/2015	G	0	0	1784956	DURADOT	0	8/31/2015
00047	4761200	5522	28130	J WHITING 9-15	Parking/Valet	0.78	3.20	9	P	9/30/2015	PV	162302	1	1329244	9/30/2015	V	0	0	1818252	DURADOT	0	9/30/2015
00047	4761200	5522	28130	E WOOD 10-15	Parking	11.16	46.00	10	P	10/31/2015	CE	34474	6	1337367	10/30/2015	G	0	0	1837451	BAYLEJ	0	10/31/2015
00047	4761200	5522	28130	E WOOD 10-15	Hotel	214.06	882.00	10	P	10/31/2015	CE	34474	9	1337367	10/30/2015	G	0	0	1837454	BAYLEJ	0	10/31/2015
00047	4761200	5522	28130	E WOOD 10-15	Hotel	45.69	188.27	10	P	10/31/2015	CE	34474	11	1337367	10/30/2015	G	0	0	1837456	BAYLEJ	0	10/31/2015
00047	4761200	5522	28130	J WHITING 10-15	Hotel	14.47	59.64	10	P	10/31/2015	CE	34585	1	1337373	10/30/2015	G	0	0	1843904	BAYLEJ	0	10/31/2015
00047	4761200	5522	28130	J WHITING 10-15	Lodging	11.42	47.06	10	P	10/31/2015	CE	34585	27	1337373	10/30/2015	G	0	0	1843932	BAYLEJ	0	10/31/2015
00047	4761200	5522	28130	C ROBBINS 11-15	SLC hotel, 3 nights	77.11	317.70	11	P	11/30/2015	CE	34887	39	1344685	11/30/2015	G	0	0	1862738	DURADOT	0	11/30/2015
00047	4761200	5522	28130	C ROBBINS 11-15	PSC Parking	0.66	2.70	11	P	11/30/2015	CE	34887	43	1344685	11/30/2015	G	0	0	1862742	DURADOT	0	11/30/2015
00047	4761200	5522	28130	J WHITING 11-15	Parking	2.79	11.50	11	P	11/30/2015	CE	35095	1	1345776	12/1/2015	G	0	0	1874743	DURADOT	0	11/30/2015
00047	4761200	5522	28130	J WHITING 11-15	Parking	8.37	34.50	11	P	11/30/2015	CE	35095	7	1345776	12/1/2015	G	0	0	1874749	DURADOT	0	11/30/2015
00047	4761200	5522	28130	J WHITING 11-15	Hotel	69.36	285.79	11	P	11/30/2015	CE	35095	10	1345776	12/1/2015	G	0	0	1874752	DURADOT	0	11/30/2015
00047	4761200	5522	28130	COR CE J WHITING 11-15	Parking	(1.82)	(7.48)	11	P	11/30/2015	JE	35140	1	1347071	12/4/2015	G	0	0		RYANC	0	11/30/2015
00047	4761200	5522	28130	J WHITING 12-15	Parking	5.58	23.00	12	P	12/31/2015	CE	35506	3	1353979	1/4/2016	G	0	0	1893776	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 12-15	Rental Car	8.25	33.98	12	P	12/31/2015	CE	35506	4	1353979	1/4/2016	G	0	0	1893777	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 12-15	Hotel	27.63	113.86	12	P	12/31/2015	CE	35506	8	1353979	1/4/2016	G	0	0	1893781	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 12-15	Parking	6.55	27.00	12	P	12/31/2015	CE	35506	15	1353979	1/4/2016	G	0	0	1893788	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 12-15	Rental Car	22.38	92.22	12	P	12/31/2015	CE	35506	16	1353979	1/4/2016	G	0	0	1893789	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 12-15	Rental Car Gas	7.29	30.05	12	P	12/31/2015	CE	35506	17	1353979	1/4/2016	G	0	0	1893790	DURADOT	0	12/31/2015
00047	4761200	5522	28130	J WHITING 12-15	Hotel	62.17	256.16	12	P	12/31/2015	CE	35506	21	1353979	1/4/2016	G	0	0	1893794	DURADOT	0	12/31/2015
00047	4761200	5630	28130	J WHITING 1-15	Office Supplies	0.83	3.42	1	P	1/31/2015	CE	30433	6	1265386	1/29/2015	G	0	0	1618237	DURADOT	0	1/31/2015
00047	4761200	5630	28130	J WHITING 2-15	Shirts	160.85	662.76	2	P	2/28/2015	CE	30992	10	1272266	2/27/2015	G	0	0	1641605	DURADOT	0	2/28/2015
00047	4761200	5630	28130	J WHITING 5-15	Credit	(0.00)	(0.01)	5	P	5/31/2015	CE	32218	19	1295923	5/29/2015	G	0	0	1706765	DURADOT	0	5/31/2015
00047	4761200	5630	28130	J WHITING 5-15	New phone items	4.35	17.91	5	P	5/31/2015	CE	32218	20	1295923	5/29/2015	G	0	0	1706766	DURADOT	0	5/31/2015
00047	4761200	5630	28130	C ROBBINS 10-15	rca terminal	0.95	3.93	10	P	10/31/2015	CE	34654	8	1338056	11/2/2015	G	0	0	1846080	BAYLEJ	0	10/31/2015

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00047	4761200	5630	28130	J WHITING 11-15	Phone cover	10.28	42.35	11	P	11/30/2015	CE	35095	13	1345776	12/1/2015	G	0	0	1874755	DURADOT	0			11/30/2015	
00047	4761200	5630	28130	C ROBBINS 12-15	office calendars	6.04	24.88	12	P	12/31/2015	CE	35369	2	1353972	1/4/2016	G	0	0	1890587	DURADOT	0			12/31/2015	
00047	4761200	5630	28130	C ROBBINS 12-15	computer speakers	5.01	20.65	12	P	12/31/2015	CE	35369	6	1353972	1/4/2016	G	0	0	1890591	DURADOT	0			12/31/2015	
00047	4761200	5851	28130	J WHITING 5-15	Registration	30.58	126.00	5	P	5/31/2015	CE	32218	12	1295923	5/29/2015	G	0	0	1706758	DURADOT	0			5/31/2015	
00047	4762100	5400	28130	YECLR1215-AUTO & WORK EQ CLEAR	Auto Clearing Entry	3.64	15.00	12	P	12/31/2015	JE	35664	12	1355664	1/7/2016	G	0	0		TSCHAUNC	0			12/31/2015	
00047	4766000	5400	28130	2006 DODGE GRAND CARAVAN		25.14	103.60	8	P	8/31/2015	TE	16388	2	59391508	9/3/2015	T	0	296		ZASTAWNC	0			8/31/2015	/00150990
00047	4766000	5511	28130	R MORMAN 2-15	Air Fare	184.26	759.20	2	P	2/28/2015	CE	1156592	1	1273535	3/5/2015	G	0	0	1635729	BUTZM	0			2/28/2015	
00047	4766000	5511	28130	R MORMAN 2-15	Baggage Fee	6.07	25.00	2	P	2/28/2015	CE	1156592	2	1273535	3/5/2015	G	0	0	1635730	BUTZM	0			2/28/2015	
00047	4766000	5511	28130	R MORMAN 2-15	Air Fare credit	(184.26)	(759.20)	2	P	2/28/2015	CE	1156592	3	1273535	3/5/2015	G	0	0	1635731	BUTZM	0			2/28/2015	
00047	4766000	5511	28130	R MORMAN 8-15	Airfare	143.70	592.09	8	P	8/31/2015	CE	1177922	2	1322207	9/3/2015	G	0	0	1800429	HUSCHKAD	0			8/31/2015	
00047	4766000	5511	28130	R MORMAN 10-15	Arifare	70.89	292.10	10	P	10/31/2015	CE	1185382	8	1338979	11/4/2015	G	0	0	1853411	HUSCHKAD	0			10/31/2015	
00047	4766000	5521	28130	R MORMAN 4-15	Lunch	1.52	6.25	4	P	4/30/2015	CE	1163121	8	1289394	5/5/2015	G	0	0	1694883	PAULD	0			4/30/2015	
00047	4766000	5521	28130	R MORMAN 4-15	Snack	0.72	2.98	4	P	4/30/2015	CE	1163121	9	1289394	5/5/2015	G	0	0	1694884	PAULD	0			4/30/2015	
00047	4766000	5521	28130	R MORMAN 8-15	Dinner	1.16	4.78	8	P	8/31/2015	CE	1177922	5	1322207	9/3/2015	G	0	0	1800432	HUSCHKAD	0			8/31/2015	
00047	4766000	5521	28130	R MORMAN 8-15	Dinner	0.79	3.26	8	P	8/31/2015	CE	1177922	9	1322207	9/3/2015	G	0	0	1800436	HUSCHKAD	0			8/31/2015	
00047	4766000	5521	28130	R MORMAN 11-15	Dinner	2.37	9.77	12	P	12/30/2015	CE	1191836	3	1353024	12/30/2015	G	0	0	1889828	HUSCHKAD	0			12/30/2015	
00047	4766000	5521	28130	R MORMAN 11-15	Dinner	1.99	8.18	12	P	12/30/2015	CE	1191836	4	1353024	12/30/2015	G	0	0	1889829	HUSCHKAD	0			12/30/2015	
00047	4766000	5521	28130	R MORMAN 11-15	Snack	0.99	4.07	12	P	12/30/2015	CE	1191836	5	1353024	12/30/2015	G	0	0	1889830	HUSCHKAD	0			12/30/2015	
00047	4766000	5521	28130	R MORMAN 11-15	MEALS	7.80	32.12	12	P	12/30/2015	CE	1191836	15	1353024	12/30/2015	G	0	0	1889840	HUSCHKAD	0			12/30/2015	
00047	4766000	5522	28130	R MORMAN 4-15	Hotel	37.79	155.70	4	P	4/30/2015	CE	1163121	12	1289394	5/5/2015	G	0	0	1694887	PAULD	0			4/30/2015	
00047	4766000	5522	28130	R MORMAN 8-15	Airport parking	1.46	6.00	8	P	8/31/2015	CE	1177922	8	1322207	9/3/2015	G	0	0	1800435	HUSCHKAD	0			8/31/2015	
00047	4766000	5522	28130	R MORMAN 8-15	Airport parking	2.55	10.50	8	P	8/31/2015	CE	1177922	11	1322207	9/3/2015	G	0	0	1800438	HUSCHKAD	0			8/31/2015	
00047	4766000	5522	28130	R MORMAN 8-15	Hotel	31.09	128.08	8	P	8/31/2015	CE	1177922	13	1322207	9/3/2015	G	0	0	1800440	HUSCHKAD	0			8/31/2015	
00047	4766000	5522	28130	R MORMAN 11-15	Long term parking	2.91	12.00	12	P	12/30/2015	CE	1191836	2	1353024	12/30/2015	G	0	0	1889827	HUSCHKAD	0			12/30/2015	
00047	4766000	5522	28130	R MORMAN 11-15	Long term parking	5.10	21.00	12	P	12/30/2015	CE	1191836	6	1353024	12/30/2015	G	0	0	1889831	HUSCHKAD	0			12/30/2015	
00047	4766000	5522	28130	R MORMAN 11-15	Hotel	93.26	384.24	12	P	12/30/2015	CE	1191836	7	1353024	12/30/2015	G	0	0	1889832	HUSCHKAD	0			12/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00039	2.02	8.32	1	P	1/19/2015	PV	1817952	39	1262368	1/19/2015	V	0	0		GRUEBELC	282276	9737708895	12/23/2014	1/19/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00051	2.82	11.62	1	P	1/19/2015	PV	1817952	51	1262368	1/19/2015	V	0	0		GRUEBELC	282276	9737708895	12/23/2014	1/19/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00244	2.90	11.96	1	P	1/19/2015	PV	1817952	244	1262368	1/19/2015	V	0	0		GRUEBELC	282276	9737708895	12/23/2014	1/19/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00352	2.02	8.32	1	P	1/19/2015	PV	1817952	352	1262368	1/19/2015	V	0	0		GRUEBELC	282276	9737708895	12/23/2014	1/19/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00356	0.82	3.37	1	P	1/19/2015	PV	1817952	356	1262368	1/19/2015	V	0	0		GRUEBELC	282276	9737708895	12/23/2014	1/19/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00365	2.02	8.32	1	P	1/19/2015	PV	1817952	365	1262368	1/19/2015	V	0	0		GRUEBELC	282276	9737708895	12/23/2014	1/19/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.02	8.32	2	P	2/1/2015	PV	1821933	39	1269454	2/13/2015	V	0	0		BECKD	282276	9739412447	1/23/2015	2/1/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.83	11.65	2	P	2/1/2015	PV	1821933	51	1269454	2/13/2015	V	0	0		BECKD	282276	9739412447	1/23/2015	2/1/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	(1.95)	(8.02)	2	P	2/1/2015	PV	1821933	245	1269454	2/13/2015	V	0	0		BECKD	282276	9739412447	1/23/2015	2/1/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.02	8.32	2	P	2/1/2015	PV	1821933	353	1269454	2/13/2015	V	0	0		BECKD	282276	9739412447	1/23/2015	2/1/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.82	3.37	2	P	2/1/2015	PV	1821933	357	1269454	2/13/2015	V	0	0		BECKD	282276	9739412447	1/23/2015	2/1/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.02	8.32	2	P	2/1/2015	PV	1821933	366	1269454	2/13/2015	V	0	0		BECKD	282276	9739412447	1/23/2015	2/1/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.02	8.32	3	P	3/16/2015	PV	1825337	35	1276062	3/16/2015	V	0	0		BAUERM	282276	9741102011	2/23/2015	3/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.83	11.65	3	P	3/16/2015	PV	1825337	47	1276062	3/16/2015	V	0	0		BAUERM	282276	9741102011	2/23/2015	3/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.91	11.98	3	P	3/16/2015	PV	1825337	241	1276062	3/16/2015	V	0	0		BAUERM	282276	9741102011	2/23/2015	3/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.02	8.32	3	P	3/16/2015	PV	1825337	341	1276062	3/16/2015	V	0	0		BAUERM	282276	9741102011	2/23/2015	3/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.82	3.37	3	P	3/16/2015	PV	1825337	345	1276062	3/16/2015	V	0	0		BAUERM	282276	9741102011	2/23/2015	3/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.02	8.32	3	P	3/16/2015	PV	1825337	354	1276062	3/16/2015	V	0	0		BAUERM	282276	9741102011	2/23/2015	3/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	4	P	4/13/2015	PV	1829534	37	1283961	4/13/2015	V	0	0		BAUERM	282276	974279429	3/23/2015	4/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	4	P	4/13/2015	PV	1829534	49	1283961	4/13/2015	V	0	0		BAUERM	282276	974279429	3/23/2015	4/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	4	P	4/13/2015	PV	1829534	243	1283961	4/13/2015	V	0	0		BAUERM	282276	974279429	3/23/2015	4/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	4	P	4/13/2015	PV	1829534	343	1283961	4/13/2015	V	0	0		BAUERM	282276	974279429	3/23/2015	4/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	4	P	4/13/2015	PV	1829534	347	1283961	4/13/2015	V	0	0		BAUERM	282276	974279429	3/23/2015	4/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	4	P	4/13/2015	PV	1829534	356	1283961	4/13/2015	V	0	0		BAUERM	282276	974279429	3/23/2015	4/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	5	P	5/29/2015	PV	1836050	37	1295742	5/29/2015	V	0	0		RUDEA	282276	9744486533	4/23/2015	5/29/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	5	P	5/29/2015	PV	1836050	49	1295742	5/29/2015	V	0	0		RUDEA	282276	9744486533	4/23/2015	5/29/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	5	P	5/29/2015	PV	1836050	238	1295742	5/29/2015	V	0	0		RUDEA	282276	9744486533	4/23/2015	5/29/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	5	P	5/29/2015	PV	1836050	340	1295742	5/29/2015	V	0	0		RUDEA	282276	9744486533	4/23/2015	5/29/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	5	P	5/29/2015	PV	1836050	346	1295742	5/29/2015	V	0	0		RUDEA	282276	9744486533	4/23/2015	5/29/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	5	P	5/29/2015	PV	1836050	355	1295742	5/29/2015	V	0	0		RUDEA	282276	9744486533	4/23/2015	5/29/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	6	P	6/23/2015	PV	1839533	37	1302729	6/23/2015	V	0	0		BAUERM	282276	9746169347	5/23/2015	6/23/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	6	P	6/23/2015	PV	1839533	49	1302729	6/23/2015	V	0	0		BAUERM	282276	9746169347	5/23/2015	6/23/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	6	P	6/23/2015	PV	1839533	237	1302729	6/23/2015	V	0	0		BAUERM	282276	9746169347	5/23/2015	6/23/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	6	P	6/23/2015	PV	1839533	338	1302729	6/23/2015	V	0	0		BAUERM	282276	9746169347	5/23/2015	6/23/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	6	P	6/23/2015	PV	1839533	344	1302729	6/23/2015	V	0	0		BAUERM	282276	9746169347	5/23/2015	6/23/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	6	P	6/23/2015	PV	1839533	353	1302729	6/23/2015	V	0	0		BAUERM	282276	9746169347	5/23/2015	6/23/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	7	P	7/16/2015	PV	1843571	37	1309459	7/16/2015	V	0	0		RUDEA	282276	9747839713	6/23/2015	7/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	7	P	7/16/2015	PV	1843571	48	1309459	7/16/2015	V	0	0		RUDEA	282276	9747839713	6/23/2015	7/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	7	P	7/16/2015	PV	1843571	228	1309459	7/16/2015	V	0	0		RUDEA	282276	9747839713	6/23/2015	7/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	7	P	7/16/2015	PV	1843571	332	1309459	7/16/2015	V	0	0		RUDEA	282276	9747839713	6/23/2015	7/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	7	P	7/16/2015	PV	1843571	338	1309459	7/16/2015	V	0	0		RUDEA	282276	9747839713	6/23/2015	7/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	7	P	7/16/2015	PV	1843571	348	1309459	7/16/2015	V	0	0		RUDEA	282276	9747839713	6/23/2015	7/16/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	8	P	8/28/2015	PV	1850492	37	1320606	8/28/2015	V	0	0		BAUERM	282276	9749508378	7/23/2015	8/28/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	8	P	8/28/2015	PV	1850492	48	1320606	8/28/2015	V	0	0		BAUERM	282276	9749508378	7/23/2015	8/28/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	8	P	8/28/2015	PV	1850492	224	1320606	8/28/2015	V	0	0		BAUERM	282276	9749508378	7/23/2015	8/28/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	8	P	8/28/2015	PV	1850492	327	1320606	8/28/2015	V	0	0		BAUERM	282276	9749508378	7/23/2015	8/28/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	8	P	8/28/2015	PV	1850492	333	1320606	8/28/2015	V	0	0		BAUERM	282276	9749508378	7/23/2015	8/28/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	8	P	8/28/2015	PV	1850492	343	1320606	8/28/2015	V	0	0		BAUERM	282276	9749508378	7/23/2015	8/28/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	9	P	9/30/2015	PV	1855766	37	1329028	9/30/2015	V	0	0		GRUEBELC	282276	9751161946	8/23/2015	9/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.58	9	P	9/30/2015	PV	1855766	48	1329028	9/30/2015	V	0	0		GRUEBELC	282276	9751161946	8/23/2015	9/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.58	9	P	9/30/2015	PV	1855766	226	1329028	9/30/2015	V	0	0		GRUEBELC	282276	9751161946	8/23/2015	9/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	9	P	9/30/2015	PV	1855766	329	1329028	9/30/2015	V	0	0		GRUEBELC	282276	9751161946	8/23/2015	9/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	9	P	9/30/2015	PV	1855766	335	1329028	9/30/2015	V	0	0		GRUEBELC	282276	9751161946	8/23/2015	9/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	9	P	9/30/2015	PV	1855766	345	1329028	9/30/2015	V	0	0		GRUEBELC	282276	9751161946	8/23/2015	9/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	10	P	10/14/2015	PV	1858186	37	1333512	10/14/2015	V	0	0		BAUERM	282276	9752806570	9/23/2015	10/14/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.58	10	P	10/14/2015	PV	1858186	48	1333512	10/14/2015	V	0	0		BAUERM	282276	9752806570	9/23/2015	10/14/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.58	10	P	10/14/2015	PV	1858186	224	1333512	10/14/2015	V	0	0		BAUERM	282276	9752806570	9/23/2015	10/14/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	10	P	10/14/2015	PV	1858186	325	1333512	10/14/2015	V	0	0		BAUERM	282276	9752806570	9/23/2015	10/14/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	10	P	10/14/2015	PV	1858186	331	1333512	10/14/2015	V	0	0		BAUERM	282276	9752806570	9/23/2015	10/14/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	10	P	10/14/2015	PV	1858186	341	1333512	10/14/2015	V	0	0		BAUERM	282276	9752806570	9/23/2015	10/14/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	11	P	11/13/2015	PV	1863135	37	1341036	11/13/2015	V	0	0		ZASTAWNC	282276	9754450249	10/23/2015	11/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	11	P	11/13/2015	PV	1863135	48	1341036	11/13/2015	V	0	0		ZASTAWNC	282276	9754450249	10/23/2015	11/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.81	11.57	11	P	11/13/2015	PV	1863135	226	1341036	11/13/2015	V	0	0		ZASTAWNC	282276	9754450249	10/23/2015	11/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	(0.85)	(3.49)	11	P	11/13/2015	PV	1863135	327	1341036	11/13/2015	V	0	0		ZASTAWNC	282276	9754450249	10/23/2015	11/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	11	P	11/13/2015	PV	1863135	333	1341036	11/13/2015	V	0	0		ZASTAWNC	282276	9754450249	10/23/2015	11/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	11	P	11/13/2015	PV	1863135	335	1341036	11/13/2015	V	0	0		ZASTAWNC	282276	9754450249	10/23/2015	11/13/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	12	P	12/30/2015	PV	1871425	39	1352824	12/30/2015	V	0	0		BAUERM	282276	9756089007	11/23/2015	12/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	2.60	10.71	12	P	12/30/2015	PV	1871425	50	1352824	12/30/2015	V	0	0		BAUERM	282276	9756089007	11/23/2015	12/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	13.91	57.30	12	P	12/30/2015	PV	1871425	220	1352824	12/30/2015	V	0	0		BAUERM	282276	9756089007	11/23/2015	12/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	0.57	2.36	12	P	12/30/2015	PV	1871425	319	1352824	12/30/2015	V	0	0		BAUERM	282276	9756089007	11/23/2015	12/30/2015	
00047	4766000	5611	28130	VERIZON WIRELESS	380528769-00001	1.41	5.83	12	P	12/30/2015	PV	1871425	321	1352824	12/30/2015	V	0	0		BAUERM	282276	9756089007	11/23/2015	12/30/2015	
00047	4766000	5630	28130	Intercall Accrual in 2014	Morman	(0.96)	(3.96)	1	P	1/1/2015	JE	1150184	30	1259596	1/7/2015	G	0	-20		WENINGEL	0			12/31/2014	
00047	4766000	5630	28130	Intercall Accrual in 2014	Nieuwsma	(0.87)	(3.60)	1	P	1/1/2015	JE	1150184	155	1259596	1/7/2015	G	0	-20		WENINGEL	0			12/31/2014	
00047	4766000	5630	28130	Intercall	Morman	0.96	3.96	1	P	1/27/2015	PV	1819647	30	1264404	1/27/2015	V	0	3 96		WENINGEL	551525	551525 12-31-14	12/31/2014	1/27/2015	
00047	4766000	5630	28130	Intercall	Nieuwsma	0.87	3.60	1	P	1/27/2015	PV	1819647	141	1264404	1/27/2015	V	0	20		WENINGEL	551525	551525 12-31-14	12/31/2014	1/27/2015	
00047	4766000	5630	28130	K PETERSON 1-15	Modesty panels	29.36	120.99	1	P	1/31/2015	CE	1153368	5	1266590	2/4/2015	G	0	0	1621436	PAULD	0			1/31/2015	
00047	4766000	5630	28130	WEBEX REALLOCATION	JESSICA MEYER	0.36	1.49	2	P	2/5/2015	JE	1153559	48	1267182	2/5/2015	G	0	0		ROEHRICK	0			2/5/2015	
00047	4766000	5630	28130	WEBEX REALLOCATION	SHAWN NIEUWSMA	1.11	4.59	2	P	2/5/2015	JE	1153559	86	1267182	2/5/2015	G	0	0		ROEHRICK	0			2/5/2015	

00047	4766000	5630	28130	Intercall	MORMAN	0.71	2.92	2	P	2/17/2015	PV	1822144	25	1269827	2/17/2015	V	0	20		LEARE	551525	1742747774	11/30/2014	2/17/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.34	1.40	2	P	2/17/2015	PV	1822144	106	1269827	2/17/2015	V	0	20		LEARE	551525	1742747774	11/30/2014	2/17/2015
00047	4766000	5630	28130	Intercall	MORMAN	2.35	9.70	3	P	3/6/2015	PV	1824025	25	1273904	3/6/2015	V	0	0		WENINGEL	551525	1742793875	1/31/2015	3/6/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.28	1.17	3	P	3/6/2015	PV	1824025	151	1273904	3/6/2015	V	0	0		WENINGEL	551525	1742793875	1/31/2015	3/6/2015
00047	4766000	5630	28130	Intercall	MORMAN	2.09	8.63	3	P	3/13/2015	PV	1825152	20	1275896	3/13/2015	V	0	20		WENINGEL	551525	1742828723	2/28/2015	3/13/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	NIEUWSMA	2.98	12.29	3	P	3/30/2015	JE	1158909	76	1279589	3/30/2015	G	0	0		WENINGEL	0			3/30/2015
00047	4766000	5630	28130	Intercall	MORMAN	1.78	7.32	4	P	4/22/2015	PV	1831248	35	1286513	4/22/2015	V	0	20		WENINGEL	551525	1742867134	3/31/2015	4/22/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.13	0.55	4	P	4/22/2015	PV	1831248	174	1286513	4/22/2015	V	0	20		WENINGEL	551525	1742867134	3/31/2015	4/22/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	J MEYER	4.93	20.32	5	P	5/31/2015	JE	1166942	59	1297436	6/3/2015	G	0	0		WENINGEL	0			5/31/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	K GEIGER	13.75	56.66	5	P	5/31/2015	JE	1166942	71	1297436	6/3/2015	G	0	0		WENINGEL	0			5/31/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	S NIEUWSMA	9.34	38.50	5	P	5/31/2015	JE	1166942	106	1297436	6/3/2015	G	0	0		WENINGEL	0			5/31/2015
00047	4766000	5630	28130	Intercall	MORMAN	1.12	4.61	6	P	6/18/2015	PV	1838783	36	1301911	6/18/2015	V	0	20		WENINGEL	551525	1742915321	4/30/2015	6/18/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	3.09	12.72	6	P	6/18/2015	PV	1838783	205	1301911	6/18/2015	V	0	20		WENINGEL	551525	1742915321	4/30/2015	6/18/2015
00047	4766000	5630	28130	Intercall	MORMAN	1.50	6.17	6	P	6/22/2015	PV	1839308	22	1302529	6/22/2015	V	0	20		WENINGEL	551525	1742940254	5/31/2015	6/22/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.71	2.92	6	P	6/22/2015	PV	1839308	186	1302529	6/22/2015	V	0	20		WENINGEL	551525	1742940254	5/31/2015	6/22/2015
00047	4766000	5630	28130	K PETERSON 6-15	Dominque Poule	67.39	277.65	6	P	6/30/2015	CE	1171089	16	1306434	7/6/2015	G	0	0	1750879	PAULD	0			6/30/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	MEYER	2.06	8.48	6	P	6/30/2015	JE	1170346	56	1305639	7/2/2015	G	0	0		WENINGEL	0			6/30/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	NIEUWSMA	2.24	9.24	6	P	6/30/2015	JE	1170346	103	1305639	7/2/2015	G	0	0		WENINGEL	0			6/30/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	J MEYER	1.01	4.16	7	P	7/31/2015	JE	1174717	61	1314657	8/5/2015	G	0	0		WENINGEL	0			7/31/2015
00047	4766000	5630	28130	Intercall	MORMAN	0.46	1.90	8	P	8/18/2015	PV	1848181	28	1317718	8/18/2015	V	0	15		WENINGEL	551525	1743000971	6/30/2015	8/18/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.15	0.61	8	P	8/18/2015	PV	1848181	193	1317718	8/18/2015	V	0	20		WENINGEL	551525	1743000971	6/30/2015	8/18/2015
00047	4766000	5630	28130	Intercall	MORMAN	0.32	1.31	8	P	8/26/2015	PV	1850045	37	1319976	8/26/2015	V	0	15		WENINGEL	551525	1743030830	7/31/2015	8/26/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.57	2.33	8	P	8/26/2015	PV	1850045	183	1319976	8/26/2015	V	0	20		WENINGEL	551525	1743030830	7/31/2015	8/26/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	MEYER	2.56	10.54	8	P	8/31/2015	JE	1177706	56	1321547	9/1/2015	G	0	0		WENINGEL	0			8/31/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	NIEUWSMA	2.53	10.42	8	P	8/31/2015	JE	1177706	98	1321547	9/1/2015	G	0	0		WENINGEL	0			8/31/2015
00047	4766000	5630	28130	WEBEX REALLOCATION	Shawn Nieuwsma	2.73	11.23	9	P	9/30/2015	JE	1181837	121	1330747	10/6/2015	G	0	20		LEARE	0			9/30/2015
00047	4766000	5630	28130	Intercall	Bob Morman	0.62	2.56	9	P	9/30/2015	PV	1855775	36	1329060	9/30/2015	V	0	15		LEARE	551525	1743043555	8/31/2015	9/30/2015
00047	4766000	5630	28130	Intercall	Shawn Nieuwsma	0.42	1.75	9	P	9/30/2015	PV	1855775	198	1329060	9/30/2015	V	0	20		LEARE	551525	1743043555	8/31/2015	9/30/2015
00047	4766000	5630	28130	Intercall	MORMAN	0.39	1.60	10	P	10/15/2015	PV	1858482	29	1333878	10/15/2015	V	0	15		WENINGEL	551525	1743100070	9/30/2015	10/15/2015
00047	4766000	5630	28130	Intercall	NIEUWSMA	0.48	1.96	10	P	10/15/2015	PV	1858482	209	1333878	10/15/2015	V	0	20		WENINGEL	551525	1743100070	9/30/2015	10/15/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	JESSICA MEYER	0.50	2.05	10	P	10/31/2015	JE	1185542	103	1339013	11/4/2015	G	0	20		LEARE	0			10/31/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	SHAWN NIEUWSMA	2.67	11.00	10	P	10/31/2015	JE	1185542	153	1339013	11/4/2015	G	0	20		LEARE	0			10/31/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	J.MEYER	0.93	3.83	11	P	11/30/2015	JE	1189338	74	1346878	12/3/2015	G	0	20		LEARE	0			11/30/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	S.NIEUWSMA	1.87	7.69	11	P	11/30/2015	JE	1189338	123	1346878	12/3/2015	G	0	20		LEARE	0			11/30/2015
00047	4766000	5630	28130	Intercall	S.NIEUWSMA	0.42	1.75	12	P	12/3/2015	PV	1866969	196	1346867	12/3/2015	V	0	20		LEARE	551525	1743141080	10/31/2015	12/3/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	J.MEYER	(0.93)	(3.83)	12	P	12/18/2015	JE	1189338	70	1346878	12/3/2015	G	0	-20		LEARE	0			11/30/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	S.NIEUWSMA	(1.87)	(7.69)	12	P	12/18/2015	JE	1189338	119	1346878	12/3/2015	G	0	-20		LEARE	0			11/30/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	J.MEYER	0.93	3.83	12	P	12/18/2015	JE	1190746	70	1350684	12/18/2015	G	0	0		LEARE	0			12/18/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	S.NIEUWSMA	1.87	7.69	12	P	12/18/2015	JE	1190746	119	1350684	12/18/2015	G	0	0		LEARE	0			12/18/2015
00047	4766000	5630	28130	Intercall	B MORMAN	0.62	2.54	12	P	12/18/2015	PV	1869769	22	1350822	12/18/2015	V	0	15		WENINGEL	551525	1743168884	11/30/2015	12/18/2015
00047	4766000	5630	28130	Intercall	S NIEWSMA	2.24	9.22	12	P	12/18/2015	PV	1869769	191	1350822	12/18/2015	V	0	20		WENINGEL	551525	1743168884	11/30/2015	12/18/2015
00047	4766000	5630	28130	WEBEX Reallocation	J MEYER	7.50	30.91	12	P	12/30/2015	JE	1191822	60	1352926	12/30/2015	G	0	0		WENINGEL	0			12/30/2015
00047	4766000	5630	28130	WEBEX Reallocation	S NIEUWSMA	4.08	16.83	12	P	12/30/2015	JE	1191822	114	1352926	12/30/2015	G	0	0		WENINGEL	0			12/30/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	JESSICA MEYER	0.05	0.20	12	P	12/31/2015	JE	1192403	72	1354007	1/4/2016	G	0	20		LEARE	0			12/31/2015
00047	4766000	5630	28130	WEBEX ALLOCATION	SHAWN NIEUWSMA	2.44	10.04	12	P	12/31/2015	JE	1192403	102	1354007	1/4/2016	G	0	20		LEARE	0			12/31/2015
00047	4766000	5630	28130	ACCRUE CHARGES IN 2015	B.MORMAN	0.53	2.19	12	P	12/31/2015	JE	1193523	31	1355739	1/7/2016	G	0	15		LEARE	0			12/31/2015
00047	4766000	5630	28130	ACCRUE CHARGES IN 2015	S.NIEUWSMA	0.34	1.41	12	P	12/31/2015	JE	1193523	185	1355739	1/7/2016	G	0	20		LEARE	0			12/31/2015
00047	4766000	5911	28130	ABB ENTERPRISE SOFTWARE INC	200006466	3,409.92	14,049.93	7	P	7/17/2015	PV	1843731	2	1309870	7/17/2015	V	0	0		BAUERM	842826	7102632828	6/22/2015	7/17/2015
00047	4766000	5911	28130	JULY 2015 ND SALES TAX REFUND	Doc. 1843731	(44.27)	(182.42)	8	P	8/13/2015	JE	1175527	30	1316516	8/13/2015	G	0	0		HUSCHKAD	0			8/13/2015

8,484.33 - 34,958.10

Oregon Total **8,484.33**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 147

Date prepared: 05/18/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 147

Related to CNGC/204 Parvinen/1, lines 10-21, please identify if Cascade is requesting in this rate case a dollar amount for Underground Storage Expense (FERC Accounts 814-837). If a dollar amount is requested, please state the dollar amount and how that dollar amount is derived.

Response:

No expenses in FERC accounts 814-837 are being requested in this rate case.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 148

Date prepared: 05/18/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 148

Related to CNGC/204 Parvinen/1, lines 10-21. If Cascade is requesting a dollar amount in this rate case for Underground Storage Expense (FERC Accounts 814-837), please provide, in a single electronic spreadsheet, for each calendar year from 2013 through 2015, and to the extent available monthly through 2016, the underground storage operating expense results, including a breakdown of the underground storage expense into supervision and engineering, other expenses, and other equipment categories. Separately identify any related labor expense for each calendar year from 2013 through 2015, and to the extent as available monthly through 2016. Provide results separately for total company and for Oregon. For spreadsheets, please provide summary hard copies, and electronic files in Excel format with all cells active, all cell references functional, all cell data sources identified, and all abbreviations and terminology defined.

Response:

No expenses in FERC accounts 814-837 are being requested in this rate case.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 149

Date prepared: May 18, 2016

Preparer: Michael Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 149

Related to CNGC/204 Parvinen/1, please provide a description of the purpose of the PGA Commodity Sharing Adjustment in column e of the Proposed Adjustments to Base Year Results. In the description, address why an adjustment is included in the rate case rather than allowing the PGA process to follow its course.

Response:

Included in the commodity deferral balances in the PGA process is the 90% portion of commodity sharing component. The remaining 10% is reflected in base year actual accounts. In 2015 actual gas costs were lower than the commodity rate built into the PGA. Therefore, the company benefited. However, there is then a mismatch between revenues and gas costs associated with the 10% that would not exist if no sharing were required. An adjustment is required to match the revenues with the associated expenses.

CASE: UG 305
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am an economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I discuss my review and analysis of Distribution Operation and Maintenance (O&M) expenses and customer service. I also present two recommendations regarding rate design.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 501	Witness Qualification Statement
Exhibit 502	Distribution O&M, CNG Resp. to Staff DR No 238
Exhibit 503	Distribution O&M, CNG Resp. to Staff DR No 336-342
Exhibit 504	AC Survey, CNG Resp. to Staff DR No 236 & 318

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Distribution O&M 2
Issue 2. Customer Service 6
Issue 3. Residential & Commericial Basic Service Charge 7
Issue 4. Seasonality in WACOG 12

ISSUE 1. DISTRIBUTION O&M

Q. How did you analyze Distribution O&M expenses?

A. I reviewed distribution O&M expenses to ensure that all expenses included in the 2016 test year reflected prudent and ongoing costs. I performed a three-year trend analysis of eighteen different expense categories associated with distribution O&M[1] and reviewed the detailed transaction-level data for imprudent or extraordinary expenses. I also reviewed Cascade's proposed Atmospheric Corrosion (AC) survey adjustment.

Q. Please describe the three-year trend analysis in further detail.

A. In Staff Data Request No. 238, I asked Cascade to provide the annual expense amounts for eighteen expense categories associated with distribution O&M for the past three years.[2] I then calculated the total and percentage change between years and over the entire range. In Staff Data Request Nos. 336-342, I asked Cascade to provide a narrative explanation for changes in seven expense categories that had large numeric or percentage changes from year to year.[3] I then reviewed the Company's responses to ensure the test year reflected a normal operating year, and am satisfied with the Company's explanations.

Q. Do you recommend any adjustments as a result of the three-year trend analysis for distribution O&M expenses?

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[1] FERC Accounts 870-71, 874, 875-881, 885-890, and 892-894.
[2] See Staff/502, Gibbens/1, Cascade Response to Staff DR No. 238.
[3] See Staff/503, Gibbens/1-7, Cascade Response to Staff DR Nos. 336-342.

A. No. I am satisfied with the responses provided by Cascade. The amount of base costs associated with non-labor distribution O&M in the test year is reasonable. I do not recommend any adjustments.

Q. What was the outcome of your review of detailed transaction level data?

A. My review of detailed transaction-level data revealed the inclusion of expenses that are typically disallowed by the Commission or shared between ratepayers and shareholders, including expenses related to meals and entertainment, travel, and memberships and dues. However, Staff's proposed adjustments to such expense categories are discussed in detail in Exhibit/600, by Staff witness Kathy Zarate. I did not find any expenses that are not appropriately recovered as O&M expense other than the particular transactions that are typically disallowed or shared between ratepayers and shareholders addressed in Exhibit/600.

Q. Please describe Cascade's proposed AC survey adjustment.

A. Cascade proposes an Atmospheric Corrosion (AC) Survey Adjustment of $12,450, reflecting the net cost of moving the AC survey work in-house, rather than using outside contracted labor.

Q. Please describe the AC survey adjustment in further detail.

A. As part of federally mandated safety procedures, Cascade is required to regularly inspect its distribution system for atmospheric corrosion. Historically, the survey has been completed by outside contracted labor. In 2015, the program was moved in-house, and is to be completed by Cascade employees. The adjustment, totaling $12,450, is associated with the increased cost of running the program in-house, which the Company says will provide better control of the work, better communication, and better tracking of information.[4]

Q. Do you find the increased AC survey costs prudent?

A. No. Cascade did not provide sufficient information in its testimony to support an increased cost to ratepayers. I issued Staff Data Request No. 236, asking the Company to expound on the benefits to customers that result from bringing the program in-house. The Company responded, but did not identify material benefits beyond those stated in the Company's opening testimony, namely explaining that it moved the program in-house to achieve better control of work and to increase information.[5] Cascade states that "the benefits for switching to Cascade labor included a cost savings (from budgeted or expected contractor labor) even though there is an increase from actual costs."[6] Staff would expect that a more direct line of communication and higher level of control would result in increased efficiencies and costs savings to ratepayers, which the Company did not demonstrate. Further, Staff found no apparent operational issues with implementation of the survey work through contracted labor that might justify the switch to in-house labor and higher costs.

Q. What is your recommendation?

A. I recommend disallowance of all cost increases associated with the transfer of the AC survey in-house, specifically the Company's proposed

[4] CNG/200/Parvinen/6, lines 20-25.
[5] See Staff/504, Gibbens/1, Cascade Response to Staff DR No. 236.
[6] See Staff/504, Gibbens/2, Cascade Response to Staff DR No. 318.

adjustment of $12,450, until the time that Cascade can demonstrate realized benefits to customers.

ISSUE 2. CUSTOMER SERVICE

Q. Please describe your analysis of Cascade's customer service.

A. Staff's goal is to ensure that all expenses associated with serving customers that are includable in establishing test year revenue requirements are prudent and reasonable. As part of the analysis, Staff reviewed Cascade's customer service record, the prudence of particular expenses, the complaints filed with the OPUC, and the customer service initiatives, customer interaction and problem resolution programs of the Company. The prudence review of particular expenses and analysis of complaints filed with the OPUC are discussed in other Staff testimony.[7]

Q. What is your opinion of Cascade's customer service program following your analysis?

A. I have not identified any concerns with Cascade's current customer service level. Problem resolution and programs aimed to improve the customer experience were excellent. I do believe that better data collection of customer complaints and call metrics would further improve Cascade's ability to implement customer centric programs to ensure prudency in costs. Cascade currently only collects data on aggregate calls by month. Total monthly calls have decreased by roughly twenty percent over the previous four years.

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[7] See Staff/700; Staff/800.

ISSUE 3. RESIDENTIAL & COMMERICIAL BASIC SERVICE CHARGE

Q. What is your concern with the residential and commercial basic service charge?

A. Cascade currently charges $3 every month for a basic service charge. Consistent with Commission policy, the monthly basic service charge should be designed to recover the short-run billing and metering costs as well as an annualized amount of fixed costs, divided by twelve, associated with the customer's connection to the natural gas system. The current $3 a month basic charge is severely insufficient given the stated costs in Cascade's Long Run Incremental Cost (LRIC) Study. I am concerned that a misallocation of costs (characterizing fixed costs as variable) to the extent present, will lead to unfair subsidization and cost shifting among customers within the same class.

Q. What are the stated costs in Cascade's LRIC?

A. Cascade computed two different metrics when looking at the direct cost associated with serving a single customer. First is the variable O&M cost of serving a customer, which includes expenses like meter reading and billing. The second category of costs are generally thought of as more fixed, upfront costs, this includes the cost of a customer's meter, the line that connects a customer's home to the customer main and the economic carrying charge associated with those items. Generally, a basic service charge does not cover the entire amount of both fixed and variable customer-related costs combined. Instead, the basic service charge tends to pay for the entire customer O&M and a portion of the meter and service carrying charge.

Q. Please provide more detail regarding the costs that should be covered by the basic service charge for each customer class.

A. The associated costs for each schedule are listed in the table below, along with what percentage of the basic charge is paying for these costs.

Table 1: CNGC Customer Cost Breakdown

Customer Class		101 Residential	104 Commercial	105 Industrial	111 Large Volume	163 General Distribution	170 Interruptible
Customer O&M		$2.51	$2.61	$2.23	$11.84	$18.92	$18.92
Meter & Service Carrying		$18.62	$30.86	$114.71	$739.74	$1866.95	$3380.22
Customer (Basic) Charge		$3	$3	$30	$200	$750	$300
% of Customer Charge going to O&M		84%	87%	7%	6%	3%	6%
% of Meter & Service paid by Customer Charge		3%	1%	24%	25%	39%	8%

It is evident that Schedules 101 and 104 have a relatively small customer charge, which pays for only a small percent of meter and service expense. For comparison, I looked at the ratio of monthly variable expense to basic service charge for Avista and NWN, which are listed in Table 2 below.

Table 2: OR LDC Customer Cost Comparrision

Customer Class		Cascade Residential	Avista Residential	NWN Residential
Customer O&M		$2.51	$3.11	$3.90
Meter & Service Carrying		$18.62	$15.19	$18.42
Customer (Basic) Charge		$3	$9	$8
% of Customer Charge going to O&M		84%	35%	49%
% of Meter & Service paid by Customer Charge		3%	39%	22%

Tables 1 and 2 show that the basic charges for Schedules 101 and 104 are low compared to the basic charges in other Cascade schedules and compared to other gas utilities in the state.

Q. Why does Cascade recommend setting the basic customer charge so low?

A. Cascade posits two arguments. First, Cascade states that a low basic charge promotes the direct use of natural gas, because it is more efficient than using natural gas to generate electricity and promotes conservation.[8] Second, Cascade states that, "…customers who choose to use natural gas will also be electricity customers, and for that reason, will have two energy bills to pay each month regardless of usage."[9] Cascade is proposing to continue charging a low basic charge and volumetric heavy rate design to alleviate that impact on customers.

Q. Do you agree with Cascade's argument?

A. No.

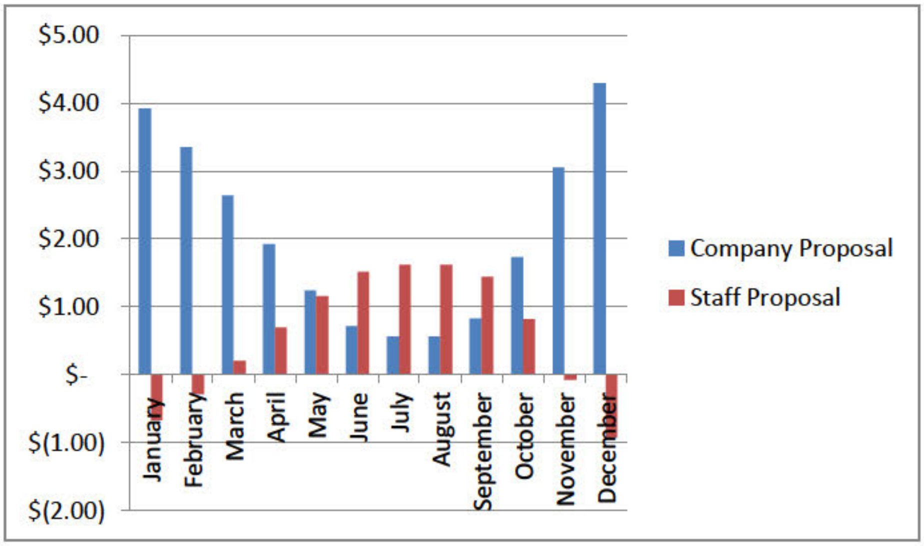
Q. Why do you disagree with Cascade's reasoning?

A. I do not agree with the premise that rates should be designed to promote the use of natural gas. Rates should reflect costs of service. I analyzed how the Cascade rate design affects bills across the year. To do this analysis, I used historic customer usage to analyze the impact a $3 vs. $5 basic charge had on ratepayers. My main finding is that a low basic charge maximizes the impact to customers during the months they already have their highest bills.

[8] CNGC/200, Parvinen/11. lines 1 through 4.
[9] CNGC/200, Parvinen/10, lines 16 through 21.

This is evidenced in Figure 1, which shows the impact of the two proposals to the average customer throughout the year.

Figure 1: Proposal Impacts to Avg. Customer



I found that in the month of December, 94 percent of all customers would have benefited from a higher basic charge. Further, because those impacted are at the lowest use levels and have a relatively small bill; the average impact on those customers was a $.68 increase. With Staff's proposal, the maximum increase to a bill is capped at $2, while Cascade's proposal has an indiscriminate maximum impact, which results in customers being more exposed to changes in demand and weather. In the eight highest-use months (October-May), the average customer is better off with a $5 customer charge.

Q. Did you perform any other analysis?

A. Yes, I also utilized EIA data to find that nationally, 13 percent of residential customers use natural gas only to heat water and three percent of customers utilize natural gas only for cooking and these customers are historically the lowest users of natural gas per month. Even if I agreed that rate design should be used to promote the direct use of natural gas, Cascade's rate design does not achieve that objective as it discourages customers to utilize natural gas to heat their homes. Under Cascade's proposal, customers who use natural gas for heat are subsidizing users who only use natural gas for cooking and water heating.

Q. What is your recommendation?

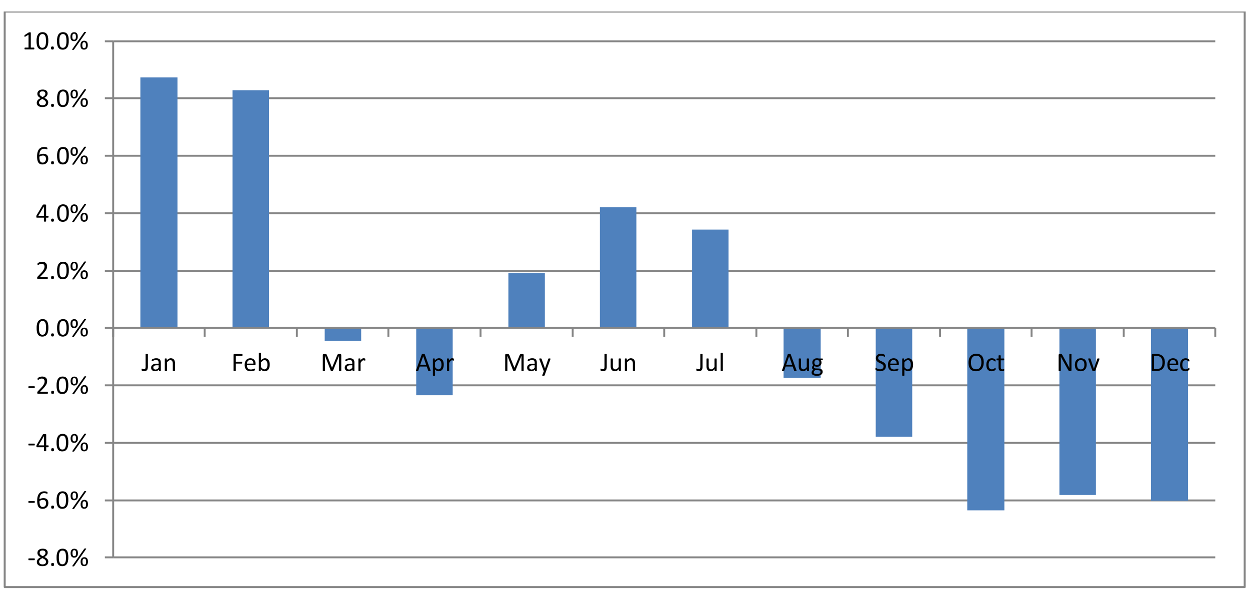
A. Increase the basic service charge for Schedules 101 and 104 to $5. While this is a big percentage change, raising the basic service charge by $2 a month is fairly modest.

ISSUE 4. CLASS VARIATION IN WACOG

Q. What is the background of this issue?

A. The Weighted Average Cost of Gas (WACOG) is an annual adjustment that is made to customers' bills based on the projected and actual costs of natural gas. The costs are passed through to customers via Schedule 177 and are the same for all customer classes. Staff's concern is based on the fact that each customer class does not have an identical usage pattern throughout the year. Figure 2 below shows the average monthly spot price at Henry Hub relative to the average annual price for the years 2010-2015. Figure 2 displays a roughly 14 percent shift in the cost of gas on average throughout the year. Given that the cost of gas varies throughout the year, customer classes have disparate impacts on the overall cost of gas purchased.

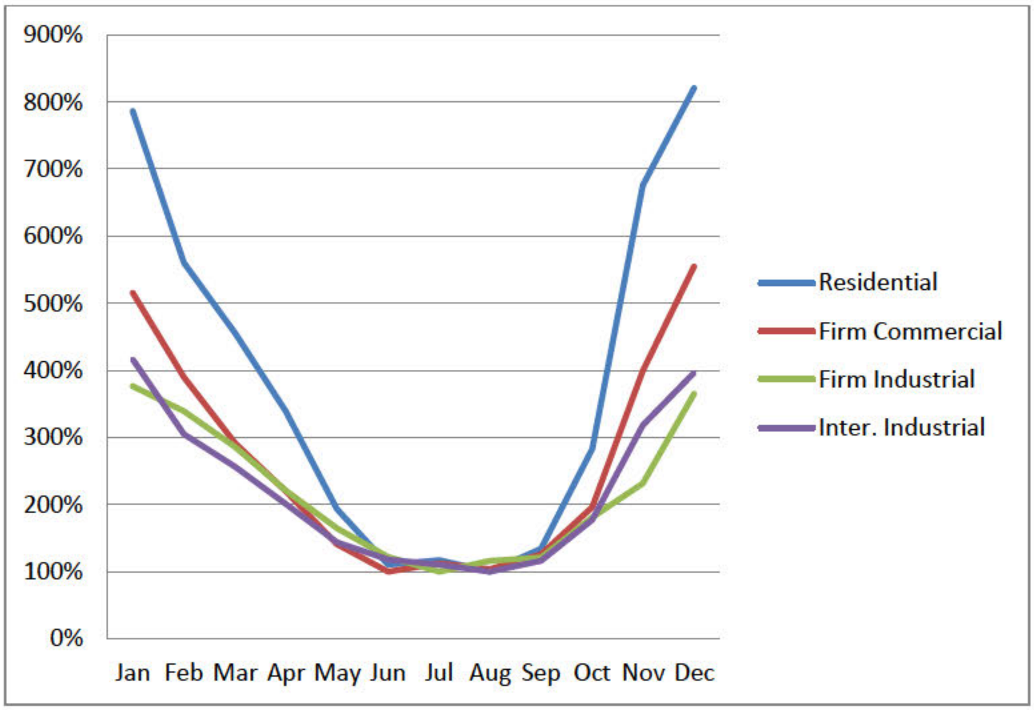
Figure 2: Henry Hub Monthly Price Relative to Avg. Annual Price



Q. How did you analyze the issue?

A. I examined the usage profile for different customer classes throughout the year. Figure 3 below shows the relative monthly use by class of customer compared to the minimum annual monthly usage by class of customer.

Figure 3: **Monthly Usage Relative to Annual Minimum**



From this graph one can see that different schedules have different patterns of use. As evidenced in the figure, residential demand exhibits a much larger percentage change leading up to the winter months than does industrial. Differences in demand variability mean that differing customer classes impose differing gas costs. Washington, also in Cascade's service territory, already implements differing gas costs between customer classes based on the average cost of each particular class.

Q. What is your recommendation?

A. I recommend altering the WACOG adjustment mechanism so that the charge each class receives is proportional to the actual cost of gas the Company incurs for that class.

Q. Can you provide more detail on how to implement your recommendation?

A. Each year Cascade files the Purchased Gas Adjustment (PGA). This adjustment forecasts the next year's cost of gas and trues up the previous year's cost of gas. The forecast and true-up per-therm gas cost should be calculated at the most granular level practical, for example by day for the whole year. Each customer class's usage should also be calculated at the same granularity as gas costs. The annual customer class gas cost is calculated by multiplying the daily cost per-therm by the daily customer class gas use. The annual gas charge is calculated by dividing the annual customer class gas cost by the annual customer class gas use. This results in an annual rate that is specific to each customer class.

Q. How do you propose finalizing the details of your proposal?

A. The general nature of the change should be specified in this docket. However, the complete methodology for implementing this change may require that parties collaborate outside this docket. I propose that Cascade hold a workshop during the 2016-2017 heating season to finalize the details of implementing this change, and that the change be implemented when Cascade files the 2017 PGA.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 305
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER: TITLE:	Public Utility Commission of Oregon Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, new product design, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

Cascade Natural Gas Corporation
Oregon Public Utility Commission
Data Request No. 238 (part e)

		2015
28700	**Total Operation Supervision & Engineering**	502,210.92
28710	**Total Distribution Load Dispatching**	140,031.91
28740	**Total Routine Main/Service Operation Expense**	1,073,812.30
28750	**Total Measuring & Regulating Expenses-General**	223,344.71
28760	**Total Measuring & Regulating Expenses-Industrial**	12,145.33
28780	**Total Routine Meter and House Regulator Expense**	543,770.80
28790	**Total Customer Installation Expenses**	451,504.49
28800	**Total Other Expenses**	1,350,047.51
28810	**Total Rents**	20,038.52
28850	**Total Maintenance Supervision & Engineering**	109,200.07
28860	**Total Maintenance of Structures & Improvements**	487.39
28870	**Total Mains - Maintenance, Repair, Relocate**	354,200.70
28880	**Total Compressor Station Maintenance**	781.37
28890	**Total Maintenance of Measuring & Regulating-General**	33,903.00
28900	**Total Maintenance of Measuring & Regulating-Industrial**	60,494.97
28920	**Total Service-Maintenance, Repair, Relocate**	331,051.78
28930	**Total Meter/Regulator Maintenance**	375,528.54
28940	**Total Maintenance of Other Equipment**	57,135.72
Grand Total		5,639,690.04

Staff/502

Gibbens/1

2014	2013	3 Yr Trend	2015 Trend	2014 Trend	2015 Delta	2014 Delta
448,040.94	463,288.99	8.4%	12.1%	-3.3%	54,169.97	(15,248.05)
167,473.91	114,637.36	22.2%	-16.4%	46.1%	(27,442.00)	52,836.55
923,626.56	1,062,025.20	1.1%	16.3%	-13.0%	150,185.74	(138,398.64)
247,474.39	206,202.27	8.3%	-9.8%	20.0%	(24,129.68)	41,272.12
13,956.76	28,583.98	-57.5%	-13.0%	-51.2%	(1,811.43)	(14,627.22)
513,912.63	470,569.38	15.6%	5.8%	9.2%	29,858.17	43,343.25
444,085.21	421,773.94	7.0%	1.7%	5.3%	7,419.28	22,311.27
1,355,829.93	1,072,594.53	25.9%	-0.4%	26.4%	(5,782.42)	283,235.40
9,450.59	14,528.66	37.9%	112.0%	-35.0%	10,587.93	(5,078.07)
103,119.35	127,384.32	-14.3%	5.9%	-19.0%	6,080.72	(24,264.98)
175.31	186.12	161.9%	178.0%	-5.8%	312.09	(10.81)
315,613.99	307,513.42	15.2%	12.2%	2.6%	38,586.72	8,100.56
160.50	25.00	3025.5%	386.8%	542.0%	620.87	135.50
70,387.01	141,025.05	-76.0%	-51.8%	-50.1%	(36,484.01)	(70,638.04)
18,789.09	31,430.90	92.5%	222.0%	-40.2%	41,705.88	(12,641.81)
386,656.59	301,087.67	10.0%	-14.4%	28.4%	(55,604.81)	85,568.92
322,281.25	309,917.91	21.2%	16.5%	4.0%	53,247.29	12,363.34
72,800.84	46,028.03	24.1%	-21.5%	58.2%	(15,665.12)	26,772.82
5,413,834.85	5,118,858.84	10.2%	4.2%	5.8%		

Cascade Natural Gas Corporation
Oregon Public Utility Commission
Data Request No. 238 (part e)

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Staff/502

Gibbens/1

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5,413,834.85	5,118,858.84	10.2%	4.2%	5.8%		

CASE: UG 305
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 336

Date prepared: 7/7/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 336

Please provide a narrative explanation for the 46 percent increase in 2014 and subsequent 16 percent decrease in 2015 in FERC account 28710: Distribution Load Dispatching. What occurred that resulted in these changes?

Response:

The primary reason for both the 2014 increase and 2015 decrease in FERC 28710 can be attributed to labor costs associated with Cascade setting up and operating its own Gas Control Facility in Spring 2014.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 337

Date prepared: 7/12/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 337

Please provide a narrative explanation for the 13 percent decrease in 2014 and subsequent 16 percent increase in 2015 in FERC account 28740: Routine Main/Service Operation Expense. What occurred that resulted in these changes?

Response:

The 13% decrease in 2014 relates to a 2013 project to perform multiple test digs to assess and analyze condition/integrity of CNG's delivery pipeline. This project included increased labor, subcontractors, and consultants.

The 16% increase in 2015 can be attributed to labor costs relating to staff growth in the Bend District necessary to complete FICA remediation of conditions identified during AC Surveys. The increased labor costs also correlate to increased demand for line locates that came about in 2015.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 338

Date prepared: 7/12/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 338

Please provide a narrative explanation for the 26 percent increase in 2014 in FERC account 28800: Other Expenses. What occurred that resulted in these changes?

Response:

The 26% increase in 2014 can be attributed to the labor costs associated with the hiring of an additional Service Mechanic in the Bend District and increased subcontract labor. Temporary Employees were hired across all Oregon Districts to remediate items identified as part of AC Surveys, such as wrapping of risers and painting of meters. Material costs also increased in relation to the above changes.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 339

Date prepared: 7/12/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 339

Please provide a narrative explanation for the 35 percent decrease in 2014 and subsequent 112 percent increase in 2015 in FERC account 28810: Rents. What occurred that resulted in these changes?

Response:

The 35% decrease in 2014 can be primarily attributed to a one-time credit from Day Wireless Company on the radio tower rental fees.

The 112% increase in 2015 is attributed to the absence of the 2014 credit described above and the increase in rental costs for district office equipment.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 340

Date prepared: 7/12/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 340

Please provide a narrative explanation for the 50 percent decrease in 2014 and subsequent 52 percent decrease in 2015 in FERC account 28890: Maintenance of Measuring and Regulating-General. What occurred that resulted in these changes?

Response:

The 2014 50% decrease and 2015 52% decrease can be attributed to changes in staffing levels in the Bend District and shift of work toward capitalized projects in the Eastern Oregon District.

The Bend District hired and trained a new meter inspector in 2013. Once the new inspector was fully trained the previous inspector left CNG. 2013's labor costs include two employees while 2014 and 2015 do not.

The Eastern Oregon District saw a temporary shift in meter and regulator maintenance costs, from normal routine maintenance to maintenance that met the company's capitalization criteria. Thus, the decrease in operational labor and related materials cost is because more work was capitalized.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 341

Date prepared: 7/12/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 341

Please provide a narrative explanation for the 40 percent decrease in 2014 and subsequent 222 percent increase in 2015 in FERC account 28900: Maintenance of Measuring and Regulating-Industrial. What occurred that resulted in these changes?

Response:

The 40% decrease in 2014 is related to the reduction of materials costs associated with normal maintenance of industrial measuring and regulating equipment.

The 222% increase in 2015 is related to a project to replace valves at the Hermiston Generation Station.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 342

Date prepared: 7/12/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 342

Please provide a narrative explanation for the 4 percent increase in 2014 and subsequent 17 percent increase in 2015 in FERC account 28930: Meter/Regulator Maintenance. What occurred that resulted in these changes?

Response:

The 2014 4% increase and 2015 17% increase can primarily be attributed to increases in labor costs. Labor costs were affected by a change in CNG's safety procedures that now requires certain types of regulator maintenance to be performed by two employees instead of one, essentially doubling the costs of such maintenance. Labor costs were also affected by the increase in the number of regulator stations requiring maintenance.

CASE: UG 305
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 504

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 236

Date prepared: June 13, 2016

Preparer: Steve Kessie

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 236

CNGC/200/Parvinen/6, lines 23 and 24 state that bringing the Atmospheric Corrosion (AC) survey program in-house will provide more control of the work, and better tracking of information.

a. Please describe how increased control will improve the survey program and how that translates into a benefit for customers.
b. Please describe how the better tracking of information will be used to improve the survey program.
c. Please describe how, and in what ways, customers will benefit from better tracking of information.

Response:

a. By using CNGC employees instead of contractors, CNGC can have more direct oversight of the field employees. This will allow management to better control and direct the work. It will also allow for a more direct information flow. By eliminating the contractor, a more direct line between the field and management will be created. The result is a more consistent and efficient process for surveys with better communication, which is a benefit to our customers.

b. Technology in the form of a work management system is something that is being piloted now and will be implemented across the company for AC survey in 2017. This tool is not something that would be easy to integrate using contractors. The software provides better tracking for meeting compliance dates and for work order generation.

c. Customers will not notice much if any change. The survey will be completed in much the same way it always has and that is by having a CNGC representative inspect their gas facility by visually inspecting the meter set and reporting on their findings. The benefit will be a more consistent and efficient process for surveys with better communication which is a benefit to our customers.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 318

Date prepared: 7/7/2016

Preparer: Mike Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 318

In reference to CNGC/200/Parvinen/6, lines 23 and 24, please explain how the Company chooses between using contract labor or Cascade employee labor. What factors are generally considered? Were these factors considered in regards to the AC Survey? Please provide and describe any analysis performed in making such decisions.

Response:

The Company makes the determination whether to use contract labor or Cascade employee labor on a case by case basis taking into account many factors such as whether the work is a project or permanent change, length of project, required expertise, cost and/or cost savings, etc.

These factors were considered in first, the determination to use outside labor and then again when switching to Cascade employee labor. The benefits for switching to Cascade labor included a cost savings (from budgeted or expected contractor labor) even though there is an increase from actual costs, better ability to control documentation, ability to perform certain remediation actions during survey process.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Staff adjustments to the expense Cascade includes in the test year for meals and entertainment; membership, dues, and donations; travel; and customer accounts (non-labor), and the allowance for operating plant materials and operating supplies that Cascade includes in rate base.

Q. What exhibits do you include as part of your testimony?

A. I have prepared the following exhibits:

Exhibit 601—Witness Qualifications Statement
Exhibit 602—Company response to Staff Data Request No. 57, regarding Meals and Entertainment
Exhibit 603—Company response to Staff Data Request Nos. 57,89,90 and 345-346, providing description of full name, purpose, vendor and how the organization benefits Oregon customers
Exhibit 604—Company response to Staff Data Request No.157, regarding increase in FERC Account 902 and Account 903
Exhibit 605—Company response to Staff Data Request Nos. 375-376, regarding changes in postage costs and electronic billing
Exhibit 606—Company responses to Staff Data Request No. 315, explaining why plant material and operating supplies has been increasing since 2011

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Meals and Entertainment....3
Issue 2. Dues, Memberships, and Donations 5
Issue 3. Travel 7
Issue 4. Customer Accounts (non-labor)....8
Issue 5. Materials and Supplies....10

ISSUE 1. MEALS AND ENTERTAIMENT

Q. Please discuss your review of meals and entertainment expense.

A. The Company's 2016 test-year estimate for meals and entertainment expense (M&E) is based on the 2015 unadjusted expenditures for M&E of $91,892. The Company then reduced the 2015 expenditures by $9,400, which is approximately 10 percent. I reviewed the M&E expenses incurred by the Company in 2015 to ensure that they were includable as M&E expenses and found no errors in this regard. I also reviewed the Company's response to Staff Standard Data Request No. 57, and added additional columns to the Company's response for each expense, including account number and object description, to aid in my analysis.

Q. Did you make any adjustments to Cascade's M&E test-year expenditures?

A. Yes. Commission policy regarding M&E expense is to require a 50 percent sharing between customers and shareholders because such expenses are discretionary and not required to provide safe and adequate service to customers.[1] Therefore, I recommend a 50/50 sharing adjustment to the Company's M&E expense, resulting in the net adjustment (Oregon-allocated) below. I also removed the entire expense amount of $772 (Object Code 5233) related to Directors' Meals and Entertainment because Cascade has made no showing of customer benefit.

Meals and Entertainment Adjustment ($36,546)

The derivation of this adjustment is shown in Exhibit Staff/602.

[1] *See* Docket No. UE 197, Order No. 09-020 at 21 (Jan. 22, 2009).

Q. Please provide a summary table showing the meals and entertainment adjustment.

A. My summary table of the M&E expense adjustment is below.

Table 1. Meals and Entertainment Expenses (A&G and O&M)

	Oregon Total	**Object Code**
2015 Expenses	$77,620	5521 – M&E
	$14,272	All Other Object Codes[2]
Total 2015 Expenses	$91,892	50% 45,946
Company Adjustment	($9,400)	($9,400)
Total	$ 36,546	
Staff Adjustment	Disallow 50% (36,546)	

[2] To locate additional meals and entertainment expenses besides those classified with Object Code 5521-Meals & Entertainment, Staff searched the expense explanations across A&G and O&M accounts for the following terms: candy, b-fast, dessert, party, balloon, funeral, flower, meal, Christmas, death, floral, recognition, appreciation, Safeway, award, going away, cake, birthday, snack, coffee, donut, doughnut, bowling, golf, prize, gift, dinner, lunch, supper, breakfast, diner, restaurant, bfast, photo, resulting in the "All other Object Codes" expense of $14,272.

ISSUE 2. DUES, MEMBERSHIPS, AND DONATIONS

Q. Please discuss your review of expenses relating to dues, memberships, and donations.

A. I reviewed Cascade's responses to Standard Data Request No. 57, 89, and 90, and to DR Nos. 155-157, 217-220, and 346, which contained information regarding the memberships Cascade paid in 2015. Based on the Company's responses, I organized the memberships by category, including "Professional Organization Dues" (Object Code 5811), "Charities Donations" (Object Code 5981), "Company Organizations Dues" (Object Code 5912), and "All Other Object Codes" (additional Dues, Membership, and Donations that I located through key term searches).

Q. Did you make any adjustments to Cascade's dues, memberships, and donations test-year expense?

A. Yes. I identified numerous instances where Cascade did not clearly identify the organization associated with the expense or explain how such membership provides customer benefits. I recommend that the Commission disallow unexplained memberships at 100% given that the Company bears the burden of demonstrating that expenses associated with membership, fees, and dues reasonably lead to the provision of safe and reliable service and provide a benefit to customers.[3]

Staff typically recommends recovery of dues and membership expenses relating to industry research organizations at 100 percent, industry trade

[3] *See* Docket No. UF 3779, Order No. 82-606 (Aug. 18, 1982).

organizations at 75 percent, and Chamber of Commerce memberships at 50 percent.[4] Charitable donations are disallowed at 100 percent. Given the difficulty identifying the type of membership and the associated benefits to customers, I recommend allowing Professional Organization Dues and Company Organization Dues at 50% until the Company provides additional information justifying the expense. Therefore, I recommend an adjustment of $(51,968).

Q. Please provide a summary table of the dues, memberships, and donations adjustment.

A. A summary table of the proposed adjustment is provided below.

Table 2. 2015 Base Year Dues, Memberships, and Donations Expenses (A&G and O&M)

	Oregon Total	Object Codes	Adjustment (disallowed in percent & $)
Total 2015 Expenses by Account	$15,632	5811 – Professional Organizations Dues	50% ($7,816)
	0	5840 – Service Club Dues	N/A
	$ 2,427	5981 – Charitable Donations[5]	100% ($2,427)
	$60,012	5912 – Company Organizations Dues	50% ($30,006)
	$11,719	All other Obj. Codes[6]	100% ($11,719)

[4] *Cascade Nat. Gas Corp. v. Davis*, 28 Or App 621, 631 (1977); Docket No. UF 3074, Order No. 74-658 (Sept. 3, 1974).
[5] Energy Trust of Oregon-related expenses were listed as "Charitable Donations" (Object Code 5981); Staff did not include these expenses in the Charitable Donations adjustment in Table 2.
[6] To locate additional Dues, Memberships, and Donation expenses besides those classified with Object Code 5811-Dues, Membership & Donations, Staff searched the expense explanations across A&G and O&M accounts for the following key terms: membership, dues, newspaper, magazine, subscription, sponsor, registration, resulting in the "All other Object Codes" expense of $11,719.

Total 2015 Expenses	$89,790		
Company Adjustment			N/A
Staff Total Adjustment			**$(51,968)**

ISSUE 3. TRAVEL

Q. Please discuss your review of travel-related expenses.

A. For travel expenses, I reviewed Cascade Object Code 5511-Commercial Air Service expenses, and searched Cascade's other object codes that were associated with travel. However, I generally did not find any description of the travel, associated purpose, or location accompanying the expense amounts included in Cascade's test year. Therefore, at this time, I recommend that the Commission not include the travel expenses in revenue requirements. Should the Company provide additional information showing that the travel was work-related and at reasonable cost, I would revisit this recommendation. A table summarizing the travel expense adjustment is provided below:

Table 3. 2015 Base Year Travel Expenses (A&G and O&M)

	Oregon Total	**Object Codes**	**Adjustment in Percent &$**
Total 2015 Expenses by Account	$39,206	5511 – Commercial Air Service	100% $(39,206)
	$55,087	All other Object Codes[7]	100% $(55,087)
Total 2015 Expenses	$94,293		
Staff Total Adjustment			**$(94,293)**

[7] To locate additional travel-related expenses besides those classified with Object Code 5511-Commercial Air Travel, Staff searched the expense explanations across A&G and O&M accounts for the following key terms: flight, hotel, airfare, travel, parking, luggage, shuttle, motel, taxi, lodging, airport, resulting in the "All other Object Codes" expense of $55,087.

ISSUE 4. CUSTOMER ACCOUNTS (NON-LABOR)

Q. Please discuss your review of customer accounts (non- labor).

A. I reviewed the trend of expenses for FERC Accounts 900-910[8] for years 2012-2015, and did not identify any concerns except with regard to FERC Accounts 902 and 903.

Regarding Account 902 (Meter Reading), I identified a significant expense increase in year 2013. I confirmed through Staff DR No. 157 that the 2013 increase is attributable to Cascade's correction of the assignment of certain software costs to this account, which is appropriate. I confirmed that the 2014 and 2015 software-related expenses were correctly assigned to Account 902.

Regarding Account 903 (Customer Records and Collection), I noted a significant increase in year 2015. I confirmed through Staff DR No.157 that the 2015 increase was the result of the Company moving postage costs from Account 921 to Account 903. I agree that postage costs were correctly relocated to this account.

Q. Do you have an adjustment to propose for customer accounts, non-labor expense?

A. Staff DR No. 375-376, attached as Exhibit Staff/605, relates to the changes in customer billing costs and investigates whether the Company captured the savings effects of the recent reduction in postage rates, as well as the trends in paperless bills (electronic billing).

[8] Other customer accounts are reviewed by Staff Witness Marianne Gardner in Exhibit 100/Garner.

The United States Postal Service reduced the cost of first class mail from $0.49 to $0.47 on April 10, 2016. In response to Staff DR No. 375, Cascade states that its budgeted postage expense for 2016 is estimated to be $1,366,000, and that the actual postage for 2015 was $1,208,000. The April 2016 reduction in U.S. postage rates is roughly four percent. Additionally, I noted that the Company is experiencing large increases in the number of customers that use electronic billing. For example, at the end of 2013, Cascade had 5115 customers on electronic billing; and at the end of 2015, 10,989 customers were on electronic billing. Therefore, the average annual increase in customers enrolling in electronic bill pay is nearly 3000 customers per year.

If I use the 2016 estimated billing cost, and reduce it by four percent, that results in an annualized amount of $54,640 in savings due to lower postage costs. However, taking into account that the change in postage occurred on April 10, 2016, the pro-rated savings is 266/366*$54,640 or $39,711. Taking the calculation of an increase in 3000 customers in electronic bill pay per year, a savings of 3000*12*$0.47, or $16,920, results. (Paper billing costs more than just the stamp, so the savings value calculated above is understated.) Adding these two impacts together results in a postage savings of $56,631. Therefore, I propose an adjustment of $56,631 to Customer Accounts (non-labor) expense.

ISSUE 5. MATERIALS AND SUPPLIES

Q. Please describe the Commission's ratemaking treatment of "materials and supplies."

A. Materials and supplies are a component of working capital. Working capital is the amount of funds provided by investors to enable the utility to pay its operating expenses prior to the collection of operating revenues from customers and to maintain a normal level of materials and supplies.[9] The Commission has typically authorized energy utilities to include an allowance for material and supplies in rate base.[10]

Q. What amount does Cascade include in rate base for working capital?

A. $1,838,066 for plant materials and operating supplies, $913,242 for gas storage expense, and $355,930 for prepayments. Staff Witness Erik Colville addresses gas storage expense and Staff Witness Marianne Gardner addresses prepayments.

Q. Please indicate your method of analysis on this issue.

A. I reviewed the historical trend to determine if the 2015 value for materials and supplies is a reasonable value.

Q. Could you provide a summary table that displays the last five years of expense for plant materials and supplies?

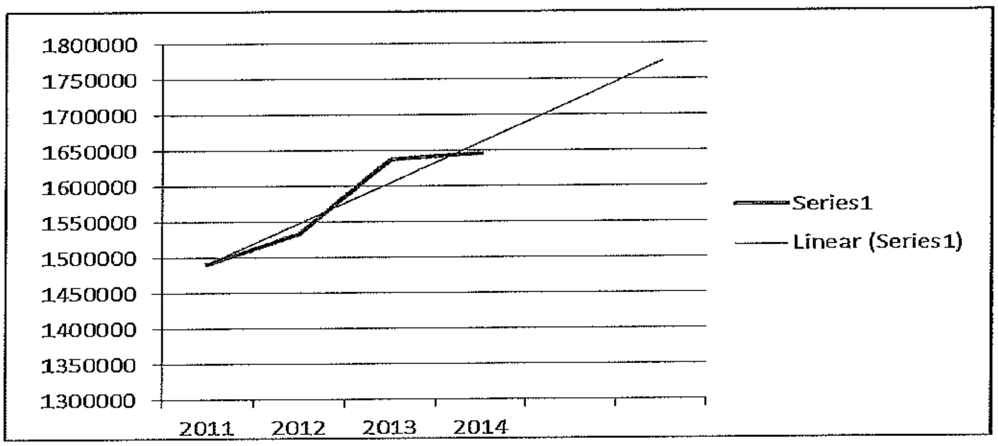
---

[9] *See* Docket No. UF 2176, Order No. 37112 (Mar. 10, 1960).
[10] *See, e.g.*, Docket No. UF 3275, Order Nos. 77–394 (June 13, 1977) and Docket No. UF 3094, Order No. 74–898 (Nov. 21, 1974).

A. Yes. The table below displays the last five years of plant materials and supplies and is taken from information contained in Exhibit Staff/606.

Table 4. Plant Materials and Supplies

Year	2011	2012	2013	2014	2015	2016
M&S	1,491,199	1,533,845	1,637,065	1,645,848	1,838,799	
Staff Adjusted					1,718,066	1,774,783



Q. In reviewing this trend, what did you conclude?

A. It appears that 2015 reflects a higher cost level than the previous trend. If the trend from 2011 through 2014 continued, the 2015 and 2016 values would be $1,718,066, and $1,774,783, respectively.

Q. Do you have any concern regarding recommending the Commission adopt the $1,774,783 value?

A. Yes. These values are end-of-year numbers, and not average year values. A different approach more consistent with past Staff practice is to use a mid-year value that would be more consistent with average rate base.[11] To

[11] *See* Docket No. UF 2782, Order No. 70-664 (Oct. 5, 1970).

derive the average value, the 2015 and 2016 end-of-year amounts are added together and divided by two. This results in a 2016 value of $1,746,425. My adjustment is the difference between the $1,838,066 amount proposed by Cascade and $1,776,425 indicated for 2016 by my trend analysis, and mid-year average approach. The adjustment results in a $61,641 reduction to rate base.

Q. Does this include your testimony?

A. Yes.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATION STATEMENT

NAME: Kathy Zarate

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100
Salem, OR. 97301

EDUCATION: Bachelor of Arts, Economics
Oregon State University, Corvallis, Oregon

Bachelor Degree in Law
Republic University, Santiago, Chile

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals.

I have approximately 10 years of professional experience in contracting and audit review work, including:

- Six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 57

Date prepared: 02/10/2016

Preparer: Candice Tschauner

Contact: Pam Archer

Telephone: (509)734-4591

57. Please provide transaction summaries for non-labor costs recorded in FERC Operations and Maintenance and Administrative and General Accounts (Oregon situs and Oregon allocated) for the historical base year. Please place in MS Excel and include:

    a. Amount charged;
    b. Description of cost;
    c. Name of vendor (if applicable);
    d. Business Unit (Profit Center) being charged;
    e. Oregon allocated cost (for Oregon allocated); and
    f. Service provided (e.g., reports to stockholders, lease, etc.).

Response: Please refer to OPUC-57.xlsx.

CNG Response to OPUC-57.xlsx

Is provided in electronic format.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 345

Date prepared: 7/13/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 345

Referring to the Company's response to SDR No. 57, OPUC-57.xlsx, for the following four object (OBJ) codes 5811,5840,5912,5981, please provide the following details:

a) The full name of the organization;
b) The purpose of the organization;
c) The vendor; and
d) How the organization benefits Oregon customers.

Response: The attached spreadsheet lists transactions for memberships and dues. Column P itemizes the expense into a handful of categories, which benefit customers in the following way.

1) Economic Development – The Company invests in organizations interested economic development so that the Company can properly plan for expected customer growth in a timely manner without jeopardizing the safe and reliable service that customers currently receive. Also, ratepayers benefit from a communities interest and investment in economic development, because additional infrastructure to serve new customers leads to improved system reliability and additional throughput reduces existing customers' overall fixed costs on a per customer basis.
2) Professional Organization – The Company pays dues to a number of industry and occupation specific organizations that provide Company employees with access to current information, contacts within specific fields, and best practices.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Ratepayers benefit because they are served by a company with qualified employees

3) Chamber of Commerce – Cascade belongs to Chambers of Commerce located within the communities where it provides service. Through this involvement, the Company is able to better understand it local customers' changing needs and learn about expansion projects or other plans that impact infrastructure like road paving's that might impact the Company's schedule for planned reinforcements or main extensions. Foreknowledge leads to better planning, and the gained efficiencies are passed through to customers.
4) Fee – Fees are costs of doing business such as irrigation at facilities and business park dues.
5) MDUR/MDU Allocation – MDUR allocations are the costs for executive overheads, insurance, and shared resources, all of which are necessary costs of doing business.
6) Notary – The Company incurs costs to maintain an active certified notary in the office which is needed as a part of doing business.

See attached Excel spreadsheet OPUC-345.xlsx

CNG Response to OPUC-345.xlsx

Is provided in electronic format.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 346

Date prepared: 07/07/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 346

Referring to the Company's response to DR 156, OPUC-156.xlsx, please explain in detail why the Company has disallowed 100% of some Chamber of Commerce membership expenses, but allowed 100% of other Chamber of Commerce membership expenses.

Response:

Referring to OPUC-156.xlsx the top section rows 4-56 are 100% Washington, the middle section rows 60-81 are 100% Oregon, and the bottom section rows 85-167 are items allocated to Oregon and Washington with column L of that section being the amount allocated to Oregon.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 57

Date prepared: 02/10/2016

Preparer: Candice Tschauner

Contact: Pam Archer

Telephone: (509)734-4591

57. Please provide transaction summaries for non-labor costs recorded in FERC Operations and Maintenance and Administrative and General Accounts (Oregon situs and Oregon allocated) for the historical base year. Please place in MS Excel and include:

    a. Amount charged;
    b. Description of cost;
    c. Name of vendor (if applicable);
    d. Business Unit (Profit Center) being charged;
    e. Oregon allocated cost (for Oregon allocated); and
    f. Service provided (e.g., reports to stockholders, lease, etc.).

Response: Please refer to OPUC-57.xlsx.

CNG Response to OPUC-57.xlsx

is provided in electronic format.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 89

Date prepared: 02/22/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)734-4591

92. Provide a schedule showing the contributions and donations included in the utility's regulatory expense accounts for the most recent historical twelve month period by FERC account. Also, provide the amounts included in the projected test year expenses.

Response: See attached spreadsheet OPUC-89.xlsx

** 2016 O&M is budgeted by Department and Object code. It is then allocated to FERC accounts based upon 2015 Actual expenses (Department/Object/FERC accounts)

CNG Response to OPUC-89.xlsx

is provided in electronic format.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 90

Date prepared: 02/22/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)734-4591

90. Provide a schedule showing all dues (industry organizations, clubs, professional organizations, etc.) included in the utility's regulatory expense accounts for the most recent historical twelve month period by FERC account. Also, provide the amounts included in the projected test year expenses.

Response: See attached spreadsheet OPUC-90.xlsx

** 2016 O&M is budgeted by Department and Object code. It is then allocated to FERC accounts based upon 2015 Actual expenses (Department/Object/FERC accounts)

CNG Response to OPUC-90.xlsx

is provided in electronic format.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 157

Date prepared: 5/25/16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 157

Regarding the Company's response, OPUC-58 (b) Revised.xls, to Staff DR No. 58 part b, the Company reported the following Customer Accounts Expenses as shown in the table below.

FERC	Description	2015	2014	2013	2012
902	Meter Reading	41,,932	42,201	55,081	23,717
903	Customer Records and Collections Exp.	586,812	267,100	233,055	259,708

Please explain in detail:

a. The sharp increase in FERC account 902 from $23,717 in 2012 to $55,081 in 2013, and the subsequent decrease to approximately $42,000 in 2014 and 2015.; and,

b. The increase in FERC account 903 to $586,812 in 2015 from the relatively flat level of approximately $250,000 from 2012 through 2014.

Response:

a. **The spike in FERC 902 for 2013 primarily relates to a single invoice related to software maintenance fees, of which CNG's portion of the fee is $52,111.16, which allocated $12,793.29 to Oregon. This invoice was inadvertently posted** to the wrong FERC Code. This annual software license fee in years since 2013 has been coded to FERC 880.

In 2012, mobile meter reading equipment was purchased for each service vehicle in Cascade's fleet, dramatically increasing the number of units in use. The increase in Subcontract Expenses (Object Account #5211) after 2012, relates to maintenance costs for those additional units.

b. As part of the general ledger data evaluation related to the Cost of Service Study, as conducted by Black & Veatch Corporation, in anticipation for filing a General Rate case in Oregon in 2015, it was determined that postage expenses, related to mailing of monthly customer billings, should be posted to FERC Account 903. These postage expenses were previously (prior to 2015) posted to FERC Account 921 (Office Supplies & Expenses).

See attached spreadsheet: OPUC 157.xlsx

CNG Response to OPUC-157.xlsx

Is provided in electronic format.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 605

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 375

Date prepared: 7/19/16

Preparer: Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 375

In its 2016 test-year cost of postage estimate for billing, did the Company take into account the reduction in postage rates from $0.49 to $0.47 per letter? If yes, please provide the calculations or adjustments demonstrating that the reduction was incorporated into the 2016 test-year billing cost estimate. If not, please provide an estimate of Cascade billing costs that includes the reduction in postage rates.

Response:

CNG did not take into account the reduction in USPS rates in the 2016 test year billing cost estimate.

The company's 2016 total initial budget for postage expenses was $1,336,000. The company is showing an underrun in costs through 6/30/16 and expects the total actual expenses for 2016 to be about $1,235,000.

Total postage expense for 2015 was $1,208,000.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 376

Date prepared: 7/18/16

Preparer: Brent Arnold/Kevin Conwell

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 376

Please provide the number of bills, by year, that were sent by Cascade in electronic format from 2012 through 2015, inclusive.

Response:

See excel spreadsheet OPUC-376.xlsx

CNG Response to OPUC-376.xlsx

Is provided in electronic format.

CASE: UG 305
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 606

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 315

Date prepared: 07/05/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 315

Please explain why a cost for Plant Material and Operating Supplies (FERC Account 154) has been increasing since 2011.

Account		2016	2015	2014	2013	2012	2011
154	Topic	1,838,799	1,838,799	1,645,848	1,637,065	1,533,845	1,491,199

Response:

Steady increase in inventory is a result of:

- Steady increase in customer base resulting in new main/service/meters
- District Replacement Projects
- FICA remediation's identified from AC survey, require materials
- Increased meter exchanges for random sampling and meter family failure exchange program
- General inflation of costs

CASE: UG 305
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I address Staff's adjustments to administrative and general (A&G) expenses; advertising, sales and marketing, and customer service; and utility plant and capital additions.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/702 and electronic Exhibit Staff/703 that contain Company responses to Staff data requests. I also prepared Exhibit Staff/704 that contains a breakdown of Staff's Utility Plant adjustment.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Miscellaneous A&G expenses 2
Issue 2. Advertising, sales and marketing, and customer service expense 5
Issue 3. Utility Plant and capital additions 10

ISSUE 1. MISCELLANEOUS A&G EXPENSES

Q. Please describe the Company's request associated with A&G expenses.

A. The Company proposes to increase its A&G costs by $229,005 to approximately $6 million in the 2016 test year, primarily as a result of wage increases of $193,869.[1] The Company proposes an "A&G Adjustment" to remove miscellaneous general expenses not appropriate for recovery in rates in the amount of $20,183.[2]

Q. Please describe Staff's analysis and recommendations regarding the Company's requested A&G expenses.

A. Staff commonly proposes certain adjustments related to A&G, supported by Commission precedent. In this testimony, I address the A&G expenses related to directors and officers (D&O) insurance, and education and training.

<u>D&O Insurance</u>

D&O insurance protects Cascade senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. Staff recommends removal of 50 percent of total D&O insurance expense in order to share the cost of the insurance equally between ratepayers and shareholders. A 2012 Towers Watson survey found the following: "Consistent with our last three reports, derivative shareholder/investor suits continue to lead the types of claims filed

[1] See Parvinen WP Exhibits 201-206, tab "Exhibit 204-Summary of Adj."
[2] CNGC/200, Parvinen/8, lines 11-15 (the column "(o)" adjustment).

over the last 10 years."[3] Thus, although the Company has not had a claim brought against its directors or officers since 2007,[4] the survey results support the conclusion that shareholders are more likely than customers to file a lawsuit.

Staff's recommendation is supported by Commission Order No. 09-020, resolving issues in a general rate case for Portland General Electric Company. In that order, the Commission held, "[w]e concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense."[5]

Staff's adjustment results in a $16,199 reduction to the Oregon-allocated portion of the total D&O insurance expense.

Training and Education Expenses

The Company's education reimbursement policy specifies that job-related courses are reimbursed at 75 percent, as non-taxable income to the employee, and non-job-related courses are reimbursed as taxable income. The annual limit for tuition reimbursement is $5,250.[6] The Company's training and education expenses for the test year and preceding three years are as follows:

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[3] Exhibit Staff/702, Willis Towers Watson, Directors and Officers Liability Survey: 2012 Summary of Results 19 (Mar. 2013), available at https://www.towerswatson.com/en-US/Insights/IC-Types/Survey-Research-Results/2013/03/Directors-and-Officers-Liability-2012-Survey-of-Insurance-Purchasing-Trends.
[4] Exhibit Staff/702, Company Response to Staff DR No. 222.
[5] Docket No. UE 197, Order No. 09-020 at 19-20 (Jan. 22, 2009).
[6] Exhibit Staff/702, Company Response to Staff DR No. 225.

Table 1. Oregon-Allocated Training and Education Expenses[7]

Year	Expense
2013	$756.61
2014	$1,996.08
2015	$2,718.49
2016 (budget)	$3,282.70

The Company included its 2015 education and training costs in the 2016 test year rather than the higher 2016 budgeted amount. The 2015 expenses include tuition reimbursements and a CPA exam fee. Staff concludes that the proposed expense of $2,718 is both minimal and reasonable for the 2016 test year. Staff proposes no adjustment.

Miscellaneous A&G Expenses

Please see the testimony of Staff Witness Kathy Zarate, Staff/600, for a complete discussion of the Company's miscellaneous A&G Expenses, including meals and entertainment; membership, fees, and dues; and travel expenses.

[7] Exhibit Staff/702, Company Response to Staff DR No. 221.

ISSUE 2. ADVERTISING, SALES AND MARKETING, AND CUSTOMER SERVICE EXPENSE

Q. Please describe the Company's request for advertising, sales and marketing, and customer service expense.

A. The Company proposes to include approximately $96,500 in its 2016 test year for advertising and sales and marketing, expense. The Company derived this amount by using the 2015 actual expense amounts, and then removed all promotional advertising expenses. In its customer service expense account (FERC Account 908), the Company includes some advertising and marketing expense, as well as other miscellaneous expenses associated with meals and travel. Such miscellaneous expenses are discussed by Staff Witness Kathy Zarate in Staff/600. The Company reported no sales and promotional expenses apart from the advertising-related expenses discussed in my testimony below.

Q. Does the Commission have a standard for how advertising-related expenses are treated for ratemaking purposes?

A. Yes. OAR 860-026-0022 sets out how advertising-related expenses are addressed in a rate case. Each type of advertising expense is classified into a category (Categories A-E), and each category has a different standard for inclusion in rates that is applied by the Commission.

Category "A" expenses are for utility service advertising expenses and utility information advertising expenses.[8] These expenses are presumed

[8] OAR 860-026-0022(2)(a).

reasonable up to 0.125 percent of the gross retail operating revenues determined in the applicable rate proceeding.[9]

Category "B" expenses are legally mandated advertising expenses, which are presumed to be just and reasonable.[10]

Category "C" expenses are institutional advertising expenses, promotional advertising expenses, and any other advertising expenses not fitting into Category "A", "B", or "D" (political advertising and non-utility advertising) expenses.[11] There is no presumption that Category "C" advertising expenses are reasonable; rather, the energy utility carries the burden of showing that any Category "C" advertising expenses are just and reasonable for rate-making purposes.[12] Furthermore, the utility must separately state the amount of advertising expenses in Category "C" in any rate filing made under ORS 757.210 and ORS 759.180.[13]

Q. Please describe your analysis of Cascade's proposed advertising expenses.

A. Cascade did not specify categories for its advertising expenses for the 2016 test year in its rate filing. However, the Company's actual 2015 expenses were provided in response to Staff DR No. 104, all of which were Category A, B, and C expenses.[14]

[9] OAR 860-026-0022(3)(a).
[10] OAR 860-026-0022(2)(b); OAR 860-026-0022(3)(b).
[11] OAR 860-026-0022(2)(c).
[12] OAR 860-026-0022(3)(c).
[13] *Id.*
[14] Exhibit Staff/702, Company Response to Staff DR No. 104.

I reviewed the Company's responses to Staff Data Requests[15] that included transaction-level detail of the 2015 base year advertising expense. In Category A, the Company spent $74,739, which is below the allowable limit of $84,563 (0.125 percent of gross revenues). I reviewed the transaction-level detail to determine whether the expenses were properly attributed to Category A, "utility service and utility information advertising." I conclude that the expenses were appropriate for Category A, the majority being informational and educational advertising concerning the need to call for utility locates before beginning any excavation ("811" advertising), and also confirmed that the proposed expense amount is within the 0.125 percent presumed reasonable.

In Category B, the Company spent $6,408. I reviewed the Category B "legally mandated" advertising expenses, which included rate case notices and safety notices, and confirmed that they were appropriate for legally mandated expenses.

In Category "C", the Company spent $34,396. However, for the 2016 test year, Cascade removed $19,501 from Category C "Institutional and Promotional" advertising. I sent a data request asking the Company to provide a narrative explanation for the remaining amount of Category C expense, totaling $14,895. The Company responded that the $14,895 was spent on promotional items, such as footballs, that contain "811-Call Before You Dig" messaging, so the Company included such advertising expenses

[15] Exhibit Staff/702, Company Response to Staff DR Nos. 104 and 292.

in Category C.[16] The Company further explained that it has found that customers throw away leaflets that discuss "Call Before You Dig" safety, but when that information is printed on promotional items, customers retain the information and the message is more effectively received.

Below is a table showing the Company's 2015 Advertising Expenses as discussed above.

Table 2. Company Proposed Advertising Expense

FERC Account		Account Description	Actual 2015	Category
908 909 913		Informational Advertising – 811	$74,739	A
908 928		Legally Mandated Advertising	$6,408	B
908 913 921 930.1 426.1		Institutional/Promotional Advertising	$34,396	C
		Political/Non-Utility Advertising	$0	D
		EE & Conversion Advertising	$0	E
		2015 Advertising Expenses	$115,543	
		Company Adjustment	($19,501)	
		2015 Proposed Base Year	$96,042	

[16] Exhibit Staff/702, Company Response to Staff DR No. 293.

Q. What is your recommendation regarding advertising expense?

A. I conclude that the Category A, B, and C expenses proposed by the Company in this rate case fall within Oregon's rules for rate recovery: Category A expenses fall within the allowable limit; Category B are presumed just and reasonable; and for Category C, the Company has met its burden of showing that the promotional footballs with Call Before You Dig information printed on them are just and reasonable. Staff proposes no adjustment.

ISSUE 3. UTILITY PLANT AND CAPITAL ADDITIONS

Q. Please describe the Company's request associated with plant and capital additions.

A. The Company proposes to add $13.6 million in capital additions, resulting in $1.6 million increase in revenue requirement.[17] After adjusting for accumulated depreciation, the total rate base would grow by $7.2 million, or 9.3 percent.

Cascade states that of the proposed $13.6 million, $8.2 million is for capital projects related to pipeline safety as well reliability upgrades.[18]

Growth projects comprise $2.5 million of the request, which is related to the cost of adding new customers to the system.

Capacity upgrades comprise $2 million, and the remaining $0.9 million is proposed for IT-related upgrades.

Q. How are plant and capital additions usually treated by the Commission?

A. Staff typically uses a company's last general rate case as a starting point for the amount of plant approved in rate base and then reviews all capital additions through the present and proposed capital additions through the end of the test year. Staff's goal in reviewing plant is to ensure that costs associated with capital additions are prudent and reasonable and that rate payers are not paying any costs that aren't directly related to providing service to customers. In addition, plant additions must be in service, or used and useful at the time rates go into effect.

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[17] CNGC/100, Kvisto/4.
[18] CNGC/205, Parvinen/1.

Q. How did Staff analyze the Company's requested plant and capital additions?

A. Staff reviewed the Company's responses to 11 Staff data requests related to plant and capital additions, as well as the testimony and supporting work papers included in the Company's filing. Consistent with Commission Order No. 16-109, Staff requested the Company provide the following information with respect to each Oregon-allocated and situs project over $150,000:[19]

- Comprehensive cost-benefit analysis of whether and when investment should be built;
- Evaluation of range of alternative build dates;
- Evidence of likelihood of disruptions based on historical experience;
- Evidence on the range of possible reliability incidents;
- Evidence about projected loads and customers in the area; and
- Evidence of consideration of the alternatives, including use of interruptibility or increase in demand-side measures to improve reliability and system resiliency.

Staff then followed up with questions requesting detailed justification for specific projects.

Staff also requested information regarding "blanket" projects, or projects that represent routine maintenance, system upgrades and growth projects. These projects may also include tool and vehicle purchases. In obtaining historical spending data for these types of projects and performing a trend

[19] Staff/702, Company Response to Staff DR No. 140.

analysis, Staff is able to ascertain whether the projected spending for these projects is in line with the Company's spending in previous years.

Q. Does Staff recommend any adjustment to the Company's capital additions?

A. Yes, based on its analysis and review of the Company's workpapers and responses to data requests, Staff recommends a reduction of $3.3 million to the Company's request.

Q. What is the basis for Staff's recommended adjustment?

A. There are three factors that inform Staff's recommendation. The first factor is the Company's reported in-service dates for some of the projects. In response to Staff data requests, the Company reported that some of the projects included in its original filing have a projected in-service date that is after the date that rates will go into effect.[20] I remove $330,000 for projects that will not be in service prior to the time rates from this filing become effective.

The second factor is the forecasted amount that will be transferred to plant during the test year period. For the Bend Pipe Replacement project, the Company includes $4.6 million in its filing. However, the Company has subsequently reported that it forecasts transferring $2.3 million of this project into plant in service during the test year period.[21] Staff removes $2.3 million from Oregon capital additions because these costs are for plant that will not be service prior to the effective date of the tariffs.

[20] Staff/702, Company Response to Staff DR No. 310.
[21] Staff/702, Company Response to Staff DR No. 310.

The third factor is the Company's reduction in spending for two information technology projects and one safety upgrade project. The Company reports that project estimates for its GIS system enhancement have been reduced from $168,000 to $104,000 on an Oregon-allocated basis.[22] Cascade's customer billing upgrade project was reduced from $326,000 to $46,000 on an Oregon-allocated basis. With respect to the costs related to its project on the Mt. Washington Bridge in Bend, Cascade is able to replace pipeline *on* the bridge rather than by boring through the river, which reduces the cost of that project from $465,000 to $146,000.[23] Accordingly, Staff's adjustment for these three projects is a total reduction of $663,000 for Oregon-allocated spending.

Staff Exhibit 704, contains a breakdown of Staff's adjustment to Plant and Capital Additions.

Q. What does Staff conclude regarding the remainder of Cascade's capital addition spending?

A. Because blanket projects reflect incremental routine capital spending, it is useful to compare the budget for these projects forecasted for the test year with historical spending. This analysis provides a basis for staff to gauge the reasonableness of the Company's forecast budget for these projects. Based on a review of these projects from 2011 through 2015, the forecasted test year spending for blanket projects falls comfortably within these historical norms.

[22] Staff/702, Company Response to Staff DR No. 139.
[23] Staff/702, Company Response to Staff DR No. 140.

The discrete capital projects examined by Staff include the following:

Table 3. Capital projects

Project	Reason	Cost	In-Service Date
Pendleton valve replacement	Valve being replaced due to inoperability and corrosion. Inoperability could lead to inability to shut down lateral to Pilot Rock	$230,536.00	12/30/2016
Sun River Gate Upgrade	Current gate under capacity requiring by-pass per cold-weather plan when low pressure alarm goes off	$1,609,608.00	12/31/2016
Athena Odorizer Replacement	Odorizer being replaced becaus outdated and unreliable. Replacement parts unavailable	$209,852.00	10/30/2016
Ontario Odorizer Replacement	Odorizer being replaced due to age and capacity concerns	$153,985.00	9/30/2016
Mission Odorizer replacement	Odorizer being replaced due to age and corrosion	$152,809.00	9/30/2016
Bend Pipe Replacement	Replacing pipe identified in DIMP as high risk due to age, lack of coating and operating history	$2,300,000.00	12/30/2016
Mt. Wash. Bridge Crossing	Pipeline being replaced due to exposed pipe and difficulty in painting and inspecting	$146,000.00	12/30/2016
GIS Enhancement	GIS enhancements to facilitate electronic access of maps, survey information, etc.	$146,000.00	2/28/2017
Customer care and billing (CC&B) software upgrade	Cascade using software that is outdated. Upgrading to more recent version of software	$46,000.00	Ongoing project

The Company provided thorough documentation explaining the need for the projects, consideration of alternatives, and benefits for customers.[24]

Q. Does this conclude your opening testimony?

A. Yes.

[24] Staff/702, Company Response to Staff DR Nos. 140, 305, 306, 307.

CASE: UG 305
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division.

My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints.

Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

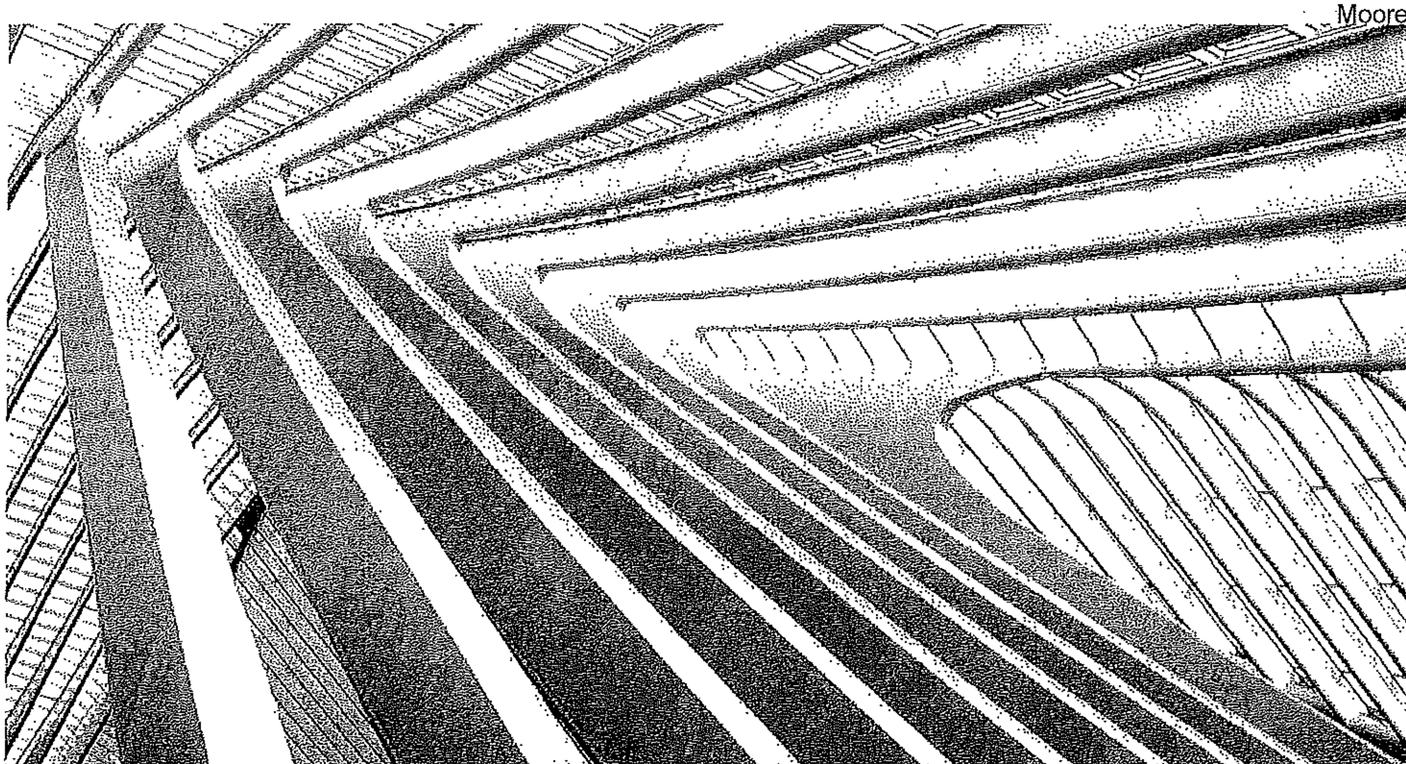
CASE: UG 305
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

August 11, 2016



Directors and Officers Liability Survey

2012 Summary of Results

TOWERS WATSON

For all respondents, the average amount of excess Side A limits purchased was $43.6 million. The largest average of $75.8 million was represented by companies with $10 billion or more in assets *(Figure 28)*. The average limit for all private organizations was more modest at $25.4 million *(Figure 29)*. When measured by market capitalization, the average for 162 public companies was $50.2 million, with larger companies ($10 billion or more, based on market capitalization) posting an average of $80.9 million in excess Side A limits purchased *(Figure 30)*.

Figure 28. Amount of excess Side A limits purchased by asset size (in millions)

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	3	$ 2.0	$ 5.0	$ 10.0	$ 5.7
$250 million to $999 million	13	$10.0	$10.0	$ 10.0	$14.3
$1 billion to $4.9 billion	55	$10.0	$20.0	$ 35.0	$26.5
$5 billion to $9.9 billion	42	$20.0	$30.0	$ 50.0	$42.4
$10 billion or more	63	$25.0	$50.0	$100.0	$75.8
All size groups excluding charities and nonprofits	186	$15.0	$30.0	$ 50.0	$47.0
All groups (total respondents)	207	$15.0	$25.0	$ 50.0	$43.6

Figure 29. Amount of excess Side A limits purchased by asset size (in millions)
Private organizations only

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	1	$ 2.0	$ 2.0	$ 2.0	$ 2.0
$250 million to $999 million	3	$ 1.0	$ 5.0	$ 10.0	$ 5.3
$1 billion to $4.9 billion	8	$10.0	$10.0	$ 17.5	$13.8
$5 billion to $9.9 billion	2	$10.0	$17.5	$ 25.0	$17.5
$10 billion or more	5	$50.0	$55.0	$100.0	$68.0
All size groups (private organizations only)	24	$ 7.5	$12.5	$ 32.5	$25.4

Figure 30. Amount of excess Side A limits purchased by market capitalization (in millions)
Public organizations only

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	5	$10.0	$10.0	$ 10.0	$12.0
$250 million to $499 million	4	$10.0	$15.0	$ 25.0	$17.5
$500 million to $999 million	9	$10.0	$10.0	$ 25.0	$16.1
$1 billion to $4.9 billion	60	$20.0	$30.0	$ 50.0	$36.7
$5 billion to $9.9 billion	27	$25.0	$40.0	$ 70.0	$48.0
$10 billion or more	44	$25.0	$50.0	$105.0	$80.9
All size groups (public organizations only)	162	$20.0	$35.0	$ 55.0	$50.2

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Request No. 140

Date prepared: May 27, 2016

Preparer: Jeremy Oden

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 140

Consistent with Commission Order 16-109, please provide the following with respect to each Oregon-allocated and situs project over $150,000, as listed in Exhibit CNGC/205, Parvinen/pgs 1-3.

a. Comprehensive cost-benefit analysis of whether and when investment should be built;
b. Evaluation of range of alternative build dates;
c. Evidence of likelihood of disruptions based on historical experience;
d. Evidence on the range of possible reliability incidents
e. Evidence about projected loads and customers in the area, and;
f. Evidence of consideration of alternatives, including use of interruptibility or increase demand-side measures to improve reliability and system resiliency.

Response:

I. FP-200663 – UG GIS ENHANCEMENT CNG DIRECT

- Projected estimate of project for 2016 has been reduced to $426,823.72. This is Cascade's share of a Utility Group wide implementation.
- Project includes various GIS System enhancements:
    1. Develop and install an internal GIS portal for Utility Group internal usage only. Specialized project maps, regulatory maps, survey maps could all be posted at this location. Site would also be used for future projects on GIS road-map.
    2. Landbase replacements and enhancements. We will continue to evaluate and update the GIS Landbase. GIS has been tasked to bring the Landbase to a higher accuracy level so we have and will continue to

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utilize consulting companies to assist in reaching this goal (estimated to be at least 50% of budget).

3. GIS development tasks, we have been asked to create a number of interfaces to other systems as well as automate some processes within the Enterprise GIS system. GIS (within GIS or closely integrated) development considerations: Leak Management, Construction (as-built) system, Inspection system.
4. Develop and Install a Utility Group ArcGIS Online cloud site (external) for use by various stakeholders external to our company firewall.
5. Additional hardware to support above tasks.

II. FP-302571 – CC&B Upgrade

- Projected estimate of project for 2016 has been reduced to $190,747. This is a significant reduction from the original estimate and is Cascade's share of a Utility Group wide upgrade project. The reduction in cost is due to the reduction in the need of external consultants, timing and an original over-estimate.
- Cascade Natural Gas is using Oracle's Customer Care and Billing system (CC&B) for Customer Service and meter billing. Cascade is currently processing on v2.2 of CC&B. Oracle released CC&B v2.2 into production in April 2008. Cascade went live on v2.2 in July of 2010. Since that time Oracle has released 3 more versions:
    - V2.3 – December 2009
    - V2.4 – November 2012
    - V2.5 – April 2015
- Cascade has been running on a release that is now 8 years old and is 3 versions behind.
- Extended support from Oracle on v2.2 expired in April 2008.
- This project is to migrate to v2.4 of CC&B. This will be a 16 to 18 month project. Upgrades will go into service along the time line of the project.

III. FP-101170 – MAIN-GROWTH-OREGON

N/A – This work order is for all mains to add new customers.

IV. FP-302666 – MT. WASHINGTON BRIDGE CROSSING

a. Pipeline is being replaced due to exposed pipe and difficulty inspecting and painting.
b. Project dates based on meeting compliance requirements.
c. Compliance, not capacity, makes project necessary.
d. Compliance, not capacity, makes project necessary.
e. Compliance, not capacity, makes project necessary.

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f. Original project plan was to install new pipeline by boring under river. CNGC worked with the City of Bend and will now be replacing pipeline on bridge, rather than boring under river. Project estimate reduced from approximately $465k to approximately $146k.

V. FP-302714 – PENDLETON V-23 REPLACEMENT

a. Valve being replaced due to inoperability and corrosion.
b. Project dates based on safety and reliability.
c. Inoperable valve can lead to inability to shut down lateral providing gas to town of Pilot Rock.
d. Project is necessary for safety and reliability, not capacity.
e. Project is necessary for safety and reliability, not capacity.
f. Relocating valve by installing 900 ft. of 6 in. high pressure main was considered as an alternative, but had higher estimated costs with no increase in safety.

VI. FP-200688 – BEND PIPE REPL

a. Pipelines are identified in Distribution Integrity Management Plan (DIMP) as being high risk due to age, lack of coating, and operating history.
b. Phase V of a multi-year project.
c. Safety and pipeline integrity, not capacity, make project necessary.
d. Project is necessary for safety and pipeline integrity, not capacity.
e. Project is necessary for safety and pipeline integrity, not capacity.
f. Pipeline is being replaced due to safety and pipeline integrity, not capacity.

VII. FP-200282 – R STA – SUN RIVER GATE UPGRADE

a. Current gate is under capacity, requiring bypass per a cold weather action plan when low pressure alarms go off.
b. Project was originally planned for 2015 and was delayed until 2016.
c. If upgrade is not completed then bypassing will need to continue. Eventually, bypassing may not be able to provide enough flow to distribution system.
d. The town of Sunriver could be without gas service if a reliability incident occurs in the future.
e. Ugraded gate station will be able to handle peak load of 500,000 cfh, which will be enough for current demands and 20 year anticipated growth.
f. Alternative to build another gate and high pressure pipeline to serve Sunriver will be more costly than upgrading this gate station.

VIII. FP-302651 – O-6 ATHENA

a. Odorizer is outdated and replacement parts are not available. Odorizer is being replaced due to reliability.
b. Project date based on safety and reliability.
c. Inoperable odorizer will result in unodorized gas in distribution system.
d. Odorizer is likely to need repairs in future; parts will not be available.

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e. Odorizer is being replaced due to reliability concerns, not to accommodate growth.
f. Odorizer is being replaced due to reliability concerns, not to accommodate growth.

IX. FP-311997 – O-1 ONTARIO

a. Odorizer is being replaced due to age as well as capacity concerns.
b. Project date based on safety and reliability.
c. Reliability of odorizer makes project necessary.
d. Project is necessary due to condition of odorizer.
e. Project is necessary due to condition of odorizer.
f. Only odorizer serving Ontario, Nyssa, and Vale and must be replaced.

X. FP-311999 – O-1 MISSION

a. Odorizer is being replaced due to age and corrosion.
b. Project date based on safety and reliability.
c. Project date based on safety and reliability.
d. Failed odorizer will result in unodorized gas in distribution system.
e. Odorizer is being replaced due to reliability concerns, not to accommodate growth.
f. Odorizer is being replaced due to reliability concerns, not to accommodate growth.

XI. FP-101176 SERV-GROWTH-OREGON

N/A - This work order is for actual costs of adding new customers.

XII. FP-101210 - PRE-CAP MTR-GROWTH-INTERSTATE

N/A – This work order is for all mains to add new customers.

XIII. FP-101259 - PRE-CAP MTR-GROWTH-INTERSTATE

N/A – This work order is for all meters to add new customers.

XIV. FP-101180 – IND M&R-GROWTH-OREGON

N/A – This work order is for all meters and regulators related to adding new customers.

XV. FP-101184 – GP TRAN VEHICLE – OREGON

N/A – This work order is for adding new and replacing old vehicles.

XVI. FP-101186 – GP POWER EQUIP – OREGON

N/A – This work order is for adding new and replacing old power operated equipment.

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Request No. 292

Date prepared: 07/05/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 292

Referring to the Company's response to Staff SDR No. 104, the total amount of "Category C" advertising listed is $34,396; referring to Parvinen Workpapers, Exhibits 201-206, tab "Advertising Adj.", the Company made a $19,501 adjustment for "Category C" advertising. Please identify all items of "Category C" advertising, as listed in Staff SDR No. 104, that are included in the Company's base year 2015, and provide for each item, an explanation and justification for inclusion in rates.

Response:

Cascade Natural Gas uses many advertising items to educate people on calling 811 before they dig as this is directly related to the safety of the public around our facilities. We have seen increases in the rate of damages to our facilities in the past 3 years so we have been targeting 811 and damage prevention as the prime objective of our advertising. These advertising items are given away at Home and Garden shows, Contractor events as well as baseball games and rodeos to educate people on what 811 is, that they have an obligation to call under the law and it is an essential component in keeping themselves and other people in their community safe. We give them handouts as well, but many people don't want to take the handout or toss it immediately so we have found that finding items that people will need and continue to read after the event are the best way to keep the messaging in their awareness and have a better impact on the likelihood that they will call when they need to. The advertising gives us an opportunity to have multiple messaging avenues so there are announcements during the events, video and radio ads running before and during the games and opportunities for tabling at the games to give away educational materials.

See OPUC-104.xlsx for list of transactions.

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Request No. 221

Date prepared: 06/07/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 221

For years 2012 through 2015, please provide the annual amount the Company spent on education reimbursement and any amounts allocated to the Company for education reimbursement; please also provide the amount included in the test year revenue requirement.

Response: **See attached file OPUC-221.xlsx which includes 2012 through 2015 plus the 2016 budget figure. The 2015 amount is what is included in the test year revenue requirement.**

Education & Training

year	amount	
2012	$920.85	
2013	$756.61	
2014	$1,996.08	
2015	$2,718.49	This amount is included in test year revenue requirement
2016 (budget)	$3,282.70	

The company has included its 2015 education and training cost amount in the test year rather than the 2016 budgeted amount. The cost amount is both reasonable and minimal. Staff proposes no adjustment.

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Request No. 222

Date prepared: 6/10/2016

Preparer: Jonathan Fleischer

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 222

With regard to the Company's response to the previous data request, please identify any legal cases brought against directors or officers of the Company in the last 10 years and provide a brief description of each, including the final outcome.

Response:

There have been no D&O legal actions against Cascade since purchased July 2, 2007.

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Request No. 225

Date prepared: 06/07/2016

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 225

Please provide a copy of the Company's current education reimbursement policy. If any costs for education are allocated to the Company for education reimbursement, please provide the education policy of the company employing the person receiving the training.

Response: **See attached file OPUC-225 Policy.pdf**

TRAINING AND EDUCATIONAL ASSISTANCE

I. PURPOSE

To identify the circumstances when training and education assistance is provided to employees. Tuition will be reimbursed to eligible employees who meet all of the requirements of this policy and follow all of the procedures set forth below.

II. SCOPE

A. To establish a policy and guidelines for the development, training and education of the Company's employees, as required by Corporate Policy Statement CORP 140.4. "Employees" as used in this policy means those persons eligible for consideration based on coverage as defined and outlined in Policy HR-1025 entitled "Benefit Eligibility."

B. This policy applies to all regular full-time employees. Tuition reimbursement requires twelve (12) months of continuous service. Employees may not apply for tuition reimbursement until the full twelve (12) months of continuous service have been completed.

C. Continued eligibility and reimbursement is contingent upon full-time employment and continued good performance, conduct, and attendance.

D. A written career plan and career discussion with the appropriate manager and a Human Resource Representative must be completed in order for college degree/certificate completion tuition reimbursement to be considered for approval.

E. Tuition reimbursement is available for courses offered by fully accredited colleges, universities, trade or technical schools. This includes face-to-face, online, independent-study, self-study, and correspondence courses.

F. Tuition for non job-related courses but required to complete a degree or certificate program that is related to employment may be reimbursable under this policy provided the appropriate approvals are obtained.

G. The company encourages employees to seek funding opportunities through grants, awards, scholarships and other financial support that will offset any reimbursable amount.

H. College Degree or certificate program completion must prepare the employee for more advanced/other positions within the Company as identified in the employee's career plan.

I. Career planning and development is the responsibility of each individual in order to maintain or attain skills and develop competencies necessary to be successful in their current or future job. Employees are encouraged and expected to manage their careers and seek out career opportunities. Financial assistance for developmental opportunities may vary based on business needs, industry practice, and budgetary limitations.

J. In some cases, tuition reimbursement may be used to assist with recruitment efforts as deemed necessary by the company, subject to appropriate taxable provisions.

III. POLICY

A. To qualify for tuition reimbursement the employee must be an active employee at the time payment is being requested. If the employee resigns or is terminated prior to successful completion of a course, no reimbursement will be made and the employee will be required to refund the amount of tuition reimbursement received within the past twelve (12) months of employment. Monies not repaid to the Company will be deducted from the employee's final paycheck to the extent allowable by law. The Repayment of Tuition Reimbursement, form no. 20002, must be completed when applying for Tuition Reimbursement.

B. Employees must receive grades of C or higher for undergraduate courses and courses at technical or trade schools. If a course is offered only as "pass-fail" a passing grade must be obtained. If an employee has the option of choosing to be graded under either a "pass-fail" or a letter grade system, the letter grade system must be used. If no grades are given, the employee must provide proof of successful completion of the course.

C. Individual study and other course work should be done outside of the employee's regular work schedule.

D. It is the employee's responsibility to obtain approval if the training or education requires time away from work and/or financial support before committing to participate.

E. Job-related courses paid for by the employer are not taxable to the employee (26 C.F.R. Sec. 1.162-5.) Courses not meeting the "job-related" test, but reimbursed by the Company, are included as wages in the employee's Form W-2 and will be subject to applicable federal and state withholding provisions. The Company is not responsible for employee's determination of reportable income to the IRS.

F. It is the employee's responsibility to request reimbursement in the year the course was approved. The Company may refuse to reimburse if requests are not timely.

G. Exceptions to the policy must be approved by the CEO and President.

IV. PROCEDURE

A. *Definition* - The Company recognizes several different types of continuing education. All must be evaluated on a course-by-course basis to determine whether they are job-related or not. Tuition reimbursement is limited to $5250 (IRS limit) each calendar year for any job-related and non-job related courses. The following definitions are applied:

1. Job-related courses are reimbursed at 75% of the cost up to the annual limit (see *Definition*) IRS limitation, as non-taxable income to the employee provided a passing grade as defined in Section III.B. This includes tuition, lab fees, books and other designated fees. All other grades will not be reimbursed. Job-related courses, per the IRS definition, include those:

   a) which maintain or improve the skills required by individuals in their employment; or

b) which meet requirements imposed as a condition of job retention (e.g. continuing professional education requirements imposed by state or professional licensing or regulatory bodies).

2. Non job-related courses will be reimbursed at 75% of the cost up to the annual limit (see *Definition*), as taxable income to the employee, provided a passing grade as defined in Section III.B. This includes tuition, lab fees, books and other designated fees. Reimbursement will be considered wages subject to applicable federal and state withholding provisions. All other grades will not be reimbursed. Non job-related, per the IRS definition, include:

   a) courses that are required to meet minimum educational requirements for employment; or
   b) courses that will qualify the individual for a different position or job.

B. Types of training and education:

1. Home Study Courses - A Home Study Course list is available on the Company's Intranet providing a wide range of subjects from technical skills to human relation skills. Courses range in length from several weeks to four years. If the course is not completed in a timely manner, or employment is terminated, the cost of the course will be withheld from the employee's paycheck.

2. Apprenticeship - Where applicable, the Company and Collective Bargaining Unit collaborate on Department of Labor approved apprentice programs via Joint Apprenticeship and Training Committees in the power production area and region operations. This on-the-job training is considered job-related.

3. External Seminars, Training and Conferences - External learning opportunities include symposiums, conferences, industry related meetings, training workshops, technical training, or vendor sponsored training and may be approved as identified in the employee's career plan to advance their career, prepare for other positions and/or deemed necessary to maintain skills for proficiency in their current job.

4. Educational Courses – As part of an undergraduate degree program, credited courses will be evaluated on a course-by-course basis. Colleges must be listed with the "Higher Learning Commission" for colleges, universities, and degree-granting institutions of higher education.

5. Professional Certificates - Examples of these types of certifications may include Professional Engineer (PE), Certified Public Accountant (CPA), Certified Internal Auditor (CIA), Human Resources certificates (SPHR, PHR), and Information Technology certificates. The costs of such certificates are eligible for reimbursement provided the employee's manager supports and approves the pursuit of such certificates. Payment is conditioned on the certificate being job related, proof of successful completion or passing of the entire certification and the employee's manager's approval. Travel to the test site closest to the community in which the employee resides or the most economical and practical for the Company and

study material that are included in a seminar fee are eligible for reimbursement if approved by the employee's manager.

C. Approval Process - An application for training and education must be approved prior to registration, travel arrangements, and attendance if reimbursement by the Company is expected. The following steps must be taken for all educational courses, conferences, seminars, certifications, etc.:

1. Educational courses are reimbursed from the Human Resources Department budget; all other conferences, seminars, courses, certificates, etc. are reimbursed or paid out of the department budget of the employee.

2. The Application for Training or Educational Assistance (Form 20326) must be completed, submitted for approval and approved prior to the start of the event.

3. The application must always be approved by the immediate supervisor and an Officer. For Executive Development, a level two approval is necessary.

4. The Human Resources Department then approves all applications to ensure a uniform, consistent policy is in place and to ensure appropriate training records are maintained. A copy will be returned to the employee when all approvals have been obtained and the employee is thereby authorized to attend.

5. In the case of external seminars, conferences or other training, payment for registration fees, etc. may be made prior to attending the session, and the remaining costs submitted in accordance with normal expense reimbursement policy.

6. Department of Labor approved apprentices will be automatically enrolled in the appropriate program when they enter their new jobs through the hiring or bidding process. The Human Resources Department will review all forms to ensure appropriate training records are maintained.

7. After completion of the course, the employee must submit a Payment Request, Form 20693, if course is job-related, or the Tuition Reimbursement Request, Form 20285, if course is not job-related. A copy of an invoice or proof of payment, the grade report, and a copy of the approved application form must be attached. Requests for reimbursement must be approved by the employee's supervisor and the Human Resources Department.

V. ADMINISTRATION

The President and Chief Executive Officer (CEO) is responsible for establishing this policy. Administration of the policy is the responsibility of the Director of Human Resources. Requiring compliance with this policy is the responsibility of all officers, directors, managers and supervisors (management). It is also the responsibility of management to ensure that policies are accessible and understood by all employees.

The Company reserves the right to deny any Application for Training or Education assistance for courses, seminars, conferences and programs.

The Company reserves the right to modify or cancel its tuition reimbursement program at any time, with our without notice to employees.

REVIEWED:	[signature]	12/7/12	APPROVED:	[signature]	12/7/12
	DIRECTOR OF HUMAN RESOURCES	DATE		PRESIDENT & CEO	DATE

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 293

Date prepared: 6-22-16

Preparer: Tony Durado

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 293

Referring to the Company's response to Staff SDR No. 58 (OPUC-58(b) Revised), "2015 Summary" tab, FERC account 908 shows $600,312 in Customer Assistance Expense. The Company's proposed adjustment to Customer Assistance Expense removes $506,656 of costs to reallocate to Public Purpose Charge/Energy Trust of Oregon. Regarding FERC account 908, please answer the following:

a. Identify all remaining transactions (excluding $506,656 reallocated for PPC) for the Company's base year 2015.

b. For all remaining transactions identified in "2. a." above, specifically those transactions that include descriptions such as gift cards or certificates; promotions; sponsorship; custom stress balls; "camo hat"; baseball tickets; etc., please explain how such expenses encourage "safe, efficient, and economical use of the utility's service" as specified in 18 CFR Part 101, 908 Customer assistance expenses.

c. For all remaining transactions identified in "2. a." that contain "S-VOLK XX", please explain what this description means.

Response:

See spreadsheet: OPUC-293

a. **All items included in the $506,656 PPC adjustment have been highlighted in yellow.**
b. **Cascade Natural Gas uses many promotional items and sponsorships to educate people on calling 811 before they dig as this is directly related to the safety of the public around our facilities. We have seen increases in the rate of damages to our**

CASCADE NATURAL GAS CORPORATION
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facilities in the past 3 years so we have been targeting 811 and damage prevention as the prime objective of our public awareness efforts. These promotional items are given away at Home and Garden shows, Contractor events as well as baseball games and rodeos to educate people on what 811 is, that they have an obligation to call under the law and it is an essential component in keeping themselves and other people in their community safe. We give them handouts as well, but many people don't want to take the handout or toss it immediately so we have found that finding items that people will keep and continue to use after the event are the best way to keep the messaging in their awareness and have a better impact on the likelihood that they will call when they need to. The sponsorships give us an opportunity to have multiple messaging avenues so there are announcements during the events, video and radio ads running before and during the games and opportunities for tabling at the games to give away promotional items and educational materials.

c. The column heading of "Explanation 1" refers to the vendor to which the charge was made. The notation of "S-VOLK XX" indicates the charge was incurred on a Corporate Credit Card by Sarah Volk, Public Awareness Coordinator, with XX equal to the month and year of the purchase.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 305

Date prepared: 6/29/16

Preparer: Lee Pfennig

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 305

For the following capital equipment projects listed below, please provide: Project justification forms, studies, presentations, memoranda, meeting notes and any other supporting documentation identifying, demonstrating, or justifying why this level of spending is necessary or prudent for Oregon operations at this time.

a. FP-101184-GP Tran Vehicle- Oregon
b. FP-101186-GP Power Equip- Oregon

Response:

Our fleet department budgets based off our fleet policies. Every year, meetings are set up with the field to discuss current and upcoming items. We are also informed if they are budgeting for any additional people needing vehicles. Attached are two files for reference our fleet policy and the 2015 budget for Oregon.

See attached files:
OPUC-305.xlsx
OPUC-305 OP 200.pdf

This policy supersedes the following company specific policies:

MDU Policy AD-12 "Operation of Company Owned Vehicles", dated January 1, 2010
MDU Policy DO-220 "Fleet Vehicles and Work Equipment", dated January 1, 2002
MDU Policy GA-504 "Compensation for Use of Personal Cars for Business Purposes", dated January 1, 2010
IGC Policy 109 "Use of Company Owned Motor Vehicles", dated July 10, 2008
IGC Procedure 2106 "Company Vehicles", dated November 17, 2008
IGC Procedure 9303 "Vehicle Mileage Reporting, dated December 7, 2009

I. PURPOSE

It is the policy of companies comprising the utility divisions and subsidiaries of MDU Resources Group, Inc. (collectively the "Companies" or "MDU Utilities Group" and individually a "Company") that Company owned vehicles are furnished to employees based on the business necessity for the vehicle and for business use only.

II. SCOPE

A. The provisions of this policy apply to all company fleet vehicle, work equipment, and trailer acquisitions, retirements, the administration, maintenance and operation thereof, including assignments to locations and employees.

B. All areas of this policy emphasize the high utilization of company vehicles. When there is a choice between using an assigned company vehicle or pool vehicle versus a personal vehicle, the company vehicle shall be used.

III. REGULATIONS

A. Certain commercial vehicles and on-highway equipment that are regularly involved in interstate travel will require additional fuel and mileage record keeping for travel in each jurisdiction. Those units registered under the International Registration Plan [1](IRP) shall be required to complete a special mileage form. Those units registered under the International Fuel Tax Agreement [2](IFTA) shall require purchased fuel tracking and fuel receipt retention.

   1. The International Registration Plan (IRP) is a registration reciprocity agreement among states of the United States, the District of Columbia and provinces of Canada providing for payment of fees apportioned on the basis of total distance operated in all jurisdictions.

   2. The International Fuel Tax Agreement (IFTA) is an agreement among all states (except Alaska and Hawaii) and the Canadian provinces (except Northwestern Territories, Nunavut and Yukon) to simplify the reporting of fuel used by motor carriers operating in more than one jurisdiction.

IV. POLICY

A. Acquisition of Fleet Vehicles, Work Equipment, and Trailers

   1. Fleet vehicle, work equipment, and trailer additions and replacements shall be prepared annually under the direction of MDU Director of Administrative Services in consultation with appropriate region and department managers and operating personnel. The appropriate business unit Vice President, in coordination with the MDU Director of Administrative Services, shall be responsible for determining the specifications of the units. The MDU Director of Administrative Services will provide price estimates for budget preparation.

   2. Planning for vehicle and work equipment purchases and replacements shall be done in conjunction with preparation of the annual capital budget and take into consideration vehicle needs for the ensuing year compared to the existing fleet vehicles, their age and operating condition. The MDU Director of Administrative Services or department

personnel will meet with region supervisors and/or region/department managers annually to document their needs on vehicle projection forms.

3. The MDU Transportation Department shall determine the annual passenger and work vehicle (classes 4 through 26) needs, including capitalized accessories, and work equipment classes 31 through 86 and associated accessories for the Company and shall budget for same. The MDU Transportation Department will then prepare Capital Budget for each region by state and utility function. The compilation of company needs as determined above will be included in the annual Capital Budget submission. Shift of budgeted capital from one blanket to another may occur if there are more economical alternatives found at the time of planned replacement.

   The aforementioned planning and budgeting requirements notwithstanding, non-budgeted purchases of fleet vehicles, equipment, and trailers shall be made in accordance with the same planning, approvals, and processes.

B. Replacement criteria of Fleet Vehicles, Work Equipment, and Trailers

1. The company shall consider replacement of vehicle classes 4 through 26 within a mileage range of 85,000 – 120,000 miles based on a variety of factors, including age, general condition, maintenance needs, residual value, and current capital budget. Exceptions to the mileage range may be considered based on individual vehicle condition and higher than normal operating costs or safety issues. Recommendations for replacement or inclusion in the next capital budget may be made either by operations management or the administrative services department.

2. The company shall replace work equipment classes 31 through 86 units when warranted giving consideration to the unit's odometer mileage, number of hours of operation, years in service and general condition.

3. The company shall replace trailers based upon years of service, capacity requirements, safety concerns and general condition.

4. Such replacement policy shall be administered so as to achieve an appropriate cost benefit ratio considering, operating costs, replacement costs, downtime, maintenance costs, and residual value.

C. Purchasing Procedure

1. Vehicles and work equipment shall be purchased in accordance with provisions of the MDU Utilities Group Procurement Procedures 5001 and 5002. Vehicle purchases shall be completed based on specifications and prices furnished by the MDU Director of Administrative Services.

D. Disposal of Fleet Vehicles and Work Equipment

1. The disposal of fleet assets shall be in accordance with the MDU Utilities Group Procurement Procedures 5001 and 5002.

2. Fleet asset disposal and value recovery shall be under the responsibility of the MDU Director of Administrative Services. After fleet asset disposal, form number 21263 "Sale of Used Vehicle(s) or Equipment Agreement and Bill of Sale" shall be completed.

E. Fleet Asset Transactions With Affiliated Companies

1. In the event a vehicle is purchased from or sold to an affiliated company, the purchase price or sales price shall be determined by the MDU Director of Administrative Services using the most current N.A.D.A. Official Guide, or other official dealer's value guides. Such amount will be based on the quoted loan value, adjusted for odometer mileage and general condition of the unit being sold or purchased. Such transactions will be processed in the same manner that vehicle purchases and sales from external sources are affected. When working with equipment for which a guide is not available, a fair

market value will be determined by the MDU Director of Administrative Services, based on current market conditions.

F. Assignment of Fleet Vehicles

1. Fleet vehicles shall be assigned to pools, individuals or work functions. Assignment determinations will be made by region managers or department managers in consultation with the MDU Director of Administrative Services.

   a) Vehicle pooling is encouraged when possible. Fleet vehicles will be assigned to pools in adequate quantities to fulfill the requirements of the location.

   b) Fleet vehicles may be assigned to a designated employee providing one or more of the following requirements is met:

      1) The employee has a continuous need for immediate availability of a vehicle during emergencies.

      2) The employee travels extensively on a daily basis while performing assigned duties and a pool car is not readily available.

      3) The employee work assignment requires a vehicle on a regular day-to-day basis.

   c) When assigned vehicles are not being used when the designated driver is on sick leave, vacation, or during other periods of leave, they shall be stored at the direction of the employee's manager, either at company facilities or available at the employee's home, for use in conducting company business.

   d) All pool and individual vehicle assignments must be reviewed by department heads and region managers in coordination with the Transportation Department personnel, on an annual basis and as assigned locations and employee job responsibilities change.

   e) When employees are hired, terminated, or when employees change jobs within the company, vehicle needs will be determined by region manager or department manager. The MDU Director of Administrative Services will then be notified if additional vehicles must be added to the fleet or if reduction in staff creates a surplus vehicle(s).

   f) Individual vehicle assignments may be withdrawn when employees change jobs or job duties; the vehicle assignment is not warranted due to reduced travel, or for other valid reasons.

G. Fleet Vehicle Care and Maintenance Requirements

1. Employees assigned company vehicles and those in charge of pool vehicles shall be responsible for the maintenance, repair and safe storage of their company vehicle. Operators are expected to keep the vehicle in good running order and have maintenance and repair work done as economically as possible. Repairs expected to exceed $500.00 should work in coordination with the Fleet Maintenance and Repair Specialist, under the direction of the MDU Director of Administrative Services. Operators shall be aware of vehicle warranties and take advantage of them whenever possible.

2. All operators shall be familiar with manufacturer's instruction manuals and the company's maintenance policy.

3. All company vehicles and work equipment exteriors and interiors shall be maintained and to be kept clean. The Tobacco Free Work Environment Practice shall be followed in all company equipment.

4. Additional accessories or equipment shall not be added or alterations made to company vehicles after initial purchases without written permission from the MDU Director of

Administrative Services. Reference form number 21992 Company Vehicle and Equipment Accessory Agreement.

5. All company vehicles, work equipment, and trailers must be identified labeled by a unique unit number, assigned by the Transportation Department, and shall normally have applicable company logos as determined by the operating company. Exceptions to company logos must be approved by the region or department manager after consultation with the MDU Director of Administrative Services.

H. Vehicle Log Reporting

1. A Company Vehicle Mileage Log, Form No. 21213 shall be maintained for each passenger automobile and other nonqualified vehicle whereon will be recorded odometer readings and the daily mileage driven for both business and personal purposes. Such log has been designed in accordance with and is in conformity with the adequate records substantiation requirement provisions of the Internal Revenue Code. Such log may also be used to distribute vehicle operating costs. Possible exclusions may include personnel which complete log books, monthly vehicle odometer reads, time tickets, or other means of communicating afore mentioned information.

I. Utilization of Employee Owned Vehicles While Conducting Company Business

1. When multiple employees are traveling on company business and there is a choice between using a company vehicle assigned to one of the employees versus using a personal vehicle, the company vehicle shall be utilized.

2. Employees may use personal vehicles while conducting authorized company business when work assignments require infrequent travel. Employees should use company transportation when available; however, when unavailable, use of a personal vehicle will be permitted if the following requirements are met:

   1) The vehicle must be in good mechanical condition, safe and of good appearance.

   2) The vehicle must be appropriately licensed.

   3) The employee must carry and keep current automobile public liability and property damage insurance.

b) Employees who are authorized to use their personal vehicles for Company business purposes will be reimbursed for their mileage in accordance with Policy Statement No. AD 102 "Employee Reimbursable Expenses" and the process identified in Accounting Procedure 2000 "Vehicle Use Reporting".

J. Fleet Vehicle, Work Equipment, and Trailers Operation Requirements

1. Company vehicles, work equipment, and trailers are to be used by employees exclusively, for transporting personnel, materials, and equipment while conducting company business.

2. Company vehicles, work equipment, and trailers are to be used within the confines of the company's service area except when the trip is incidental to the job or is specifically authorized by appropriate management personnel.

3. Vehicle pooling is encouraged to maximize utilization of fleet vehicles. When pooling is used, the region or department managers shall designate an employee to supervise the use, preparation of mileage reports and maintenance of the pool vehicles. Pool vehicles will be stored at company facilities during non-working hours except for exclusions stated below.

4. Company vehicles are to be stored at company facilities after working hours. Exceptions to this rule are:
   a) The company has requested that the employee start their work day from their residence.
   b) The employee is designated to be on call that night or weekend.
   c) When beginning a next day trip prior to the time vehicles are available at the assigned storage location.
   d) When returning from a trip after normal working hours.
   e) The need of a vehicle for emergency calls after normal work hours, weekends or holidays.
   f) When the designated employee routinely conducts approved job responsibilities after normal work hours.
5. The vehicle assigned to the employee can be used to commute to and from work with the resulting mileage being deemed personal use, if the Company designates it beneficial to have the vehicle readily available to the employee. Any personal use will be charged at the "standard mileage rate" in Addendum 'A' of Policy Statement No. AD 102, prescribed by the Internal Revenue Service, and that calculated value will be added to the employee's taxable income for income tax and Social Security tax purposes. Refer to Accounting Procedure 2000 "Vehicle Use Reporting" for reporting requirements.

K. Use of Vehicles

1. Safety – All operators of Company vehicles and work equipment are expected to observe the rights of pedestrians and other drivers, observe the ordinary rules of courtesy and restraint in driving and to operate the vehicles in accordance with Policy SF 409.
2. Driver Qualification and Training – All operators of Company vehicles and work equipment (including ATV's, snow machines, forklifts, etc.) must be made familiar with and meet the requirements of Policy SF 405 before operating.
3. Licensing Requirements – Licensing requirements shall be met as required in the Corporate Motor Vehicle Safety Policy 26.1. Those drivers operating a vehicle with a registered weight of over 10,000 lbs. or a truck and trailer combination over 10,000 lbs. must possess a D.O.T. Medical Examination Card. Those drivers operating a vehicle with a registered weight of 26,000 lbs. or towing a trailer with a GVRW over 10,000 lbs. shall posses a Class A drivers license in addition to a D.O.T. Medical Examination Card.
4. Inspection Requirements – Annual and Daily inspections are required for those drivers operating a vehicle with a registered weight of over 10,000 lbs. or a truck and trailer combination over 10,000 lbs. A daily pre and post trip inspection form (Form 20411) shall be completed in duplicate and maintained on file, one copy with their supervisor, and one copy maintained in the truck. Units equipped with electronic inspection equipment will supersede the requirement of the paper daily inspection form. Annual D.O.T inspections as performed by a qualified inspector are also required for this group of vehicles. A copy of the most current annual inspection form must be retained in the vehicle at all times.
5. Theft Prevention – Caution should be used where the vehicle is parked in order to avoid possible theft and/or vandalism. In most cases when the vehicle is left unattended, the windows should be closed and all doors locked. The ignition keys will always be removed from an unattended vehicle, except as provided for in paragraph 8, listed below. If fleet equipment is left on a job site overnight, it should be completely secured prior to leaving the site.

6. Traffic Violations - Traffic violations and any resulting fines are the driver's responsibility and should be settled promptly by the driver. Fines resulting from traffic violations will not be reimbursed by the Company.
7. Trailers - The use of Company vehicles or work equipment to tow anything other than a Company-owned trailer or trailer rented/leased for business purposes is prohibited. It is also prohibited to tow a Company-owned trailer with a personal vehicle.
8. Unattended Vehicle - The engine of an unattended vehicle may be left running ONLY if it is the power source for other equipment in use, or by manager exception depending on weather conditions.
9. Passengers – Company vehicles and work equipment shall not be used to transport personnel for non-business purposes, unless approved by management or in emergency situations.
10. Other Drivers – Personnel whom are not employed by, or contracted by, MDU Resources Group shall not operate Company vehicles or work equipment.
11. Drugs Alcohol – Operation of Company vehicles and work equipment under the influence of alcohol or illegal drugs is strictly prohibited. Prescription and OTC drugs that affect driving ability also prohibit operation.
12. Fueling – Refer to Policy PR 300.

V. RECOGNIZED EXCEPTIONS

None

VI. ADMINISTRATION

The President and CEO of the Companies is responsible for establishing this policy. Administration of this policy is the responsibility of the Executive Vice President – Utility Operations Support of Montana-Dakota Utilities Co. through the Director of Administrative Services. A designated individual will be further identified in each Company for the development, application and administration of this policy and its provisions.

Reviewed: ______________________
Executive Vice President – Utility Operations Support

Date: 6/23/11

Approved: ______________________
President and CEO

Date: 6/23/11

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 306

Date prepared: 7/7/2016

Preparer: Mike Parvinen/Kathleen Chirgwin

Contact: Pam Archer

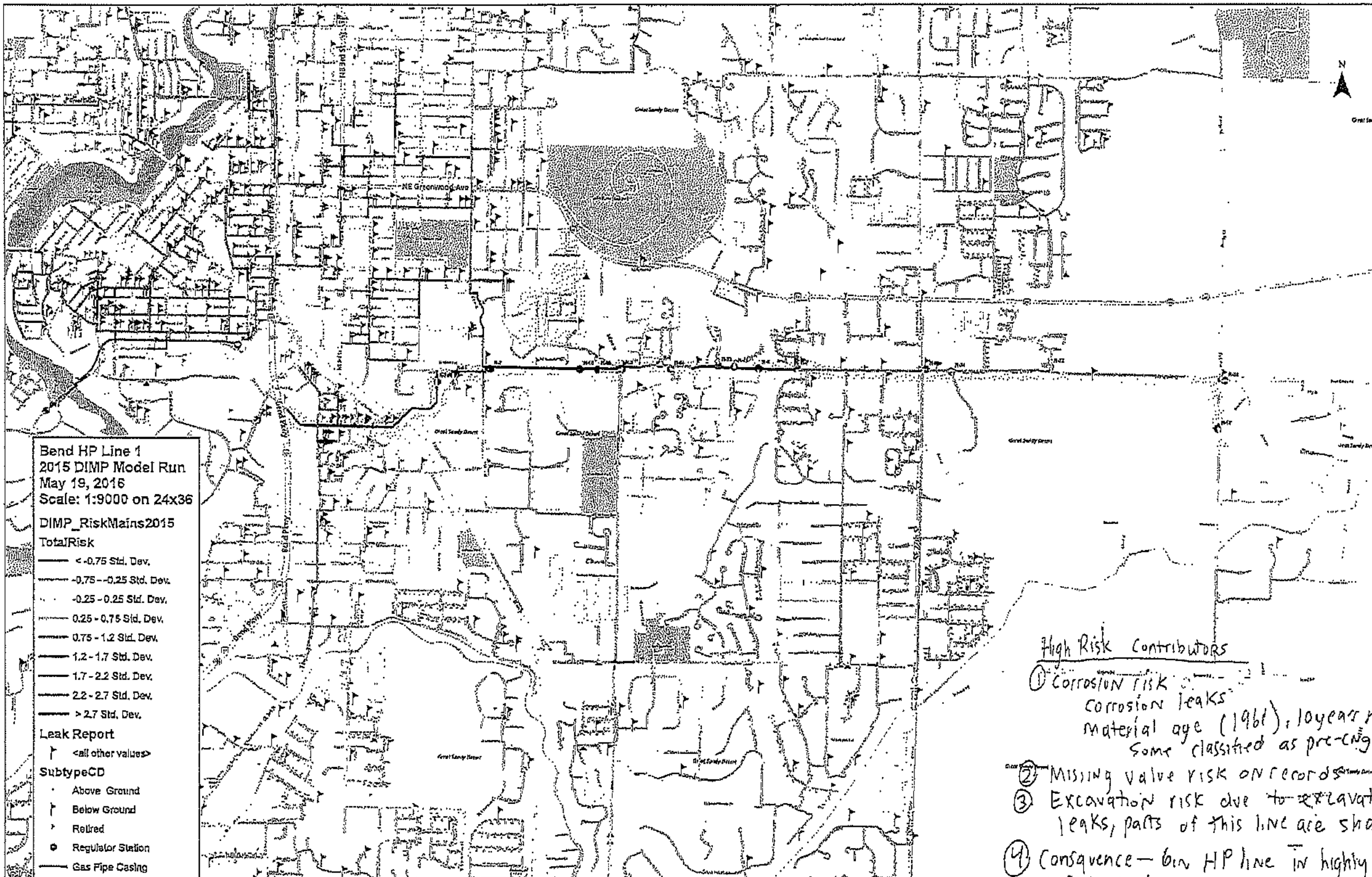
Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 306

Regarding the Company's response to DR #159, in which the Company identifies six projects based on DIMP modeling, please provide all data that supports the prudency of completing these projects before rates go into effect.

Response:

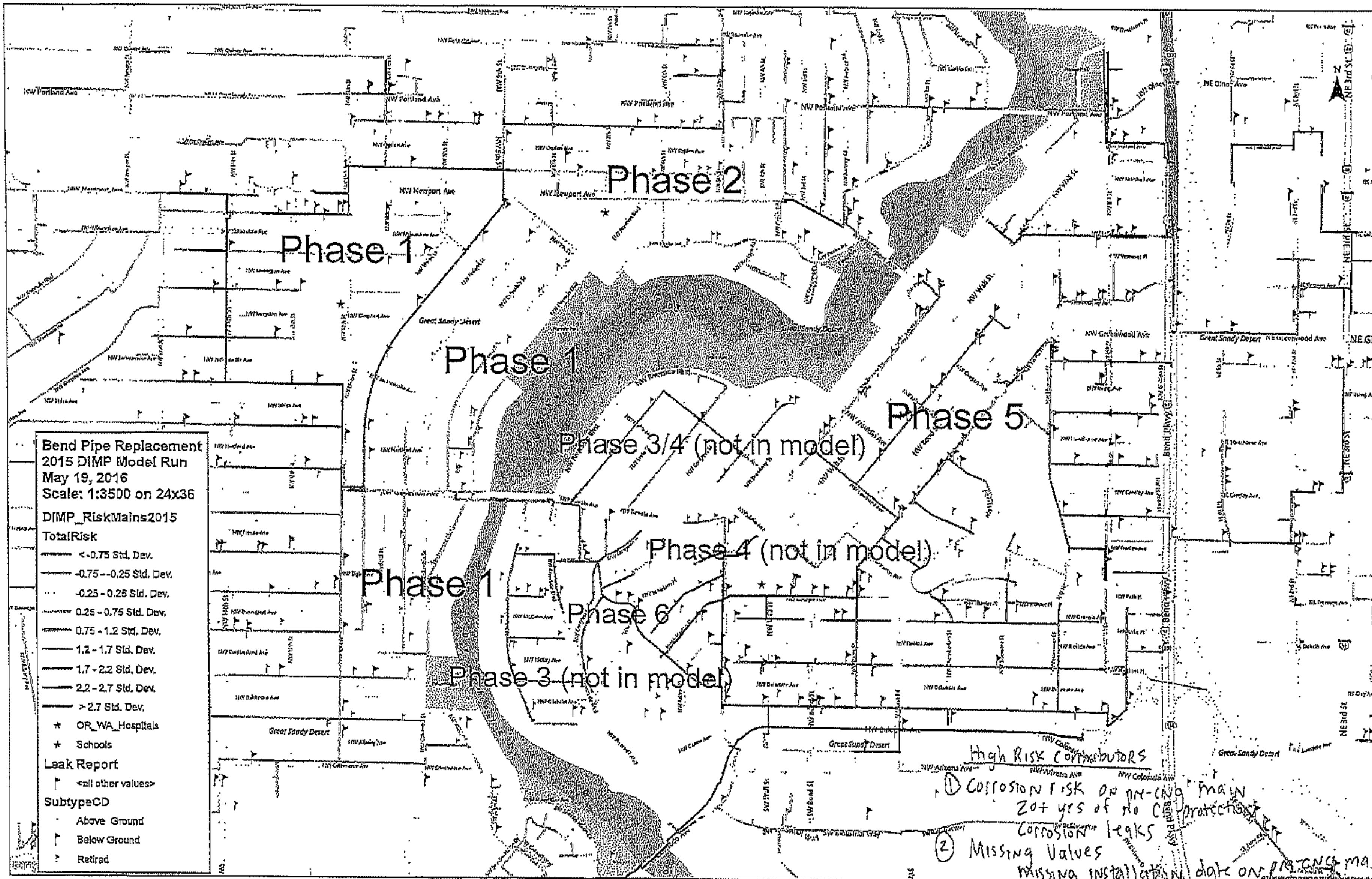
See attached documents labeled "OPUC 306 - …" supporting the six projects.



High Risk Contributors

1. Corrosion risk
   Corrosion leaks
   material age (1961), 10 years no CP.
   Some classified as pre-CNG main.
2. Missing valve risk on records
3. Excavation risk due to excavation leaks, parts of this line are shallow.
4. Consequence — 6in HP line in highly populated area, and response time for steel tapping emerency support for Division.

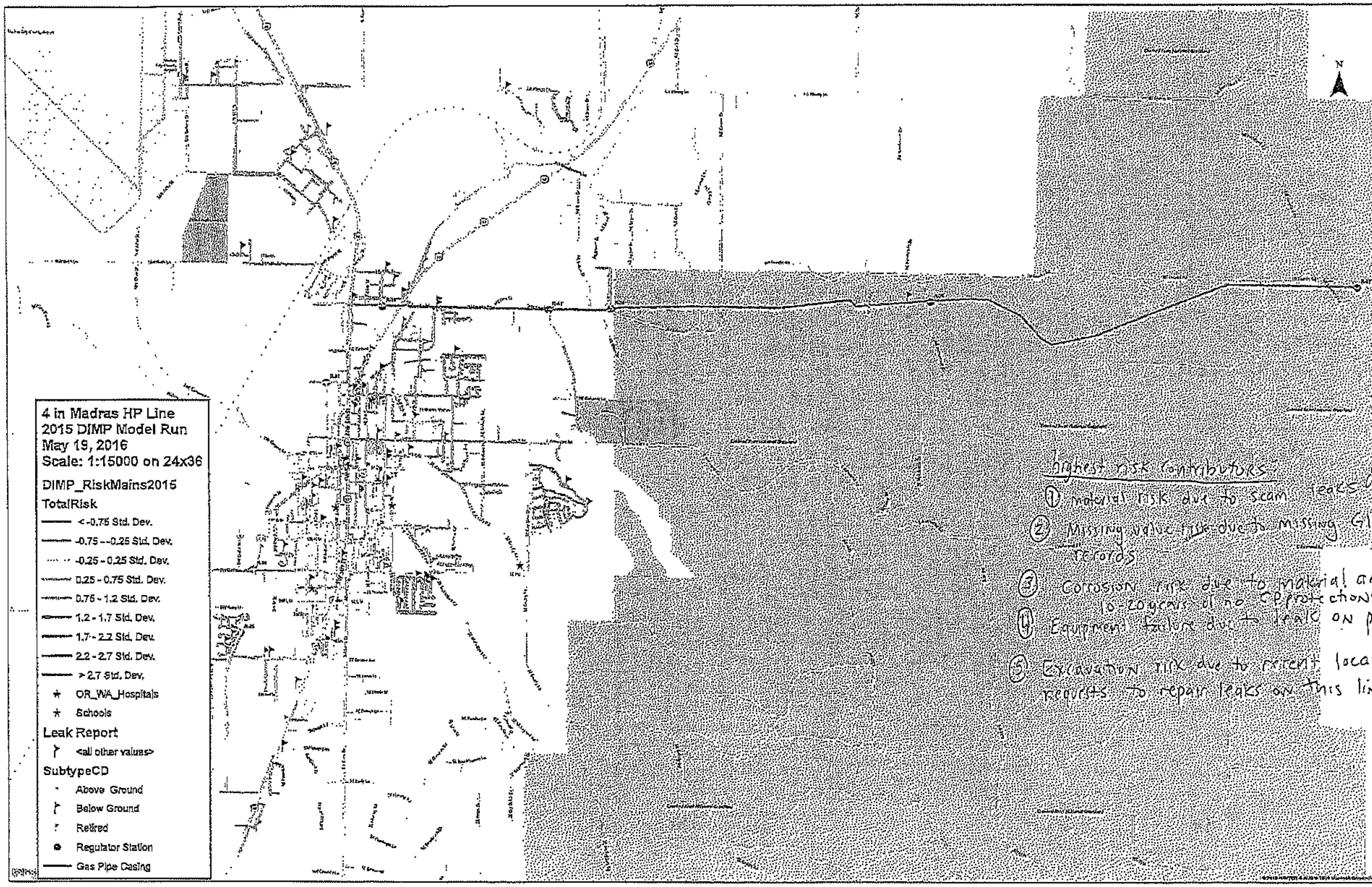
DR 306



High Risk Contributors

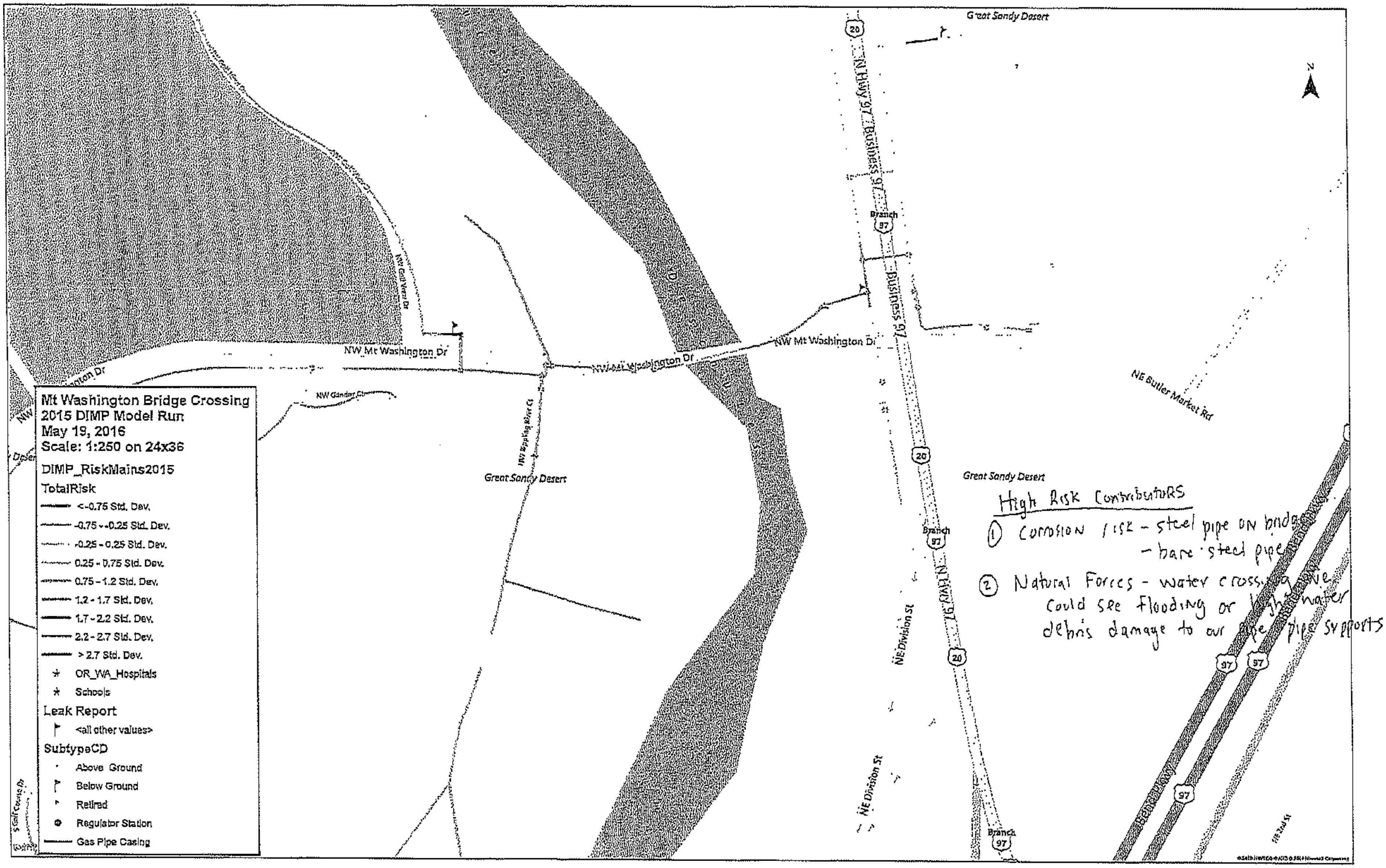
1. Corrosion risk on pre-CNG main
20+ yrs of no CP protection
Corrosion leaks
2. Missing Values
Missing installation date on pre-CNG mains acquired from COB.
missing data in records
3. Joints - Joint leaks on welds/fittings found.

DR30b

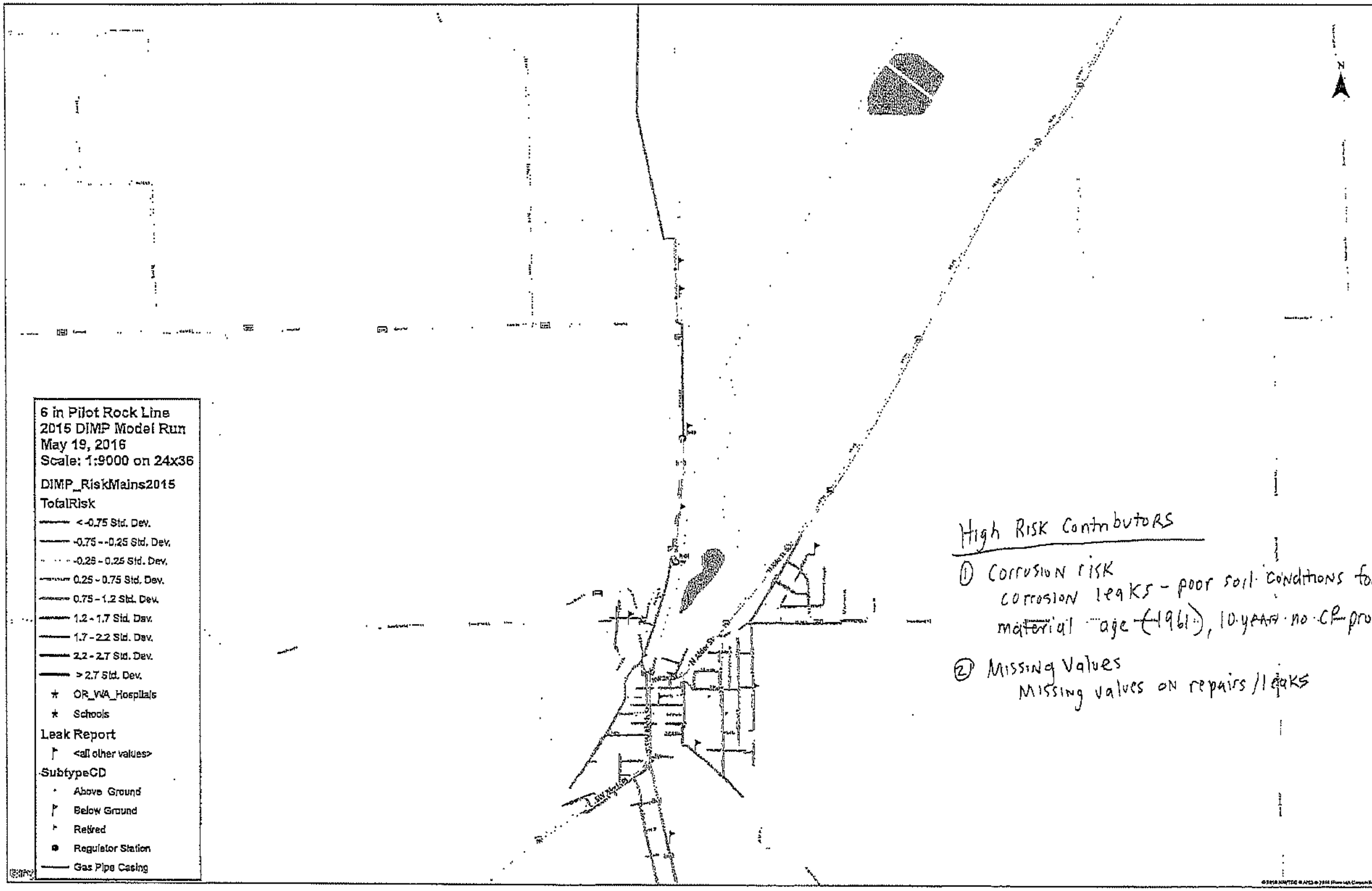


highest risk contributors:
① material risk due to seam leaks classified as material failure.
② Missing value risk due to missing GIS records
③ Corrosion risk due to material age (1962) 10-20 years of no CP protection
④ Equipment failure due to leak on pigko
⑤ Excavation risk due to recent locate requests to repair leaks on this line

DR #306


Mt Washington Bridge Crossing
2015 DIMP Model Run
May 19, 2016
Scale: 1:250 on 24x36
DIMP_RiskMains2015
TotalRisk
<-0.75 Std. Dev.
-0.75 - -0.25 Std. Dev.
-0.25 - 0.25 Std. Dev.
0.25 - 0.75 Std. Dev.
0.75 - 1.2 Std. Dev.
1.2 - 1.7 Std. Dev.
1.7 - 2.2 Std. Dev.
2.2 - 2.7 Std. Dev.
> 2.7 Std. Dev.
OR_WA_Hospitals
Schools
Leak Report
<all other values>
SubtypeCD
Above Ground
Below Ground
Retired
Regulator Station
Gas Pipe Casing
NW Mt Washington Dr
NW Mt Washington Dr
NW Mt Washington Dr
Great Sandy Desert
Great Sandy Desert
Great Sandy Desert
N Hwy 97 Business 97
Business 97
N Hwy 97
Branch
NE Division St
NE Butler Market Rd
High Risk Contributors
① Corrosion risk - steel pipe on bridge
- bare steel pipe
② Natural Forces - water crossing
Could see flooding or high water
debris damage to our pipe / pipe supports

DR 306

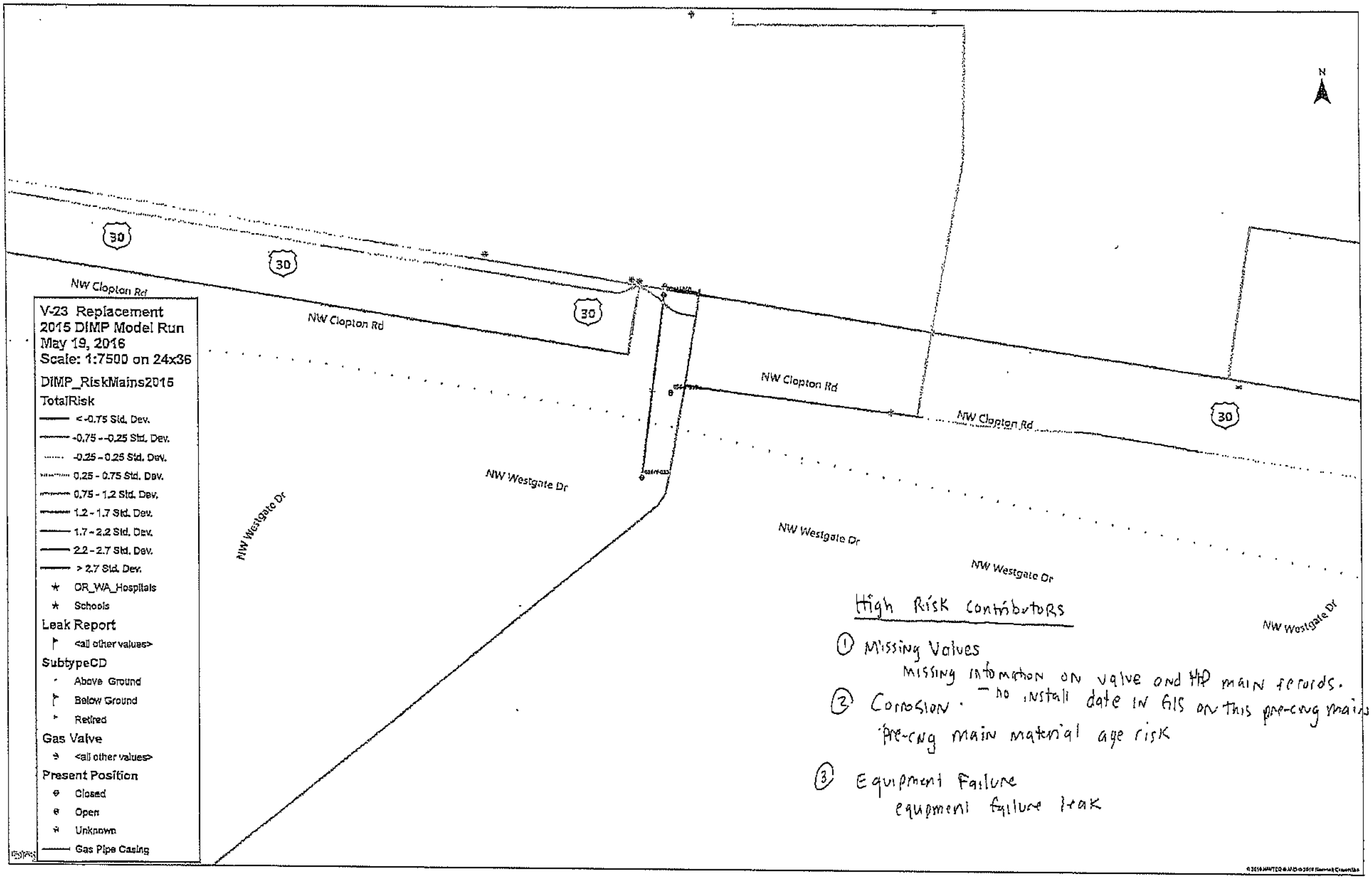


High Risk Contributors

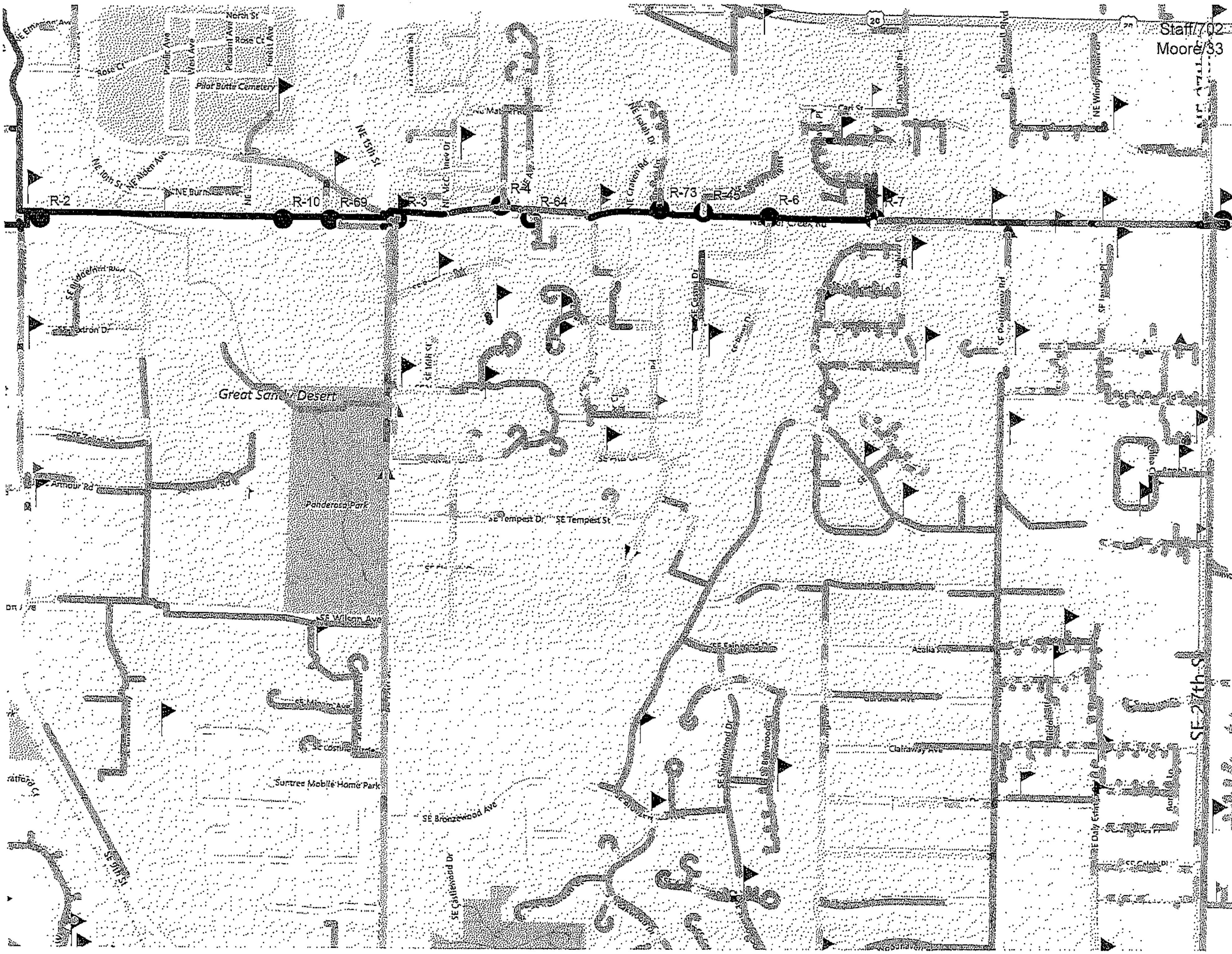
① Corrosion risk
corrosion leaks - poor soil conditions for CP.
material age ~~(1961)~~, 10 year no CP protection

② Missing Values
Missing values on repairs / leaks

DR # 306


V-23 Replacement
2015 DIMP Model Run
May 19, 2016
Scale: 1:7500 on 24x36
DIMP_RiskMains2015
TotalRisk
< -0.75 Std. Dev.
-0.75 - -0.25 Std. Dev.
-0.25 - 0.25 Std. Dev.
0.25 - 0.75 Std. Dev.
0.75 - 1.2 Std. Dev.
1.2 - 1.7 Std. Dev.
1.7 - 2.2 Std. Dev.
2.2 - 2.7 Std. Dev.
> 2.7 Std. Dev.
OR_WA_Hospitals
Schools
Leak Report
<all other values>
SubtypeCD
Above Ground
Below Ground
Retired
Gas Valve
<all other values>
Present Position
Closed
Open
Unknown
Gas Pipe Casing
N
30
NW Clopton Rd
NW Westgate Dr
High Risk Contributors
① Missing Values
missing information on valve and HP main records.
② Corrosion - no install date in GIS on this pre-cng mains
pre-cng main material age risk
③ Equipment Failure
equipment failure leak

DR #306


R-2
R-10
R-69
R-3
R-4
R-64
R-73
R-45
R-6
R-7
Pilot Butte Cemetery
Great Sandy Desert
Ponderosa Park
SE Wilson Ave
SE Tempest Dr
SE Tempest St
SE Fairwood Dr
Suntree Mobile Home Park
SE Bronzewood Ave
SE Castlewood Dr
SE 27th St
NE 15th St
Rose Ct
SE 9th St
Azalia Ave
Clairaway Ave

DR 306

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 307

Date prepared: 7/7/16

Preparer: Jeremy Ogden

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 307

Please provide the detailed city-gate analysis referred to in the Company's January 7, 2016 request for extension of IRP filing date (See pg 2, at 23) that would support the inclusion of the Sun River Station Gate upgrade (FP-200282 – R STA-Sun River Gate Upgrade) in this filing.

Response:

Please see OPUC-307 Executive Summary – Sunriver Gate Upgrade.pdf

Project Summary – Sunriver Gate Upgrade, Bend District

Submitted by: Kathleen Chirgwin, P.E.
5/17/2016

Background

The Sunriver gate serves the town of Sunriver in the Bend district. The town of Sunriver has seen significant growth and the current gate is undersized. In the last couple years we have seen significant pressure problems at the gate compromising the serviceability of Cascade's high pressure system. At the gate during peak winter flows we have had pressure alarms over the last couple years due to pressure drop in the undersized facilities with peak flow rates.

Proposal

This project consists of a gate upgrade by Transcanada and Cascade. Transcanada will be installing new 4 in taps, 4 in piping and a larger meter. Cascade will be taking over regulation and heating and will be upgrading all facilities at the current gate to meet peak demand.

Timing

Cascade's gate station design has been completed and we have received quotes and lead times for special order items like SCADA, building, heater, and the odorizer.

Cascade has been coordinating with Transcanada and Transcanada has given Cascade a cost estimate for their upgrade requirements and they are prepared to move forward with the facilities agreement and $150,000 pre-payment agreement. Transcanada requires 5 months from after they receive approval to complete their upgrade.

Cascade fabrication is expected to take 2 month and onsite construction is expected to take 6 weeks to in-service the facility. Due to snow in central Oregon we need to have this station in serviced by October 30, 2016 to be online for 2016 peak cold weather flows. Construction is expected to take place in September and October and fabrication will take place in July and August after special order parts arrive, some parts are 6-8 week lead time. A detailed schedule has been submitted with executive approval and is available upon request.

Costs

This project is in the 2016 capital budget and it has been budgeted for $1,559, 570.93. This project will be fabricated and installed with Cascade labor. Below is a total cost breakdown.

Sunriver Gate Upgrade Cost Estimate			
Updated by: Kathleen Chirgwin on 5/17/2016			
	Direct Cost	Overhead	Total Cost
TRANSCANADA SITE UPGRADE	$ 1,286,000.00	$ 116,578.99	$ 1,402,578.99
CNG GATE - TAKE OVER REGULATION AND HEATING	$ 535,360.22	$ 124,203.57	$ 659,563.79
UPGRADE ODORIZER AND ADD STORAGE TANK	$ 169,137.77	$ 39,239.96	$ 208,377.73
TOTAL ESTIMATED COST	$ 1,990,497.99	$ 280,022.52	$ 2,270,520.52

The cost is higher than budgeted because Transcanada re-estimated the project in spring of 2016 with their Houston project managers. In the fall of 2015 Transcanada had estimated the project at $731,048 by their Spokane project managers, which would have been right at budget. According to Transcanada the cost increased because the Spokane project managers were underestimating projects and they added a second meter and meter switching runs to accommodate the low flow rates during summer flows. The original estimate also did not account for GA and AFDUC overhead on the Transcanada cost as advised by our accounting group.

Benefits

1. Gate will be able to handle peak demand flow rate of 500,000 cfh which is sized for 20 year IRP.

2. Gate upgrade will eliminate low pressure alarms and ensure reliable service to Sunriver, Oregon. In the last couple years gas control and the district have had to respond to the low pressure alarms during peak demand.

3. District will be benefited by eliminating a cold weather action plan.

4. The facility we are upgrading was installed in the 1960's and we have integrity concerns on the current odorizer and storage tank, these facilities will be replaced with this upgrade.

5. The regulators and odorizer will be placed in a building, this site is on the way to Mt Bachelor and experiences a lot of snow, facilities will be accessible during large snowfall events.

Alternatives

No alternatives can be identified with similar scope. For the last couple years we have put this project off and have implemented a cold weather action plan activated by low pressure alarms where the district bypasses as needed to maintain inlet pressures to downstream regulators. Bypassing the station is not a reliable long term solution.

Project Team

Project Manager/Engineer: Kathleen Chirgwin
District Lead: William Walker
Division: Winnie Clemenson

CASE: UG 305
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

August 11, 2016

Exhibit 703 - (703.1 to 703.4)

are provided in electronic format.

CASE: UG 305
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

Exhibits in Support
Of Opening Testimony

August 11, 2016

Staff Adjustment to Plant and Capital Additions

	Company Filing		Staff		Adjustment	
Description/ Account No.	Total Company	OR-Allocated	Total Company	OR-Allocated	Total Company	OR-Allocated
FP-302640 - 6" PILOT ROCK HP REPLACEMENT	$ 62	$62	$ -	$ -	$ (62)	$ (82)
FP-302641 - 4" PILOT ROCK IP REINFORCEMENT	$ 62	$62	$ -	$ -	$ (62)	$ (62)
FP-303142 - PENDLETON BARE STEEL REPLACEMENT	$ 62	$62	$ -	$ -	$ (62)	$ (62)
FP-306997 - 4" MADRAS HP LINE REPLACEMENT	$ 62	$62	$ -	$ -	$ (62)	$ (62)
FP-101481 - UG GPSLS PROJECT - SOFTWARE	$ 74	$18	$ -	$ -	$ (74)	$ (18)
FP-301808 - UG-Routing Software - Survey System	$ 22	$5	$ -	$ -	$ (22)	$ (5)
FP-200689 - RPL 12" BEND HP LINE #1	$ 64	$64	$ -	$ -	$ (64)	$ (64)
FP-302666 - Mt. WASHINGTON BRIDGE CROSSING	$ 466	$466	$ 146	$ 146	$ (320)	$ (320)
FP-200688 - BEND PIPE REPL WO	$ 4,638	$4,638	$ 2,308	$ 2,308	$ (2,330)	$ (2,330)
FP-200663 - UG GIS ENHANCEMENTS CNG DIRECT	$ 695	$ 168	$ 427	$ 104	$ (268)	$ (64)
FP-302571 - CC&B UPGRADE	$ 1,341	$ 326	$ 191	$ 46	$ (1,150)	$ (280)
TOTAL	**$ 7,548**	**$5,933**	**$ 3,072**	**$ 2,604**	**$ (4,476)**	**$ (3,329)**

CASE: UG 305
WITNESS: SCOTT SHEARER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Scott Shearer. I am a Senior Compliance Specialist employed in the Consumer Services Section of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide data and analysis of consumer complaints filed with the Commission against Cascade (CNG) and the proposed tariff housekeeping changes in this docket.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared Exhibits Staff/801, my witness qualification statement; Staff/802, Consumer Services Complaint Records and Statistics; and Staff/803, proposed Tariff Language Revisions.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Consumer Complaints 2
Issue 2. Housekeeping Changes 4

ISSUE 1. CONSUMER COMPLAINTS

Q. Why is the analysis of consumer complaints important to this proceeding?

A. The Commission has an interest in resolving consumer issues and over the years, the Commission has directed the Consumer Services Section Staff to look into various issues raised by consumers.

Q. How many consumer complaints has the Commission received involving CNG during the base year (2015) and the first six months of the test year (2016)?

A. There were nine complaints filed against CNG in the review period involving twelve individual issues.[1] For context, there were just over 5000 consumer issues investigated by Consumer Service Staff during that same time period.[2]

Q. Please describe the twelve individual issues?

A. The issues are broken down as follows:

a. three disconnect issues,

b. three customer service issues,

c. three service issues,

d. one billing issue,

e. one rate protest (from prior rate case UG 287), and

f. one damages issue.

[1] Nine individual customers filed complaints. These nine customers had a total of twelve separate issues identified.

[2] Data retrieved from Consumer Service complaint records opened 1/1/2015 to 6/30/2016.

Q. For how many of these complaints did Consumer Services Staff conclude that CNG was "at fault"?

A. There were three "at faults," including: [3]

a. one rule fault for failure to offer a time-payment arrangement,
b. one customer service fault for not providing proper notice during an emergency shutoff, and
c. one customer service fault for not providing a copy of the customer's final bill.

Q. How do the consumer complaints filed against CNG compare with other utilities?

A. For the timeframe, CNG has a customer complaint rate of .209 per 1000 customers. This compares to a rate of .308 per 1000 for all gas customers and .366 per 1000 for all energy utilities.[4]

Q. Does Consumer Services Staff have concerns with the complaint rate or how CNG handled complaints?

A. No, CNG handles complaints in a timely fashion and resolves issues in a reasonable manner.

Q. Were there any other issues found by the Consumer Services Section Staff?

A. Yes. In 2012, there were major revisions to landlord and tenant law in Chapter 90 of the Oregon Revised Statutes, relating to resale of utility services

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[3] Staff/802.
[4] Staff/802.

and the utilities' handling of master-metered service in landlord and tenant situations.[5]

Q. How were CNG's tariffs impacted by these new standards?

A. The current CNG tariff language states, "The consumer shall use the gas delivered hereunder for his own purposes only and shall not, under any circumstances resell or share with others any gas delivered hereunder." This conflicts with the ORS 90.536(1), which allows the resale of utility services to master-metered multi-unit facilities.[6]

Q. How did CNG respond to this concern?

A. On March 1, 2016, CNG was notified of the issue and asked to review and propose revisions to the tariff. CNG agreed with the assessment and responded that they would file changes to this language during this docket.

Q. Did CNG address the concerns, as discussed?

A. Yes. In its original filing on April 29, 2016, the proposed tariffs by CNG did not include this the conflicting language.

Q. Did this issue only affect CNG tariffs?

A. No, the changes to the statutes necessitated adjustments to several other utilities' tariff language regarding master-metered customers.

<u>Issue 2. HOUSEKEEPING CHANGES</u>

Q. What concerns does Staff have with the proposed tariff housekeeping changes as filed?

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[5] See ORS 90.315, 90.532, and 90.534-543 at http://www.oregonlaws.org/ors/chapter/90
[6] See ORS 90.536 (1) at http://www.oregonlaws.org/ors/90.536

A. At first glance, the changes seem to be more substantial than simple housekeeping changes. However, after review, it appears that the changes were done in an effort to clarify language, remove or replace outdated information, and reorganize the tariff in a more readable format. Due to the substantial rewrite, Staff reviewed the tariff as a new product.

Q. What issues were found in the review of the revised language?

A. My review focused on proposed Tariff Rules 1-6 and found issues in Rules 2, 3, 5, and 6.

A. Tariff Rule 2.1 - The definition of "Applicant" incorrectly refers to Tariff Rule 2. The appropriate reference appears to be Tariff Rule 3.

B. Tariff Rule 2.1- Definition of "Customer" does not include information on customers who voluntarily disconnect service and request new service within 20 days as required by Oregon Administrative Rule (OAR) 860-021-0008(3).

C. Tariff Rule 2.3 - Definition of "High Priority Use" is unclear in application and refers to the Code of Federal Regulations, which does not appear to relate to the definition.

D. Tariff Rule page 3.1 - The information in "Establishing Credit" does not include the requirement of accepting a written surety agreement in lieu of paying a deposit as required in OAR 860-021-0200(3a).

E. Tariff Rule page 3.2 - Non Residential Service includes the term "customer" when only "applicant" applies. Per OAR 806-021-0008(3) a customer is "...a person who has been applied for, been accepted, and is receiving service." An existing customer does not need to "establish credit" as they have already done so. Staff will continue to work with CNG to propose acceptable language.

F. Tariff Rule page 5.2 - The information required on the notices of pending disconnection is not the same as what is required by OAR 860-021-0405.

G. Tariff Rule page 5.3 – 15-day notice exceptions are incorrect according to OAR 860-021-0405 (3)(a)-(e). The rule does not allow an exception to the 15-day notice requirement for failure to establish credit, but does allow an exception to the 15-day notice when the customer provides false identification.

H. Tariff Rule page 5.3 – 15-day notice mailing service definition states that "...service is complete on the date of mailing." This is incorrect. OAR 860-021-0405(8) states "...service is complete on... the day after the date of the ... post mark or postage metering."

I. Tariff Rule page 5.4 - The timeframe a medical certificate is valid is missing a caveat. Per OAR 860-021-0410(4) for chronic conditions, a certificate can be for 12 months.

J. Tariff Rule page 6.1 – 15-day notice mailing service definition states the bill is due and payable as of the dates rendered. This is incorrect. OAR 860-021-0125(1) states "... the period from the billing... to the due date is not less than 15 days."

K. Tariff Rule page 6.2 - Estimated Billing Capability. The tariff states "The Company may issue... an estimated bill during the months of June through September." OAR 860-021-0120(3) allows estimated readings if circumstances warrant. This appears to be a remnant of tariff language that is no longer needed. I propose removing this language from the tariff.

L. Tariff Rule page 6.2 - Budget Payment Plan for Payments of Gas Bills - The statement, "...average monthly payments for ... customer who can establish satisfactory credit with the company[,] " and "... customer with satisfactory credit and no balance outstanding..."; doesn't match the criteria in OAR 860-021-0414, which only requires customers to have no outstanding balance and agree to remain on the plan for 12 months. Establishing credit does apply in this situation.

Proposed changes to A., B., C., D., F., G., H., I., J., and L. are included as a redline version in Staff exhibit 803.

Q. Have you discussed these issues with CNG?

A. Yes. I discussed these issues with CNG on June 27, 2016, to better understand CNG's intentions and communicate Staff concerns. As a result of this discussion, CNG agreed in principle to all of these concerns. Staff Exhibit 803 contains revisions based on these discussions. CNG agreed to submit proposed revised draft language to these sections that mirrors Staff proposed language.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 305
WITNESS: SCOTT SHEARER

PUBLIC UTILITY COMMISSION
OF
OREGON

Staff Exhibit 801

Witness Qualification Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME: Scott Shearer

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Compliance Specialist
Consumer Services Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Corban University Salem, Oregon
Bachelors of Science in Business, Organizational Leadership

EXPERIENCE:

2014 - Current - Heritage Grove Credit Union
Board of Directors/Chairman of the Board
Provide strategic direction for a credit union with assets of over 100 million dollars. Reviewing and approving monetary expenditures and budget.

2007 - Current - Oregon Public Utility Commission
Telecommunications Specialist/Consumer Specialist/Senior Compliance Specialist
Reviewing and applying Oregon Administrative Rules to tariffs in relation to consumer complaints.

2006 - 2007 - Oregon Department of Justice/Division of Child Support
Administrative Specialist
Researching responsible parties in Child Support orders

1999 - 2006 - EPIQ Systems/Poorman Douglas Corp.
Claims Analyst/Senior Claims Analyst
Reviewing and implementing orders and settlements for the largest Class Action Lawsuit administrator in the United States. Auditing and processing class action lawsuits with payouts from two-hundred thousand to over one billion dollars to claimants.

CASE: UG 305
WITNESS: SCOTT SHEARER

PUBLIC UTILITY COMMISSION OF OREGON

Staff Exhibit 802

Consumer Services Complaint Records and Statistics

Exhibits in Support of Opening Testimony

August 11, 2016

Time frame - January 1, 2015 to June 30, 2016

	Cascade Natural Gas	*Avista Natural Gas*	*NW Natural Gas*	*All Gas*
Customer count[1]	**57415**	85798	565155	708368
Total complaints[2]	**12**	14	192	218
Complaint rate	**0.000209**	0.000163	0.000340	0.000308
Complaints per 1000	**0.209**	0.163	0.340	0.308

	Idaho Power	*Pacific Power*	*PGE*	*All Electric*
Customer count[1]	13347	485307	735502	1234156
Total complaints[2]	8	144	340	492
Complaint rate	0.000599	0.000297	0.000462	0.000399
Complaints per 1000	0.599	0.297	0.462	0.399

	Energy Total
Customer count[1]	1942524
Total complaints[2]	710
Complaint rate	0.000366
Complaints per 1000	**0.366**

[1] Customer counts from the 2014 Oregon Utility Statistics Book

[2] Total complaints from Consumer Services database as of June 30, 2016

CASE: UG 305
WITNESS: SCOTT SHEARER

PUBLIC UTILITY COMMISSION
OF
OREGON

Staff Exhibit 803

Proposed Tariff Language Revisions

Exhibits in Support of
Opening Testimony

August 11, 2016

Tariff Rule 2 Issues

DEFINITIONS

Issue A

Applicant - A person, firm, or corporation that (1) applies for service; (2) reapplies for service at a new or existing location after service has been disconnected; or (3) has not met the requirements for becoming a customer as established in Rule ~~2~~3.

Issue B

Customer - Any person, firm, or corporation that has:

a. Applied for, been accepted, and is currently receiving gas and, or distribution service from the Company under these Rules and Regulations at one location under one rate classification contract~~.~~, or
b. Received gas or distribution service from the Company, and voluntarily terminated service within the past twenty days.

Issue C

High Priority Use - ~~As defined in 281.203(a), Title 18 Code of Federal Regulations, high priority use is natural gas in a residence, a small commercial establishment, in a school or hospital, or for police protection, for fire protection or in a correctional facility.~~ High priority use is where continuity of gas service is considered in the public's best interest such as gas usage in a residence, school, hospital, or correctional facility, or for police or fire protection.

Tariff Rule 3 Issues

Issue D

ESTABLISHING CREDIT

Below are the criteria for establishing credit for residential and non-residential customers, respectively. A customer who cannot meet the requirements put forth below must pay a Deposit or provide other security in accordance with the terms and conditions in Rule 4.

Tariff Rule 5 Issues

NOTICE OF PENDING DISCONNECTION OF RESIDENTIAL SERVICE

Issue F

2. The notice shall be printed in **bold face type** and shall state in easy to understand language:

~~a. The reason for the proposed disconnection;~~
~~b. The amount to be paid to avoid disconnection;~~
~~c. The earliest date for disconnection;~~
~~d. An explanation of the time-payment agreement provisions;~~
~~e. An explanation of the medical certificate provisions;~~
~~f. The name and telephone number of the appropriate unit of the Department of Human Services or other agencies which may be able to provide financial aid; and~~
~~g. An explanation of the Commission's complaint process and toll-free number.~~

a. The reason for the proposed disconnection;
b. The earliest date for disconnection;
c. An explanation of the Commission's complaint process and toll-free number; and
d. If the disconnection is for nonpayment of services rendered, including failure to abide by a time payment agreement, the noti failure to establish credit, theft of service, or safety.ce must also state:
1. The amount to be paid to avoid disconnection;
2. An explanation of the time payment agreement provisions of OAR 860-021-0415;
3. An explanation of the medical certificate provisions of OAR 860-021-0410; and
4. The name and telephone number of the appropriate unit of the Department of Human Services or other agencies that may be able to provide financial assistance.

Issue G

3. At least 15 days before Cascade disconnects a residential customer for nonpayment of services rendered, Cascade will provide written notice to the customer. A 15-day notice is not required when disconnection is for~~:~~
~~a) providing false identification to establish service, continue service, or verify identity~~
~~b) meter tampering diverting service, or other theft;~~
~~c) the existence of unsafe conditions.~~ failure to establish credit, theft of service, or safety.

Issue H

5. Cascade may serve the 15-day notice of disconnection in person or send it by first class mail to the last known address of the customer. Service is complete on the date of ~~the mailing or personal delivery~~ personal delivery or the day after notification is postmarked.

Issue I

EMERGENCY MEDICAL CERTIFICATE FOR RESIDENTIAL SERVICE

3. An emergency medical certificate shall be valid only for the length of time the health endangerment is certified to exist, but no longer than six months without renewal when the certificate is issued for a non-specific chronic illness or no longer than twelve months without renewal when the certificate is issued for a specific chronic illness. At least 15 days before the certificate's expiration date, Cascade will give the customer written notice of the date the certificate expires unless it is renewed with Cascade before that day arrives.

Tariff Rule 6 Issues

Issue J

GENERAL

Gas consumed, as indicated by meter readings, will be billed to customers as promptly as possible after reading dates, at approximately thirty day intervals, computed per applicable filed tariff rates. Bills will be due and payable ~~as of dates rendered and delinquent or past due~~ fifteen days ~~thereafter~~ after they are rendered.

Issue K

~~**ESTIMATED BILLING CAPABILITY**~~

~~The Company may issue small commercial customers and residential customers excluding accounts with pool water heating load an estimated bill during the months of June through September. Actual meter readings will be made the month following any month in which the customer's bill is estimated.~~

Issue L

BUDGET PAYMENT PLAN FOR PAYMENTS OF GAS BILLS

The budget payment plan for payment of gas bills ~~is devised to~~ averages ~~out the~~ a residential customer's monthly payments for gas service for a period of no less than twelve months. The budget payment plan is available to residential customers who have no outstanding balance ~~of any residential customer who can establish satisfactory credit~~ with the Company.

CASE: UG 305
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Senior Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. I reviewed the depreciation expense and accumulated depreciation, or depreciation reserve, portions of Cascade Natural Gas Corporation's (CNG or Company) revenue requirement for this rate case as documented by the Company witness in CNGC/200 Parvinen.

Q. What exhibits are included as part of your testimony?

A. I have prepared the following exhibits: Exhibit Staff/901, Witness Qualification Statement and Exhibit Staff/902, Cascade Response to Staff Data Request (DR) No. 160.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Analysis of Depreciation from a Ratemaking Perspective............2
Issue 2. Depreciation Effect on Revenue Requirement...........................7

ISSUE 1. ANALYSIS OF DEPRECIATION FROM A RATEMAKING PERSPECTIVE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

The statement above defined "Depreciation" from a valuation perspective. From an accounting perspective, "Depreciation" is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1), states in relevant part:

> Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to

[1] NARUC, Public Utility Depreciation Practices p.318 (1996).

> the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate (1) the combination of survivor curve-service life (Curve-Life) of utility property, and (2) net salvage (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. What depreciation rates did CNG use in its Test Year revenue requirement?

A. The current depreciation rates for the Company were authorized by OPUC Order 15-315 (Docket UM 1727) in October 2015 and effective on January 1, 2016. In Order 15-315, the Commission specified the Curve-Life and Net Salvage parameters for "each plant account" (FERC account), from which the depreciation rates are derived for each account. The estimated "Composite" (overall) depreciation rate for "Total Depreciable Plant" is 2.77% or $20.55 million per year of depreciation expense system-wide.

Q. Did you identify any errors in the Company's filing relating to depreciation?

A. Yes. Staff found data entry errors in Cascade's Summary of Adjustments, submitted as Exhibit CNGC/204, and Results of Operations for 2015, submitted as Exhibit CNGC/201, that unintentionally misreported $390,322 of "Depreciation & Amortization" Expense as "Administrative & General" Expense, resulting in a Depreciation & Amortization Expense adjustment of "zero". Additionally, the Company mistakenly omitted the $390,322 of Depreciation & Amortization Expense from the Accumulated Depreciation calculation.

Staff discussed the data entry mistake in the depreciation calculation and the missing information for accumulated depreciation with the Company. In its response to Staff DR No. 160, the Company provided a corrected version of "Parvinen Workpapers Exhibit 201 – 206" and addressed accumulated depreciation with "OPUC – 160 A.xlsx".

Q. How did you analyze the Company's proposed depreciation expense, and what information did you review?

A. To confirm that the depreciation expense was properly calculated using the authorized depreciation parameters in Commission Order 15-315, Staff, as discussed above, sent the Company DR No.160 asking for calculations of "Depreciation Expense" and "Total Accumulated Depreciation" in Excel format with cell reference links and formulae intact, along with other supporting work papers.[2]

Upon receiving the Company's response, Staff verified the Company's calculations. First, Staff checked the reference links, formulae, and calculations provided in the data response. Second, Staff reviewed how the Company

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[2] See Staff/902.

calculated depreciation expense using the rates authorized in Order 15-315. Third, Staff verified how the Company forecasted 2016 depreciation expenses. Fourth, Staff reviewed how the Company calculated the depreciation expense adjustment.

Staff also conducted one phone conference with Cascade's witness Michael Parvinen to gain a better understanding of Cascade's depreciation adjustment.

Q. Did you identify additional errors after the Company's re-calculation of depreciation in its data response?

A. No. Staff did not find additional errors in the Company's calculation after the correct information was submitted in response to Staff DR No. 160.

Q. Did you make any adjustments? If so, please explain.

A. Yes. I propose the following adjustments. However, the following adjustments are a result of the data entry mistakes made in the exhibits and work papers submitted by the Company in its original filing, as well as the omission of information related to Accumulated Depreciation.

1. An increase in the Depreciation & Amortization Expense adjustment by $390,322, from $507,672 to $897,994. This is a result of a mistake in the Company's original filing, in which the depreciation expense adjustment of $390,322 was entered into a different cell.
2. An increase in the Accumulated Depreciation adjustment by $390,322, from $6,365,348 to $6,755,669. This is a result of an omission in the Company's original filing, in which $390,322 was omitted from the Total

Accumulated Depreciation calculation. The Total Accumulated Depreciation of $6,755,669 should be subtracted from the Company's rate base.

ISSUE 2. DEPRECIATION EFFECT ON REVENUE REQUIREMENT

Q. Describe the depreciation effect on the revenue requirement of a utility.

A. In the traditional rate base rate-of-return environment, customer rates and utility costs are components of a utility's revenue requirement. NARUC, in its "Public Utility Depreciation Practices" manual on "Depreciation Expense and Its Effect on the Utility's Financial Performance – Revenue Requirement" states:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[3]

Q. What are the relationship between depreciation and revenue requirement?

A. Under cost of service regulation, revenue requirement refers to the revenues the utility must earn to recover the cost of providing service and to earn a reasonable return on its investment. To compute the revenue requirement (RR) (RR is measured by cost-of-service), a basic formula is followed[4]:

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

Rate Base = Gross Plant – "Accumulated Depreciation" – Accumulated Deferred Income Taxes + Working Capital

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[3] NARUC, Public Utility Depreciation Practices p.195 (1996).

[4] Federal Energy Regulatory Commission, Cost-of-Service Rates Manual p. 6-7 (1999), www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc

In this formula, “Depreciation” is one of the largest line items in the cost of service; therefore, “Depreciation” is important as both an annual expense and as a reduction of rate base.

Q. How are depreciation parameters used in determining the utility’s revenue requirement?

A. In a general rate case filing, the depreciation expense is calculated by using the Commission’s authorized depreciation parameters, from which depreciation rates are derived (in this case, those rates set forth in Order No. 15-315), and in traditional FERC classification of generation, transmission, distribution, and general plant assets.

Accumulated Depreciation is the cost of the investment in gross plant that is recovered through the cost-of-service as Depreciation Expense. Accordingly, the depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the Net Book Plant. The net book plant represents the portion of gross plant that is not depreciated.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 305
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION & TRAINING:
M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

C.R.R.A. Certified Rate of Return Analyst
Society of Utility and Regulatory Financial Analysts

Depreciation studies - the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

300+ credit hours on 30+ topics trainings in public utility industry

EXPERIENCE: 1/11/1999-Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 17 years since January 1999. My roles include: Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst
I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

Principal Analyst & Case Manager, Settlement Leader/Negotiator for Depreciation and Ratemaking:
For the "Depreciation Rate Determination" (fixed cost allocation, capital recovery), I have served as a Principal Analyst and Case Manager for the

determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for past eight years.

In this position, I investigate, analyze and calculate "Energy Asset Retirement Cost & Impact" and "Power Plant Decommissioning Cost & Impact" on Customer Rates. I review, calculate, analyze fixed asset depreciation and propose depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on are Steam/Coal, Hydraulic, Natural Gas, Wind, Solar and Geothermal.

My analyses of "Power-Plant-Shutdown" activities include the following cases:

1. PGE closes Boardman Coal plant (UM 1679 & UE 215) ,
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246)
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 - Recovery of investment in Klamath River dams in OPUC UE 219.

I conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my present position, I was a lead analyst and case manager for cost of capital, mainly debt capital analysis for nine years. My responsibilities included: review and analyze regulatory policy on Cost of Capital and Market Risks from utility's financial applications for their Derivative Instruments & Hedging Activities and Capital Raising Activities.

I advised the Commission on over 60 Financial Dockets and obtained the Commission orders.

I passed the certification test offered by "Society of Utility and Regulatory Financial Analysts", become a "Certified Rate of Return Analyst" in 2002.

Public Utility & Policy Analyst:

Energy Merger & Acquisition: I have testified in formal state hearings involving Energy Merger & Acquisition, I conducted Acquisition Premiums & Credit Risk Analysis and testified for the Merger case of "PacifiCorp vs. MidAmerican Energy Company" (a subsidiary of Berkshire Hathaway Energy) in UM 1209. My reviews on Energy Merger & Acquisition also include "PacifiCorp vs. Scottish Power", "PGE vs. Enron".

<u>Clean Energy – Dollar Impact on Customer Rates</u>: I performed analyses of "Rate Impact Calculation of Oregon Clean Energy Capital Investment, Comparative Advantage of Oregon Clean Energy – Dollar Impact in Rates".

<u>General Rate Case Ratemaking (Revenue requirement) and Other Cases</u>: I testified and conducted analyses on some subjects in the revenue requirement models for General Rate Cases. I testified on Fuel Price Forecasting regarding Property Sales; I reviewed Load Forecasting, Weather Normalization in "Integrated Resource Planning" (IRP) and Rate Case filing.

My work functions have also included the Statistical Sampling Design & Procedure Design, and I testified on Revenue Issues (UM 1288) by presenting the sampling results.

I conducted Energy Utility Auditing for cost of capital component on energy companies and also preformed utility operational auditing. I have conducted "Interest Rate and Late Payment Charge" Survey and Analysis annually for state of Oregon (UM 779).

I conducted Telecommunications "Market Competition and Economic Policy Survey Analysis" and write report for House Bill 2577, the report has been published on OPUC web annually for 15 years.

<u>Mentor in the ICER - International Confederation of Energy Regulators</u>

I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My "Mentoring Topics" were focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in US and "Price-Cap" in Europe; Cost of Capital, Energy Demand and Price Forecasting Models; Least Cost Planning; and Regulatory Policy & Renewable Energy issues affecting Utility Rates.

CASE: UG 305
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

August 11, 2016

Staff Data Request & CNG Response No. 160

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 160

Date prepared: 6/3/2016

Preparer: Michael Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 160

Please provide the "Depreciation Expense" Adjustment and "Total Accumulated Depreciation" Adjustment from "Parvinen Workpapers Exhibits 201 – 206" tab named "Exh 204 - Summary of Adj". Please provide the calculation in Excel format with the cell reference links and formulae for exhibits CNGC/201, Parvinen/1, and CNGC/204, Parvinen/1.

a. Please add cell reference links and formulae on Total Adjustments to Depreciation & Amortization ($390,322) and Accumulated Depreciation & Amortization ($xxx).

b. From the file titled "Copy of Depreciation Change Analysis.xlsx," please provide the cell reference links and formulae between the depreciation parameters and depreciation rates that CNGC used in this filing to calculate "Depreciation Expense Adj" and the depreciation parameters and depreciation rates in OPUC Order 15-315/UM 1727.

Response:

Attached is the Excel copy of "Parvinen Workpapers Exhibit 201 – 206" entitled "OPUC – 160.xlsx". The attachment has all links and formulae.

a. The Accumulated Depreciation impact of the adjustment was omitted in the Company's filing. Attached is a corrected version of "Parvinen Workpapers Exhibit 201 – 206" entitled "OPUC – 160 A.xlsx". This file provides corrected exhibits once the Accumulated Depreciation impact is included.

b. Attached as "OPUC-160 B.xlsx" is a copy of the referenced file "Copy of Depreciation Change Analysis.xlsx". Column T in the attached file is transferred to the "Depreciation

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Expense Adj" tab in "OPUC-160.xlsx", excluding Washington plant shown in rows 76-114.

The depreciation rates shown in Column C are the depreciation rates approved in UM 1727. As Cascade only has a pdf file of Order 15-315 the rates were manually inputted into Column C, so no link can be provided.

	A	B	C	P	Q	R	S	T	V	W
10			**Cascade Natural Gas**	2016 Plant	Inflation	Resource	Depreciation	A&G		**Total**
11			**Proposed Adj to Base Year Results**	Additions	Factor	Planning	Expense	Adjustment		**Adjustments**
12			**UG 305**		Adj	Adjustment	Adj			**(Base Rates)**
13			**Exh 204 - Summary of Adj**	(k)	(l)	(m)	(n)	(o)		(p)
14			**New Depr. Data**							
15	1		**Operating Revenues**							
16	2		Natural Gas Sales		$0	$0	$0	$0		1,437,260
17	3		Gas Transportation Revenue		0	0	0	0		0
18	4		Other Operating Revenues		0	0	0	0		0
19	5		SUBTOTAL	$0	$0	$0	$0	$0		$1,437,260
20	6		LESS: Nat. Gas/Production Costs							$433,904
21	7		Revenue Taxes							$30,326
22	8		OPERATING MARGIN	$0	$0	$0	$0	$0		$973,030
23	9									$0
24	10		**Operating Expenses**							$0
25	11		Production		1,299					$1,299
26	12		Distribution		34,024	50,728				$97,202
27	13		Customer Accounts		20,514					$222,609
28	14		Customer Service		0					($506,656)
29	15		Sales							($19,501)
30	16		Administrative and General		34,392			(20,183)		$229,005
31	17		Depreciation & Amortization	507,672			390,322			$897,994
32	18		Regulatory Debits							$0
33	19		Taxes Other Than Income	200,857						$200,857
34	20		State & Federal Income Taxes	(282,987)	(36,037)	(20,261)	(155,894)	8,061		$87,882
35	21		**Total Operating Expenses**	425,543	54,191	30,467	234,427	(12,122)		$1,210,691
36	22		**Net Operating Revenues**	($425,543)	($54,191)	($30,467)	($234,427)	$12,122		($237,662)
37										
38	24		**Rate Base**							
39	25		Total Plant in Service	13,673,972						$13,673,972
40	26		Total Accumulated Depreciation	(6,365,348)			(390,322)			($6,755,669)
41	27		Contributions in Aid of Construction							$0
42	28		Customer Adv. For Construction							$0
43	29		Deferred Accumulated Income Taxes	(70,305)						($70,305)
44	30		Deferred Debits							$0
45	31		Working Capital Allowance							$0
46	32		**TOTAL RATE BASE**	$7,238,320	$0	$0	($390,322)	$0		$6,847,998
47	33									
48	34		**Revenue Requirement Effect**	$1,632,204	$92,679	$52,106	$352,155	($20,731)		$1,262,113

			C	P	Q	R	S	T	V	W
10			**Cascade Natural Gas**	2016 Plant	Inflation	Resource	Depreciation	A&G		**Total**
11			**Proposed Adj to Base Year Results**	Additions	Factor	Planning	Expense	Adjustment		**Adjustments**
12			**UG 305**		Adj	Adjustment	Adj			**(Base Rates)**
13			**Exh 204 - Summary of Adj**	(k)	(l)	(m)	(n)	(o)		**(p)**
14			**Original Depr. Data**							
15	1		**Operating Revenues**							
16	2		Natural Gas Sales		$0	$0	$0	$0		1,437,260
17	3		Gas Transportation Revenue		0	0	0	0		0
18	4		Other Operating Revenues		0	0	0	0		0
19	5		SUBTOTAL	$0	$0	$0	$0	$0		$1,437,260
20	6		LESS: Nat. Gas/Production Costs							$433,904
21	7		Revenue Taxes							$30,326
22	8		OPERATING MARGIN	$0	$0	$0	$0	$0		$973,030
23	9									$0
24	10		**Operating Expenses**							$0
25	11		Production		1,299					$1,299
26	12		Distribution		34,024	50,728				$97,202
27	13		Customer Accounts		20,514					$222,609
28	14		Customer Service		0					($506,656)
29	15		Sales							($19,501)
30	16		Administrative and General		34,392		390,322	(20,183)		$619,327
31	17		Depreciation & Amortization	507,672			0			$507,672
32	18		Regulatory Debits							$0
33	19		Taxes Other Than Income	200,857						$200,857
34	20		State & Federal Income Taxes	(282,987)	(36,037)	(20,261)	(155,894)	8,061		$83,673
35	21		**Total Operating Expenses**	425,543	54,191	30,467	234,427	(12,122)		$1,206,482
36	22		**Net Operating Revenues**	($425,543)	($54,191)	($30,467)	($234,427)	$12,122		($233,453)
37										
38	24		**Rate Base**							
39	25		Total Plant in Service	13,673,972						$13,673,972
40	26		Total Accumulated Depreciation	(6,365,348)						($6,365,348)
41	27		Contributions in Aid of Construction							$0
42	28		Customer Adv. For Construction							$0
43	29		Deferred Accumulated Income Taxes	(70,305)						($70,305)
44	30		Deferred Debits							$0
45	31		Working Capital Allowance							$0
46	32		TOTAL RATE BASE	$7,238,320	$0	$0	$0	$0		$7,238,320
47	33									
48	34		**Revenue Requirement Effect**	$1,632,204	$92,679	$52,106	$400,925	($20,731)		$1,303,685

CASE: UG 305
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy, Rates, Audits, and Finance Division of the Public Utility Commission of Oregon (OPUC).My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. This testimony reviews allocations of costs among Cascade and its affiliates.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1002, Cascade's Cost Allocation Manual, Exhibit Staff/1003, a list of Cascade affiliates, Staff/1004, NARUC Guidelines for Cost Allocations and Affiliate Transactions, and Staff/1005, Staff's Affiliate Cost Allocation Adjustments.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Affiliated Interests 2
Issue 2. Cost Allocations 4

ISSUE 1. AFFILIATED INTERESTS

Q. Please summarize Cascade's affiliates.

A. Cascade is a multi-state local natural gas distribution company (LDC) operating in Washington and Oregon. Cascade performs no unregulated operations. Cascade is owned by MDU Resources Group, Inc. (MDUR). The Commission authorized MDUR to purchase Cascade in 2007.[1] MDUR owns regulated and unregulated entities.

Cascade allocates costs to and is allocated costs from affiliates. Cascade provides services such as Gas Control and information technology (IT) to other MDUR operating companies.[2] MDUR provides payroll, procurement, enterprise technology, administrative, and general services to Cascade.

Montana Dakota/Great Planes (MDU) provides leadership, customer services, information technology, administrative services and gas supply and control to Cascade. Intermountain Gas provides the use of a customer care center. Centennial Holdings Capital LLC carries liability insurance policies for Cascade. Knife River Corporation provides asphalt services for Cascade. Cascade pays a total of $19.7 million to affiliates.

Q. Has Cascade filed an affiliated-interest agreement for each affiliated transaction?

A. Yes, this appears to be the case. Cascade has filed affiliated-interest agreements in Docket Nos. UI 354, UI 331, UI 295, UI 278, and UI 274. The

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[1] *See In the Matter of MDU Resources Group, Inc., Application for Authorization to Acquire Cascade Natural Gas Corporation*. Docket UM 1283, Order 07-221.

[2] *See* Staff/202 Kaufman/21.

Commission has approved each of these agreements. All affiliated transactions described by the Company are pursuant to these approved agreements.

Q. Do you have any concerns regarding Cascade's affiliated interest transactions?

A. Yes. When asked to identify direct charges from affiliates, Cascade identified its 2015 affiliated interest report. Cascade should be capable of identifying transactions that are with affiliates. The Commission's past approval of Cascade's affiliated interest contracts was conditional on the Commission access to affiliated interest records.

Q. What is your proposal regarding affiliated interests?

A. I propose that Cascade audit its past and expected transactions to determine which transactions are with affiliates. MDUR owns numerous construction related entities. All MDUR subsidiaries are listed in Exhibit Staff/1003. I also recommend that Cascade and MDUR review the costs of allocated transactions to ensure that all affiliated transactions are approved by the OPUC.

ISSUE 2. COST ALLOCATIONS

Q. Please summarize how Cascade allocates costs.

A. Cascade's allocation methodology is described in the cost allocation manual (Allocation Manual) provided in Exhibit Staff/1002. Allocations from MDUR to its subsidiaries and between the subsidiaries are based on a variety of allocation factors. Corporate overhead costs are allocated to MDUR's subsidiaries based on each subsidiary's capitalization. Cascade's 2015 corporate allocation factor was 10.4 percent.

Costs for procurement services provided by MDUR are allocated based on a five-factor allocation that equally weights Visa cards, Visa spend, national accounts spend, number of equipment acquisitions and number of fleet acquisitions. Cascade's procurement allocation factor is 6.76 percent. This allocation factor is currently based on 2013 data.

Costs for accounts payable services provided by MDUR are allocated based on a 25-75 weighting of payments and vouchers. Cascade's allocation for accounts payable in 2015 was 11.4 percent.

Enterprise technology services provided by MDUR include six accounts that are allocated using five distinct allocators. Cascade's allocators range from 2.89 to 6.83 percent.

Costs for some services are shared between MDUR's utility subsidiaries and not shared with non-utility subsidiaries. The allocations of these costs do not appear to be based on cost drivers, but instead are fixed values. For example, Cascade is allocated one third of leadership expenses, 35 percent of director costs, and 25 percent of team lead costs.

Some assets used by Cascade are owned by MDUR subsidiaries. The costs for these assets are calculated using a revenue requirement model and are allocated to individual utilities based on customer counts.

Allocations between Cascade's two state jurisdictions are based on a three factor formula. The three factors include share of customers, share of employees and share of gross plant. This formula results in an Oregon allocation factor of 24.72 percent.

Q. Please summarize your adjustments related to cost allocations.

A. I propose the following adjustments related to cost allocations:

Adjustment	**System**	**Oregon**
Customer Service Allocation Adjustment	$(773,180)	$(191,130)
General Overhead Allocation Adjustment	$(951,379)	$(235,181)
Non-Utility Cost Exclusion	$(234,201)	$(57,894)
No Supporting Description Exclusion	$ (334,770)	$(82,755)
Affiliate Rent Charge	$ (635,007)	$(156,974)
Total Cost Adjustment	$(2,928,536)	$(723,934)
Affiliate Rent Receipts	$257,335	$63,613
Total Revenue Adjustment	$257,335	$63,613

Q. Please evaluate the transparency of Cascade's cost allocations.

A. Cascade's cost allocations are not transparent. In response to Staff DR No. 360, Cascade provided transaction level detail on allocated costs. However, the data provided cannot be linked to the cross charges that appear on Cascade's books. The data provided also does not identify what allocation factor is being used, or what costs are being directly assigned. I was unable to identify the original cost of items allocated to Cascade or track the costs through the intermediate entities to Cascade. Cascade utilizes a computerized accounting system and the nature of this system may be responsible for the opacity of Cascade's allocations.

This opacity is a violation of the NARUC principle that costs be traceable.[3] Cost allocations to Cascade from affiliates should be fully transparent. This enables Staff to verify that costs are fully distributed and that all costs allocated to Cascade are appropriate for recovery.

Transparency also allows Staff to ensure that it does not duplicate adjustments to Cascade's revenue requirement. Staff's recommendations in a rate case can include adjustments to allocation factors and to the utility's proposed expenses or costs. Without transparency in allocation, Staff cannot necessarily determine if there is overlap in these two types of adjustments. For example, in this testimony I reduce the corporate overhead allocator from 10.4 percent to 6.9 percent. This adjustment results in a reduction of costs allocated to Cascade. Other Staff exclude certain costs, such as costs for meals and

[3] *See* Exhibit Staff/1004, NARUC Guidelines for Cost Allocations and Affiliate Transactions.

entertainment. Some meals and entertainment costs are cross charged from MDUR to Cascade. If the cross charge is made using Cascade's corporate overhead allocator, then it is possible that Staff will overstate the fair adjustment. If the cross charge is made using a different allocator, then Staff has not overstated the adjustment.

Q. Please evaluate the allocation factors used to allocate costs from MDU to Cascade.

A. Cascade is allocated many customer service costs based on fixed allocation factors between 30 and 35 percent. The allocators are fixed in the sense that they are not tied to any Cascade operating characteristics such as number of customers. The fixed allocation factors used to allocate costs associated with MDU's utility operations support violate the NARUC cost allocation principals. NARUC's Guidelines state that "[t]he primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products." However, because fixed allocators do not vary with firm behavior, these allocators do not represent cost drivers or relevant proxies.

I calculated Cascade's share of MDUR utility customers to be 25.6 percent. I applied this percentage to the customer service cost categories allocated to Cascade. This customer service cost allocation reduces

Cascade's allocation of customer service costs by $773,180 (or $191,130 Oregon allocated).[4]

Q. Please evaluate the allocation factor used to allocate corporate overhead from MDUR to Cascade.

A. The allocation factor used to allocate corporate overhead is based on share of capitalization. Cascade's share of capitalization is calculated to be 10.4 percent.[5] However, in calculating this value, Cascade excludes approximately $2.4 billion from the total MDUR capitalization of $7.4 billion. The excluded capitalization is related to unregulated subsidiaries. The subsidiaries associated with the excluded capitalization do not share in the corporate overhead. As a result, the Cascade corporate overhead factor is too large.

I recalculated the share of capitalization appropriately attributable to Cascade and derived a 6.9% corporate overhead allocator. Using the more appropriate 6.9% corporate overhead allocator reduces Cascade's share of corporate overhead by $951,379 (or $235,181 Oregon allocated).[6]

Q. Please evaluate appropriateness of certain corporate overhead costs allocated to Cascade rate payers.

A. Cascade is allocated many costs from MDUR that do not appear to have a utility purpose. These costs include a corporate jet and private air hanger,

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[4] *See* Exhibit Staff/1005.
[5] *See* Exhibit Staff/1002, Kaufman/26.
[6] *See* Exhibit Staff/1005.

flights to Palm Springs for Board of Director meetings held at luxury estates, golf supplies, golf green fees, jewelry purchases, lobbying expenses and investor relation expenses. In addition, many of the costs allocated to Cascade include no description or explanation in the accounting data and the purpose could not be identified.

I do not recommend recovery of business expenses that included explanations related to expenses typically viewed as not appropriate to be included in rates.

The accounting details that appear on the affiliate accounts – those provided in response to Staff DR No. 360 – contain more description than the accounting details for cross charges and allocations in Cascade's accounts. Staff reviewing Cascade accounts must rely on "object codes" to determine the business purpose of allocated amounts. To ensure no double-counting of certain Staff adjustments, I did not exclude any expenses with object codes ending in 233, 511, 521, 811, 840, 851, 912 and 981 in connection with review of Cascade's allocations because these object codes are reviewed by other Staff.

Removing expenses that do not appear to be utility-related results in a reduction of Cascade allocated costs by $334,770 (or $82,755 Oregon allocated).[7] This expense reduction is based on Staff's proposed corporate overhead allocator. If Staff's proposed corporate overhead allocator is not

[7] *See* Exhibit Staff/1005.

used, the recommended costs that should not be included in developing revenue requirements would be $476,405.

In addition to removing non-utility expenses, I also recommend excluding expenses from rates where the Company has not provided the stated purpose of the expense-related activity. Staff recognizes that expenses with no stated purpose may have valid justification for inclusion in rates, but I cannot tell whether this is true from the Company's filing. Removing expenses with no stated purpose reduces Cascade's allocation of costs by $234,201 (or $57,894 Oregon allocated). [8]

Q. Please evaluate the allocations based on revenue requirement models.

A. Cascade uses a revenue requirement model to charge rent to affiliated interests and pay rent to IGC and MDU. As described in more detail below, I found that some of the assumptions in the revenue requirement models were not correct. I made changes to all three revenue requirement models. The impact of these changes is an increase to other revenue by $257,335 ($63,614 Oregon allocated) and a decrease to rental expense of $635,007 ($156,974 Oregon allocated).

Q. Please summarize the changes made to the Cascade Kennewick revenue requirement allocation model.

A. The allocation model as filed used a projected cost of capital of 8.75 percent. However the Cascade filing in this case projects a cost of capital of 7.309 percent. I updated the cost of capital used in the model. The Kennewick

[8] *See* Exhibit Staff/1005.

building is used for multiple purposes. Only some of the building is used for shared operations such as IT, and only costs associated with the shared space are charged to affiliates. The Company's model assumes that common space is not shared space. I split common space between shared and unshared functions at the same ratio that offices are split between shared functions and unshared functions.

Further, the revenue requirement is intended to be allocated based on customer counts. However, the company has not accurately counted customers. I updated the customer counts. This change increases rent charged to other utilities by $257,335.

Q. Please summarize the changes made to the IGC revenue requirement allocations.

A. I made the same cost of capital and customer count adjustments as with the Cascade model. In addition, I calculated the 13 month average balance for net plant in 2016. This reduces the charge to Cascade by $97,019.

Q. Please summarize the changes made to the MDU revenue requirement allocations.

A. I made the same cost of capital, customer count and net plant average balance adjustments as for the IGC revenue requirement. In addition, I excluded items that are not appropriately booked to rent, such as postage, shipping, labor, tax preparation and private jet costs. The MDUR general office and Annex are primarily used for document generation, shipping and storage. I allocated the revenue requirement for these buildings based on each affiliate's share of printing impressions. I updated the allocation model to be consistent with the corporate capitalization allocator described previously in this testimony. This reduces the charge to Cascade by $558,065.

Q. Do you have any caveats regarding the calculations for your adjustments?

A. Yes, due to the lack of transparency, Staff was unable to tie the transaction level detail of the affiliates to the rental charges. Because of this, it is possible that the rent adjustments overlap with the other adjustments proposed in this testimony. If overlap exists, the adjustments should be reduced appropriately.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 305
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPCU). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on Cost Allocations in the following OPUC dockets: PAC UE 263, AVA UG 246, and UM 1050. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. I have worked on Cost Allocations in the following Alaska Regulatory Commission dockets: U-14-114/115/116/117/118, U-14-104/105/106/107, and U-14-102. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UG 305
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

August 11, 2016

e-FILING REPORT COVER SHEET

COMPANY NAME: Cascade Natural Gas Corporation

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☒ No ☐ Yes, report docket number:

Report is required by: ☒ OAR 860-027-0100, 860-027-0048
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☒ Yes, docket number: RG-44(4)

List Key Words for this report. We use these to improve search results.

Affiliated Interest

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 3930 Fairview Industrial Drive SE, Salem, OR 97302.

Print

CASCADE NATURAL GAS CORPORATION®
A Subsidiary of MDU Resources Group, Inc.

8113 W. GRANDRIDGE BLVD., KENNEWICK, WASHINGTON 99336-7166
TELEPHONE 509-734-4500 FACSIMILE 509-737-7166
www.cngc.com

May 31, 2016

Oregon Public Utility Commission
P.O. Box 1088
Salem, OR 97308-1088

Attn: Filing Center

RE: RG-44(4), Cascade Natural Gas Corporation's 2015 Affiliated Interest Report

Pursuant to OAR 860-027-0100, Cascade Natural Gas Corporation ("Cascade" or the "Company") submits the attached 2015 Affiliated Interest Report. In accordance with the requirements in OAR 860-027-0048(6), Attachment C to this report is the Company's Cost Allocation Manual.

Please contact me at (509) 734-4593 if you have any questions regarding this filing.

Sincerely,

Michael Parvinen
Director, Regulatory Affairs

Enclosures

CASCADE NATURAL GAS CORPORATION

Affiliated Interest Report for the
Calendar Year 2015

I. An Organizational chart showing the parent company, all subsidiaries, and the percentage of ownership for each.

Please see Attachment A.

A. Changes in the list of directors and, or other changes in the list of directors and or officers in common to the regulated utility and the affiliated interest.

Please see the Attachment B. Common directors and officers among Cascade Natural Gas Corporation, IGC, MDU, Knife River and Centennial Holdings Capital LLC are named in bold font.

B. Changes in successive ownership between the regulated utility and the affiliated interest.

Please see Attachment A for organizational chart for Cascade's affiliates & subsidiaries.

C. A narrative description of the affiliated entity with which the regulated utility does business.

- MDU Resources Group Inc. - Parent Company to Cascade Natural Gas Corporation. Provides management/consulting/legal services to Cascade Natural Gas Corporation.
- Knife River Corporation - A subsidiary of MDU Resources. Provides asphalt services for Cascade Natural Gas Corporation. In addition, Cascade leases part of the facility with Knife River and provides distribution system transportation (Tariff Schedule 163) for a Knife River subsidiary company in Central Oregon.
- Centennial Holdings Capital LLC - A subsidiary of MDU Resources. Carries various liability insurance policies on behalf of Cascade Natural Gas Corporation.
- Montana-Dakota Utilities Co. (MDU) – A subsidiary of MDU Resources. Cascade provides 24/7 gas control monitoring of MDU's distribution system and provides notification to the appropriate personnel when a problem is detected.
- Intermountain Gas Co. (IGC) - A subsidiary of MDU Resources. Cascade provides 24/7 gas control monitoring of IGC's distribution system and provides notification to the appropriate personnel when a problem is detected.

- FutureSource Capital Corp. – A subsidiary of Centennial Holdings Capital. Owner of MDUR corporate office buildings and land.

D. A balance sheet and income statement for the twelve months ending December 31, 2015.

Knife River Corporation is part of MDU Resources Construction Materials and Contracting. Below is the Income Statement and Balance Sheet for Construction Materials and Contracting.

Construction Materials and Contracting	
Year ended December 31,	**2015**
Income statement data (Dollars in millions)	
Operating revenues	$1,904.3
Operating expenses:	
Operation and maintenance	$1,652.3
Depreciation, depletion and amortization	$65.9
Taxes, other than income	$40.1
Total operating expenses	$1,758.3
Operating income	$146.0
Interest expense	$15.2
Income (loss) before taxes	$130.8
Income taxes	$41.6
Earnings (loss) on common stock	$89.2

Construction Materials and Contracting	
Year ended December 31,	**2015**
Balance sheet data (000's)	
Property, plant and equipment	$1,553.4
Less accumulated depreciation, depletion and amortization	$866.2
Net property, plant and equipment	$687.2
Other assets	$591.9
Total identifiable assets	$1,279.1

Montana-Dakota Utilities Co.

Year ended December 31,	2015
Income statement data (000's)	
Operating revenues	$541,923
Operating expenses:	
Purchased natural gas sold	$325,231
Operations	$98,776
Depreciation and amortization	$46,512
Taxes other Than Income	$37,553
Total operating expenses	$508,072
Operating income	$33,851
Other income (expense)	$23,331
Other Income	$9,916
Income (loss) before taxes	$20,436
Income taxes	$7,019
Net Income	$13,417

Year ended December 31,	2015
Balance sheet data (000's)	
Property, plant and equipment	$1,483,735
Less accumulated depreciation, depletion and amortization	$(533,176)
Net property, plant and equipment	$950,559
Other assets	$451,484
Total identifiable assets	$1,402,043

Centennial Holdings Capital LLC

Year ended December 31,	**2015**
Income statement data	
Operating revenues	$9,190,965
Operating expenses:	
Operations	$704,139
Depreciation	$2,070,308.04
Taxes other Than Income	$91,011
Gain on Disp. Of Property	$(8,483.74)
Loss on Disp. Of Property	$1,927,661.55
Total operating expenses	$4,784,635
Operating income	$4,406,329
Other income	$807,079
Other Income Deductions	$236,749
Income (loss) before taxes	$4,976,659
Income taxes	$2,109,452
Net Income	$2,867,207

Year ended December 31,	**2015**
Balance sheet data	
Property, plant and equipment	$49,497,274
Less accumulated depreciation, depletion and amortization	$(13,753,546)
Net property, plant and equipment	$ 35,743,728
Other assets	$10,406,296
Total identifiable assets	$46,150,024

Intermountain Gas Company

Year ended December 31,	2015
Income statement data (000's)	
Operating revenues	$258,368
Operating expenses:	
Purchased natural gas sold	$168,926
Operations	$45,587
Depreciation and amortization	$18,829
Taxes other Than Income	$10,710
Total operating expenses	$244,052
Operating income	$14,316
Other income (expense)	$3,509
Other Income	$301
Income (loss) before taxes	$11,108
Income taxes	$4,080
Net Income	$7,028

Year ended December 31,	2015
Balance sheet data (000's)	
Property, plant and equipment	$602,793
Less accumulated depreciation, depletion and amortization	(228,488)
Net property, plant and equipment	374,305
Other assets	21,702
Total identifiable assets	$396,007

II. Service Payments by Cascade to an Affiliate

	MDU Resources Group, Inc.		
Account	**Description**	**Total Company**	**Total Oregon**
	MDU/MDUR Consulting-Cap Exp	$3,502,197.73	$849,983.39
426.1	Donation Expense	$6,586.12	$1,598.43
426.4	Political Activities	$14,489.41	$3,516.58
426.5	Other	$213,883.08	$51,909.43
813	Other Gas Supply Expenses	$208,841.01	$50,685.74
875	Measuring & Regulating Expenses	$111,429.34	$27,043.92
880	Other Expense	$746,653.88	$181,212.89
902	Routine Meter Reading Expense	$156,601.16	$38,007.11
903	Customer Collection Expense	$5,609,929.57	$1,361,530.07
909	Informational & Instructional Advertising Expense	$19,805.30	$4,806.73
913	Promotional Advertising	$115.37	$28.00
920	Administrative & General Salaries	$3,941,952.04	$956,711.83
921	Office Supplies & Expenses	$1,743,769.36	$423,212.79
922	Administrative Expense Capitalized	($4,522.76)	($1,097.67)
923	Outside Services Employed	$309,592.04	$75,137.99
925	Injuries and Damages	$1,222.49	$296.70
926	Employee Pensions & Benefits	$326,605.41	$79,267.18
930.1	General Advertising Expenses	$18,805.33	$4,564.05
930.2	Misc. General Expenses	$175,232.34	$42,528.90
931	Rents	$1,214,385.80	$294,731.52
	Grand Total	**$18,317,574.02**	**$4,445,675.58**

Name	Description	Total Company	Total Oregon
Knife River Corporation	931 Rent/Various Tariff Distribution	$ 94,691.77	$ 94,691.77
Centennial Holdings	928 Injuries & Damages	$1,270,149.02	$308,265.17
Future Source Capital Corp.	921 Office Supplies & Expenses	$13,229.80	$3,210.87

SERVICE PAYMENTS BY THE AFFILIATE TO THE UTILITY			
Name	**Description**	**Total Company**	**Total Oregon**
Knife River Corporation	887 Maint. Of Mains	$ 14,814.77	$ 14,814.77
Intermountain Gas Co.	24/7 gas control monitoring	$791,525.71	$192,103.29
Montana Dakota Utilities Co.	24/7 gas control monitoring	$782,625.63	$189,943.24

Descriptions of Basis Pricing
Attachment C is the Cost Allocation Manual which describes the costing method procedures for Cascade Natural Gas Corporation.

III. Intercompany loans to Cascade from an affiliate or loans from an affiliate to Cascade

A. **Month-end amounts outstanding for short term and long term loans.**
Cascade made no loans to any of the Affiliates during 2015, and no Affiliate loaned Cascade money in 2015.

B. **The highest amount during the year.**
Not applicable.

C. **A description of the terms and conditions for loans including interest rate.**
Not applicable.

D. **The total amount of interest charged and the weighted average rate of interest.**
Not applicable.

E. **Commission Order approving the transactions.**
Not applicable.

IV. Parent guaranteed debt of affiliate

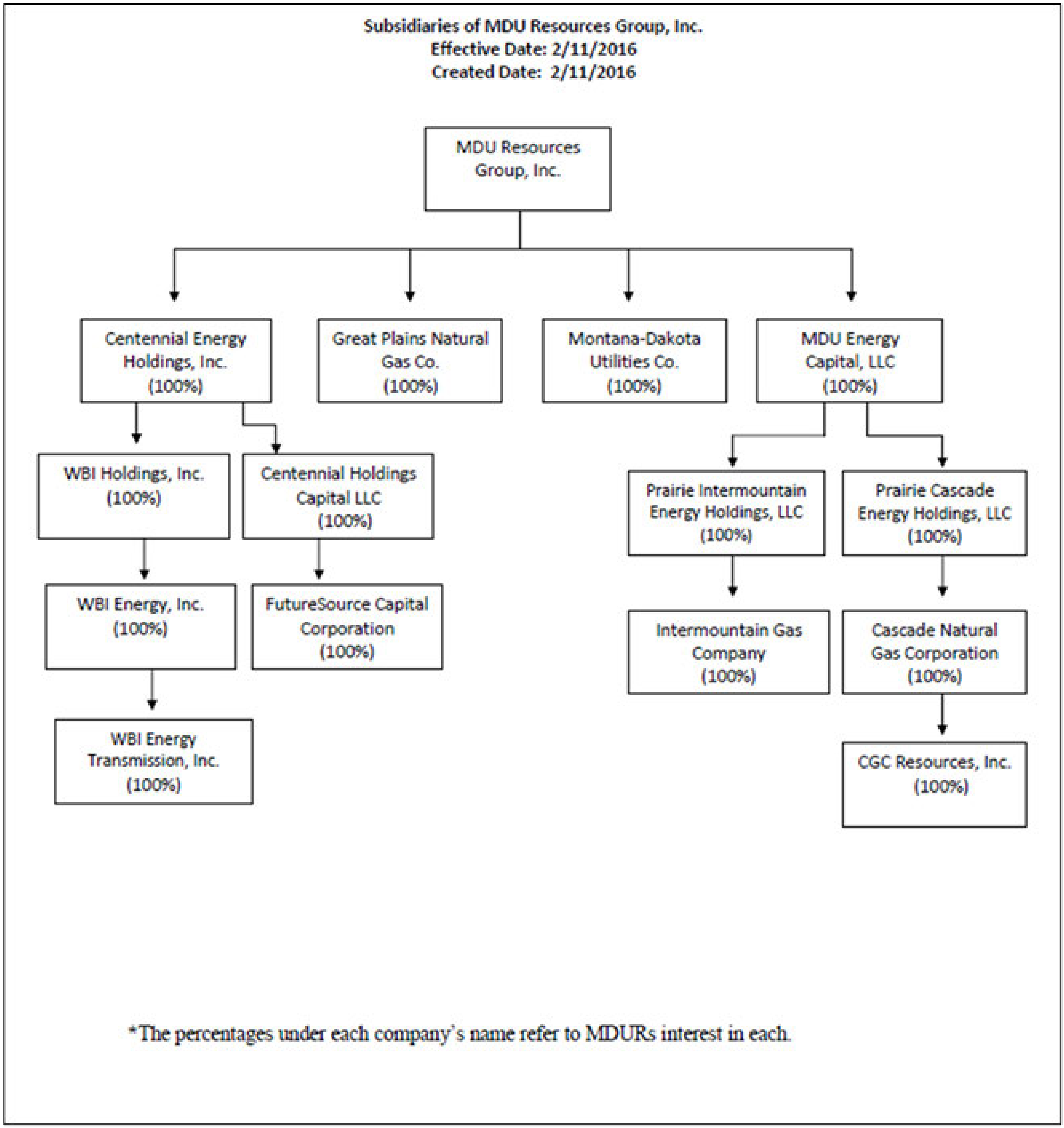
None.

V. Transactions other than services

None.

Attachments

ATTACHMENT A



ATTACHMENT B

CASCADE NATURAL GAS CORPORATION		
Directors	**David L. Goodin**	
	Nicole A. Kivisto	
	Daniel S. Kuntz	
	Doran N. Schwartz	
Officers	**David L. Goodin**	**Chairman of the Board**
	Garret Senger	Executive Vice President, Regulatory Affairs, Customer Service and Gas Supply
	Mark A. Chiles	Vice President, Regulatory Affairs and Customer Service
	Julie A. Krenz	Assistant Secretary
	Daniel S. Kuntz	**General Counsel and Secretary**
	Scott W. Madison	Executive Vice President, Western Region Operations, Business Development and Strategy
	Jason L. Vollmer	Treasurer
	Eric P. Martuscelli	Vice President, Operations
	Nicole A. Kivisto	President and Chief Executive Officer
	Margaret A. Link	Chief Information Officer
	Ann M. Jones	Vice President, Human Resources
	Karl A. Liepitz	Assistant Secretary
KNIFE RIVER CORPORATION		
Directors	David C. Barney	
	David L. Goodin	
	Doran N. Schwartz	
	Daniel S. Kuntz	
Officers	David C. Barney	President and Chief Executive Officer
	Nancy K Christenson	Vice President, Administration and Treasurer
	Christopher B. Ford	Chief Accounting Officer
	David L. Goodin	Chairman of the Board
	Trevor J. Hastings	Vice President, Business Development and Operations Support
	Daniel S. Kuntz	**General Counsel and Secretary**
	Karl A. Liepitz	Assistant Sectretary

ATTACHMENT B (continued)

INTERMOUNTAIN GAS COMPANY		
Directors	**David L. Goodin**	
	Nicole A. Kivisto	
	Daniel S. Kuntz	
	Doran N. Schwartz	
Officers	**David L. Goodin**	**Chairman of the Board**
	Garret Senger	Executive Vice President, Regulatory Affairs, Customer Service and Gas Supply
	Mark A. Chiles	Vice President, Regulatory Affairs and Customer Service
	Julie A. Krenz	Assistant Secretary
	Daniel S. Kuntz	**General Counsel and Secretary**
	Scott W. Madison	Executive Vice President, Western Region Operations, Business Development and Strategy
	Jason L. Vollmer	Treasurer
	Hart Gilchrist	Vice President, Operations
	Nicole A. Kivisto	**President and Chief Executive Officer**
	Margaret A. Link	Chief Information Officer
	Ann M. Jones	Vice President, Human Resources
	Karl A. Liepitz	Assistant Secretary
MONTANA-DAKOTA UTILITIES CO.		
Members	**David L. Goodin**	
	Nicole A. Kivisto	
	Daniel S. Kuntz	
	Doran N. Schwartz	
Officers	Patrick C. Darras	Vice President, Operations
	Kristi B. Hourigan	Assistant Secretary
	Daniel S. Kuntz	**General Counsel and Secretary**
	Ann M. Jones	Vice President, Human Resources
	Nicole A. Kivisto	**President and Chief Executive Officer**

ATTACHMENT B		
MONTANA-DAKOTA UTILITIES CO (CONTINUED)		
	Margaret A. Link	Chief Information Officer
	Garret Senger	Executive Vice President, Regulatory Affairs, Customer Service and Gas Supply
	Mark A. Chiles	Vice President, Regulatory Affairs and Customer Service
	Julie A. Krenz	Assistant Secretary
	Karl A. Liepitz	Assistant Secretary
	Jay Skabo	Vice President, Electric Supply
	Scott W. Madison	Executive Vice President, Western Region Operations, Business Development and Strategy
CENTENNIAL HOLDINGS CAPITAL LLC		
Managers	**Doran N. Schwartz**	
	David L. Goodin	
	Daniel S. Kuntz	
Officers	Alvin J. Feist	Vice President and Treasurer
	David L. Goodin	**Chairman of the Board**
	Daniel S. Kuntz	**General Counsel and Secretary**
	Doran N. Schwartz	**President and Chief Executive Officer**
	Jason L. Vollmer	Assistant Secretary
FUTURESOURCE CAPITAL CORP.		
Directors	**Doran N. Schwartz**	
	David L. Goodin	
	Daniel S. Kuntz	
Officers	Alvin J. Feist	Vice President and Treasurer
	David L. Goodin	**Chairman of the Board**
	Daniel S. Kuntz	**General Counsel and Secretary**
	Doran N. Schwartz	**President and Chief Executive Officer**
	Jason L. Vollmer	Assistant Treasurer
	Julie A. Krenz	Assistant Secretary

Cascade Natural Gas

Cost Allocation Manual

2015

In the Community to Serve®

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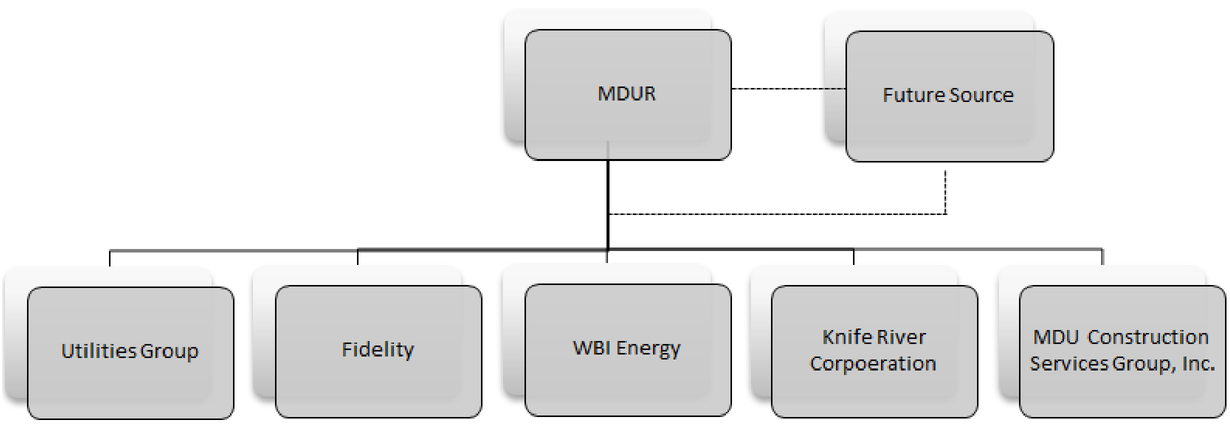
Overview

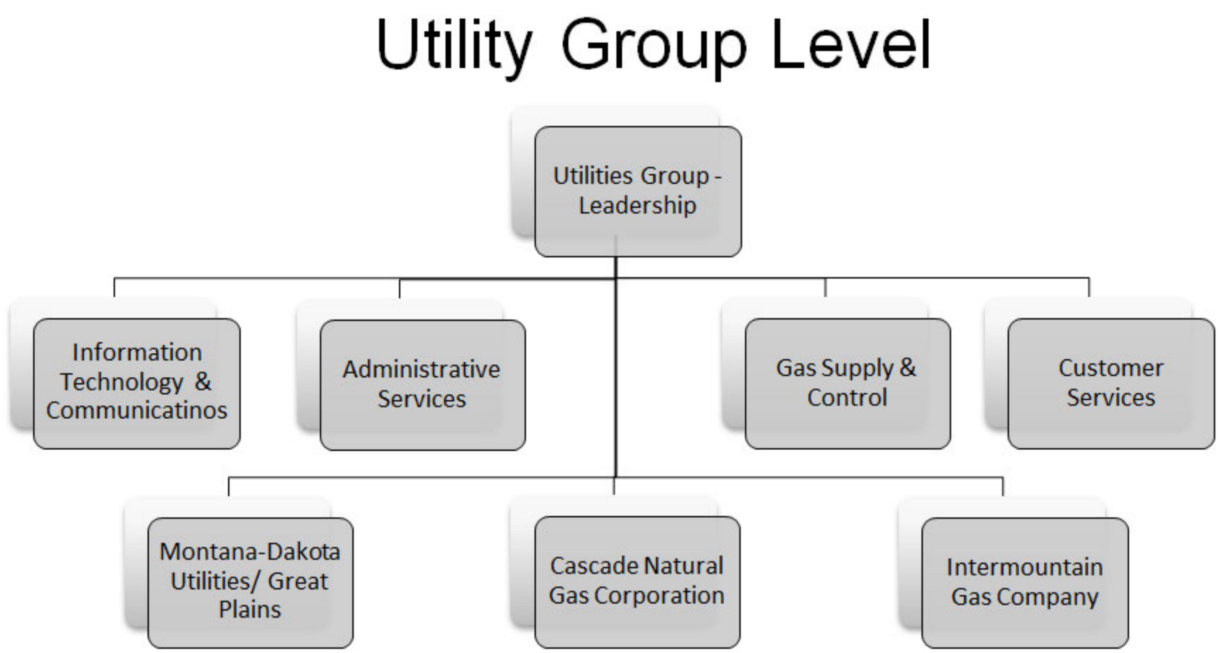
Cascade Natural Gas Corporation (Cascade), a subsidiary of MDU Resources Group, Inc. (MDUR), conducts business in two states with regulated gas distribution operations.

Below is an overview of the operational structure for the purpose of assigning costs. The diagrams presented are intended to provide an overview for cost allocation only and are not intended to represent the legal structure of the Corporation. Note that costs from MDUR and FutureSource are directly assigned or allocated and charged to the operating companies (i.e. Utilities Group, WBI Energy, etc.)

Corporate Level



CASCADE NATURAL GAS CORPORATION



This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to the proper utility and state jurisdiction for Cascade.

This document will discuss the allocations from:

- MDUR and FutureSource to Cascade Natural Gas
- Montana-Dakota/Great Plains (MDU) and Intermountain Gas Company (IGC) to Cascade Natural Gas
- Cascade to MDU and IGC
- State jurisdictions

Overall, the approach to allocating costs at each level is to directly assign costs when applicable and to allocate costs based on the function or driver of the cost.

MDU Resources Group, Inc. (MDUR) Allocations

The MDUR corporate staff consists of shared services departments (payroll, procurement and enterprise technology) and administrative and general departments.

CASCADE NATURAL GAS CORPORATION

Shared Services

MDU Resources Group, Inc. has several departments that provide specific services to the operating companies. These departments have developed a pricing methodology which is updated annually for the allocation of costs to the MDUR operating companies that utilize their services. (See Exhibit III)

These departments include:

Payroll Shared Services

Payroll Shared Services department provides comprehensive payroll services for MDUR companies and employees. It processes payroll in compliance with appropriate federal, state and local tax laws and regulations. Payroll Shared Services is also responsible for preparation, filing and payment of all payroll related federal, state and local tax returns. It also maintains and facilitates payments and accurate reporting to payroll vendors for employee benefits and other payroll deductions. For Cascade, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Cascade does not have any departments that provide these payroll related services.

Procurement Shared Services

Procurement Shared Services creates and maintains the Corporation's national accounts for the purchase of products, goods and services. National accounts take advantage of the combined purchasing power of all of the Corporation's operating companies. National accounts, or preferred vendor agreements, typically are negotiated at the corporate level rather than at the local company level. Procurement Shared Services also is responsible for monitoring the level of services, quantities, discounts and rebates associated with established national accounts. Cascade has a single procurement department that places specific purchase requests for materials and services required to conduct business with approved vendors.

Enterprise Technology Service

Enterprise Technology Services (ETS) provides policy guidance, infrastructure related IT functions and security-focused governance. ETS seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. ETS works to increase the quality and consistency of technology, increase functionality and service to the enterprise, provide governance for managing and controlling risk and reduce costs through economies of scale.

Cascade's IT department consists of Montana-Dakota/Great Plains employees physically located in Kennewick, Washington, Boise, Idaho, and Bismarck, North Dakota. This Department is responsible for supporting applications specific to the utility group such as the Customer Care & Billing System, the JD Edwards financial software, Scada and mobile applications, Enterprise GIS, and PowerPlan which is the project and fixed asset accounting software. In addition the utility group IT department develops business continuity plans in the case of disaster recovery.

General and Administrative Services

Administrative and general functions performed by MDUR for the benefit of the operating companies include the following departments:

- Corporate governance, accounting & planning
- Communications & public affairs
- Human resources
- Internal audit
- Investor relations
- Legal
- Risk management
- Tax and compliance
- Travel
- Treasury services

Cascade receives an allocation of these corporate costs. Corporate Policy No. 50.9 states "*It is the policy of the Company to allocate MDU Resources Group, Inc.'s (MDU) administrative costs and general expenses to the MDU's business units*". Business units described in the policy have been referred to as operating companies in this document. The policy states that costs that directly relate to a business unit will be directly assigned to the applicable business unit and only the remaining unassigned expenses will be allocated to the operating companies using the corporate allocation methodology. The allocation factor developed to apportion MDUR's unassigned administrative costs is a capitalization factor which is based on 12 month average capitalization at March 31, effective July 1 and at September 30, effective January 1 each year. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations). The computation of the Corporate Overhead Allocation Factors is shown in Exhibit I.

Cascade is reflected as CNGC in the Corporate Overhead Allocation Factors in Exhibit I. Operating companies that receive allocated costs on a monthly basis from MDUR include:

- Montana Dakota – Electric utility segment
- Montana Dakota/Great Plains – Gas utility segment
- Cascade Natural Gas Corporation (CNGC)
- Intermountain Gas Company (IGC)
- Fidelity

- WBI Energy Transmission
- WBI Midstream
- Knife River (KR)
- MDU Construction Services Group, Inc.

The corporate costs allocated to Cascade are subsequently allocated to the state jurisdictions. Corporate costs are recorded in the administrative and general (A&G) function for Cascade. (See state jurisdictional allocation discussion on page 8.)

Montana-Dakota/Great Plains Allocation of Cost to/from Others

Allocations to/from other MDUR Companies

Certain Montana-Dakota/Great Plains owned assets, such as the General Office/Annex facility, located at the utility headquarters in Bismarck, and the assets associated with the contribution made for FutureSource assets, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including CNGC and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Intermountain Gas owns the customer care center located in Meridian, ID. To cover the cost of ownership and operating costs associated with that owned asset, a revenue requirement (asset return plus annual operating expenses) is computed similarly to Montana-Dakota owned assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Certain Cascade owned assets, such as the portion of the General Office facility used for Shared Services (i.e. Gas Control, IT), located at the utility headquarters in Kennewick, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including MDU and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Allocations to other Utility Companies

Montana-Dakota/Great Plains has several departments that provide services to all four utility operating companies (Montana-Dakota, Great Plains, Cascade Natural Gas Co. and Intermountain Gas Company). These departments include:

- Leadership Group - composed of the Executive Group and Directors that oversee shared utility specific functions
- Customer Services - (Call Center, Scheduling and Online Services)
- Information Technology and Communications- (Management Information Systems, Technology and Compliance)
- Administrative Services - (Procurement, Office Services, Fleet Operations)
- Gas Supply & Control

These operational groups have calculated the proper allocation to use to allocate the costs to the utility companies based on services performed for each utility company. The allocation methodology is included in Exhibit IV.

Standard Labor Distributions

Labor/Reimbursable expense allocations

The development of standard labor distributions for Cascade employees is described below based on the type of employee. Standard labor distributions are used for all employees to account for certain expenses as detailed below.

Labor, benefit costs and reimbursable expenses are directly assigned to a jurisdiction where possible. If the expense is not direct, the appropriate jurisdiction is charged as follows:

Union Employees

Time tickets are required for productive time. The employee specifies the proper location and FERC account based on work performed. To account for non-productive time, standard payroll labor distributions are established for all employees. These standard labor distributions are calculated for union employees based on the historical actual charges.

Non-Union Employees

Non-union employees are not required to submit detailed time tickets with applicable general ledger accounts specified. Rather each employee has a “standard” set of general ledger accounts that split the labor costs based on an expected ratio of work. This split can be unique and is based on the employee's position. Costs are distributed based on this standard labor distribution for each employee, and the allocations are reviewed periodically.

Cascade Allocations to State Jurisdictions

Cascade utilizes an automated allocation process each month to record the income statement and rate base account activity to the financial ledger (state jurisdiction) to facilitate regulatory reporting. This process is based on the general ledger account structure used in the financial software (JD Edwards). As with other items, costs are directly assigned to a jurisdiction when possible. Costs common to more than one state jurisdiction are allocated between jurisdictions. The primary driver of the allocation is the Business Unit component of the general ledger account; however, the FERC account associated with the charge is also used to determine the proper allocation method. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Cascade for recording financial transactions as well as the jurisdictional allocation process for all accounts except those related to fixed assets.

The account structure within JDE consists of the following components:

Business Unit **-** The Business Unit is one of the primary components used for identifying the regulatory allocation of costs. It usually defines a location such as an operating region, operating district or facility (i.e. gas regulator station), or department (i.e. human resources, engineering).

Object **–** The object for operations and maintenance (O&M) expense accounts represents the resource consumed (i.e. payroll or materials). For balance sheet accounts, the object represents the FERC account.

Subsidiary **–** The subsidiary portion of the account for O&M accounts identifies the utility segment (2 represents gas) and the FERC account. For balance sheet accounts the subsidiary represents a further breakdown of the account such as which bank for a cash account.

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Revenue Accounts – Revenues are directly assigned to the jurisdiction when possible. The applicable FERC account is part of the account structure. It is the combination of the business unit, and FERC that drive the allocation factor used. An example of revenue that is allocated to the jurisdictions is revenue from the cost of service calculation which is assigned an allocable location (Business Unit).

Operation and Maintenance (O&M) accounts – As costs are incurred, the approver of the expense assigns the general ledger account structure.

It is the combination of the location (Business Unit), and FERC that drive the allocation factor utilized. Locations are assigned a factor based on the geographic area for which they serve and the FERC function assigned. For example, location (Business Unit) 47041 represents the geographic location of the Bend, Oregon District. The Bend District is therefore directly assigned to Oregon for all FERC accounts.

Another example is location 4767000, representing the Credit and Collections Department. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department. An allocation code is used to split the costs between the states. The most common allocation factor is the 3-factor formula (customer, employee and plant). However, the customer ratio, employee ratio, gross plant ratio, and rate base ratio are also used. See Exhibit II for the allocation factor calculations.

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*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00047	47041		2870	29359999	200601	203512	Central OR District	00002	2	00038
00047	47041		4261	42659999	201208	203512	Bend District-BTL	00002	2	00038
00047	47041	4081	0	99999999	200601	203512	Central OR District-4081	00002	2	00038
00047	47041	5981	4261	4261	200902	201207	Central OR District	00002	2	00038
00047	47041	5984	4263	4263	201111	201207	OR 5984	00002	2	00038

Code 00038 = 100% allocated to Oregon

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00047	4767000		0000	99999	201101	203512	Customer Service Allocated C...	00002	2	00100
00047	4767000	5211	4264	4264	201101	203512	Labor Rel & Comp	00002	2	00100
00047	4767000	5984	4263	4263	201108	203512	Corporate 5984	00002	2	00100

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00047	47042		2870	29359999	200601	203512	Pendleton District	00002	2	00038
00047	47042		4261	42659999	200601	203512	Pendleton District-BTL	00002	2	00038
00047	47042	4081	0	9999999	200601	203512	Pendleton District-4081	00002	2	00038

Allocation Code 01 Represents the code used to allocate to a Jurisdiction
00038 = Oregon
00048 = Washington
00100 = 3 Factor Formula (customer, employee, plant)
00101 = Customer Ratio
00102 = Employee Ratio
00103 = Gross Plant Ratio

Co	Juris Alloc Code	Juris Start Date	Juris Stop Date	Description 10	State 01	Percent 01	State 02	Percent 02
00047	00100	201501	201512	3 Factor formula -(customer, employee, plant)	OR	24.270000	WA	75.730000
00047	00101	201501	201512	Customer Ratio	OR	24.940000	WA	75.060000
00047	00102	201501	201512	Employee Ratio	OR	25.440000	WA	74.560000
00047	00103	201501	201512	Gross Plant Ratio	OR	22.420000	WA	77.580000
00047	00104	201501	201512	Rate Base Ratio	OR	23.540000	WA	76.460000

Exhibit I- MDUR Corporate Overhead factor

CASCADE NATURAL GAS CORPORATION

MDU Resources Group Inc.
Corporate Overhead Allocation Factors
January- June 2015

	MDU Electric	MDU/GP Gas	CNGC	IGC	WBI Energy	Fidelity	WBI Non-Regulated	KR	CSG
MDUR corporate factor	10.6%	7.9%	10.4%	6.9%	5.6%	26.9%	4.9%	20.2%	6.6%

	Utilities	WBI Holdings				Construction	
	Group	Transmission	Fidelity	Other	Knife River	Services	Total
Debt and Equity							
Short-term borrowings	$4,725,000						$4,725,000
LTD due within one year	17,881,342	$1,266,056	$6,120,496	$1,110,555	$14,749,607	$5,013,969	46,142,025
Long-term debt	820,826,670	119,857,876	579,428,942	105,136,553	364,144,141	76,620,712	2,066,014,894
Total Debt	**843,433,012**	**121,123,932**	**585,549,438**	**106,247,108**	**378,893,748**	**81,634,681**	**2,116,881,919**
Stockholders' equity:							
Preferred stock	**15,000,000**						**15,000,000**
Common stock	191,925,108	149	720	131	800,000	1,000	192,727,108
Other paid-in capital	1,521,081,527	97,970,621	473,619,385	85,937,560	485,948,676	134,430,866	2,798,988,636
Retained earnings	1,674,807,588	56,537,562	273,319,542	49,593,440	149,530,017	110,166,923	2,313,955,072
Accumulated other comprehensive loss	(40,827,124)	(2,185,717)	(10,566,414)	(1,917,261)	(19,404,583)	(2,153,395)	(77,054,494)
Treasury stock	(3,625,813)						(3,625,813)
Total common stockholders' equity	**3,343,361,287**	**152,322,614**	**736,373,233**	**133,613,870**	**616,874,110**	**242,445,394**	**5,224,990,509**
Total stockholders' equity	**3,358,361,287**	**152,322,614**	**736,373,233**	**133,613,870**	**616,874,110**	**242,445,394**	**5,239,990,509**
Total liabilities and stockholders' equity	**4,201,794,299**	**273,446,546**	**1,321,922,671**	**239,860,979**	**995,767,858**	**324,080,075**	**7,356,872,429**
Investment in Subsidiaries	2,447,121,024						2,447,121,024
Capitalization	**$1,754,673,276**	**$273,446,546**	**$1,321,922,671**	**$239,860,979**	**$995,767,858**	**$324,080,075**	**$4,909,751,405**
	35.8%	5.6%	26.9%	4.9%	20.2%	6.6%	100.0%

	2014 Year End Capitalization	Share of Corp. Allocation	Corporate Allocation	Electric	Gas
Montana-Dakota 1/	$952,540	51.7%	18.5%	10.6%	7.9%
Cascade	537,073	29.1%	10.4%		10.4%
Intermountain	353,195	19.2%	6.9%		6.9%
Total Utilities Group	$1,842,808	100.0%	35.8%	10.6%	25.2%

1/ Electric and gas segments allocated on Montana-Dakota's Corporate Overhead Factor

CASCADE NATURAL GAS CORPORATION

Exhibit II- Cascade Allocation Factors

Cascade Natural Gas Corportation
CY 2014 Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2014

	Washington	Oregon	Total
Customers	75.06%	24.94%	100.00%
Employees	74.56%	25.44%	100.00%
Gross Plant	77.58%	22.42%	100.00%
3-Factor Formul	75.73%	24.27%	100.00%
Rate Base Ratio	76.46%	23.54%	100.00%

Cascade Natural Gas Corporation
Average No. of Employees
2014

Source: Customers Per Employee rep	Mo-Yr	Washington District Employees (1)	Oregon District Employees (1)	
	Dec-13	154	56	
	Jan-14	165	56	
	Feb-14	165	56	
	Mar-14	166	56	
	Apr-14	166	57	
	May-14	170	57	
	Jun-14	174	58	
	Jul-14	174	60	
	Aug-14	169	57	
	Sep-14	172	58	
	Oct-14	167	59	
	Nov-14	168	59	
	Dec-14	169	55	
		2,179	744	
Average of Monthly Averages		168	57	226
	Percentage	74.56%	25.44%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2014

	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	607,126,362	175,487,064	782,613,426
Percentage	77.58%	22.42%	100.00%

Cascade Natural Gas Corporation
Average Number of Customers
2014

	Average No. of Customers	Percentage
Washington	202,195	75.06%
Oregon	67,182	24.94%
Total	269,377	100.00%

Cascade Natural Gas Corporation
Rate Base Ratio
2014

The following percentages are used for allocating interest on debt:

	2014 Average Rate Base	Plant Formula
Washington	228,079,689	76.46%
Oregon	70,217,372	23.54%
	298,297,061	100.00%

CASCADE NATURAL GAS CORPORATION

Exhibit III- MDUR Shared Services Pricing Methodology

MDU Resources Shared Services
Pricing Methodology - Effective for 2015

Note: MDU Resources' use of Shared Services – MDU Resources costs for each shared services function is charged based on the corporate allocation factor.

761 – Payroll Shared Services:

Payroll Shared Services costs are invoiced based on the number of employees paid and stated as a cost per check. The word check, for this purpose, generically refers to paper paychecks, direct deposits and paycard transactions.

Checks are charged on a tiered structure, intended to recognize the fixed or baseline effort associated with maintaining a payroll cycle and associated reporting, regardless of number of people paid. It is also intended to reward consolidation of multiple pay groups and companies where possible and to align charges with the additional effort required to maintain multiple pay groups and pay cycles.

The monthly volume for this step pricing is accumulated individually for each pay cycle processed.

Checks for weekly pay cycles, cost per check based on the number of checks written per month:
$ 4.25 per check for the first 500 checks
$ 0.75 per check for the next 500 checks
$ 0.00 per check for each additional check

Checks for non-weekly pay cycles, cost per check based on the number of checks written per month:
$ 4.25 per check for the first 1000 checks
$ 0.75 per check for the next 1000 checks
$ 0.00 per check for each additional check

Additionally, there will be a $3.00 charge for each tax payment and $240.00 charge for each quarterly tax filing

There is a $500 per month minimum charge for each operating company.

There is a premium charge of $50 per transaction for specific off cycle checks and back-pay calculations. Examples of transactions included in the premium charge schedule are missing hours, refunded deductions, length of service awards submitted too late for inclusion in a scheduled payroll process, and back pay calculation because an increase was submitted after the pay period that includes the effective date. Examples of transactions excluded from the premium charge calculation are bonus payments, final paychecks, certified wage settlements, or any payment required as a result of a Shared Service or system error.

762 –Procurement Shared Services:
Procurement Shared Services costs are invoiced based on five separate factors, all carrying an equal weight of 20%. The factors are:

- Number of Visa Cards as of 8/1/14
- Total Visa Spend for 2013
- National Account Spend for 2013
- Number of Construction Equipment Acquisitions in 2013
- Number of Fleet Acquisitions in 2013

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IMG	Total
# VISA cards	141	805	364	155	845	659	282	88	3,339
% of VISA cards	4.22%	24.11%	10.90%	4.64%	25.31%	19.74%	8.45%	2.64%	100%
VISA spend	2,158,498	6,589,113	3,337,060	1,464,610	9,190,014	7,644,519	2,984,759	1,567,358	34,935,930
% of Total VISA spend	6.18%	18.86%	9.55%	4.19%	26.31%	21.88%	8.54%	4.49%	100%
National Account Spend	2,026,585	3,244,617	1,831,527	79,372	20,683,247	13,945,478	1,255,335	888,731	43,954,891
% of National Account Spend	4.61%	7.38%	4.17%	0.18%	47.06%	31.73%	2.86%	2.02%	100%

CASCADE NATURAL GAS CORPORATION

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IMG	Total
# Construction Equip Acquisitions	0	55	8	2	87	40	14	7	213
% of Construction Equip Acquisitions	0.00%	25.82%	3.76%	0.94%	40.85%	18.78%	6.57%	3.29%	100%
# Fleet Acquisitions	0	43	35	11	189	232	43	19	572
% of Fleet Acquisitions	0.00%	7.52%	6.12%	1.92%	33.04%	40.56%	7.52%	3.32%	100%
Total weighted allocation factor	3.00%	16.74%	6.90%	2.37%	34.51%	26.54%	6.79%	3.15%	100.00%

766 –Time Entry Shared Services:

Service provided 100% to the MDU Utility Group.

767 –Accounts Payable Shared Services:

Accounts Payable Shared Services costs are invoiced based on three factors:

- Number of payments processed based on activity from 7/1/13 through 6/30/14 (25%)
- Number of vouchers processed by AP Shared Services staff based on activity from 7/1/13 through 6/30/14 (75%)

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IGC	Total
# of Payments	2556	52880	0	0	0	1522	27126	26222	110,306
% of payments	2.32%	47.94%	0.00%	0.00%	0.00%	1.38%	24.59%	23.77%	100%
# of Vouchers	3,046	11,879	0	0	0	1,389	1,333	1,246	18,893
% of vouchers	16.12%	62.88%	0.00%	0.00%	0.00%	7.35%	7.06%	6.60%	100%
Totals	12.7%	59.1%	0.0%	0.0%	0.0%	5.9%	11.4%	10.9%	100.00%

Enterprise Technology Services (ETS):

There are several ETS departments, and each is billed out based on its own criteria. They are as follows:

Application Services (765) 100% of these costs are based on the corporate factor.

Customer Relations (965) – Two factors are used in the invoicing of the enterprise costs associated with customer relations. 85.8% of the costs are associated with the help desk. Those costs are invoiced based upon the number of devices supported by customer relations. The metric used to determine device counts is devices that have checked into active directory during a 60 day period in the summer of 2014. The remaining 14.2% of the costs are for costs specific to the AS/400 are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IMG	Total
Device Counts	287	1,080	460	313	1,820	1305	432	626	6,323
% of Device Counts	4.54%	17.08%	7.28%	4.95%	28.78%	20.64%	6.83%	9.90%	100%
Totals	4.54%	17.08%	7.28%	4.95%	28.78%	20.64%	6.83%	9.90%	100.00%

CASCADE NATURAL GAS CORPORATION

Communications & Security (971) – Now includes 977.

Enterprise charges for the communications group are invoiced using three separate factors. They and their estimated % of work are:

1. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (20%)
2. Internet/Security – Number of user accounts (30%)
3. Handsets – Number of IP devices(50%)

Each of these three areas is assigned a percentage (identified above). Those portions of the costs are invoiced via the above identified denominators.

For 2014 the costs are invoiced based on the following percentages:

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IMG	Total
WAN/LAN/MAN	2	40	100	8	190	59	18	13	430
% of Business Unit Locations	0.47%	9.30%	23.26%	1.86%	44.19%	13.72%	4.19%	3.02%	100%
Internet Access/Firewall	287	1080	460	313	1820	1305	432	626	6323
% of User Accounts	4.54%	17.08%	7.28%	4.95%	28.78%	20.64%	6.83%	9.90%	100%
Security									
% of Handsets	16.50%	16.70%	16.70%	16.70%	16.70%	16.70%	0.00%	0.00%	100%
Totals	9.70%	15.33%	15.19%	10.21%	25.82%	17.29%	2.89%	3.57%	100.00%

Operations (972) – Enterprise costs for the operations group are invoiced based upon the number of servers that are supported for a particular business unit.

For 2014 the costs are invoiced based on the following percentages:

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IMG	Total
Full Service Servers	178	147	85	64	196	104	33	90	897
% of Full Service Servers	19.84%	16.39%	9.48%	7.13%	21.85%	11.59%	3.68%	10.03%	100%
Totals	19.84%	16.39%	9.48%	7.13%	21.85%	11.59%	3.68%	10.03%	100%

Security (977) – This is now included in 971.

Finance and Administration (982) –. Costs for the finance and administration group are invoiced based upon the combined methodologies of the four previously identified ETS groups.

	MDUR	MDU	WBIE	FEPC	KRC	CSG	CNG	IMG	Total
% of Total Finance & Administration	21.32%	14.35%	11.24 %	7.29%	22.70%	13.78%	3.49%	5.83%	100%

Exhibit IV- Utility Operations Support Allocation Methodology

Utility Operations Support
Labor Distribution Allocation Methodology

Leadership Group:

- Includes Executive Vice Presidents & Directors
- Oversees all shared, utility specific functions in the following areas:
  - Customer Services
  - Administrative Services
  - Information Technology & Communications
  - Engineering and Operations Procedures
  - Gas Supply and Gas Control
- Allocation methodology:
  - Equal portion allocated to each utility company, or brand
  - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for Great Plains) to non-utility based on historical estimates, with remainder allocated to gas and electric based on meter count.
  - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocate between gas and electric based on meter count.

Customer Services:

- Director
  - 35% to CNG, 30% to IGC, 35% Montana-Dakota/Great Plains [1] (1% to non-utility) and remainder split between gas and electric meter count.
- Management team
  - Supervisors: Front line supervision for Customer Service Center
    - 30% to CNG, 30% to IGC, 40% Montana-Dakota/Great Plains [1] (2% to non-utility) and remainder allocated to gas and electric based on the estimate of time required to supervise
  - Manager: Customer service
    - 30% CNG, 20% IGC, 50% Montana-Dakota/Great Plains [1] (2% to non –utility) and remainder allocated to gas and electric meter count.
- Credit
  - Responsible for credit and collections for the Utility Group
  - Allocation Methodology
    - Most agents only handle credit activity for one brand, they charge all time to that brand
    - For agents that handle multiple brands, time is charged based on how much time is spent on each brand

____

[1] Based on estimated time using history

        - For agents that only handle credit activity for Montana-Dakota/Great Plains:
            - Allocated to gas and electric based on meter count

          For agents that handle credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on average time spent in each utility with the Montana-Dakota/Great Plains portion allocated to gas and electric based on meter count.

- Scheduling
    - Responsible for scheduling field work for employees performing work in the field for the Utility Group
    - Responsible for emergency response 24/7
    - Allocation Methodology:
    - Management team:
        - Manager 20% IGC, 30% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
        - Team Leads 25% IGC, 25% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
        - For employees that only schedule one brand, charge time to that brand
        - For employees that schedule both IGC and CNG, split time 50/50 based on estimated time required
        - For employees who schedule all brands, split evenly
        - For employees that only schedule Montana-Dakota/Great Plains:
            - Allocated between gas and electric based on meter count
        - For employees that schedule credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on the shared utility. The Montana-Dakota/Great Plains allocation is based on the gas and electric meter count.

- Customer Service
    - Responsible for handling all inbound calls during regular operating hours
    - Allocation Methodology:
        - Teams leads and Customer Care Representatives (CCR's) when only responsible for one brand, charge all that time to one brand
        - For employees covering multiple brands, estimates are routinely made for allocations for the pay period
        - For employees responsible for Montana-Dakota/Great Plains:
            - 3% (including 0.5% for Great Plains) is charged to non-utility for credit activity associated with non-utility charges, based on best estimate of time required
            - Remainder is allocated between gas and electric based on meter count

        - For employees responsible for Montana-Dakota/Great Plains and another brand, the portion allocated to non-utility is reduced accordingly to 3% (including 0.5% for Great Plains) of the total associated with Montana-Dakota/Great Plains.

- Customer Programs & Support
    - Responsible for inbound self-service, web help, customer program transactions, and analytical support for the Utility Group
    - Allocation Methodology:
    - Manager
        - 30% IGC, 30% CNG, 40% Montana-Dakota/Great Plains[1] (allocate to gas and electric based on meter count)
            - Based on additional time for Montana-Dakota/Great Plains on social media updates & Credit Dept. responsibilities
    - Supervisor, Team Lead, and Support Staff
        - Equal portion allocated to each brand
        - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for GPNG) to non-utility, based on historical estimates, with remainder allocated to gas and electric based on meter count.
        - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocated to gas and electric based on meter count.

- Note: Exceptions may be made on an individual basis from these guidelines
    - Employees may be assigned special projects, and allocation methodology may be changed accordingly.
    - Labor allocation may always be made on an actual time spent basis rather than these guidelines.
    - Supervisors may alter these guidelines based on their individual scenario.

CASE: UG 305
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

Exhibits in Support
Of Opening Testimony

August 11, 2016

MDU RESOURCES GROUP, INC.
List of Subsidiaries
(effective December 31, 2015)

Subsidiaries	Jurisdiction of Formation
1250 Gladding Road, LLC	Delaware
Alaska Basic Industries, Inc.	Alaska
Ames Sand & Gravel, Inc.	North Dakota
Anchorage Sand and Gravel Company, Inc.	Alaska
Baldwin Contracting Company, Inc.	California
BEH Electric Holdings, LLC	Nevada
Bell Electrical Contractors, Inc.	Missouri
BMH Mechanical Holdings, LLC	Nevada
Bombard Electric, LLC	Nevada
Bombard Mechanical, LLC	Nevada
Capital Electric Construction Company, Inc.	Kansas
Capital Electric Line Builders, Inc.	Kansas
Cascade Natural Gas Corporation	Washington
Centennial Energy Holdings, Inc.	Delaware
Centennial Energy Resources International, Inc.	Delaware
Centennial Energy Resources LLC	Delaware
Centennial Holdings Capital LLC	Delaware
Central Oregon Redi-Mix, LLC	Oregon
CGC Resources, Inc.	Washington
Concrete, Inc.	California
Connolly-Pacific Co.	California
Continental Line Builders, Inc.	Delaware
Coordinating and Planning Services, Inc.	Delaware
D S S Company	California
Desert Fire Holdings, Inc.	Nevada
Desert Fire Protection, a Nevada Limited Partnership	Nevada
Desert Fire Protection, Inc.	Nevada
Desert Fire Protection, LLC	Nevada
Duro Electric, LLC	Delaware
E.S.I., Inc.	Ohio
Fairbanks Materials, Inc.	Alaska
Fidelity Exploration & Production Company	Delaware
Fidelity Oil Co.	Delaware
Frebco, Inc.	Ohio
FutureSource Capital Corp.	Delaware
Granite City Ready Mix, Inc.	Minnesota
Hamlin Electric Company	Colorado
Harp Engineering, Inc.	Montana

Hawaiian Cement, a partnership	Hawaii
ILB Hawaii, Inc.	Hawaii
Independent Fire Fabricators, LLC	Nevada
Intermountain Gas Company	Idaho
International Line Builders, Inc.	Delaware
InterSource Insurance Company	Vermont
Jebro Incorporated	Iowa
JTL Group, Inc. (Montana corporation)	Montana
JTL Group, Inc. (Wyoming corporation)	Wyoming
Kent's Oil Service	California
Knife River Corporation	Delaware
Knife River Corporation – North Central	Minnesota
Knife River Corporation – Northwest	Oregon
Knife River Corporation – South	Texas
Knife River Dakota, Inc.	Delaware
Knife River Hawaii, Inc.	Delaware
Knife River Marine, Inc.	Delaware
Knife River Midwest, LLC	Delaware
KRC Holdings, Inc.	Delaware
LME&U Holdings, LLC	Nevada
Lone Mountain Excavation & Utilities, LLC	Nevada
Loy Clark Pipeline Co.	Oregon
LTM, Incorporated	Oregon
MAAK Holdings, Inc.	Nevada
MDU Brasil Ltda.	Brazil
MDU Construction Services Group, Inc.	Delaware
MDU Energy Capital, LLC	Delaware
MDU Holdings, LLC	Delaware
MDU Industrial Services, Inc.	Delaware
MDU Resources International LLC	Delaware
MDU Resources Luxembourg I LLC S.a.r.l.	Luxembourg
MDU Resources Luxembourg II LLC S.a.r.l.	Luxembourg
MDU United Construction Solutions, Inc.	Delaware
Midland Technical Crafts, Inc.	Delaware
Nevada Solar Solutions, LLC	Delaware
Nevada Valley Solar Solutions I, LLC	Delaware
Nevada Valley Solar Solutions II, LLC	Delaware
Northstar Materials, Inc.	Minnesota
On Electric Group, Inc.	Oregon
Pouk & Steinle, Inc.	California
Prairie Cascade Energy Holdings, LLC	Delaware
Prairie Intermountain Energy Holdings, LLC	Delaware
Prairielands Energy Marketing, Inc.	Delaware
Rocky Mountain Contractors, Inc.	Montana
USI Industrial Services, Inc.	Delaware
Wagner Group, Inc., The	Delaware

Wagner Industrial Electric, Inc.	Delaware
Wagner-Smith Company, The	Ohio
Wagner-Smith Equipment Co.	Delaware
Wagner-Smith Pumps & Systems, Inc.	Ohio
WBI Canadian Pipeline, Ltd.	Canada
WBI Energy Midstream, LLC	Colorado
WBI Energy Services, Inc.	Delaware
WBI Energy Transmission, Inc.	Delaware
WBI Energy Wind Ridge Pipeline, LLC	Delaware
WBI Energy, Inc.	Delaware
WBI Holdings, Inc.	Delaware
WHC, Ltd.	Hawaii

CASE: UG 305
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1004

Exhibits in Support
Of Opening Testimony

August 11, 2016

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

CASE: UG 305
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1005

Exhibits in Support
Of Opening Testimony

August 11, 2016

Customer Service Allocation Adjustment

	Affiliate Total	Company Factor	Company Allocation	Staff Factor	Staff Allocation	Allocation Adj	Disallowance	Total Adj	Oregon Allocated
Credit and Collections	$ 1,636,353	29.1%	$ 476,417	25.6%	$ 418,360	$ (58,057)			
Customer Services, Dir	$ 1,678,418	37.6%	$ 631,294	25.6%	$ 429,115	$ (202,180)			
Meridian-Cust Svc Ctr	$ 6,220,883	32.4%	$ 2,017,506	25.6%	$ 1,590,468	$ (427,038)			
Customer Development/Programs	$ 1,331,892	32.0%	$ 426,424	25.6%	$ 340,520	$ (85,905)			
								$ (773,180)	**$ (191,130)**
General Overhead Allocation Adjustment									
MDUR General Overhead to CNGC	$ 26,416,450	10.5%	$ 2,784,836	6.9%	$ 1,833,457	$ (951,379)		**$ (951,379)**	**$ (235,181)**
Excluded Expenses									
MDUR General Overhead to CNGC		-	-	6.9%	$ 1,833,457				
No Description							$ (234,201)	**$ (234,201)**	**$ (57,894)**
Non-utility expense							$ (282,829)		
MDU Allocated Costs	$ 12,833,345	18.9%	$ 2,422,548	18.9%	$ 2,422,548		$ (15,006)		
IGC Allocated Costs	$ 3,978,482	13.9%	$ 552,534	13.9%	$ 552,534		$ (36,935)		
								$ (334,770)	**$ (82,755)**

CASE: UG 305
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Judy Johnson. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to investigate and make recommendations for Cascade Natural Gas Company's (Cascade or Company) Environmental Remediation Costs and to review any proposals for recovery of Pipeline Safety Costs.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1101, Witness Qualification Statement; Exhibit Staff/1102, Company Response to DR Nos. 333 and 335; and Exhibit Staff/1103, Company Response to DR No. 159.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Environmental Remediation Costs 2
Issue 2. Pipeline Safety Costs 9

ISSUE 1. ENVIRONMENTAL REMEDIATION COSTS

Q. Why does Cascade have Environmental Remediation Costs?

A. Cascade has incurred and continues to incur environmental remediation costs associated with the former Manufactured Gas Plant (MGP) in Eugene, Oregon[1] that the Company and its predecessor, Northwest Cities Gas Company (Northwest Cities), owned from 1929-1958.

Q. Please discuss the history of ownership of the Eugene MPG.

A. The Eugene MGP was constructed around 1907 by the Willamette Valley Company as a coal carbonization facility with a high pressure distribution system serving the City of Eugene.[2] In May of 1910, the Eugene plant was sold to Northern Idaho and Montana Power Company (which later organized the Oregon Power Company).[3] The new owner converted the plant into a modern water-gas plant, changed the high pressure system to a low pressure system, and began serving the City of Springfield by 1911.[4] In July of 1918, the property was sold to Mountain States Power Company (a PacifiCorp predecessor), and was serving 1769 gas customers in Eugene.[5]

In June of 1929, Mountain States Power Company, through an intermediary, Union Utilities Company, Inc., sold the MGP and underlying

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[1] Staff/1102, Company Response to Staff DR No. 335.
[2] Records: History of Natural Gas in Oregon, "Eugene-Springfield Gas Systems" Appendix D at 1, available at Oregon State Archives, Salem, OR; Records: History of Natural Gas in Oregon, "Eugene" Appendix A at 2, available at Oregon State Archives, Salem, OR.
[3] "Eugene-Springfield Gas Systems" Appendix D at 1.
[4] "Eugene-Springfield Gas Systems" Appendix D at 1; "Eugene" Appendix A at 3.
[5] "Eugene-Springfield Gas Systems" Appendix D at 2.

property to Northwest Cities.[6] In 1943, Northwest Cities was reorganized through Chapter 77-B bankruptcy proceedings, and in 1950, the Eugene plant was converted to a propane-air gas system for distribution and storage.[7]

Cascade was incorporated in January of 1953 with the intent to merge with several small liquefied-air gas systems, including those owned by Northwest Cities, in anticipation of the arrival of natural gas.[8] Thus, in January of 1953, Cascade merged with Northwest Cities (merger complete in 1954). Northwest Cities' application for approval of a merger with Cascade stated that the purpose of the merger was for Cascade to acquire stock or assets in "operating gas utility companies . . . and the ultimate creation of a large integrated operating gas utility."[9]

In 1958, Cascade sold the Eugene plant and property to Northwest Natural Gas Company (Northwest Natural).[10] In 1960, Northwest Natural converted the plant into a natural gas plant.[11] Eugene Water & Electric Board (EWEB) eventually purchased the plant and property in 1976.[12] EWEB, PacifiCorp, and Cascade entered into a participation agreement for site investigation on

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[6] Docket No. UF 946, Order No. 7232 at 2 (Mar. 5, 1940); "Eugene-Springfield Gas Systems" Appendix D at 3.
[7] Docket No. UF 946, Order No. 7232 at 1 (Mar. 5, 1940); "Eugene" Appendix A at 5.
[8] "Eugene-Springfield Gas Systems" Appendix D at 5; Records: History of Natural Gas in Oregon, "Cascade Natural Gas Corporation" at 1, available at Oregon State Archives, Salem, OR.
[9] "Eugene-Springfield Gas Systems" Appendix D at 5.
[10] "Eugene-Springfield Gas Systems" Appendix D at 6.
[11] "Eugene" Appendix A at 5; "Eugene-Springfield Gas Systems" Appendix D at 6.
[12] George Kramer, M.S., H.P, EWEB's Standby Steam Plant at 2 n.1 (2012).

February of 1996. Currently, EWEB and the University of Oregon own the contaminated property at issue.[13]

Q. Did you locate any historical Commission orders or other evidence that the Eugene MPG owned and operated by Cascade or its predecessor provided service and benefits to Oregon customers?

A. Yes. I examined documents held by the Oregon State Archives (Archives) for evidence that the Eugene MGP served Oregon customers. As discussed above, the MPG facility opened in approximately 1907 and was owned by a PacifiCorp predecessor until it was sold in 1929 to Northwest Cities. In June of 1915, prior to the sale to Northwest Cities, PacifiCorp's predecessor had installed 33.9 miles of main and provided service to 934 meters and 659 pre-pay meters in the Eugene area.[14]

Historical orders show that Northwest Cities was a public utility regulated by the PUC and a predecessor of Cascade.[15] Specifically, Order No. 7232 notes that Northwest Cities is "a public utility . . . and is authorized to carry on a public utility business in the State of Oregon and presently owns and operates plants and systems for the manufacture and distribution of artificial and/or butane gas for domestic and commercial use in Eugene."[16] Historical records held in at Archives also confirm the time period of Northwest Cities' ownership of the facility: "The Eugene-Springfield gas properties were operated by

[13] Oregon Department of Environmental Quality, Record of Decision Eugene Manufactured Gas Plant (former) Cul-de-sac Portion (Jan. 21, 2015).
[14] "Eugene-Springfield Gas Systems" Appendix D at 2.
[15] Docket No. UF 946, Order No. 7232 (Mar. 5, 1940)(reorganization and issuance of stock); Docket No. UF 804, Order No. 5123 at 1 (1937)(authorization to transact with affiliated interest); Docket No. UF 712, Order No. 3254 at 1 (1936)(issuance of notes); "Cascade Natural Gas Corporation" at 1.
[16] Docket No. UF 946, Order No. 7232 at 2 (Mar. 5, 1940).

Northwest Cities Gas Company from the time of its acquisition in 1929, to 1954, when the company merged with Cascade Natural Gas Company."[17] Order No. 7232 also indicates that Northwest Cities was selling gas to customers, for example, the order records the operating income of $341,595.33 for "Manufactured Gas Sales" for the "12 Months Ended Sept. 30, 1939 ACTUAL."[18] By the time the Northwest Cities' merger with Cascade was complete in 1954, "all cities served by Northwest [Cities] were on a propane-air basis of operation.[19] In the spring of 1955, Cascade hired the Fish Service and Management Corporation to determine if the then existing manufactured and propane-air systems could be converted to natural gas.[20]

On May 7, 1958, Cascade signed an agreement for sale of its Eugene-Springfield gas properties to Northwest Natural Gas Company; "[t]he purchase price was $310,000 for all properties, less the amount of customer deposits, plus accounts receivable, materials and supplies."[21] The transaction was completed on July 28, 1958.[22] Although by 1959, Northwest Natural was the owner of the Eugene MGP, a report states that 1705 customers were being served at an annual sales volume of 17,874,943 therms for total Eugene-Springfield sales revenue of $1, 072,018.[23] Based on the information gained from the historical records and commission orders discussed above, Staff

[17] Docket No. UF 712, Order No. 3254 (Mar. 13, 1936); "Eugene" Appendix A at 5.
[18] Docket No. UF 946, Order No. 7232 at 6 (Mar. 5, 1940).
[19] "Cascade Natural Gas Corporation" at 2.
[20] "Cascade Natural Gas Corporation" at 4.
[21] "Eugene-Springfield Gas Systems" Appendix D at 6.
[22] "Cascade Natural Gas Corporation" at 5.
[23] *Id.*

concludes that the Eugene MPG was owned by Cascade from 1929-1958 and was providing benefits to Oregon customers.

Q. How has Cascade accounted for its Environmental Remediation Costs to date?

A. Cascade has asked for and received permission to defer these costs since 2012.

Q. Please explain the types of costs Cascade has experienced since 2012.

A. The Company's response to Staff Data Request No. 333 shows three categories of costs, including DEQ Fees, Interim Remediation, and Legal Fees, as well as a category for Insurance Proceeds.[24] The Company's response shows a net balance of environmental remediation-related expenses of $154,573 at the end of 2015, which includes insurance proceeds netted against the costs. Additionally, Cascade expects the balance at the end of 2016 to be approximately $190,310, net of insurance proceeds.

Q. What is Staff's recommendation with regard to the Company's Environmental Remediation Costs associated with the Eugene MGP?

A. Staff recommends that the Company amortize its costs in the UM 1636 deferral that have accumulated through December 31, 2016 when the new rates that result from this rate case go into effect in March of 2016.

Q. Why is Staff making this recommendation?

A. Staff has gained considerable experience with environmental remediation costs from past NW Natural environmental remediation-related dockets. Staff

[24] Staff/1102, Company Response to Staff DR No. 333.

is concerned about an unintended consequence to customers that occurred in the NW Natural docket, specifically, the significant accumulation of interest on the deferral that is born by ratepayers. Staff believes it is in the best interest of customers to avoid accrual of a large amount of interest in Cascade's deferral account, and therefore recommends that the Company begin to amortize costs while the accrued interest is manageable. Notably, interest on the deferred amount has been accruing at Cascade's authorized rate of return.

Q. Does Staff agree with the balance Cascade shows at the end of 2015?

A. No. In reviewing the Company's response to information requests filed with prior deferral applications, Staff found that Cascade entered 2012 costs into the deferral account that precede the date of the original deferral application on November 30, 2012.[25] Any costs prior to November 30, 2012 are not eligible for deferral.

Staff believes the correct amount to be charged to the deferral in 2012 is a credit of $(6,574), instead of the $97,053 charge that the Company shows.[26] Additionally, Staff believes that the Company may have incorrectly calculated the interest on the outstanding balance of the deferral each year, for years 2012-2015. To confirm the correct interest amount for each year, Staff issued Data Request Nos. 377-380. Staff will calculate the correct interest amounts upon receiving the information on August 9, 2016.

Q. What is Staff's recommendation?

[25] Calculated from Cascade's 2012 Eugene Expenses Worksheet in UM 1636.
[26] *Id.*

A. Staff proposes to correct the total expense amount in the Environmental Remediation deferral upon receipt of the Company's responses to DR Nos. 377-380. After the correct expense amount is calculated, Staff recommends that the Commission order the Company to begin amortizing the balance of the deferral through December 31, 2016, when new rates go into effect on March 1, 2017.

Q. Are there any other considerations?

A. Yes. Given the relatively small balance of deferred environmental remediation costs, Staff does not recommend that the Commission implement a specific cost recovery mechanism at this time. Instead, Staff simply recommends amortization, subject to the earnings test required by ORS 757.259(5).

ISSUE 2. PIPELINE SAFETY COSTS

Q. Is Cascade proposing a Pipeline Safety Cost recovery mechanism in this rate case?

A. No. However, Cascade, Avista, NW Natural, Staff, and other interested parties are currently involved in Docket No. UM 1722, which is an investigation into pipeline safety cost recovery mechanisms. In UM 1722, there have been extensive discussions about possible cost recovery mechanisms, how they would work, and whether they would work appropriately. Docket UM 1722 is ongoing at this time, however, there is a draft Stipulation circulating among the parties.

Q. How is Cascade proposing to recover costs related pipeline safety?

A. In this rate case, Cascade proposes that its pipeline safety costs be entered into rate base as additional new plant-in-service.[27] This proposed method of recovery is the same as that used by Avista to recover its costs related to pipeline safety. Staff Witness Mitchell Moore, Exhibit 700, has reviewed the prudence of investment in new plant and has included a discussion on the recovery of pipeline safety costs in his review.

Q. Does this conclude your opening testimony?

A. Yes.

[27] See Staff/1103, Company response to Staff DR No. 159 (explaining that proposed pipeline safety-related costs are included in the "2016 Plant Additions Adjustment" and the "AC Survey Adjustment").

CASE: UG 305
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Judy A. Johnson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

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

CASE: UG 305
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 333

Date prepared: 07/12/2016

Preparer: Candice Maes

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 333

Please list all Oregon environmental remediation-related costs that the Company has deferred since the UM 1636 deferral was granted, including for years 2012, 2013, 2014, 2015, and 2016. Please list all deferred costs individually by amount, and provide a description of the type of cost, i.e., investigation, pursuing insurance recovery, remediation, etc. If applicable, the deferred costs listed should be the full deferred cost amount with no netting of any type of proceeds.

Response:

All Oregon environmental remediation-related costs.

OREGON MGP REMEDIATION RELATED COSTS 2012-2016						
EXPENSE TYPE	**2012**	**2013**	**2014**	**2015**	**2016**	**TOTAL**
DEQ FEES	1,459.50	450.27	138.05	133.02	-	2,180.84
INSURANCE PROCEEDS	(9,675.00)	(87,860.12)	(17,555.41)	(56,168.49)	(35,802.60)	(207,061.62)
INTERIUM REMEDIATION	35,413.71	15,014.46	35,779.17	65,681.25	45,100.65	196,989.24
LEGAL	69,855.21	38,350.21	25,794.45	37,763.45	26,438.56	198,201.88
	97,053.42	**(34,045.18)**	**44,156.26**	**47,409.23**	**35,736.61**	**190,310.34**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 335

Date prepared: 7/13/2016

Preparer: Kalle Godel

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 335

Please provide a detailed description of the following:

a) Each of the Company's environmental remediation sites;

b) The activities that gave rise to materials and substances that now need to be addressed through environmental remediation;

c) The business that was in operation for which the activities occurred;

d) The relationship of that business to Cascade; and

e) How these activities should be considered regulated and recoverable from Cascade retail customers.

Response:

a.) Currently Cascade has three active environmental sites, Bremerton Gas Works Site is in the investigation stage, Eugene Manufactured Gas Plant Site is in the design phase, and Sunnyside Site is in the remediation phase.

b.) Bremerton and Eugene sites were former Manufactured Gas Plant (MGP) locations. It is believed that accidental releases or spills occurring during normal operations of the MGPs and is what caused site conditions that require remediation. Sunnyside Site substances are the result of a leaking underground storage tank (UST) the soil is contaminated with diesel, gasoline, benzene, and 1,2-dichloroethane.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

c.) Bremerton MGP was in operation from approximately 1930 to 1955 and manufactured gas from coal and other petroleum products. The Bremerton MGP was originally operated by Western Gas Company of Washington ("WGC"). WGC operated the MGP from approximately 1930 to 1952. In 1952, Bremerton Gas Company ("BGC") purchased certain assets from WGC, including the MGP and associated property. BGC operated the MGP for approximately one year, before merging with Cascade Natural Gas in 1953. Cascade Natural Gas sold the MGP property to private individuals in 1972.

Eugene MGP was in operation from approximately 1907 to 1950 and manufactured gas from coal and other petroleum products. During operation of the facility it is believed that MGP residue contaminated the soil and ground water. Predecessors to PacifiCorp own and operated the MGP from approximately 1907-1929. Predecessors to PacifiCorp sold the MGP and underling property to Northwest Cities in 1929. Northwest Cities merged with Cascade in 1953. Cascade sells MGP and property to Northwest Natural in 1958.

Sunnyside Site property was owned by Yakima County (County) between approximately 1928 and 1955, during which time the County operated a public works shop and equipment yard. In 1997 Cascade and the County entered into a Settlement Agreement to allocate responsibility for the Contamination (the "Settlement Agreement"). The Settlement Agreement generally obligates the county to preform and pay for all work needed to investigate and remediate the contamination and to indemnify Cascade and future owners and operators of the Property against all claims relating to the performance of or failure of perform such work. In 1998, Cascade, the county and the Washington Department of Ecology entered into a Consent Decree pursuant to which Cascade and the County agreed to remediate the Contamination. The County alone bears responsibility to satisfy the Consent Decree because of the Settlement Agreement.

d.) As stated above prior companies merged with Cascade Natural Gas in 1953 for Bremerton and Eugene Sites. Cascade purchased the Sunnyside property and has no direct connection with the prior owner or the contamination.

e.) Under current environmental laws Cascade Natural Gas or it predecessors companies are responsible or share in the responsibility for investigation and remediation cost at MGP sites as a previous owner or operator. The MGPs were a rate base asset and were used and useful part of utility operation providing service to area customers.

CASE: UG 305
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Exhibits in Support
Of Opening Testimony

August 11, 2016

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

Request No. 159

Date prepared: 6/3/2016

Preparer: Michael Parvinen

Contact: Pam Archer

Telephone: (509)-734-4591

OPUC STAFF DATA REQUEST NO. 159

Has the Company included any Oregon costs related to pipeline safety in either expenses or rate base for either the 2015 base level of costs or for projected 2016 test-year values? If yes:

a. Please provide a worksheet showing the breakdown of costs by project.
b. Please provide projected in-service dates for each project.

Response:

The request is vague and open to interpretation. However, Cascade is interpreting the request to be those costs that would relate to a pipeline safety replacement mechanism as proposed in it last general rate UG 287. Costs included in the Company sponsored adjustment entitled "2016 Plant Additions Adjustment" in this docket that would have been included in the proposed recovery mechanism are based on DIMP modeling include:

FP-200689 – RPL 12" BEND HP LINE #1	$63,641.86
FP-302640 – 6" PILOT ROCK HP REPLACEMENT	$62,069.48
FP-302666 – MT. WASHINGTON BRIDGE CROSSING	$465,521.53
FP-302714 – PENDLETON V-23 REPLACEMENT	$230,536.03
FP-306997 – BEND PIPE PEPL	$4,637,699.96
FP-303142 – PENDLETON BARE STEEL REPLACEMENT	$62,069.48

Several projects included in the 2016 Plant Additions Adjustment are replacements and upgrades for safety and reliability purposes include:

FP-101171 – MAIN REINFORCE-OREGON	$51,515.38
FP-302641 – 4" PILOT ROCK IP REINFORCEMENT	$62,069.48
FP-101175 – R STA-RELO-REPL-OREGON	$124,960.68

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 305

FP-200282 – R STA – SUN RIVER GATE UPGRADE	$1,609,608.08
FP-302650 – O-4 UMATILA	$95,686.16
FP-302651 – O-6 ATHENA	$209,852.11
FP-311997 – O-1 ONTARIO	$153,985.41
FP-311999 – O-1 MISSION	$152,809.12
FP-312013 – R-9 WESTON	$103,910.19
FP-312015 – R-4 HERMISTON	$103,910.19

The Company sponsored adjustment entitled "AC Survey Adjustment" identifies the 2015 and 2016 level of O&M expense to provide AC surveys to help determine the safety of Cascade's system.

2015 Expense (system)	$505,133
2016 Expense (system)	$555,499

CASE: UG 305
WITNESS: JEAN-PIERRE (JP) BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is Jean-Pierre Batmale. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (PUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. To explain why Energy Trust of Oregon (Energy Trust) delivers Cascade's energy efficiency programs and why the PUC believes it is in the best interest of Cascade ratepayers to continue this practice.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Why are Cascade's energy efficiency programs administered by Energy Trust? 2
Issue 2. Is continuing the current arrangement in the best interests of ratepayers? 5

ISSUE 1. WHY ARE CASCADE'S ENERGY EFFICIENCY PROGRAMS ADMINISTERED BY ENERGY TRUST?

Q. Describe Energy Trust.

A. Energy Trust began operating in 2002 and is a nonprofit corporation authorized to administer "public purpose" programs including energy conservation programs under a grant agreement with the Public Utility Commission of Oregon.[1] Energy Trust receives revenue collected from the ratepayers of Portland General Electric Company (PGE), PacifiCorp, NW Natural Gas Company, Avista Utilities,[2] and Cascade and administers certain public purpose programs on behalf of these utilities.[3]

Energy Trust reports its activities, costs, and results to the Commission quarterly and annually, measuring actual performance against annual targets set by the Commission.[4] An independent board of directors oversees Energy Trust operations, provides strategic direction, and approves annual budgets and major expenditures.[5] A Conservation Advisory Council and Renewable Energy Advisory Council comprised of interest groups and stakeholders assist the board with strategic development and provide guidance on implementation.

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[1] The grant agreement between the Commission and Energy Trusts can be found at https://energytrust.org/About/PDF/grant_agreement.pdf . It was updated in 2005.
[2] Avista's conservation programs are in the process of transferring to the Energy Trust with full transfer to take place in January of 2017.
[3] Energy Trustcommence administering some public purpose programs for
[4] Energy Trust's Commission specific reports can be found at https://energytrust.org/About/policy-and-reports/OPUCDocuments.aspx . Reports on annual energy savings and renewable generation can be found at https://energytrust.org/About/policy-and-reports/Reports.aspx.
[5] Information on Energy Trust's Board of Directors, Advisory Councils and public meetings can be found at https://energytrust.org/About/public-meetings/

In 2015, Energy Trust spent $164 million from utility customers to serve more than 83,000 residential, commercial and industrial locations in Oregon and meet all of its Commission goals in acquiring energy efficiency as a least-cost resource and stimulate renewable energy investments.[6]

Q. When did Energy Trust of Oregon begin delivering Cascade's energy efficiency programs?

A. In 2006, Energy Trust began administering Cascade's energy efficiency programs. Energy Trust does not administer Cascade's low-income programs.[7]

Q. Why was Energy Trust given the responsibility of delivering Cascade's energy efficiency programs?

A. Energy Trust was given the responsibility of delivering Cascade's energy efficiency programs for two reasons: decoupling and programmatic consistency across other decoupled, investor-owned utilities. In October 2005, Cascade sought an order authorizing decoupling, broadly called a Conservation Alliance Plan (CAP).[8] The CAP was designed to be a comprehensive mechanism to encourage energy efficiency while affording Cascade some protection from adverse rate impacts associated with reduced load from energy efficiency and conservation, and other factors affecting loads. As part of the CAP, the funds collected for energy efficiency programs – public purpose funding – were

[6] For a summary of Energy Trust 2015 OPUC performance see http://www.puc.state.or.us/electric_restruc/purpose/Energy%20Trust%202015%20Results%20At%20a%20Glance.pdf . For Energy Trust's overall 2015 results, including dollars spent and customers served, please see the annual report at http://assets.energytrust.org/api/assets/reports/2015.Annual.Report.OPUC.with.NEEA.pdf or http://assets.energytrust.org/api/assets/reports/PublicAnnualReport_2015_Final.pdf

[7] For details see Order No. 06-191at http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=06-239

[8] See Docket No. UG 167.

directed to Energy Trust for the administration and implementation of Cascade's energy efficiency programs.[9] This arrangement capitalized on Energy Trust's public purpose activities already underway for other investor-owned utilities.[10] Energy Trust began delivering services and incentives to the customers of Portland General Electric and Pacific Power in 2002 and Northwest Natural in 2003. By expanding Energy Trust's operations to include the customers of Cascade, Energy Trust could deliver a consistent set of energy efficiency and renewable services and incentives across nearly all of Oregon's investor-owned utilities' landscape.

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[9] *Id.*

[10] For a comprehensive history of Energy Trust please see https://energytrust.org/About/who-we-are/

ISSUE 2. IS CONTINUING THE CURRENT ARRANGEMENT IN THE BEST INTEREST OF RATEPAYERS?

Q. What is the importance of energy efficiency to Oregon ratepayers?

A. The Commission currently views energy efficiency as a prudent, least-cost resource investment that cost-effectively allows utilities to meet customer energy needs through decreases in the demand for energy.[11] The Commission's Integrated Resource Planning (IRP) Guideline document specifically directs utilities to include in their IRP action plans, "…all best cost/least risk portfolio conservation [energy efficiency] resources for meeting projected resource needs."[12] Energy Trust independently delivers to each utility annual savings goals and also creates saving forecasts for the utilities to use in their IRP action plans.

Q. How has Energy Trust performed in Cascade's territory?

A. Energy Trust has exceeded its PUC savings target for natural gas savings in Cascade Natural gas territory for the past six years, see table below: [13]

Year	Energy Trust Annual Therm Savings Goal	OPUC Therm Performance Goal	Achieved Net Therm Savings	% of Achieved Savings to Energy Trust Goal
2010	379,960	322,966	367,875	96.8%
2011	406,122	345,204	443,108	109.1%
2012	370,492	314,918	431,070	116.4%
2013	402,331	341,981	347,091	86.3%
2014	470,561	399,977	420,513	89.4%
2015	433,020	368,067	572,526	132.2%

[11] The Commission's 2015 letter to the Oregon House Committee on Energy and Environment provides a concise summation of the Commission view on energy efficiency, http://olis.leg.state.or.us/liz/2015R1/Downloads/CommitteeMeetingDocument/46640
[12] Order No. 07-047 http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=07-047
[13] Data compiled from Energy Trust annual reports to OPUC. These reports can be found at https://energytrust.org/About/policy-and-reports/Reports.aspx

These results were achieved within annual budgets, cost-effectiveness and levelized cost limitations. As the results in the table show, Energy Trust's continued innovation in services and measures has allowed for the sustained acquisition of cost-effective energy efficiency in Cascade's service territory. In a 2013 filing to extend Cascade's decoupling mechanism it was noted that Energy Trust's work had resulted in, "…a significant increase in conservation measures…," in Cascade's service territory.[14]

Q. Would continuing the current arrangement be in the best interest of ratepayers?

A. Based on Energy Trust's past results and current focus it would be in Cascade ratepayers' best interest to continue this arrangement.

Q. Does this conclude your opening testimony?

A. Yes.

[14] Order No. 13-079 http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=13-079

CASE: UG 305
WITNESS: JEAN-PIERRE (JP) BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Jean-Pierre Batmale
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE., Suite 100 Salem, Oregon 97301
EDUCATION:	M.A. Public Policy University of California, Los Angeles (1999) B.A. History and Liberal Studies University of California, Riverside (1993)

EXPERIENCE:

I have been employed by the Oregon Public Utility since April 2016 as Senior Utility Analyst in the Utility Program's Energy Resources and Planning Division. My current responsibilities include economic analysis, policy support, and development of recommendations pertaining to energy efficiency, renewable energy and least-cost planning at Oregon's investor owned utilities and other organizations.

Prior to the Oregon Public Utility Commission I worked as the Planning Manager at the Energy Trust of Oregon for one year. I led a team of three analysts in developing Energy Trust's near- and long- term plans to achieve the organization's energy efficiency and renewable energy goals. I developed and monitored organization-wide activities and budgets reporting to senior management, the Energy Trust board, the Oregon Public Utility Commission and other stakeholders. Prior to my work in the Planning Department, for three years I was the Senior Program Manager of the Industrial Sector at Energy Trust. I led a team of five staff and seven contractors implementing a $30 million budget that acquired approximately one-third of Energy Trust's annual energy savings.

CASE: UG 305
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

August 11, 2016

Q. Please state your name, occupation, and business address.

A. My name is George R. Compton. I have been employed by the Public Utility Commission of Oregon since March of 2007. I am a Senior Economist within the Energy, Rates, Finance, and Audits Division. My business address is 201 High St. SE, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. I will be addressing elements of cost allocations and rate spread.

Q. Did you prepare additional exhibits for this docket?

A. Yes.

Exhibit 1302	Plant Carrying Costs
Exhibit 1303	Mains System Replacement Cost
Exhibit 1304	LRIC Study Summary
Exhibit 1305	Cost Functionalization
Exhibit 1306	Response to Staff DR No. 123

Q. How is your testimony organized?

A. My testimony is organized as follows:

Topic 1. An Alternative Estimate of Customer Mains Costs 7
Topic 2. An Alternative Estimate of Mains System Replacement Costs 11
Topic 3. Eliminating Some Customer Main Costs as LRIC-Irrelevant 14
Topic 4. An Alternative LRIC Allocation of Core Mains Costs 15
Topic 5. Achieving Consistency in Cost Functionalization Prior to Allocating Embedded Costs 17
Topic 6. Rate Spread and the Desired Maximum Percentage Increase 19

Q. Please give us an overview of your testimony.

A. Notwithstanding the altered assumptions and other analytic modifications described below, the results of my long run incremental cost (LRIC) study do not depart in a major way from the Company's. Notably, my recommendations for several customer schedules to receive no increase align with Cascade's. As is typical with gas utilities, the filing and supporting analytics are performed on Cascade's non-gas costs. The following table (from Staff/1304,Compton/2) presents both Cascade's and Staff's recommended percentage increases for the non-gas portion of rates *assuming the Company's requested overall increase is granted. The table also shows the percentage increase where the gas commodity costs are included.*

SUMMARY TABLE OF RECOMMENDED PERCENTAGE INCREASES

	Non-Gas Portion		Overall (Core Customers)	
Schedule	**Cascade**	**Staff**	**Cascade**	**Staff**
Overall Total	6.43%	6.43%		
101 Residential	8.91%	10.41%	4.2%	4.9%
104 Commercial	0%	0%	0%	0%
105 Industrial	32.16%	19.29%	9.5%	5.7%
111 Large Vol.	25.73%	19.29%	6.4%	4.8%
163 Gen. Dist.	8.04%	0%	Non-Core	
170 Interruptible	0%	0%	0%	0%
900 Spec.Contracts	0%	0%	Non-Core	

Q. Why are the overall percentage increases not shown for the non-core customers?

A. These are customers who buy their commodity from a third party. Since we don't know the commodity cost, we can't average it in with the non-gas portion of the cost to obtain the overall percentage increase.

Q. In your previous answer you mentioned "altered assumptions and other analytic modifications." Would you please explain briefly what you meant?

A. I find several elements in Cascade's LRIC study to be unreasonable. Most notably the estimate of the cost to replace Cascade's distribution system, which is used to establish the ratio used to allocate costs, is too high, and their estimate of the embedded commercial and residential customer mains, a portion of the costs actually allocated, is too low. These unreasonable estimates ultimately result in shifting cost responsibility from residential customers to industrial customers. I correct these assumptions in my own LRIC analysis and alter the rate spread outcomes accordingly.

In the interest of achieving internal consistency and other expository virtues, most of my testimony entails rearranging or recalibrating various items contained in the exhibits produced for Cascade by Ronald J. Amen of Black & Veatch Management Consulting LLC.[1] And, in order to make a direct comparison regarding the effects of various adjustments between my

[1] Mr. Amen has been Cascade's witness in both the current case and UG 287.

cost allocations study and Mr. Amen's, I employ the same total revenue requirement proposed by Cascade.

Q. What standard does Commission use to determine rate spread?

A. The Commission generally determines cost allocation between rate classes based on analysis of long-run-incremental-costs (LRIC). However, the Commission does not determine rate spread strictly on LRIC, but also considers other factors, such as impact to customer classes.[2]

Q. Please summarize your recommendations regarding rate spread.

A. Regarding the final rate spread recommendations, I agree with Cascade that Schedules 105 (Industrial Service Rate) and 111 (Large Volume Service Rate) should receive the largest percentage increases but disagree that the maximum increase should be as much as five times the average.[3] I recommend that the maximum increase for Schedules 105 (Industrial Service Rate) and 111 (Large Volume Service Rate) be three times the average rate increase. The result of this lowered maximum would still result in an increase to the non-gas portion of those schedules' rates by over nineteen percent (assuming Cascade's proposed revenue requirement).

I also agree with the Company that the commercial schedule should receive no increase in this docket and that the residential schedule should receive an increase that is somewhat greater than the overall average. Finally, I conclude that industrial Schedules 163 (General Distribution) and

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2 *See, e.g.*, UG 288, Order No. 16-109 at 21 (March 15, 2016).
3 A large multiple of a *miniscule* average increase would be acceptable.

170 (Interruptible) should receive no increase since current revenues exceed my cost estimates.

Paring the industrial increase from five times the average increase to three times the average increase as indicated, would add to the residential increase in the non-gas portion of their rates by about one-half of one percent over the Company's recommended 8.91 percent. My proposed estimate of the average customer mains costs in the LRIC analysis raises that residential increase by another one percent. When the increase is applied to the total gas bill (not just the non-gas portion), the combined one and one-half percent increase translates to something under three-fourths of one percent.

Q. You have said nothing about pricing. Does Staff still advocate increasing the monthly residential customer charge from three dollars to five dollars as it did in Docket No. UG 287?

A. Yes. Staff witness Scott Gibbens is testifying on this subject.

Q. Before proceeding with the presentations of your specific topics, would you please provide a brief overview of the process of developing LRIC and the ensuing "spread" of rates?

A. Certainly. The first step is to compartmentalize the utility costs among several functional categories. Cost-wise the largest function consists of the distribution mains themselves, which in turn are divided between customer mains that traverse the neighborhoods and core mains, which take the gas into the neighborhoods. Customers' "services," which connect the customers' on-premise meters to the customer mains in the streets, constitutes the nextcostliest plant category.[4] Far less costly functions are scheduling and planning, meter reading, and billing.

Under the LRIC standard, the amount of costs that each customer class/schedule places on the system is estimated on a forward-looking, long-run incremental cost (LRIC) basis, relying on estimates of what it would cost to replace the functional elements. Under this bottoms-up approach, each schedule's LRIC for each function is established. A total LRIC for each function is then established by summing all the schedules' LRIC for that function. Comparisons of each schedule's LRIC for a particular function to the total LRIC for that function are used to establish an allocation ratio for each schedule and function, which are then applied to allocate the utility's embedded costs. In other words, the embedded costs for each function are allocated to each customer schedule in proportion to that schedule's percentage share of the summed LRICs for the function.

The final "rates spread" portion of the case involves assigning final portions of the total revenue requirement in a manner that comes closest to accounting/embedded cost shares indicated by the LRIC analysis while not imposing too large of an increase on any subset of customer class. The Commission generally addresses this latter consideration by limiting the

[4] The term "customer mains" is probably a misnomer in the sense that it implies something dedicated to individual customers. To the contrary, if I'm a gas customer living on an urban residential street, then *the* "customer main" that "serves me" likely runs the entire length of my street and *all* the customers on my street tap into that *single* main**—**which in this instance happens to be 1200 feet long. The distance between each of the "taps," or connections, is then a function of the lot density, or average frontage length, along my street. The narrower the frontages, the more customers can be served off of "my" single one-block length of main.

maximum rate increase that can be given to any one rate class to no more than two or three times the system average increase granted by the Commission's final order.

Finally, prices are established that will produce for the test period each customer schedule's allocated share of the total revenue requirement, assuming the accuracy of the individual schedules' sales projections established for the docket.

Topic 1. An Alternative Estimate of *Customer* Mains Costs

Q. When I visualize a gas distribution company I see a massive array of pipes. How are the elements of that array labeled and categorized?

A. The pipes running up and down what are mostly residential streets are referred to in the industry as "main extensions" or "customer mains."[5] The pipes that deliver the gas into the neighborhoods are referred to as "core mains" or "system core mains."[6] The pipes that connect the customers' meters to the main extensions are labeled "services" or "service lines." Because of their close association in terms of cost-causation, customer-premise meters and services are commonly lumped together for cost allocations purposes. By far the lion's share of the cost allocations project involves the three operationally distinct plant categories of core mains, customer mains, and, jointly, meters and services.

[5] Avista employs the former label; Cascade employs both.
[6] Utah's Questar gas utility refers to these core mains as "feeders" and "large diameter mains."

Q. Please review those three plant categories and how their distinctive natures relate to the way their costs might be allocated among the various customer classes or schedules.

A. In the case of meters and service lines located on individual customers' premises, the individual customer schedules—as surrogates for the customers themselves—should be responsible for paying for their own meters and services and not those of other schedules. In the case of residential, commercial, and small industrial customers, the costs of their associated customer mains are determined by the LRIC-based cost per foot of pipe dedicated to those mains and the per-customer average amount of footage required to serve the customers of each of those two customer classes.

The customer count for the larger industrial schedules is far smaller, allowing for LRIC-based customer main costs to be estimated on an individualized basis and then aggregated within the schedules.

Finally, core mains serve entire sections of a community—where a section may contain residential, commercial, and industrial customers. Based upon their peak-day demand levels, all the customers in the section contribute to the cost burden and all share in the benefits of the core main/mains that bring the gas to them.

Q. From a LRIC standpoint, how are the costs for customers' mains determined for each customer schedule?

A. As suggested in the previous answer for the primary customer schedules, 101 (Residential), 104 (Commercial), and 105 (Industrial), per-customer average main extension footages are estimated, along with the cost per foot of a new installation.[7] Multiplying the average footage times the cost per foot times the number of customers in the schedule yields the LRIC investment for each of those schedules. The investment is multiplied by the annual carrying cost percentage to yield the LRIC revenue requirement. These calculations are found in Exhibit CNGC/303, Amen/1.

As for the remaining large industrial or interruptible customer schedules,[8] these classes' investments are depicted directly, i.e., without the average footage and cost-per-foot workups, but still taking into consideration new installation costs as opposed to depreciated, embedded costs.

Q. In reviewing Cascade's customer mains cost estimates, do you find them reasonable?

A. No. The Company estimated its two-inch plastic pipe to cost $7.81 per foot, installed.[9] The recent estimate of Avista's customer main average cost per foot is several times greater than Cascade's.[10] The more urbanized NW Natural's figure lies in between, but is still about double Cascade's.[11]

Q. The full amount of gas main costs should include the costs of permits, engineering, heavy equipment write-off, installation and site restoration supervision and labor, plus the purchase price of the pipe itself. Did

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7 Those schedules are, respectively, residential, commercial, and [small] industrial.
8 Those schedules are 111: Large Volume Service, 163: General Distribution, 170: Interruptible, and 900: Special Contracts. Schedules 163 and 900 obtain their gas from a third-party.
9 *See* CNGC/303, Amen/1, line 23.
10 UG 288 Avista/801, Miller/2, line 10 shows an estimate of $37.23.
11 UG 221 NWN/1101, Feingold/7, line 24 shows an un-escalated, 2011 figure of $14.56 per foot.

Staff submit a Data Request asking the Company to break its $7.81 cost per foot estimate for two-inch plastic pipe into those cost components to show Cascade had not disregarded major cost elements when estimating customer main costs?

A. Yes, we submitted such a request, but the information rendered was of no value. I am confident that if Cascade had included estimated costs for all of the items mentioned, the total estimated cost would be well in excess of Cascade's $7.81.

Q. Have you a more tangible basis for disputing the Cascade cost estimate beside the fact that it is much lower than that of the other gas utilities regulated by the Commission?

A. I do. The Company's response to Staff Data Request No. 123 lists customer main installation work-orders dating from 2009 through 2015. It shows *installed* cost-per-foot averages as low as *fourteen* cents per foot, which is remarkable given a price for two-inch PVC of about *eighty* cents per foot *just for the pipe* at The Home Depot. The utility would get a volume discount for the pipe, but there are still all those other costs to be taken into consideration. My point is that having such impossibly small individual item estimates going into an overall average estimate renders that latter estimate quite implausible.

Q. What amount do you propose as part of Staff's LRIC work-up for the per-foot costs of customer mains for the residential and commercial schedules?

A. I will base my estimate on the lower of the cost estimates provided by NWN in Docket No. UG 221 and Avista in UG 288, which is $14.56.

Q. You have focused on the costs of the residential and commercial schedules' customer mains. Are you just going to adopt the Company's customer main cost estimates for the other schedules?

A. Yes. In comparing Cascade's estimate of per-foot costs of steel pipe with estimates supplied by Avista in its last general rate case, I find no reason to question Cascade's.

Q. Have you prepared an exhibit that incorporates the alternative costs of customer mains that you have just developed?

A. My Exhibit Staff/1302, Compton/1 is identical to Exhibit CNGC/303, Amen/1, except for the substitution of those alternative cost estimates.

Topic 2. An Alternative Estimate of Mains *System* Replacement Costs

Q. You have spoken of how the LRIC investments for customer mains are estimated…how is the LRIC investment in core mains estimated?

A. I estimate the cost of rebuilding the entire mains system and then subtract from that amount the sum of the estimates of schedules' customer mains.

Q. Do you have an exhibit that shows Mr. Amen's calculation of the "Mains System Replacement Costs" on an LRIC basis?

A. I do. The upper portion of Exhibit Staff/1303, Compton/1 is a replication of Cascade Workpaper RJA-WP-3A. It shows a total replacement cost estimate of almost $410 million.

Q. Do you question the accuracy of that estimate, and if so, on what basis?

A. I do question its accuracy. The estimate is based on installation of more steel pipe than is reasonable given the likelihood that pipe used to replace the existing pipe connecting residential and commercial customers would be plastic. Cascade's assumption that it would duplicate its system with almost a 50/50 mix of steel and plastic two-inch pipe is inconsistent with Cascade's customer profile of customers connected to two-inch pipe (i.e., the number of residential, commercial, and Schedule 105 industrial customers, who together account for all but 52 of Cascade's 70,743 customers), and the average lengths of pipe per customer shown in Exhibit CNGC/303, Amen/1, and replicated in Exhibit Staff/1302, Compton/1.

Q. Please explain.

A. Exhibit CNGC/303, Amen/1 shows over 60 thousand residential service customers who account for 78.68 feet of two-inch plastic pipe per customer and almost 10 thousand commercial service customers who account for 121 feet per customer. Multiplying the feet per customer times the number of customers and dividing by 5280 feet-per-mile yields 1108 miles of two-inch plastic pipe that would be used to connect residential and commercial customers on a LRIC basis. But the subject Amen workpaper shows only 633 miles of two-inch plastic pipe, with another 552 miles of two-inch steel pipe.

Q. How do you account for such a large discrepancy?

A. The indicated mix of almost 50 percent steel pipe probably reflects what is actually in the ground, which in turn reflects an outdated technology that has been superseded by a material, plastic, that is both cheaper and possessing of superior, noncorrosive, slower-to-deteriorate properties.

Q. I notice from Exhibit CNGC/303, Amen/1 that two-inch steel pipe is used for industrial service customers. Have you performed the same kind of analysis for steel that you just did for two-inch plastic, and if so, would you please describe it?

A. I did. The 128 industrial service customers accounted for 899.14 feet of two-inch steel pipe each. Multiplying those two numbers together and dividing by 5280 yields only 21.8 miles of two-inch steel pipe—versus the 552 miles shown in Cascade Workpaper RJA-WP-3A. Again, if the mains system were to be *replaced* in a manner consistent with the LRIC work-up of the customer mains, there would be a whole lot more plastic pipe and a whole lot less steel pipe than is shown in Cascade Workpaper RJA-WP-3A.

Q. Have you prepared an exhibit that shows the "Mains System Replacement Costs" on an LRIC basis, but with your estimate of the plastic/steel pipe mix?

A. Yes. The lower portions of Exhibit Staff/1303, Compton/1 combine the plastic-intensive mix with the per-foot costs shown in Exhibit Staff/1302, Compton/1. Main system replacement costs here are about $65 million, or 16 percent, below those developed by Mr. Amen.

Topic 3. Eliminating Some of Cascade's Customer Main Costs as LRIC-Irrelevant

Q. You have now provided alternative estimates, on a LRIC basis, of customer mains costs and total system *replacement* costs. Do you have an additional objection to the way Cascade has estimated those items, and, if so, what are they?

A. The Company has recently made a small capacity-related investment in customer mains and a larger mains investment that is safety-related. In both cases the investments are a matter of making retro-fits or upgrades to the existing system. In Exhibit CNGC/303, Mr. Amen adds these investment costs to the estimated costs to duplicate customer mains that were described earlier in my testimony. That is improper: with new plant and new plant costs in the LRIC context of having newly *replaced* the system in its entirety, it does not make sense to inflate those new-system costs by adding repair/ retrofit costs. New, and therefore expensive, un-depreciated plant should not require repairs and retrofits.

Q. So how do you treat those incremental capacity- and safety-related customer mains investments?

A. I deleted them from my costing analyses—substituting NA's for these amounts.[12]

[12] See Staff/1302, Compton/2, lines 28, 29, 31, and 32.

Topic 4. An Alternative LRIC Allocation of Core Mains Costs

Q. Now that you have developed alternative customer mains and total main replacement costs, what is the next step in the cost allocations process?

A. Allocating the core mains costs, which are defined as total main replacement costs less the LRIC customer mains costs.

Q. What drives the costs of core mains?

A. The piping is sized to meet the system peak day demand; but the size-driven incremental cost is relatively small compared to the aggregate of all the other costs—by which I mean the costs of permits, engineering, installation labor and equipment, etc. The size-driven share of the costs are allocated among the customer schedules in proportion to their shares of the system peak day demand while the balance is commonly allocated on the basis of shares of system annual throughput. An exception is made for both categories of allocated costs in cases where customers are served solely on the basis of specific plant dedicated to them. The Company asserts that this occurs for the Special Contract customers, Schedule 900.

Q. What is the rationale for allocating a portion of the costs on the basis of annual throughput?

A. I would say there is a vague value-of-service basis, where such value is correlated with annual usage, or throughput.

Q. You stated earlier that the annual throughput-based allocation places more of the core mains costs onto the industrial customers. What throughput share is embodied in Cascade's allocations, and how does that share compare with, for example, Avista's?

A. Cascade's annual throughput percentage share is 22 percent while Avista's is 50 percent. But that only tells part of the story. Avista's share of total mains costs designated as core mains costs is much smaller than Cascade's. On an engineering design basis, Avista's mix of core mains versus customer mains seems much more realistic.

Q. What percentage share of core main costs are you recommending be allocated on the basis of annual throughput?

A. My recommendation is to stay with the Company's figure of 22 percent. Substituting 50 percent for the 22 percent used by Cascade would exacerbate the effect of Cascade's unrealistically high share of total mains costs that is attributable to core mains. Accordingly, allocating 22 percent of the total mains costs on throughput will yield more sensible analytic results than would be obtained using a higher percentage.

Q. What use is made of the 22 percent and 78 percent figures in the allocation process?

A. I start by subtracting my enlarged aggregate of the customer mains costs from my shrunken system replacement costs in order to obtain an estimate of total core mains costs. Then, I allocate a percent of those costs on the basis of the customer schedules' shares of annual throughput (excluding Special

Contract customers who do not share in the use of the core mains). Finally I allocate the remaining 78 percent of the core main costs according to the schedules' shares of the annual peak day loads. Because the system capacity is not designed to accommodate interruptible loads on an extreme peak demand day, interruptible schedules commonly—albeit not inevitably—don't receive a capacity-related core main cost allocation. I have accepted Cascade's treatment of Schedules 163 (General Distribution), 170 (Interruptible Service), and 900 (Special Contracts) in this regard.

Q. Do you have an exhibit which performs the steps which you have just presented?

A. Yes, Exhibit Staff/1302, Compton/2.

Topic 5. Achieving Consistency in Cost Functionalization Prior to Allocating Embedded Costs

Q. In your introductory remarks you said that functionalized *embedded* costs are allocated among the customer schedules in proportion to those schedules' proportional shares of the summed *LRIC-based* estimates of those same functions' costs. Applying this connection to Mr. Amen's analyses, the embedded costs shown in the Total column of Exhibit CNGC/301, Amen/2, lines 33 through 36, were allocated to the indicated customer schedules on the basis of those customer schedules' shares of the Total column of lines 27 through 30 of Exhibit CNGC/301, Amen/1. Do I detect an inconsistency insofar as "Mains

Extensions" (i.e., customer mains) are combined with "Meters and Services" on page 1 of Exhibit CNGC/301, while "Meters and Services" stands alone on page 2 of that exhibit?

A. Yes, there is an inconsistency. Indeed, it does not make sense to allocate embedded Meters and Services costs in proportion to shares of combined LRIC costs of Meters, Services, *and* Main Extensions.

Q. How would you rectify that inconsistency?

A. In order to be consistent with the functionalized embedded costs on CNG/301, Amens/2, "Mains Extensions" on page 1 of that exhibit needs to be separated from "Meters and Services" and combined with "System Core Mains." If you'll refer to line 8 of CNGC/302, Amen/ 1, you will see that Mains in their entirety fall under the column labeled "System Core Mains."[13] Exhibit Staff/1304, Compton/1 shows the corrected placement of Main Extensions as a separate line item, 29a. The two types of mains can then be combined for the purpose of allocating the embedded total mains costs shown as line 37 of my Exhibit Staff/1304, Compton/2.

Q. Are there other functionalization inconsistencies that should be corrected?

A. There is one. The "Meters & Regulators," the costs of which are shown on Exhibit CNGC/303, Amen/1, are plant elements that are located on customers' premises. It is the LRICs of these elements that underlay the allocation of embedded costs of Meters & Regulator which, ostensibly, serve

[13] My alternative Exhibit Staff/1305,Compton/1 shows the same thing.

the same, on-premise function. *Off*-premise meters and regulators—i.e., the M & R Station Equipment shown on line 10 of Exhibit CNGC/302, Amen/ 1—properly belong in the "System Core Mains" column since their *function* is to protect and control the activities of the core mains. I would note that Maintenance and other Expenses associated with the "Meas. & Reg. Station" equipment are properly located under the "System Core Mains" column of line 8 of Exhibit CNGC/302, Amen/ 2. The embedded costs that are allocated in my Exhibit Staff/1305, Compton/1 have been adjusted to move "M & R Station Equipment" over to the System Core Mains column.

Topic 6. Rate Spread and the Desired Maximum Percentage Increase

Q. Would you please now walk us through the rate spread process for this docket? By that I mean show us the steps by which the final revenue requirement increases or decreases are obtained for all customer schedules.

A. Certainly. I will organize this portion of the testimony by displaying numbered steps. And except where indicated, I will make use of Cascade witness

Ronald Amen's spreadsheet modeling architecture found in Exhibit CNGC/301, Amen/2, which in turn is represented in my Exhibit Staff/1304, Compton/2. In most cases the steps themselves are quite similar Mr. Amen's.

Step *Minus* 1:[14] Allocate the functionalized embedded costs to the customer schedules based upon their respective percentage shares of the LRIC totals for the same functions. (Referring to Exhibit Staff/1305, Compton/2, the four right-hand column headings denote the four functions among which the revenue requirement has been compartmentalized. Line 70 shows the revenue requirement contribution of each function: added together they produce the overall total amount also shown on that line. Those same five values are shown in the "Total" column for lines 33-37 in Exhibit Staff/1304, Compton/2. The shares of those function totals assigned to each of the customer schedules correspond to the same percentage shares of the respective customers of the LRIC totals of lines 27-30 of Staff/1304, Compton/1. (Line 29a and 30 are combined for the purpose of allocating the embedded costs of line 36 of Exhibit Staff/1304, Compton/2.) Line 32 of Exhibit Staff/1304, Compton/2 shows the non-gas revenues collected from each schedule under current rates and assuming the test-period annual sales amounts. Line 38a indicates the percentage increase required to bring the revenues up to the levels shown on line 37.[15]

Step Zero: Start with line 39 of Exhibit Staff/1304, Compton/2, which is the target revenue requirement increase from Cascade's rate case application, and add it to the line 32 Total (current revenues) to obtain the total revenue requirement target, line 39e in Exhibit Staff/1304, Compton/2. Note the factor

[14] I start with Step Minus 1 in order, later, to be in sync with Amen's steps 1 and 2.
[15] The amount in line 37 of Exhibit Staff/1304, Compton/2 is CNGC's target increase, which would be a 6.43 percent overall increase in Cascade's revenue requirement. Staff does not support this percentage increase, but used it for illustrative purposes.

by which values of line 37 must be increased in order to reach the final revenue requirement target of line 39a. To achieve a direct comparison with Mr. Amen's approach and results, I will work with the same revenue requirement that he uses.

Step 1 (same as Amen's Step 1): Determine the maximum percentage increase to be experienced by affected customer schedules and expressed as multiples of the overall average increase, and calculate the associated revenue increases that would be the result thereof. This step is guided in part by referring to Exhibit Staff/1304, Compton/2. line 38a. Line 40 shows the indicated multiples, with the maximum being three. By contrast, Mr. Amen had one of the schedules receiving a percentage increase that would be five times the average. Exhibit Staff/1304, Compton/2, line 43, shows the dollar increases, with line 43a showing the residual portion of the overall increase that must be collected from one or more of the other schedules.

Step 2 (same as Amen's Step 2): Allocate whatever revenue requirement that won't be collected from the schedules that experienced the upper limits in Step 1 to the remaining applicable schedules. In this case the "applicable schedules" is singular—Residential Service Schedule 101. The two remaining schedules, Commercial Service and Special Contracts, receive neither an increase nor a decrease. Both Staff's and Cascade's analyses support a decrease for the Commercial Service Schedule. Special Contracts, by definition, do not experience rate changes under normal rate case conditions.

Line 47 in Staff/1304, Compton/2 compiles all of the dollar increases consistent with the 6.43 percent overall increase; line 48 shows the resulting shares of the increased total revenue requirement; line 49 shows the associated percentage increase for each customer schedule; and line 50 shows the revenues-to-costs ratios, where the costs of line 37 have been expanded by the factor shown on line 39a (i.e.,1.02) in order to be consistent with the overall asked-for revenue requirement. Line 51 expresses the indicated percentage increase as a multiple of the overall percentage increase.

Q. Looking at line 50 of Staff/1304, Compton/2, I observe that, for those schedules that are to receive increases, in no instance does the recommended revenue increase bring the revenue up to the schedule's full, LRIC-allocations-based embedded costs. Mathematically speaking, how can that be?

A. This is made possible by not granting decreases to the two schedules where both Staff's and Amen's LRIC analyses suggest such would be warranted. However, Staff does not recommend a rate decrease to any customer schedule, to be consistent with Commission precedent.[16] Allowing some schedules to carry rates in excess of costs enable other schedules to have rates that are beneath costs.

[16] In its 2015 order in Avista's recent general rate case, the Commission declined to reduce rates for large customers while increasing rates for other customers. *See* OPUC Order No. 15-054.

Q. Have you an exhibit which shows the percentage increase that the affected customer schedules will receive when the gas commodity costs are combined with the non-gas portion of costs?

A. I do. Those amounts are shown on line 55 of Staff/1304, Compton/2.

Q. Does this conclude your opening testimony?

A. Yes.

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

August 11, 2016

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street, SE., Suite 100
Salem, OR. 97301

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE 210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UG 305
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Plant Carrying Costs

Line	Description	Unit	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
1	**Billing Determinants**									
2	Peak Day Forecast	Dth-Day	91,882	52,034	35,256	2,906	1,686	-	-	-
3	Customer Count		70,743	60,662	9,901	128	13	31	4	4
4	Throughput	Dth	31,599,959	3,996,951	2,811,784	254,327	156,543	3,272,979	243,922	20,863,452
5	**Service Installation**									
6	Typical Size	in.		0.5	1	2				
7	Material			Plastic	Plastic	Plastic				
8	Average Cost	$		$ 1,089	$ 1,198	$ 2,868				
9	Total Investment	$	$ 79,880,857	$ 66,031,665	$ 11,864,310	$ 366,796	$ 108,411	$ 1,133,852	$ 295,860	$ 79,962
10	Economic Carryin Charge Rate			16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%
11	Annual Carrying Charge per customer	$		$ 180.10	$ 198.27	$ 474.60				
12	Class Annual Carrying Charge	$	$ 13,216,697	$ 10,925,277	$ 1,963,011	$ 60,688	$ 17,937	$ 187,602	$ 48,952	$ 13,230
13	**Meters & Regulators**									
14	Average Cost	$		$ 225	$ 895	$ 4,690				
15	Total Investment	$	$ 27,612,779	$ 13,673,227	$ 8,861,469	$ 599,753	$ 522,247	$ 2,636,185	$ 589,218	$ 730,680
16	Economic Carryin Charge Rate			19.23%	19.23%	19.23%	19.23%	19.23%	19.23%	19.23%
17	Annual Carrying Charge per customer	$		$ 43.34	$ 172.10	$ 901.87				
18	Class Annual Carrying Charge	$	$ 5,309,590	$ 2,629,190	$ 1,703,949	$ 115,325	$ 100,422	$ 506,905	$ 113,299	$ 140,501
19	**Mains Investment**									
20	A. Customer Mains Investment									
21	Typical Size	in.		2	2	2				
22	Material			Plastic	Plastic	Steel				
23	Avg. Mains extension per customer	ft		78.68	121.00	899.14				
24	Average cost per ft	$/ft		$ 14.56	$ 14.56	$ 62.34		Amen's 2" Plastic $/ft =		7.81
25	Customer mains investment per customer	$		$ 1,146	$ 1,762	$ 56,051				
26	Customer Mains Investment by Class		$ 124,932,815	$ 69,496,595	$ 17,442,563	$ 7,167,381	$ 1,731,462	$ 16,560,413	$ 2,287,390	$ 10,247,011
26a			Amen's estimates:	$ 37,276,241	$ 9,356,210					

Comparison Reference: CNGC/303, Amen/Page 1 of 2 Shaded items represent Staff substitutions.

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Plant Carrying Costs

Line	Description	Unit	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
27	B. Capacity Related									
28	Incr. mains capacity investment	$	NA	NA	NA	NA	NA			
29	Capacity Mains Investment per customer	$								
30	C. Commodity (Safety) Related									
31	Incr. mains commodity investment/therm	$	NA	NA	NA	NA	NA	NA	NA	
32	Safety Related Investment per customer	$								$ -
33	Long-Run System Replacement Investment									
34	Mains System Replacement Cost	$	$ 318,188,249	Source: Staff/1303, Compton/ 1						
35	Less: Customer Mains Investment	$	$ (124,932,815)							
36	Core Mains System Replacement Cost	$	$ 193,255,434							
37	Capacity	%	78%							
38	Investment per Peak Day Capacity	$/Dth-Day	$ 1,641							
39	Investment by Class	$	$ 150,739,239	$ 85,366,123	$ 57,839,209	$ 4,768,073	$ 2,765,834	$ -	$ -	$ -
40	Investment per customer	$		$ 1,407	$ 5,842	$ 37,288	$ 207,438	$ -	$ -	$ -
41	Commodity	%	22%							
42	System Replacement Investment per Dth	$/Dth	$ 3.96							
43	Investment by Class	$	$ 42,516,196	$ 15,827,787	$ 11,134,567	$ 1,007,128	$ 619,906	$ 12,960,884	$ 965,924	
44	Investment per customer	$		$ 261	$ 1,125	$ 7,876	$ 46,493	$ 418,093	$ 241,481	$ -
45	Total mains investment by class	$	$ 318,188,249	$ 170,690,504	$ 86,416,340	$ 12,942,581	$ 5,117,202	$ 29,521,297	$ 3,253,314	$ 10,247,011
46	Economic Carryin Charge Rate			15.86%	15.86%	15.86%	15.86%	15.86%	15.86%	15.86%
47	Class Annual Carrying Charge	$	$ 50,466,170	$ 27,072,326	$ 13,706,043	$ 2,052,755	$ 811,613	$ 4,682,218	$ 515,991	$ 1,625,225
48	**Total Carrying Costs**		**$ 68,992,457**	**$ 40,626,793**	**$ 17,373,003**	**$ 2,228,768**	**$ 929,971**	**$ 5,376,725**	**$ 678,242**	**$ 1,778,955**

CASE: UG 305
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Mains System Replacement Cost

Workpaper RJA-WP-3A   Reference to Exhibit CNGC/303, Amen/Page 2 of 2, Line 34

	Steel			Plastic			Others			Total		
Size	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)
<=2"	553	$61.40	$179,243	633	$7.73	$25,843	17	$32.75	$2,919	1203	$32.75	$208,006
>2"-4"	146	$114.61	$88,479	100	$15.20	$8,026	11	$74.24	$4,194	257	$74.24	$100,699
>4"-8"	113	$148.33	$88,501	8	$28.23	$1,206	1	$140.31	$993	122	$140.31	$90,700
>8"-12"	11	$185.60	$10,358	0		$0	0		$0	11	$185.60	$10,358
Total	823		$366,581	741		$35,075	29		$8,106	1593		$409,763

Unit cost used for other materials is weighted average of steel and plastic mains.

Staff alternatives regarding <= 2" pipe values: All inputs substitutes are from Exhibit Staff/1302, Compton/ 1 of 2.

Plastic: Cost/Ft. = $14.56

Miles = Res. Miles + Comm. Miles = {78.68*60,662 + 121.00*9901}/6280 = 1108

where 78.68 is the residential feet per customer and 60,662 is the number of residental customers.

where 121.00 is the commercial feet per customer and 9901 is the number of commercial customers.

Steel: Cost/Ft. = $ 62.34

Miles = Total minus Plastic miles = 1203 - 1108 = 95

	Steel			Plastic			Others			Total		
Size	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)	Miles	Cost/Ft (2015 $)	Total Cost Ths. (2015 $)
<=2"	95	$ 62.34	$31,261	1108	$14.56	$85,170				1203		$116,431
>2"-4"	146	$114.61	$88,479	100	$15.20	$8,026	11	$74.24	$4,194	257	$74.24	$100,699
>4"-8"	113	$148.33	$88,501	8	$28.23	$1,206	1	$140.31	$993	122	$140.31	$90,700
>8"-12"	11	$185.60	$10,358	0		$0	0		$0	11	$185.60	$10,358
Total	365		$218,599	1216		$94,402	12		$5,187	1593		$318,188
											$318,188,249	

CASE: UG 305
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1304

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Summary

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
1	Billing Determinants								
2	Peak Day Forecast	91,882	52,034	35,256	2,906	1,686	-	-	-
3	Customer Count	70,743	60,662	9,901	128	13	31	4	4
4	Throughput	31,599,959	3,996,951	2,811,784	254,327	156,543	3,272,979	243,922	20,863,452
5	O&M Costs								
6	Gas Supply Related								
7	Gas Planning	$ 21,037	$ 9,609	$ 6,556	$ 550	$ 323	$ 528	$ 107	$ 3,364
8	Gas Supply	$ 42,749	$ 17,007	$ 11,964	$ 1,082	$ 666	$ 1,491	$ 1,038	$ 9,502
9	Gas Control	$ 79,283	$ 32,689	$ 22,996	$ 2,080	$ 1,280	$ 5,241	$ 1,995	$ 13,002
10	Customer Related								
11	Meter Reading	$ 251,985	$ 210,829	$ 34,410	$ 444	$ 1,606	$ 3,733	$ 482	$ 482
12	Customer Acoount records and collection	$ 1,153,862	$ 986,592	$ 161,026	$ 2,080	$ 217	$ 3,137	$ 405	$ 405
13	Billing Postage & Printing	$ 385,330	$ 330,420	$ 53,929	$ 697	$ 73	$ 169	$ 22	$ 22
14	Uncollectible	$ 361,003	$ 300,336	$ 60,462	$ 205	$ -	$ -	$ -	$ -
15	Subtotal: O&M Costs	$ 2,295,250	$ 1,887,480	$ 351,344	$ 7,139	$ 4,165	$ 14,299	$ 4,048	$ 26,776
16	Customer Investment Carrying Costs								
17	Meter	$ 5,309,590	$ 2,629,190	$ 1,703,949	$ 115,325	$ 100,422	$ 506,905	$ 113,299	$ 140,501
18	Service	$ 13,216,697	$ 10,925,277	$ 1,963,011	$ 60,688	$ 17,937	$ 187,602	$ 48,952	$ 13,230
19	Mains	$ 19,814,939	$ 11,022,491	$ 2,766,474	$ 1,136,781	$ 274,618	$ 2,626,560	$ 362,791	$ 1,625,225
20	Subtotal: Customer Investment Costs	$ 38,341,226	$ 24,576,957	$ 6,433,434	$ 1,312,794	$ 392,977	$ 3,321,067	$ 525,042	$ 1,778,955
21	System Core Main Carrying Costs								
22	Capacity	$ 23,907,961	$ 13,539,473	$ 9,173,574	$ 756,239	$ 438,674	$ -	$ -	$ -
23	Commodity	$ 6,743,271	$ 2,510,362	$ 1,765,995	$ 159,735	$ 98,320	$ 2,055,658	$ 153,200	$ -
24	Subtotal: System Core Main Costs	$ 30,651,231	$ 16,049,836	$ 10,939,569	$ 915,974	$ 536,994	$ 2,055,658	$ 153,200	$ -
25	LRIC - Distribution	$ 71,287,708	$ 42,514,273	$ 17,724,347	$ 2,235,907	$ 934,136	$ 5,391,024	$ 682,290	$ 1,805,732
26	Fuctional Cost Assignment by LRIC								
27	Scheduling & Planning	$ 143,069	$ 59,304	$ 41,516	$ 3,712	$ 2,270	$ 7,259	$ 3,140	$ 25,868
28	Meter Reading, Billing etc.	$ 2,152,181	$ 1,828,176	$ 309,828	$ 3,426	$ 1,895	$ 7,039	$ 908	$ 908
29	Meters & Services	$ 18,526,287	$ 13,554,467	$ 3,666,960	$ 176,013	$ 118,359	$ 694,507	$ 162,251	$ 153,731
29a	Mains extensions	$ 19,814,939	$ 11,022,491	$ 2,766,474	$ 1,136,781	$ 274,618	$ 2,626,560	$ 362,791	$ 1,625,225
30	System Core Mains	$ 30,651,231	$ 16,049,836	$ 10,939,569	$ 915,974	$ 536,994	$ 2,055,658	$ 153,200	$ -
31	Total	$ 71,287,708	$ 42,514,273	$ 17,724,347	$ 2,235,907	$ 934,136	$ 5,391,024	$ 682,290	$ 1,805,732

Comparison Reference: CNGC/301, Amen/Page 1 of 2

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Summary

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
32	Non-Gas Revenue at Current Rates	$ 29,640,042	$ 16,926,173	$ 7,741,020	$ 505,501	$ 242,548	$ 2,159,441	$ 300,244	$ 1,765,115
	Functionalized Embedded Costs -- Apportioned by LRIC Shares								
33	Scheduling and Planning	$ 544,487	$ 225,698	$ 157,999	$ 14,129	$ 8,637	$ 27,627	$ 11,949	$ 98,447
34	Meter Reading & Billing	$ 3,756,032	$ 3,190,571	$ 540,719	$ 5,979	$ 3,307	$ 12,285	$ 1,585	$ 1,585
35	Meters & Services	$ 11,751,960	$ 8,598,137	$ 2,326,098	$ 111,652	$ 75,080	$ 440,553	$ 102,922	$ 97,518
36	Mains (Extensions plus Core)	$ 15,023,841	$ 8,059,465	$ 4,080,306	$ 611,108	$ 241,618	$ 1,393,902	$ 153,611	$ 483,831
37	Total LRIC Based Non-gas Rev Req.	$ 31,076,320	$ 20,073,871	$ 7,105,122	$ 742,868	$ 328,642	$ 1,874,368	$ 270,068	$ 681,381
38	Revenue to Cost Ratio	0.95	0.84	1.09	0.68	0.74	1.15	1.11	2.59
38a	Percent Revenue Increase to Bring to Truncated Cost	4.85%	18.60%	-8.21%	46.96%	35.50%	-13.20%	-10.05%	-51.40%
39	Incremental Non-gas Revenue Requirement	$ 1,906,285							
39a	Total Non-gas Revenue Requirement	$ 31,546,327	/31,076,320 =	1.02	Where $29,640,042 + $1,906,285 =			$ 31,546,327	
40	Step 1								
41	Increase multiple relative to system average			-	3.00	3.00		-	-
42	Percent Increase	6.43%	??	0.00%	19.29%	19.29%	0.00%	0.00%	0.00%
43	Increase Step 1	$ 144,331		$ -	$ 97,533	$ 46,798	$	$ -	$ -
43a	Unallocated Incremental Non-gas Rev. Req.	$ 1,761,953	Where $1,761,953 = $1,906,285 - $144,331						
44	Step 2								
45	Current revenue basis (i.e., Line 32)	$ 16,926,173	$ 16,926,173	$ -	$ -	$ -	$ -	$ -	$ -
46	Increase Step 2	$ 1,761,953	$ 1,761,953	$ -	$ -	$ -	$ -	$ -	$ -
47	Total Non-gas Revenue Increase	$ 1,906,285	$ 1,761,953	$ -	$ 97,533	$ 46,798	$ -	$ -	$ -
48	Non-Gas Revenue after Revenue Increase	$ 31,546,327	$ 18,688,127	$ 7,741,020	$ 603,035	$ 289,346	$ 2,159,441	$ 300,244	$ 1,765,115
49	Percent Increase		10.41%	0.00%	19.29%	19.29%	0.00%	0.00%	0.00%
50	Revenue to Cost Ratio	1.00	0.92	1.07	0.80	0.87	1.13	1.10	2.55
51	Final Increase multiple relative to system average		1.62	-	3.00	3.00		-	-
	Schedule-Average-Bill Percentage Increases from Requested Revenue Increases								
52	Net Commodity Per-Therm Gas Cost (from Tariffs)		$ 0.48409		$ 0.47278	$ 0.47278		$ 0.47272	
53	Commodity Gas Revenues		$ 19,348,840		$ 1,202,409	$ 740,105			
54	Total Revenue Requirement Before Non-Gas Increase		$ 36,275,013		$ 1,707,911	$ 982,654			
55	**Overall Percentage Increase**		4.9%	0.00%	5.7%	4.8%	Non-Core	0.00%	Non-Core
56	COMPANY RECOMMENDATIONS (From CNGC/301, Amen/2)								
57	Non-Gas Percentage Increase		8.91%	0.00%	32.16%	25.73%	8.04%	0.00%	0.00%
58	Non-Gas Revenue Increase		$ 1,508,122	$ -	$ 162,569	$ 62,408	$ 173,619	$ -	$ -
59	Net Commodity Per-Therm Gas Cost (from Tariffs)		$ 0.48409		$ 0.47278	$ 0.47278		$ 0.47272	
	Commodity Gas Revenues		$ 19,348,840		$ 1,202,409	$ 740,105			
	Total Revenue Requirement Before Non-Gas Increase		$ 36,275,013		$ 1,707,911	$ 982,654			
	Overall Percentage Increase		4.2%	0.00%	9.5%	6.4%	Non-Core	0.00%	Non-Core

Comparison Reference for the Above: CNGC/301, Amen/Page 2 of 2

CASE: UG 305
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1305

Exhibits in Support
Of Opening Testimony

August 11, 2016

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Functionalization

No.	FERC	Description	2015 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
		Plant In Service								
1		Intangible Plant	$ 187,041	$ 941,750	$ 1,128,791	Plant	$ -	$ -	$ 471,017	$ 657,774
2		Production Plant			$ -					
3		Storage Plant			$ -					
4		Transmission Plant	$ 5,900,639		$ 5,900,639					$ 5,900,639
5		Distribution Plant			$ -					$ -
6	374	Land and Land Rights	$ 223,037		$ 223,037					$ 223,037
7	375	Structures and Improvements	$ 363,785		$ 363,785					$ 363,785
8	376	Mains	$ 82,433,817	$ 5,710,753	$ 88,144,569					$ 88,144,569
9	377	Compressor Station			$ -					$ -
10	378	M & R Station Equipment	$ 7,895,830	$ 2,621,131	$ 10,516,961					$ 10,516,961
11	380	Services	$ 46,742,011	$ 1,818,540	$ 48,560,551				$ 48,560,551	
12	381	Meters	$ 12,802,931	$ 1,084,336	$ 13,887,267				$ 13,887,267	
13	382	Meter Install	$ 8,242,825		$ 8,242,825				$ 8,242,825	
14	383	House Regulator & Install.	$ 2,583,471	$ 123,447	$ 2,706,918				$ 2,706,918	
15	385	Industrial M & R Station Equipment	$ 1,670,381	$ 226,964	$ 1,897,345				$ 1,897,345	
16	388	ARO - Distribution	$ 12,504,773		$ 12,504,773	Plant	$ -	$ -	$ 5,217,942	$ 7,286,832
17		General Plant	$ 12,200,707	$ 1,147,052	$ 13,347,759	Plant	$ -	$ -	$ 5,569,699	$ 7,778,059
18		Subtotal Plant In Service	$ 193,751,247	$ 13,673,972	$ 207,425,219		$ -	$ -	$ 86,553,564	$ 120,871,655
19		**Accumulated Depreciation**								
20		Intangible Plant	$ (2,032,242)		$ (2,032,242)	Plant	$ -	$ -	$ (848,006)	$ (1,184,236)
21		Production Plant			$ -					
22		Storage Plant			$ -					
23		Transmission Plant	$ (3,280,283)		$ (3,280,283)					$ (3,280,283)
24		Distribution Plant	$ (80,106,396)		$ (80,106,396)	DistPlant	$ -	$ -	$ (34,556,497)	$ (45,549,899)
25		General Plant	$ (5,954,748)		$ (5,954,748)	Plant	$ -	$ -	$ (2,484,773)	$ (3,469,974)
26		Test Year Accumulated Depreciation Adjustment		$ (6,365,348)	$ (6,365,348)	Plant	$ -	$ -	$ (2,656,107)	$ (3,709,241)
27		Subtotal Accumulated Depreciation	$ (91,373,668)	$ (6,365,348)	$ (97,739,016)		$ -	$ -	$ (40,545,382)	$ (57,193,634)
28		**Other Ratebase Items**								
29		Contributions in Aid of Construction	$ -	$ -	$ -					
30		Customer Adv. For Construction	$ (495,562)	$ -	$ (495,562)				$ (495,562)	
31		Deferred Accumulated Income Taxes	$ (26,536,580)	$ (70,305)	$ (26,606,885)	Plant	$ -	$ -	$ (11,102,414)	$ (15,504,471)
32		Deferred Debits	$ -	$ -	$ -					
33		Working Capital Allowance	$ 2,287,971	$ -	$ 2,287,971	Plant	$ -	$ -	$ 954,715	$ 1,333,256
34		Subtotal Other Ratebase	$ (24,744,171)	$ (70,305)	$ (24,814,476)		$ -	$ -	$ (10,643,261)	$ (14,171,215)
35		Total Ratebase	$ 77,633,407	$ 7,238,320	$ 84,871,727		$ -	$ -	$ 35,364,920	$ 49,506,807

Comparison Reference: CNGC/302, Amen/Page 1 of 2

Cascade Natural Gas Corp.
Oregon Jurisdiction
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No.	FERC	Description	2015 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
36		Rate of Return			7.31%					
37		Return on Ratebase			$ 6,200,751		$ -	$ -	$ 2,583,771	$ 3,616,981
38		**Operating Expenses**								
39		Production	$ 108,233	$ 1,299	$ 109,532		$ 109,532			
40		Distribution								
41	870	Operation Supervision & Engineering	$ 502,211		$ 502,211	OpEx	$ 28,768	$ -	$ 204,465	$ 268,977.90
42	871	Distribution Load Dispatching	$ 140,032		$ 140,032		$ 140,032			
43	872	Compressor Station	$ -		$ -					$ -
44	874	Mains and Services Expenses	$ 1,073,812		$ 1,073,812					$ 1,073,812
45	875	Meas. & Reg. Station Expenses	$ 223,345		$ 223,345					$ 223,345
46	876	Meas. & Reg. Station Expenses - Ind	$ 12,145		$ 12,145					$ 12,145
47	878	Meter & House Regulator Expenses	$ 543,771		$ 543,771				$ 543,771	
48	879	Customer Installations Expenses	$ 451,504		$ 451,504				$ 451,504	
49	880	Other Expenses	$ 1,350,048		$ 1,350,048	OpEx	$ 77,333	$ -	$ 549,646	$ 723,068.61
50	881	Rents	$ 20,039		$ 20,039	Plant	$ -	$ -	$ 8,362	$ 11,677
51	885	Maint. Supervision & Engineering	$ 109,200		$ 109,200	MaintEx	$ -	$ -	$ 66,720	$ 42,480
52	886	Maint. of Structures & Improvements	$ 487		$ 487					$ 487
53	887	Maint. of Mains	$ 354,201		$ 354,201					$ 354,201
54	888	Maint. of Compressor Station Equip.	$ 781		$ 781					$ 781
55	889	Maint. of Meas. & Reg. Station Expenses-General	$ 33,903		$ 33,903					$ 33,903
56	890	Maint. of Meas. & Reg. Station Expenses-Indust.	$ 60,495		$ 60,495					$ 60,495
57	892	Maint. of Services	$ 331,052		$ 331,052				$ 331,052	
58	893	Maint. of Meters & House Regulators	$ 375,529		$ 375,529				$ 375,529	
59	894	Maint. of Other Equipment	$ 57,136		$ 57,136	MaintEx	$ -	$ -	$ 34,909	$ 22,226
60	NA	Distribution Adjustments	$ -	$ 97,202	$ 97,202	DistEx	$ 4,242	$ -	$ 44,225	$ 48,735
61		Customer Accounts	$ 1,709,474	$ 232,767	$ 1,942,241			$ 1,942,241		
62		Customer Service	$ 612,804	$ (506,656)	$ 106,148			$ 106,148		
63		Sales	$ 2,313	$ (19,501)	$ (17,189)			$ (17,189)		
64		Administrative and General	$ 5,451,075	$ 619,327	$ 6,070,401	O&M	$ 184,580	$ 1,724,832	$ 1,998,205	$ 2,162,785
65		Depreciation & Amortization	$ 6,111,512	$ 507,672	$ 6,619,184	Plant	$ -	$ -	$ 2,762,026	$ 3,857,157
66		Regulatory Debits	$ -	$ -	$ -	Plant	$ -	$ -	$ -	$ -
67		Taxes Other Than Income	$ 1,926,429	$ 200,857	$ 2,127,286	Plant	$ -	$ -	$ 887,665	$ 1,239,621
68		State & Federal Income Taxes	$ 1,356,152	$ 824,921	$ 2,181,073	Plant	$ -	$ -	$ 910,109	$ 1,270,964
69		Total Operating Expense	$ 22,917,681	$ 1,957,888	$ 24,875,569		$ 544,487	$ 3,756,032	$ 9,168,190	$ 11,406,861
70		Functionalized Revenue Requirement	$ 22,917,681	$ 1,957,888	$ 31,076,320		$ 544,487	$ 3,756,032	$ 11,751,960	$ 15,023,841

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CASE: UG 305
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1306

Exhibits in Support
Of Opening Testimony

August 11, 2016

Final Twenty-Five Items in Customer Mains Recent Installation Work Orders
Cascade's Reponse to Staff's Data Request No. 123

Work Order	Year	Material	Cost	Footage	Count	HW Index	Growth (Cost)	Growth (Footage)	**Cost per Ft**	Schedule 101	Schedule 104	Total	Avg. Footage
213097	2014		622	768	1	1	635	768	**0.83**	1	0	1	768.0
213102	2014		67	407	1	1	68	407	**0.17**	2	0	2	203.5
213727	2014		12707	3301	1	1	12968	3301	**3.93**	11	0	11	300.1
214157	2014		14110	1542	1	1	14400	1542	**9.34**	0	5	5	308.4
214389	2014		7,360	197	1	1	7511	197	**38.13**	1	0	1	197.0
214561	2014		1,742	418	1	1	1778	418	**4.25**	1	0	1	418.0
214995	2014		891	1884	1	1	910	1884	**0.48**	2	0	2	942.0
215083	2014		8,113	2144	1	1	8279	2144	**3.86**	19	0	19	112.8
215119	2014		4,154	1312	1	1	4239	1312	**3.23**	12	0	12	109.3
215303	2014		4,566	781	1	1	4660	781	**5.97**	4	0	4	195.3
215631	2014		2,099	511	1	1	2142	511	**4.19**	4	0	4	127.8
216141	2014		1,225	154	1	1	1250	154	**8.12**	4	0	4	38.5
216566	2014		5,771	3450	1	1	5890	3450	**1.71**	0	1	1	3450.0
217022	2014		4,535	977	1	1	4628	977	**4.74**	4	0	4	244.3
217438	2014		7,010	2242	1	1	7154	2242	**3.19**	19	0	19	118.0
217828	2015		6,007	2048	1	1	6007	2048	**2.93**	3	0	3	682.7
218715	2015		5,527	523	1	1	5527	523	**10.57**	2	0	2	261.5
219076	2015		1,203	526	1	1	1203	526	**2.29**	1	0	1	526.0
219506	2014		5,029	1579	1	1	5132	1579	**3.25**	2	0	2	789.5
220315	2015		618	1065	1	1	618	1065	**0.58**	7	0	7	152.1
220386	2015		772	304	1	1	772	304	**2.54**	2	0	2	152.0
220928	2015		222	1559	1	1	222	1559	**0.14**	2	0	2	779.5
220953	2015		13331	3180	1	1	13331	3180	**4.19**	8	0	8	397.5
222015	2015		69383	378	1	1	69383	378	**183.55**	1	0	1	378.0
222045	2015		9,380	2663	1	1	9380	2663	**3.52**	1	0	1	2663.0
							188087	33913					
								5.546162					

UG 305, LRIC, DR 123 response
Mains Regression Data