ORDER NO. 99-272

ENTERED APR 19 1999

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

UM 903

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| In the Matter of an Investigation into Policy Issues and Procedures Associated with Recovery of Purchased Gas Costs by Oregon's Regulated Gas Distribution Utilities. | ) ) ) ) ) | ORDER |

DISPOSITION: PGA PROCEDURES AND STANDARDS ADOPTED

## INTRODUCTION

On May 19, 1998, we initiated this investigation to examine policies and procedures related to the recovery of purchased gas costs by Oregon's three regulated gas distribution companies—Northwest Natural Gas Company (NW Natural), Cascade Natural Gas Corporation (Cascade), and Avista Corp., formerly Washington Water Power, (Avista). *See* Order No. 98-197. The primary issues for review include the appropriate structure of the risk-reward sharing incentive mechanism for gas cost differences and the role and structure of earnings reviews. These issues, and the determination of whether changes should be made to current practices, represent significant policy matters relating to the local distribution companies' (LDCs) recovery of purchased gas costs.

### Background

Purchased Gas Adjustments (PGAs) are "automatic adjustment clauses" as defined in ORS 757.210(1). This Commission has authorized PGA rate changes for Oregon's natural gas companies for over 20 years. The purpose of the PGA is to permit each LDC to adjust revenue annually to reflect actual increases or decreases in gas costs without filing a full rate case. PGAs, however, are not intended to address all costs of service of the gas utility.

The PGA has two components. The first component is prospective and resets base gas costs each year to reflect changes in the LDC's cost of purchased gas. These include changes in gas commodity costs and changes in fixed charges not related to the acquisition of the commodity, primarily interstate pipeline demand charges. The second component is retroactive and allows the LDC to defer, for later inclusion in rates: (a) 100 percent of the monthly differences between actual fixed costs and the base level in rates; and (b) a portion of the monthly differences between actual commodity-related costs and the base level in rates.[1] The LDCs accumulate the gas cost differences in a balancing account; the amounts are charged or credited to customers through annual temporary rate adjustments.

Under the PGA, each LDC files changes to its purchased gas costs and temporary rate increments to be effective on December 1 of each year. In conjunction with the filings, the Commission has typically reviewed each LDC's normalized earnings prior to authorizing changes in base gas costs and amortization of deferrals. The determination of a reasonable earnings level for these reviews has taken place through an informal process, and the results have sometimes been contentious. Difficulties arose because there were neither rules prescribing how earnings would be reviewed, nor standards governing what would constitute excessive earnings.

These difficulties, and disputes relating to the Commission's authority, surfaced in NW Natural's 1997 PGA filing, docket UG 131. While the parties were able resolve the case through a stipulation, approved by the Commission in Order No. 98-019, the stipulation indicated that the parties would continue to discuss continuing differences concerning the PGA mechanism. On May 19, 1998, the Commission formally opened this investigation to address these longstanding issues.

**Procedural History**

**1. Prehearing Conference**

On June 2, 1998, an Administrative Law Judge held a prehearing conference in this matter to identify parties and interested persons, and to establish a procedural schedule. At the conference, the parties also discussed an issues list, which was formally adopted in a July 30, 1998, Memorandum.

**2. Bifurcation**

On August 17, 1998, a second prehearing conference was held to address the status of the docket. At that conference, NW Natural submitted a petition for adoption of an administrative rule. In its memorandum accompanying the proposed rule, NW Natural argued that the remaining disputed issues, which address policy matters, should be addressed in a rulemaking proceeding to allow all interested parties an opportunity to comment, respond to comments, and present arguments to the Commission in a public meeting. NW Natural did not believe that lengthy contested case hearings with discovery and cross-examination on these issues was necessary.

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[1] By Order No. 89-1046, entered August 4, 1989, the Commission established an 80-20 (customer-LDC) incentive sharing mechanism for commodity-related cost differences. For NW Natural and Cascade Natural Gas, the sharing percentage for commodity cost differences has been modified to 67-33. (Order Nos. 98-019 and 98-502.) Avista continues to defer 80 percent of commodity cost differences.

At its September 15, 1998, Public Meeting, we denied NW Natural's request in part. We noted that the PGA, as an automatic adjustment clause, was in fact a rate schedule. Therefore, we concluded, any adjustments to the PGA must be accomplished through contested case procedures set forth in ORS 757.205 *et seq*. We further concluded, however, that a number of procedural matters relating to the PGA mechanism could be enacted in a rulemaking proceeding.

Accordingly, we concluded that the issues associated with the structure and review of PGA filings should be bifurcated and resolved in two dockets: (1) a rulemaking proceeding to establish the procedural steps for PGA filings and associated earnings reviews; and (2) a contested case proceeding to determine specific standards for the earnings review and sharing mechanisms. We continued this docket, UM 903, to address the contested case issues. We opened another docket, AR 357, to address the rulemaking portion of the PGA investigation.

**3. Stipulations with Avista and Cascade**

As a result of settlement discussions, Staff entered into separate stipulated agreements with Avista and Cascade. Both agreements, which the parties clarified on December 17, 1998, set forth certain parameters to be used in the application of a PGA-related earnings review for each company. We reviewed the stipulations and approved them in Order No. 98-543.

In this proceeding, Northwest Industrial Gas Users (NWIGU) requests that we clarify the intent of Paragraph 11 of those stipulations. That paragraph provides, in part, that:

> If adjusted earnings are above the threshold earnings level and the purchased gas cost deferrals produced a potential customer surcharge, the Company will share (return to customers) the lesser of: (a) the amount of revenue in the readjusted test year representing 80 percent of earnings above the threshold earnings level, or (b) the amount of revenue related to offsetting the purchased gas deferrals.

NWIGU requests that we confirm its understanding that this provision pertains only to the total dollars to be allocated in the proposed fall earnings review. NWIGU notes that Staff shares in that understanding of the provision.

We agree with NWIGU and Staff and confirm that Paragraph 11 of the stipulations approved in Order No. 98-543 does not speak to the rate spread, but pertains only to the total dollars to be allocated during the proposed fall earnings review. That provision is hereby clarified to reflect this understanding as to the intent of the paragraph.

**4. Hearing**

On January 27, 1999, Michael Grant, an Administrative Law Judge, held a hearing in this matter in Salem, Oregon. The following appearances were entered: Susan Ackerman and Susan Bergles, attorneys, on behalf of NW Natural; Paul Graham, Assistant Attorney General, on behalf of the Commission Staff (Staff); Denise Saunders, attorney, on behalf of Portland General Electric (PGE); Paula Pyron, attorney, on behalf of NWIGU; Peter Schwartz, Jon Stoltz and John West, on behalf of Cascade; and Don Faulkner, on behalf of Avista. The Citizens' Utility Board (CUB) also participated as a party in this docket. The parties filed simultaneous briefs on February 25, 1999.

## FINDINGS OF FACT AND CONCLUSIONS OF LAW

### Stipulated Issues

Following settlement discussions, the parties reached agreement on several issues and submitted a Statement of Stipulated Issues, attached as Appendix A. Using the issues list as a template, the parties indicated that they had reached agreement on several issues, including those related to the sharing of commodity gas differences, the relationship of earnings review to PGA filings, and the timing and structure of the earnings reviews.

We have reviewed the stipulated agreements and find them to be reasonable. Accordingly, the stipulated agreements, set forth in Appendix A, are adopted.

### Contested Case Issues

The parties identified four issues to be resolved through the contested case process. Those issues are as follows:

1. The calculation of the top of the earnings range at which sharing will begin;
2. The sharing percentage;
3. The allocation method for shared amounts to be amortized among customer classes—equal percentage of revenue or equal percentage of margin; and
4. The treatment of hedging instruments in PGA filings.

In addition to these four issues, the Commission will address two others. First, as part of Issue 4, NW Natural also contends that the Commission should modify its practice regarding the treatment of index deals in PGA filings. The Commission will treat that as a separate issue:

5. The treatment of index deals in PGA filings.

We also added another issue relating to the normalizing adjustments to test period operations. That issue had initially been identified for resolution in the companion rulemaking docket, AR 357. In that proceeding, we concluded that test periods results should be normalized, but deferred resolution of what those adjustments should be to this docket, UM 903. Accordingly, we will also address a sixth issue in this proceeding:

6. Normalizing adjustments to test period operations.

We will consolidate the first two issues for discussion, and address the remaining four issues separately.

**Issues 1 and 2: The calculation of the top of the earnings range at which sharing will begin, and the sharing percentage.**

**A. Positions of the Parties**

At the outset, **NW Natural** first notes that an earnings review is not a mandatory feature of a PGA proceeding. Because PGA filings are automatic adjustment clauses under ORS 757.210, NW Natural contends they should be, by their nature, automatic. It points out that most jurisdictions allow LDCs to pass through changes in gas costs without a review of earnings. Furthermore, NW Natural argues that the application of an earnings test amounts to retroactive ratemaking, because it would use past earnings to set future rates.[2]

Notwithstanding these allegations, NW Natural recognizes that it cannot afford the financial risk of trying to recover increases in gas commodity costs without a PGA. It notes that gas costs represent as much as 43 percent of its total revenues. Therefore, NW Natural states that it is willing to accept a PGA-related earnings review mechanism if it is fair. The company proposes an earnings threshold mechanism with four key components:

(1) For the first year, establish a baseline return on equity (ROE) equal to the currently authorized ROE from the company's last rate case (13.25 percent). In future years, use an updated ROE from the company's pending rate case, docket UG 132.

(2) Adjust the baseline ROE each year by the amount of change in the average yield on the 5-, 7-, 10-, and 30-year U.S. debt securities.

(3) Establish a "no action band" to be added to the baseline ROE for the excessive earnings threshold. NW Natural proposes a "no action band" of 300-400 basis points.

[2] NW Natural relies on an Attorney General Letter of Advice, which explains that retroactive ratemaking occurs when past profits or losses are incorporated in future rates. *See* Op-6076, March 18, 1987. Although not mentioned by NW Natural, the letter addresses automatic adjustment clauses. The letter concludes that such clauses, while retroactive in operation, do not violate the rule against retroactive ratemaking because: (1) they are authorized by the legislature; (2) they do not affect the utility's authorized rate of return; and (3) past losses or profits are not used in setting future rates. The letter does not address whether the Commission may include an earnings review within an automatic adjustment clause.

(4) Each spring, compare the company's earnings for the prior year to the earnings threshold. If the test year earnings are at or below the threshold, there would be no sharing of revenue. If the test year earnings are above the threshold, the company would refund to customers 33 percent of the excessive earnings.

**Staff** agrees that an earnings threshold should be established for the company, and that a percentage of earnings deemed excessive should be refunded to customers. Staff proposes a different methodology, however, to establish that threshold. In short, Staff recommends that the Commission determine the ROE benchmark by calculating two components: a risk free rate plus an industry average market risk premium. The average market risk premium would be adjusted for the risk of the particular LDC. On top of these two components, Staff would add a dead band earnings range to determine the earnings threshold.

Staff contends that the risk free rate should be calculated from the monthly 5-, 7-, and 10-year constant-maturity U.S. Treasury rates averaged each month, then adjusted to a "rate case" basis, then averaged over the entire earnings test period. This risk free rate would be calculated each year for the prior calendar year. Using this method, the risk free rate for 1998 is 5.2 percent.

To determine the market risk premium, Staff relies on Discounted Cash Flow (DCF) analyses and a Capital Asset Pricing Model (CAPM) analysis to estimate the cost of equity and, ultimately, the risk premium range above the risk free rate for an average LDC. Staff based these calculations on a sample of some 74 companies from the electric utility industry and some 17 LDCs. Staff then used additional company-specific information about betas to derive the company-specific risk premium for NW Natural. Using this method, Staff concludes that NW Natural's risk premium is 300 basis points (3 percentage points).

Staff contends that an earnings dead band of 225 basis points (2.25 percentage points) above the ROE benchmark should be adopted to establish an earnings threshold. Staff recognizes that a decision on the width of a dead band is a matter of judgment, but argues that its recommendation of 225 basis points is fully 50 percent wider than what is supportable based on an analysis of the distribution of actual electric utility ROEs and cost of equity estimates in the electric industry around their respective medians. Finally, Staff recommends that revenues equal to 50 percent of the amount exceeding the earnings threshold should be shared with customers through a temporary rate credit.

**NWIGU** supports Staff's proposal. It contends that an ROE benchmark should be adopted based on the economic and financial analysis offered in Staff's testimony. It contends that NW Natural's analysis of a proposed ROE benchmark are based on inappropriate considerations. First, it opposes the company's proposal to use, as an interim benchmark, its currently authorized ROE of 13.25 percent. NWIGU contends that capital costs from a proceeding completed ten years ago are irrelevant for a current benchmark ROE. Second, NWIGU urges the Commission to reject NW Natural's reliance on the 30-year U.S. Treasury security rates to update the ROE benchmark. NWIGU points out that this Commission has previously rejected the use of 30-year treasury rates in other proceedings and should do so again here.

**PGE** contends that the Commission should consider several factors in determining the top of the earnings range. PGE first notes that the earnings review proposed in this proceeding is not symmetrical. While an LDC would be required to share any earnings above a certain range, it would not be able to recover any of its unexpected costs, no matter how low its earnings. Therefore, PGE argues that the earnings threshold should be higher than the high end of authorized ROEs decided in other jurisdictions during the relevant period.

To establish the earnings threshold, PGE recommends that the Commission obtain relevant decisions on ROEs from an independent source, such as Regulatory Research Associates, calculate the mean of those authorized ROEs, then add an additional 150 basis points to reflect the asymmetry. For example, using a relevant period of July 1, 1997, through June 30, 1998, PGE states that the range of approved ROEs is 10.7 to 12.2 percent, with a mean of 11.2 percent. Adding 150 basis points would produce a 12.7 percent figure for the top of the earnings range. PGE does not address what percentage of earnings above that threshold should be shared with customers.

**The Citizens' Utility Board (CUB)** believes that, to properly balance the interests of customers and shareholders, the Commission should adopt an earnings review mechanism that does not permit an LDC to continue to earn profits above an excessive level. It proposes the following earnings threshold and sharing percentage:

(1) Use an earnings benchmark based on the LDC's allowable rate of return, updated for current interest rates.

(2) Establish a two-tiered sharing percentage mechanism for earnings 150 basis points above that benchmark. For earnings 150 to 500 basis points above the designated level, the company would refund to customers 50 percent of the excessive earnings. If earnings are more than 500 basis points above the benchmark, the company would return to customers all revenue necessary to reduce earnings back to the 500 basis point level, with 50 percent sharing thereafter for all earnings 150 basis points above the designated level.

### B. Resolution

At the outset, we note that our discussion on this issue is focused on establishing an earnings threshold and sharing percentage of revenues deemed excessive for NW Natural. As noted above, we previously approved stipulations in this docket for Avista and Cascade. *See* Order No. 98-543. In those stipulations, both companies and Staff agreed to an earnings threshold calculated annually by adding 7.1 percent to the risk free rate (rate case adjusted average yields of 5-, 7-, and 10-year U.S. Treasury debt securities). If a company is earning above that threshold, revenues representing

33 percent of the excessive earnings would be shared with customers. Using a 1998 risk free rate of 5.2 percent, the earnings threshold for the companies' upcoming PGA-related earnings review will be 12.3 percent.

Turning to the applicable threshold and sharing percentage for NW Natural, we observe that significant disagreement exists as to the point at which earnings should be deemed excessive. Under NW Natural's recommendation, customer sharing would initially be triggered only if the company earned more than 16.25 percent on equity.[3] Under Staff's recommendation, NW Natural earnings would be considered excessive at 10.45 percent. The proposals offered by PGE and CUB fall between those two figures.

All parties do agree, however, that the earnings review mechanism should be fair to all parties and efficient to administer. The objective should be simply to determine whether or not an LDC's earnings are excessive prior to passing through prudently incurred gas cost changes in rates. It should not be structured so as to turn each PGA filing into an annual rate case or show cause hearing where the company's earnings would be subject to detailed review and adjustment. Indeed, such scrutiny may eliminate any incentive for the company to pursue efficiencies.

A fair approach to an excessive earnings review should begin with an ROE threshold determined to be just and reasonable—not excessive—as a matter of policy. We believe such a threshold should be tied to the company's authorized ROE. The traditional standard for determining a reasonable ROE was stated in *FPC v. Hope Natural Gas*, 320 U.S. 591, 603 (1944):

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]

While ROE determinations have been a fundamental part of utility regulation, they are often one of the most contentious aspects of a utility proceeding. We need not consider the detailed and technical arguments that typically accompany cost of equity testimony in this proceeding, however. As stated above, NW Natural has a general rate case pending with this Commission, docket UG 132. In that proceeding, we will establish a new ROE for NW Natural. Accordingly, we accept NW Natural's proposal to adopt, as a baseline ROE for purposes of this PGA docket, the ROE determined for the company in its pending rate case, UG 132. Later in this order, we will discuss the baseline ROE and earnings threshold to be used pending the final decision in UG 132.

<u>Annual Adjustment.</u> To keep the earnings review mechanism consistent with changes in market conditions, the baseline ROE should be adjusted, up or down, by the amount of change that is experienced for the year in the average yield on U.S. Treasury debt securities. Both Staff and NW Natural propose the use of these

[3] This figure would be reduced to reflect the new ROE authorized in its pending rate case, UG 132.

securities to adjust the benchmark earning level. Their proposals differ, however, in two respects. First, Staff recommends the use of the average of three debt securities: the 5-, 7-, and 10-year U.S. Treasury interest rates. NW Natural contends that the average should also include the 30-year Treasury. Second, Staff contends that the average should be adjusted to be consistent with the average-of-year rate base on which the earnings test is based. NW Natural maintains that no rate case adjustment should be made.

Of the two adjustment proposals, we find Staff's more reasonable and adopt it. This Commission has consistently rejected the use of 30-year U.S. Treasury security rates in financial models that utilize U.S. Treasury security rates. In fact, NW Natural did not even propose the use of the 30-year U.S. Treasury security rate in its last rate case, UG 81. We also agree with Staff that the average rate should be adjusted for an average-of-period adjustment to take into account that the earnings test will be based on an average rate base.

Accordingly, the benchmark ROE should be adjusted annually by the difference between the base rate and the average for the test year of the annual yields reported monthly, and rate-case adjusted, on 5-, 7-, and 10-year constant maturity U.S. Treasury rates as reported by Federal Reserve Statistical Release H.15. The base rate shall be the risk-free rate used to determine the previous ROE or change in ROE. The change in the risk-free rate represents a reasonable proxy for the change in the company's cost of equity capital. The rate case adjustment shall be calculated through use of the following formula, rounded to the nearest 10 basis points: Adjusted Yield = $((1 + \text{Reported Yield}/2)^{1/6} - 1) \times 12$.

For the first earnings review following adoption of an ROE for NW Natural in UG 132, the amount of change shall be calculated using as a base rate the risk-free rate used in calculating such ROE.

<u>"No Action" Band.</u> The baseline ROE, as adjusted, plus a "no action" or dead band would equal the excess earnings threshold. NW Natural argues that a no action band of 300-400 points is appropriate for several reasons. It primarily contends that a wide band is reasonable because, as discussed above, an excessive earnings test is not and should not be treated as a general rate case. Staff contends that a dead band of 225 points provides reasonable results for both shareholders and customers. CUB, on the other hand, proposes a no action band of 150 basis points.

After our review, we find that the dead band of 300 basis points is reasonable for NW Natural. Our primary goal in this docket is to establish a process for ensuring that the company's earnings are not excessive prior to passing through increases in gas costs. It is not to transform the PGA process into an opportunity to micro-manage the company's earnings. An earnings threshold set at 300 basis points above the benchmark ROE will protect the interests of ratepayers and allow the company the opportunity to pursue increased earnings through cost management and operating efficiencies.

Sharing Percentage. As stated above, the parties have presented three different sharing percentage proposals. NW Natural believes that 33 percent of any earnings that exceed the threshold for excessive earnings be shared with customers. Staff maintains that 50 percent of the excessive earnings should be shared with customers through a temporary rate credit. CUB proposes a two-tiered mechanism, in which the company would return: (1) 50 percent of earnings above the threshold; and (2) 100 percent of all earnings that exceed 500 basis points above the threshold.

We conclude that NW Natural's proposed sharing percentage of 33 percent provides reasonable results for both shareholders and customers and should be adopted for the company. This degree of sharing is significant enough to ensure customers that the LDCs earnings are not excessive, while allowing LDCs to benefit from productive management of the business. We note that the 33 percentage figure mirrors the percentage risk allocation that NW Natural has accepted with regard to the deferral mechanism for gas cost variances in the PGA.

Interim Earnings Threshold. We have concluded to adopt, as a baseline ROE for purposes of the PGA related earnings mechanism, the ROE determined for the company in its pending rate case, UG 132. That rate case, however, will not be concluded until September 1999. Consequently, we must adopt an interim earnings threshold to use for NW Natural's PGA earnings review this spring.

Because only NW Natural proposed the adoption of the ROE authorized in its rate case as a baseline ROE in this docket, it presented the only proposed interim earnings threshold—its currently authorized return on equity of 13.25 percent. That ROE, however, was established in NW Natural's last general rate case, UG 81, which was concluded in 1989. We do not believe it would be prudent to compare the company's earnings from 1998 against capital costs that existed some 10 years ago.

We also are reluctant to determine an interim rate through a lengthy cost of capital analysis. As noted above, this is not a general rate case, but rather a proceeding to determine a straightforward earnings test to be applied in conjunction with gas cost trackers. Thus, we do not believe it would be judicious to focus on the detailed and technical arguments relating to cost of equity in this proceeding. That matter awaits our review and determination in docket UG 132.

Another option to determine an interim earnings threshold would be the use of a mid-point of ROEs contemporaneously awarded to other LDCs and electric utilities around the country. In support of their respective positions, both PGE and NW Natural submitted surveys from industry sources listing recent state commission determinations of ROE allowances for electric and gas distribution utilities. We acknowledge the custom of some state commissions to view an ROE set by another state as persuasive evidence of what should be adopted in their own case. This Commission, however, has consistently avoided that practice. Without detailed information as to how and why a particular ROE was adopted by another commission, it is impossible to determine whether a similar figure should be used for a utility in this state. Different state commissions have different regulatory goals and responsibilities. Moreover, some reported ROEs also appear to be but one related component of a non-traditional rate proceeding, such as an industry restructuring plan or a merger approval. Due to differing policy concerns and other matters, it would be difficult to conclude ROEs from other jurisdictions should be applied here for use in establishing a PGA-related earnings mechanism.

We note, however, that this record contains evidence of two earnings thresholds approved for LDCs in this state—those contained in the stipulations for Avista and Cascade. *See* Order No. 98-505. Those stipulations, which we concluded fall within the range of acceptable plans, established an earnings threshold for the two LDCs 1999 spring earnings review of 12.3 percent.[4] We find that figure an appropriate starting point to determine an initial earnings threshold for NW Natural for purposes of its 1999 spring earnings review.

We believe that figure should be modified slightly to reflect the increased risks experienced by NW Natural as compared to Avista and Cascade. NW Natural primarily operates in Oregon solely as an LDC. In contrast, Avista is an integrated electric and natural gas utility with the vast majority of its operations in Washington and Idaho. Cascade has the bulk of its gas utility operations in Washington. For these reasons, NW Natural contends that it is subject to greater exposure financially to regulatory risks than the other two LDCs that operate in this state. The company's argument is supported by Staff's cost of equity testimony, which found NW Natural's equity risk premium to be 30 basis points higher than that for Cascade. *See* Staff/200, Thornton/34.

Accordingly, we conclude that an interim earnings threshold of 12.6 percent should be used for NW Natural's 1999 spring earnings review of 1998 operations. If the company is earning above that level, revenues equal to 33 percent of the amount exceeding the earnings threshold should be shared with customers through a temporary rate credit. For future years, the earnings threshold will equal an updated ROE from the company's pending rate case plus a 300 basis points no action band, as described above.

**Issue 3: The allocation method for shared amounts to be amortized among customer classes—equal percentage of revenue or equal percentage of margin.**

**A. Positions of the Parties**

**Staff** believes that the method for sharing excess earnings among the gas company's rate schedules should be developed in a manner that relates to the company's earnings and is fair and equitable to customers. For that reason, Staff recommends that any excessive earnings should be allocated among a company's rate schedules and customer classes proportionally to the percent of revenue margin contributed by each customer class. Staff defines revenue margins as the rate schedule or customer class

[4] As explained above, the stipulations established an earnings threshold to be calculated by adding 7.1 percent to a risk-free rate (rate case adjusted yields of the 5-, 7-, and 10-year U.S. Treasury debt securities). Using 1998 data, the risk free rate was 5.2 percent, producing an earnings threshold of 12.3 percent.

sales revenue levels minus the company's weighted average cost of gas as grossed up for revenue sensitive effects.

Staff does not recommend allocating excessive earnings proportionately on the basis of customer class sales rate or revenue levels. Staff argues that class-specific revenue margins are more closely related to the creation of excess earnings that are generated to the extent price exceeds cost. Staff does not believe it to be reasonable to allocate excess earnings using class revenue levels because revenue by itself does not imply anything about net earnings.

**Cascade** also agrees that an allocation based on an equal percentage of margin is the most appropriate method to amortize shared amounts among customer classes. Cascade notes that it is the margin of the sales and transportation rate schedules that is designed to recover the non-gas operating cost operating expenses and a return on rate base of the utility. Because the control of these non-gas cost expenses will be the primary opportunity for the utility to generate earnings in excess of the earnings threshold, Cascade contends that an allocation of the sharing based on an equal percentage of margin is most appropriate.

**NW Natural** states that it is willing to accept an "equal percent of margin" spread of revenue reduction as a starting point. The company, however, would like to keep the approach to this issue open for consideration of other rate spreads on a case-by-case basis. NW Natural states that it recently completed a long run incremental cost (LRIC) study in preparation for its general rate case filing in docket UG 132. According to NW Natural, that LRIC study revealed discrepancies between the allocation of costs among customers. The LRIC study purportedly shows that costs are under-allocated to some of the company's schedules, while substantially over-allocated to others.

NW Natural would like the flexibility to move rates in all of its schedules toward LRIC results when there are opportunities to do so. As an example, NW Natural states that it might be prudent to move allocated schedules closer to LRIC results in a year where gas costs are declining and there are excessive earnings to be shared with customers. This would allow a rebalancing of rates without the need to bill rate increases to under-allocated customer classes. In other years where gas costs are increasing, NW Natural states that it may be preferable to use a more standard "equal percent of margin" approach to mitigate large, one-time billing rate increases to sales customers.

**NWIGU** also favors an equal percentage of margin allocation method. NWIGU believes that, in making a temporary rate adjustment based on over-earnings by the utility, the Commission should allocate those earnings in a manner that causes the least distortion from the existing margins in rates. NWIGU contends that, if rate adjustments are made on an equal percentage of revenue basis, the resulting margin rates between sales and transportation customers will be skewed. Because gas costs are passed through to customers, NWIGU explains that there is no excess earnings potential from gas cost revenues. Therefore, NWIGU believes that excessive earnings should be returned to customers based on an equal percentage of margin basis, unless the

Commission finds in a particular proceeding that good cause exists for the application of another methodology.

**CUB** recommends that the Commission adopt an allocation method that distributes the overearnings to customers based on an equal percentage of revenues. CUB cites a recent study that shows that industrial customers have benefited more than residential customers have since the gas industry was deregulated in 1985. CUB believes that the Commission should adopt an equal percent of revenue allocation method to help ensure that all classes of customers benefit from industry deregulation.

**B. Resolution**

The Commission concludes that, as a general rule, any earnings found to be excessive in a PGA related earnings review shall be allocated among customer classes on an equal percentage of margin basis. We favor this method over an equal percentage of revenue basis, because class-specific revenue margins are more closely related to the creation of excess earnings.

We agree with NW Natural and NWIGU, however, that the LDCs, Staff, or other interested parties should have the opportunity to request the application of some other method to address some particular or unique circumstance. The Commission will evaluate such requests on a case-specific basis, and require the moving party to establish good cause for application of some other methodology. Absent such a finding, the Commission will use equal percentage of margin as the basis for any excessive earnings allocation.

**Issue 4: The treatment of hedging instruments in PGA filings.**

**A. Positions of the Parties**

**Staff, NW Natural, Cascade,** and **PGE** all agree on the definition of hedging instruments, also known as commodity derivatives. These financial instruments can be used by an LDC to manage its gas costs by reducing the risk of price volatility. To date, LDCs in Oregon have used two different types of derivative products: fixed price swaps and price caps.

A fixed price swap allows an LDC to purchase supplies of gas at fixed prices known in advance. To complete such a transaction, an LDC first enters into a contract with a producer to purchase a certain quantity of gas at the prevailing index price at the time of each delivery. At the same time, the LDC enters into a second agreement with a bank or other financial counterparty regarding the same supply of gas. In this second agreement, known as the swap agreement, the LDC agrees to pay a negotiated fixed price to the bank for the same quantity of gas, and the bank agrees to pay the indexed price to the company. Together, the two agreements allow the LDC to purchase a secure quantity of gas at a known price.

To demonstrate how a swap would work, assume that the current market suggests that the average gas price for the next 12 months will be $0.24 per therm. That price, however, will change with market conditions as the year progresses, and it may go up or down. To protect its customers from a possible spike in the gas costs, an LDC may want to lock in a price for the entire period. A gas producer, however, may not want to lock in the $0.24 per therm price today, especially if it believes that gas prices will increase. If it is willing to lock in the price at all, the producer may ask for a fixed price of $0.26 per therm to do so. The LDC may find a counterparty in the financial community, however, that may not share the producer's opinion of future gas prices. This counterparty might be willing to enter into a swap agreement with the LDC at a price of $0.25 per therm.

Under this scenario, if the actual indexed price for a future month turns out to be higher than the fixed price agreed to in the swap agreement, then the LDC receives a settlement payment from the counterparty to cover the additional costs of gas for that month. If, on the other hand, the index price turns out to be lower than the fixed, swapped price, then the LDC pays the lower price to the producer, and then makes an additional settlement payment to the counterparty.

A price cap, also known as a call option, similarly allows an LDC to limit exposure to spikes in gas costs. As with a swap, an LDC first enters into an agreement with a producer for a quantity of gas at a price that is usually tied to the market index. The company then enters into another agreement with a counterparty for the call option. In this second agreement, the LDC agrees to make an up-front payment in exchange for the counterparty's agreeing to set a ceiling on prices the LDC will pay for gas under the contract. This ceiling price is usually called the strike price. If the index price is higher than the strike price, then the counterparty pays the LDC the difference. If the index price is lower than the strike price, the LDC does not exercise the option and allows it to expire.

For an example of a price cap, assume that an LDC wants to hedge against the index price going above $0.27 per therm. It could purchase a gas price call option from a counterparty with a strike price of $0.25 per therm for a certain amount of gas. For the set ceiling price, the LDC would pay the counterparty a option premium, say $0.02 per therm. If the index price goes above $0.25 per therm, the LDC would exercise the call option and receive a settlement from the counterparty to cover any costs of the gas above that ceiling price. However, if the index price stayed below the $0.25 per them ceiling price, the LDC would not exercise the option and pay the lower index price.[5]

While agreeing on the definition of hedging instruments, the parties disagree as to how the costs for the financial instruments should be treated in PGA filings. All derivative products have a price, known as the premium. In swaps, the premium is a slightly higher fixed price for the gas than the current market conditions would suggest. With price caps, an LDC is required to make an up-front payment to the

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[5] In addition to swaps and caps, there are other types of commodity derivatives that may be used by LDCs in the future. These include commodity collars, which combine a cap—establishing a strike price above the market price—with a parallel strike price below the market. While eliminating a portion of an LDC's ability to take advantage of price reductions at the bottom of the market, commodity collars cost less than pure caps and still protect an LDC from price spikes at the top of the market.

counterparty to set a ceiling price of the gas. An LDC is required to make this payment, even if it later decides not to exercise the cap. The primary dispute between the parties is whether derivative option costs be included in base costs or actual costs in PGA filings. In prior PGA filings, we have allowed these costs to be included in base gas costs.

**NW Natural** proposes that current practices be continued and that the company be permitted to use the swap price to establish the "known and measurable" base gas costs for the upcoming year. Under this practice, the "swapped" price is built into the weighted average cost of gas for the quantity of gas purchased at the swapped price. As the year progresses, NW Natural would record the actual gas costs it pays to the producers, plus all of the gains or losses it realizes on the swaps, to the PGA account.

NW Natural contends that its use of swaps does not allocate more risk to customers and less to shareholders. Rather, it contends that the derivative product simply reduce the overall level of price risk for the gas portfolio as a whole. It acknowledges that, under current practice, ratepayers pay for swaps. Because the swap locks in the price for blocks of gas purchased from suppliers, there is no gas cost variance or deferral associated with that block of gas. Thus, the 67/33 sharing mechanism does not apportion any of the costs, or savings from, that block of gas to shareholders. NW Natural maintains, however, that this treatment is similar for gas purchases for which prices were "fixed" directly through negotiations with producers or suppliers. It adds that these existing policies support the principle that prudently incurred gas costs are the responsibility of customers, not shareholders.

NW Natural also explains that it accepted 33 percent of the risk of gas cost variances in settlement of the 1997 PGA filing in part because it believed that the existing treatment of hedging instruments would continue. The company is willing to continue to accept one-third of the risk of gas cost variances, but only if it can continue to use the risk management tools, such as swaps, in the manner previously approved by the Commission.

NW Natural does, however, recommend a change in the way caps are treated in developing base gas costs. Like prior years, NW Natural proposes that the cost of caps, *i.e.,* the premium, be included in base gas costs with each PGA. NW Natural now recognizes that the cost of the gas itself should be included in base gas costs at the market price, not the strike price. In this way, NW Natural believes the 67/33 sharing mechanism works fairly to apportion the risks. If actual costs vary, up or down, from the market price embedded in the base gas costs, both customers and the company share in those fluctuations at the risk sharing percentage.

**Staff** recommends that the costs of hedging instruments no longer be built in the PGA base gas costs. Rather, it proposes that the costs of these transactions be flowed through actual gas costs subject to the cost sharing mechanism. Staff believes that, if an LDC uses a swap or other financial derivative to hedge against gas cost volatility, such activities should be subject to the incentive sharing mechanism for commodity-related cost differences. Otherwise, Staff states the ratepayers bear all the risk of the financial instruments.

Staff also contends that it is possible for an LDC to use price swaps to "game" the PGA base and benefit under the cost difference sharing mechanism. Staff explains that an LDC's decision to enter into a fixed price swap may depend on the spot gas prices from the prior winter, which are used to determine base commodity costs. If last winter's actual spot gas prices were low, an LDC has an incentive to negotiate a fixed price swap to avoid having to defer differences from a low base cost for this upcoming winter. Conversely, if a previous winter's actual spot gas prices were high, an LDC might decline to enter into a fixed price swap and thereby enjoy a high base cost for deferrals in the current winter. While Staff does not accuse any LDC of engaging in such conduct, it explains that the possibility would exists for such "gaming" if derivative option costs were included in the PGA base gas costs.

**Cascade** proposes that current practice continue and that hedging instruments purchased for the sole purpose of insulating the core market gas supply portfolio from spikes in the price of gas should be part of the costs of the portfolio and included in the PGA filings. While the company is not currently using any hedging instruments, Cascade explains that it attempts to acquire the lowest cost portfolio available to meet the forecasted requirements of the core market. To hedge against price spikes in the monthly index, Cascade generally purchases a diversified portfolio of fixed gas supplies and indexed priced gas. Because the use of swaps and other hedging instruments is simply another option or alternative to protect the portfolio from unexpected price spikes in indexed priced gas supplies, Cascade believes that the costs for this protection should be included in the cost of that portfolio.

**PGE** also believes that the cost of hedging instruments should be included in base gas costs. It explains that the use of both commodity and financial hedging is common and one of the primary means by which a utility manages its exposure to adverse price swings. As long as the LDCs purpose is to manage its exposure to adverse cost swings, PGE contends that the swapped price of gas be built in to the weighted average cost of gas in the PGA filings.

**B. Resolution**

The deregulation of the natural gas industry has significantly changed the gas purchasing practices of LDCs. Ten years ago, LDCs purchased virtually all of their gas supplies under bundled sales tariffs regulated by the Federal Energy Regulatory Commission (FERC). The companies had little or no contact with the suppliers and pipeline companies upstream from the various interconnection points. Moreover, most gas purchase contracts were very long term in nature.

After the process of buying and transporting gas was deregulated by Congress, LDCs began purchasing gas directly from suppliers. Through practice and experience, the LDCs also gradually increased the proportion of supplies purchased under shorter duration agreements. Today, gas purchase contracts are designed to closely match the pattern of usage requirements over a seasonal, monthly, and even daily basis.

In acquiring a gas supply portfolio to meet the forecasted requirements of its customers, an LDC must balance price stability with reasonableness of cost. Neither goal may be pursued to the exclusion of the other. An LDC may be able to achieve complete price stability by locking in fixed prices with producers, but producers would most likely ask for prices that exceed the market, thus jeopardizing the reasonableness of cost standard. Conversely, an LDC could seek the lowest cost by taking the lowest available price at all times. This strategy, however, would jeopardize price stability and expose customers to price spikes during the winter heating season. Consequently, LDCs attempt to purchase a diversified portfolio of fixed gas supplies and index priced gas.

To help balance these competing interests, LDCs have begun to use hedging instruments to reduce the overall variability of the cost of gas. Like fixed priced contracts, swaps and caps allow an LDC to insulate the gas supply portfolio from unexpected price spikes in the monthly index. To date, NW Natural has used swaps and caps in its 1996 and 1997 PGA filings.

Under current PGA policies, LDCs are permitted to embed in base gas costs the price of a block of gas prudently purchased in a fixed price deal. No party is recommending a change in that practice. The question presented is whether LDCs should be continued to be allowed to similarly include in base gas costs the full costs of swaps and caps.

After our review, we conclude that the swap price—the price of a quantity of gas that the company has locked in through negotiations with a bank or other financial counterparty—should continue to be used to establish the "known and measurable" base gas cost for the upcoming year. These financial instruments provide the same benefit to a gas supply portfolio that fixed-producer prices provide, that is, diversity in pricing terms and protection from spikes in gas costs. The record demonstrates that LDCs use a price swap or cap to fix the price of a quantity of gas under two scenarios: (1) when producers are unwilling to fix a price, based on their belief that prices will be increasing; and (2) when the LDC can obtain a fixed price from a bank or counterparty that is as good as, or better than, the price asked by the producers directly. So long as the utility's purpose in entering such agreements is to manage its exposure to adverse cost swings, we believe that such transactions should be treated in PGA filings in the same manner as fixed price agreements with producers.

We agree with NW Natural that there is no practical difference to customers when an LDC locks in a price through the use of swaps as opposed to through direct negotiation with producers. In a fixed price deal with a producer, the block of gas purchased at that price becomes embedded in the base gas costs, and there is no deferral activity associated with it. Thus, for that block of gas, the customers bear all the risk as they will pay a known price that might be higher or lower than the prevailing index price at the time the gas flows. The same is true for prices that are fixed for a quantity of gas through use of a swap. Again, the customer will bear all the risk for a block of gas sold through a swap because they will pay a known price that might be higher or lower than the then prevailing market conditions. Thus, use of swaps to establish base gas costs does not change or shift the risks between the LDC and customers because the risks of fixing prices with swaps are the same as the risks of fixing prices with producers.

The record also demonstrates that NW Natural has used derivative products to the benefit of customers. While the use of hedging instruments cannot guarantee lower costs, the company's use of such financial products since 1995 have enabled it to reduce its gas commodity costs by a net cumulative of $3.1 million. As NW Natural points out, this figure represents the savings after subtracting the cost of the caps the company purchased in the winter following the 1996/1997 price spike.

We acknowledge Staff's concern that the use of financial instruments to price gas supplies may potentially create opportunities for an LDC to "game" the process to the benefit of its shareholders. However, we agree with NW Natural that similar opportunities already exist in fixing prices directly with suppliers. If last winter's actual spot gas prices were low, an LDC could negotiate a fixed price contract with a supplier to avoid having to defer differences from a low base cost for this upcoming winter. If a previous winter's actual spot gas prices were high, an LDC might decline to enter into a fixed price contract. Because the Commission reviews gas purchases to determine if they were prudently incurred, we believe that safeguards exist to protect customers from such practices. Indeed, the use of derivative products may reduce the potential for "gaming" since their availability will provide more opportunity for review and comparison than offers made and accepted by direct negotiations with suppliers.

In addition, we want to emphasize that there is no evidence that any LDC has ever "gamed" the PGA process. In fact, NW Natural declined to "game" the PGA when it would have greatly benefited its shareholders. Following the 1996/1997 winter price spike, the company could have embedded the higher historic prices in base gas costs the following winter to help it recover from the financial loss experienced under the risk sharing mechanism the prior winter. Instead, NW Natural entered into several financial agreements, whose lower prices were embedded in the base gas costs for the following winter. Thus, when the company had the opportunity to "game" the process by not utilizing swap prices in gas costs, it declined to do so.

Accordingly, we conclude that LDCs be permitted to use the swap price to establish the "known and measurable" base gas costs for the upcoming year. This "swapped" price is built into the weighted average cost of gas for the quantity of gas purchased at the swapped price. As the year progresses, LDCs will continue to record the actual gas costs it pays to the producers, plus all of the gains or losses it realizes on the swaps, to the PGA account.

We further conclude that a change is warranted in the way caps are treated in developing base gas costs. The cost of caps, *i.e.,* the premium, should continue to be included in the PGA. The cost of the gas itself, however, should be included in base gas costs at the market price, not the strike price. This will ensure that the 67/33 mechanism operates on the variance of actual gas costs to the market price built into rates. If the cap is actually exercised, 100 percent of all the gains from exercising the cap will be flowed through to customers.

### Issue 5: Treatment of index deals

#### A. Positions of the Parties

**NW Natural** contends that the Commission should modify its practice regarding the use of index prices in base costs. To the extent that an LDC's portfolio included purchases at indexed prices that are not fixed directly with the supplier or through a financial derivative, NW Natural proposes that the company shall include these costs at the average projected price of two or more independent sources for such projected prices. Currently, such costs are embedded in the base gas costs at the historical prices from the prior year's index. NW Natural's proposal moves the PGA gas costs away from the use of historical prices and replaces them with forward-looking prices.

NW Natural contends that this Commission indicated some support for this approach in Order No. 89-1046, but noted that there were no reliable forward-looking gas price indices at the time. NW Natural contends that is no longer the case and points out that projections of gas costs in this region are readily obtainable from an active market in derivative products for Pacific Northwest gas trading points.

**Staff** opposes NW Natural's proposal. It contends that the base gas costs should not be artificially adjusted with market index projections because such estimates do not meet the "known and measurable" standard. It points out that winter gas price indexes are extremely volatile because of weather-driven demand. Staff contends that the ability of the market to project price spikes is no better than the ability of weather forecasters to predict cold snaps more than two months in advance.

#### B. Resolution

We agree with Staff and decline to modify the current practice of using historical costs to establish base gas costs. While the company's proposal would eliminate the prior year's price swings, it would not be capable of predicting the current year price swings. We believe that the consistent use of the prior year monthly index to derive base gas costs will wash out credit and debit referrals under the PGA.

### Issue 6: Normalizing adjustments to test period operations

#### A. Positions of the Parties

In the companion ratemaking docket AR 357, we concluded that test period results should be normalized, but deferred resolution of what those adjustments should be to this docket, UM 903. Accordingly, we must identify which list of ratemaking adjustments should be made.

**Staff** recommends that we adopt the list of adjustments shown in Staff/501, which has been attached to this order as Appendix B. Staff contends all of these adjustments, referred to as a Type 1 normalizing adjustment, are straightforward, easily calculated, and based on ratemaking treatment the Commission has traditionally applied.

With regard to weather normalization, Staff recommends that the LDCs be allowed to make a one-time selection as to whether a such a normalizing adjustment would or would not be made for purposes of the PGA-related earnings review. Staff notes that Cascade and Avista have already reached agreements with Staff to not include a weather normalization adjustment to recorded results. Staff recommends the Commission direct NW Natural to make its election at the time it makes its spring 1999 earnings review filing.

In AR 357, **NW Natural** argued that, in the PGA-related earnings review, the test year earnings should be actual utility earnings as recorded by the utility in accordance with utility accounting practices. NW Natural maintained that applying normalizing adjustments to these results would effectively turn the PGA process into a mini-rate case. We rejected that argument in that companion docket, and concluded that test period results should be normalized. NW Natural did not provide a proposed list of such normalizing adjustments in this docket.

**A. Resolution**

We agree with Staff and adopt normalizing adjustments contained in Appendix B. In AR 357, we concluded that there are certain items relating to non-utility operations and prior reporting periods that should be excluded from the utility's results of operations. The list of adjustments contained in Appendix B accurately identifies those items. We also agree that these recommended adjustments are straightforward and easily calculated. As Staff points out, LDCs have been making these types of adjustments in their semi-annual reports of operations for more than ten years.

We further agree that LDCs should be allowed to make a one-time selection whether to include or exclude a weather normalizing adjustment in PGA earnings review. NW Natural is directed to make this election in its spring 1999 earnings review filing. Whichever approach the company chooses, the risk-reward relationship will be balanced between customers and shareholders for purposes of this type of earnings review.

## ORDER

IT IS ORDERED that:

1. The stipulated agreements on issues set forth in Appendix A are adopted.

2. For purposes of the PGA-related earnings review, an interim earnings threshold of 12.6 percent will be used for NW Natural this spring, pending the outcome of UG 132. In future years, the earnings threshold will be calculated by adding 300 basis points to the company's most recently PUC-authorized ROE, updated annually by the change in the rate-case adjusted risk-free rate using yields on the 5-, 7-, and 10-year U.S. Treasury debt securities.

3. If adjusted earnings are below the earnings threshold, there will be no rate adjustment. If adjusted earnings are above the earnings threshold, the amount of revenue in the test year representing 33 percent of the earnings exceeding the threshold level will be shared with customers.

4. As a general rule, any earnings found excessive shall be allocated among customer classes on an equal percentage of margin basis. Any party may request and attempt to show good cause for the application of some other method to address a particular or unique circumstance.

5. If an LDC prudently enters into a fixed price swap agreement with a bank or other financial counterparty to manage its exposure to adverse cost swings in the price of gas, the LDC shall be permitted to use the swap price to establish the "known and measurable" base gas costs for the upcoming year. If an LDC similarly enters into a cap agreement, the cost of cap, *i.e.,* the premium, shall be embedded in the base gas costs. The cost of the gas itself, however, shall be included in base gas costs at the market price, not the strike price.

6. Historical gas costs will continue to be used to establish base gas costs for blocks of gas to be purchased at indexed prices.

7. Recorded results of operations will be adjusted for Type 1 adjustments set forth in Appendix B. NW Natural shall elect whether to include a weather normalization adjustment in its spring 1999 earnings review filing.

Made, entered, and effective APR 19 1999.

**Ron Eachus**
Chairman

**Roger Hamilton**
Commissioner

**Joan Smith**
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-14-095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-13-070(2)(a). A party may appeal this order to a court pursuant to ORS 756.580.

**Statement of Stipulated Issues**

1. Changes to PGA Mechanism
   a. Sharing of commodity gas cost differences.
   Agreement: For LDCs that adopt a 67-33 risk-reward sharing mechanism for commodity cost differences under the PGA (that is, 67% of the difference is deferred for subsequent surcharge or refund to ratepayers), there will be no earnings test prior to amortizing deferrals. For LDCs with an 80-20 sharing mechanism, an earnings test will be applied prior to amortizing deferrals.
   b. Alternative incentive mechanisms.
   Agreement: The current PGA risk-reward mechanism will be continued. Outside of UM 903, LDCs may propose an alternative mechanism to replace the current incentive system; Staff will work with the LDC to review and evaluate the proposal for possible implementation at a later date.

2. Relationship of Earnings Review to PGA filings
   a. Prospective base gas cost changes.
   Agreement: Prudently incurred base gas cost changes will be passed through in the annual Fall PGA filings, subject to the Commission's review of the LDC's gas cost purchasing practices. A separate general earnings review will be held each spring beginning in 1999; a portion of revenues above a specified return on equity level would be booked to a deferred account. (Also see 3.a.b.)
   b. Deferred gas costs.
   Agreement: Same as 1.a., above. If an earnings review is conducted, the results of the spring earnings review will be used.

3. Structure of Earnings Reviews
   a. Timing of review.
   b. Results of operations.
   Agreement: By May 1 each year beginning 1999, LDCs will file results of operations for the twelve months ended the prior December 31. (Cascade will file its results for its fiscal year ending September 30.) Any person may request to be placed on a list to receive all such filings at the time they are submitted to the Commission or may request a copy of individual filings. Any person wishing to participate as a party shall so notify the Commission and other parties via letter. Staff will complete its review and distribute summary conclusions by mid-June to all parties. By mid-July, Staff will present the results of the earnings review at a regular public meeting; alternatively, if issues are unresolved among all parties, a settlement conference including all parties will be conducted. By mid-August, the parties will file position statements on unresolved issues, if needed. The Commission would issue its decision on unresolved issues, if needed, by September 30. By October 15, LDCs will file annual gas cost tracking filing, including amortization of credit amount in deferred account, if any, resulting from the spring earnings review.
   c. Adjustments to recorded results.
   No agreement.

d. Type of rate adjustment (temporary or permanent; affected schedules; rate spread issues.
   Agreement: Temporary rate adjustment to all cost-based sales and transportation schedules.
   No Agreement: Whether basis will be equal percentage of revenue or equal percentage of margin.
e. Effective date of rate adjustment.
   Agreement: Amount of overearnings to be returned to customers will be booked to a deferred account, with interest beginning the previous January 1. The rate adjustment and amortization will be effective with the date of the subsequent base gas cost change.
f. Calculation of benchmark return on equity—formula or annual determination.
   No agreement.
g. Earnings range(s) and sharing.
   No agreement.
h. Commission decision if disputed issues.
   Agreement: Process allows parties, in lieu of an evidentiary hearing, to provide information in the form of a position statement for Commission decision on unresolved issues. Absent a Commission determination to hold an evidentiary hearing, the Commission would make the decision at a public meeting. (See 3.a.b.)
i. Notice and opportunity to participate.
   Agreement: Any person that wishes to participate as a party shall so notify the Commission and other parties via letter. (See 3.a.b.)

4. Treatment of hedging instruments.
   a. Fixed vs. floating gas price swaps.
   b. Derivative options.
   c. Others.
   No agreement.

Staff/501
Busch/1

## LDC Spring Earnings Reviews

OPUC Staff proposal, December 1998

Adjustments to recorded results of operations:

- Making significant ratemaking adjustments not reflected on books:
  - Advertising
  - Memberships
  - Uncollectible expense (3-year average of net write-offs)
  - Officers' bonuses (removed) and other incentive plans (rate case treatment)
  - Major rate base adjustments

- Removing non-operating items that were improperly recorded above the line.

- Removing entries related to prior period activity, and including subsequent period transactions clearly related to the test period.

- Making an interest coordination adjustment to restate income taxes based on the interest deduction implied by the weighted cost of debt and the rate base in the earnings report.

- Removing the effect of any temporary rate adjustment in the period, including any related to a prior earnings review.

A normalizing adjustment for weather would/would not be made for purposes of this general, retrospective earnings review (one-time selection by the LDC).