BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1286

Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's Three Local Distribution Companies	Staff's Reply Comments

INTRODUCTION

Staff, as well as the other Parties, submitted opening comments in this docket on December 4, 2007. As agreed in a letter to Judge Power on September 25, 2007, the opening comments addressed mechanisms for the recovery of gas costs, including any proposed incentive arrangements. At this time, Staff responds to the Parties'[1] opening comments and clarifies, to the extent necessary, its own proposals as well as any criticisms of those proposals.

Finally, we suggest questions (and our responses to those questions) the Parties should be able to address at the time of a workshop scheduled for February 4, 2008, in order to provide additional support for a purchased gas adjustment (PGA) mechanism in this docket.

STAFF'S RESPONSES TO THE PARTIES' OPENING COMMENTS

In Staff's view there are six fundamental questions in this docket for the Commission to address. Staff's reply comments are organized around those questions.

Should the LDCs be allowed to recover 100% of prudently-incurred natural gas purchase costs?

Yes. But this simple response is based on our understanding of the background and experience with the operation of PGA tariffs and recovery of gas costs by LDCs. Staff believes that a short historical lesson would inform the response.

LDCs purchase natural gas for their customers but in Oregon, like all other states, do not earn a return or realize any revenues above actual prudently-incurred gas costs for

[1] Parties submitting opening comments include Staff, Avista Utilities (Avista), Cascade Natural Gas Corporation (Cascade), Northwest Natural Gas Company (NW Natural), Citizens' Utility Board (CUB) and Northwest Industrial Gas Users (NWIGU).

this purchasing effort. Historically, LDCs accepted this role, despite this limitation, because gas prices were generally low and stable and thus presented few risks for the LDCs, and because State commissions granted the LDCs full recovery of prudently-incurred gas costs.[2] Today's natural gas market makes carrying out this role much more difficult for LDCs. This is not to say that nothing can be done to alleviate this difficulty—Commissions can, and have, required more frequent PGA filings, increased their scrutiny of LDC procurement practices, required more detailed gas accounting audits and implemented incentive mechanisms that provide a reasonable revenue incentive to the LDC to purchase natural gas at the lowest possible price.

The current Oregon PGA sharing arrangement added a new level of risk to this situation. This arrangement added the risk that the LDC had to absorb 33% (Cascade and NW Natural) or 10% (Avista) of any differences in actual monthly gas price that exceeded its embedded price. In the current market, large differences are likely and large differences based on the monthly price being higher than the embedded price (set at the time of the annual PGA filing) are not only possible but likely. For the LDCs this risk could not go unmitigated. The LDCs mitigated the risk by fixing (physically or financially) the price of most of their expected annual sales volumes prior to the PGA filing. This effectively reduced any variance, over or under, to zero or near zero (only volumes unhedged at the time of the PGA filing could move the difference away from zero). Staff has objected to this mitigation strategy because it violates the basic tenets of portfolio purchasing. Portfolio purchasing, as discussed throughout Staff's comments, is the only prudent, reasonable, balanced, and effective strategy to protect customers and LDC shareholders from the risks of the current natural gas market, over the long term. But LDCs generally only see the end game. While portfolio purchasing is generally accepted as the best protection for customers and the LDC shareholders over the long term, it does not protect an LDC's revenues from being eaten away by the current PGA sharing arrangement during any particular year.

For smaller LDCs like Cascade and Avista, this risk could lead to significant reductions in operating revenue and in extreme circumstances to the total loss of operating revenue. Even for a larger LDC like NW Natural, the risks to revenues of the current

[2] Contrast this recovery arrangement with that established for capital investments made by LDCs for measurement, safety, billing and customer services related to the delivery of natural gas to its customers. The rates approved for these investments provide for both the return of and return on the investments. Historically, LDCs have been allowed only the recovery of costs for gas supplies and their transportation to the LDC's distribution system. The trade-off here is a simple one: customers guarantee the LDC full (100%) recovery of prudent gas supply and transportation costs, and the LDC gives up any request for a return on gas supply and transportation costs. This arrangement functioned successfully for over twenty years, until the risks associated with purchasing gas supply began to grow and eventually become more than most LDCs could accept. Since that time (mid- to late-1990s) most State commissions have sought ways to keep gas supply prices to customers as low as possible, compared to available market prices. Ways to achieve this end have included various purchasing/contracting arrangements, financial hedging, storage, GPIMs, and removing the LDC from the gas purchasing function. None of these has been totally successful. Still, even as the price and volatility in gas supply markets continued and continues to increase, most state Commissions have retained the original guarantee to LDCs of full recovery of prudent gas supply and transportation costs. The results of a survey taken by Staff of State commissions show that most of these commissions continue this guarantee.

Oregon PGA sharing arrangement are quite real and substantial. Two examples might help demonstrate the level of this risk:

1. In its Advice No. 07-6, NW Natural proposed a change in its PGA mechanism for the 2007-2008 PGA year primarily to protect the company's revenue from reductions due to the operation of the Oregon PGA sharing arrangement. NW Natural's proposal was to effectively cap the revenues at risk due to Oregon's PGA sharing arrangement at $5,000,000. This cap is about 5-8% of NW Natural's annual non-gas commodity operating revenues.

2. In Docket UM 1282, Staff originally proposed a disallowance of gas costs of almost $4 million. This disallowance represents about 60% of Avista's annual Oregon non-gas cost revenues. Yet the difference between the WACOG proposed by Avista and the WACOG proposed by Staff was only about 5%. Thus even relatively small variances in WACOGs can translate to large reductions in LDC revenues.

With that background in mind, *Staff* supports 100% recovery of prudently-incurred gas purchase costs by the LDCs. Avista's and Cascade's comments are consistent with Staff's on this question.

Avista supports a simple PGA providing for 100% pass-through of prudently-incurred actual LDC gas costs, saying the current mechanism "makes no sense when applied to the current natural gas market."

Cascade believes the current PGA mechanism is appropriate for the recovery of gas costs, except that "the mechanism should be modified to allow LDCs to defer and recover 100% of their prudently incurred gas costs." Cascade correctly points out that the current basis for sharing differences between estimated costs and actual costs is flawed because those differences occur primarily due to (1) market factors completely outside an LDC's control and (2) the uncertainties and complexities inherent in forecasting prices.

NW Natural's comments are nearly opposite those of Cascade's with regard to the efficacy of a mechanism that would pass-through to customers 100% of prudently-incurred gas costs. At Page 4 of its comments NW Natural states:

> While a 100% pass-through mechanism does not penalize an LDC for market conditions over which it has no control, this mechanism should not be adopted because it fails to align shareholder and customer interests. Without sharing, the 100% pass-through would motivate the LDC to avoid the risk of disallowances rather than to pursue cost savings.

Staff disagrees. Staff proposal calls for 100% recovery of prudently-incurred gas costs—prudency being assessed by Staff and other Parties based on well thought-out purchasing principles and guidelines that allow the Commission to decide whether any costs were imprudently-incurred. In addition, we have included a Gas Purchase

Incentive Mechanism (GPIM), to encourage the LDC to purchase gas at the lowest price possible compared to available market price at the time of purchase. The two proposals work in tandem—they are not mutually exclusive. It's very likely the sort of behavior described by NW Natural would be uncovered through Staff reviews of LDC purchasing practices and price, particularly when "avoiding disallowances" means failure by the LDC to adhere to portfolio purchasing practices. What all this means is that the scenario laid out by NW Natural in the quote above is not likely to occur if the Commission adopts Staff's recommendation for a PGA that allows the LDC 100% recovery of prudently-incurred gas costs.

NWIGU does not oppose 100% recovery but notes such a change should be accompanied by "heightened scrutiny." (p. 3) Staff agrees that detailed prudence reviews of LDC natural gas purchasing practices and price are essential. Such reviews are currently carried out by Staff, not only at the time of the annual PGA filing, but throughout the year. This will not change when the Commission allows 100% recovery by the LDCs of prudently-incurred gas costs. As Staff indicated in its opening comments, a complete discussion of natural gas portfolio purchasing practices is the scope of the second phase of this docket, including the importance of providing adequate documentation of those purchases for Staff, and ultimately, the Commission, to allow for recovery of only prudently-incurred gas costs.

CUB opposes 100% recovery by LDCs of prudently-incurred gas costs. Part of that opposition comes from CUB's belief that the LDCs have equal potential to under- or over-hedge their gas supply under the current "risk-reward" sharing mechanism and that Staff's proposal for 100% recovery only addresses the "utility whose risk-aversion led it to imprudently over-hedge." (p. 8) CUB contends this recovery would come with a tradeoff in that "shareholders and utility managers, who would now be completely insulated from gas commodity costs, wouldn't have a personal stake in gas commodity costs. In abandoning risk-reward sharing, the Commission would be removing the alignment of customer and shareholder interest in keeping gas costs low. Under this proposal, too, customers would have to rely on regulatory prudence reviews to ensure that utilities procure gas in a prudent manner, despite their lack of a personal stake in gas costs." (p. 9)

Staff disagrees. Commission tariffs create incentives for LDC decisions and actions. There is a direct link between the sharing arrangement in the current PGA mechanism and LDC hedging levels. Under-hedging does not protect LDC revenues from the current PGA sharing arrangement. Thus, LDCs have no incentive to under-hedge under the current PGA. Over-hedging <u>does</u> protect LDC revenues from the sharing component of the current PGA mechanism. This means the only "personal stake" the current PGA mechanism gives LDCs in the cost of gas is to protect its revenues from the sharing arrangement and/or to manipulate the benchmark price (the embedded weighted average cost of gas in the energy charge) in pursuit of unearned revenues from the sharing arrangement. Only incentive mechanisms like those proposed by Staff provide both an incentive for LDCs to purchase gas at the lowest price possible and support portfolio purchasing (no over- or under-hedging). CUB also notes that regulatory prudence reviews will be required with 100% recovery. As we noted above, Staff believes prudence reviews are mandatory under any regulatory scheme for purchased gas costs and so we do not equate our proposal with a higher level of scrutiny not currently expected.

Should the Commission continue the existing PGA sharing arrangement or put in place the alternative to this arrangement proposed by CUB?

Neither—the Commission should not continue the existing PGA sharing arrangement, nor should it impose a dead band as proposed by CUB. We address each "option" separately.

Should the Commission continue the existing PGA sharing arrangement?
No. As Staff has indicated throughout this docket, in Docket UM 1282[3], and over the last three years, the current PGA mechanism is both ineffective and counterproductive in achieving the lowest possible gas prices for LDC customers. It encourages LDCs to focus first and foremost on mitigating the risk to their revenues from the PGA sharing arrangement and the denial of full recovery of prudently-incurred natural gas costs. It also impedes use of portfolio purchasing of natural gas by LDCs.

Avista points to Staff's 2005 Natural Gas Procurement Study and agrees that the "current gas cost sharing mechanism within the PGA encourages LDCs to hedge a majority of their gas supply to avoid the potential financial risk of high gas prices."

Cascade proposes, consistent with Staff's opening comments, that "the Commission terminate the 1/3 sharing portion of the current mechanism because it does not work in today's highly volatile natural gas market and does not provide a true incentive to lower gas costs" and it imposes an unreasonable and unnecessary risk on LDCs when prices are higher than anticipated, and also deprives customers of receiving the full benefit of gas prices that are lower than expected."

NW Natural recommends the Commission retain the existing PGA, but "modify its sharing levels from 67/33 to 80/20." This recommendation rests on NW Natural's conclusions that the current PGA (particularly its sharing arrangement), ". . . works to align customer and shareholder interests, encouraging the LDCs to meet purchasing goals that benefit customers with the lowest reasonable cost." (p. 1)

The modification to the sharing levels the company proposes is already allowed by Commission Order No. 99-272, entered April 19, 1999. In Staff's view, this modification would merely allow the severe problems with the current PGA mechanism to continue, most particularly the existing sharing arrangement. Staff does not agree with the company that this modification would be sufficient to incent the company to purchase

[3] Docket UM 1282 was the investigation into Avista's 2006 PGA purchasing strategy which resulted in, by stipulation of most of the parties, a $500,000 reduction in the gas costs to be recovered by the company's customers. CUB was not a stipulating party.

gas for its customers at the lowest reasonable price. By its support for continuation of the existing PGA mechanism, including its sharing arrangement, NW Natural implicitly opposes recovery by LDCs of 100% of prudently-incurred natural gas costs. It is not clear why 67/33 sharing "is no longer sustainable," 100% recovery cannot be supported, but 80/20 sharing is sustainable and can be supported. NW Natural's answer is that the 67/33 sharing "exposes the Company to an unacceptable amount of risk," but that some level of sharing is needed as an incentive for the company to purchase gas at the lowest price possible. That level is, NW Natural claims, the 80/20 it has proposed.

As Staff argues in its opening comments, this may have been the case in 1989, or even in 1999, when the natural gas market was very different than it is today. But in today's natural gas market, the current PGA and its sharing arrangement is useless for encouraging LDCs to purchase gas at the lowest price possible. In fact, this PGA actually discourages such actions by the LDCs by presenting an overriding threat to LDC revenues (as NW Natural, Cascade and Avista all note), thus demanding that the LDC focus on mitigating this risk first before seeking lowest possible gas prices.

NWIGU notes the same problems with the current PGA as does Staff. It notes that, "[t]he problem that NWIGU sees with the current incentive structure is that the utilities have a tendency to financially or physically hedge too large a portion of their natural gas needs to protect their exposure and that may or may not coincide with customers' best interests depending on what is expected to happen in the natural gas market." (p. 7)

NWIGU suggests two solutions to this problem. One is that a threshold be determined in advance, above which the utilities must meet a burden of proof for customer benefit that exceeding that threshold for hedging is prudent. The second solution is to set an "externally derived" benchmark to determine how gas costs are set for recovery from customers. (pp. 7-8) NWIGU states that these options should be reviewed no matter the ultimate sharing arrangement.

Although Staff certainly supports discussion of these options, we continue to recommend Commission adoption of Staff's proposed 100% recovery of prudently-incurred gas costs, along with one or more appropriate incentive mechanisms.

CUB supports continuation of the current PGA mechanism, including the sharing arrangement, with the addition of a dead band. CUB bases this recommendation on its conclusion that the current PGA is functioning reasonably well." (p. 1) CUB's exact proposal is described on page 2 of its comments:

> Our proposal attempts to modify mechanisms that are functioning reasonably well, by adjusting the distribution of risk within the mechanisms to better reflect which entity, shareholders or customers, is better able to manage the risk in question. Though a deadband is new to an Oregon PCA mechanism, it is a well-established measure of normal business risk

that has been used for electric utilities for years, and we do not see it as a radical departure from the current Oregon regulation.

Staff has issues with many of the ideas underlying this conclusion and discuss them here before moving to a more complete discussion of the dead band mechanism CUB proposes.

- First, in reviewing pages 3-4 of CUB's opening comments, it appears that CUB does not entirely understand how the current PGA mechanism, including the sharing arrangement(s) works. The mechanism is quite simple in its calculations, but to clarify for the Commission, we quickly describe it here: In the current mechanism, a forecasted gas commodity cost is embedded in rates based on the annual PGA filing. Monthly collections based on this rate are compared each month with the actual cost of the LDC's gas for each month. Any variances between collections and actual commodity costs are shared between the LDC and its customers, 33%/67% (LDC/customers) for Cascade and NW Natural and 10%/90% for Avista. CUB is also factually inaccurate in its description of the mechanism.[4]

- Second, CUB doesn't entirely understand the massive changes that have occurred in natural gas markets since implementation of the current PGA mechanism, as well as the consequences of those changes for LDCs. Since 2000, annual gas prices have increased between four and sevenfold, and price volatility has increased by well over 500% (for example, the difference between highest and lowest price in September 2001 was $0.62; the same difference in September 2005 was $4.04—a 557% increase). In fact, today's natural gas market bears little resemblance to that in 2000, except that selling and buying natural gas remains, ostensibly at least, the purpose of the market. The market's shape and operation is the result of multiple and complex actions and factors (including hedge funds with billions of dollars invested in speculation on the direction and size of gas price changes). This market is not only beyond the control of LDCs but is so complex as to make full understanding of it nearly impossible. This market is, in point of fact, beyond the understanding of many seasoned gas traders. Even these venerable veterans fear this market.[5] So it should not surprise anyone that LDCs fear it. Understand, Staff is

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[4] For example, neither Cascade's nor NW Natural's current PGA mechanism allows pass through to customers of 100% of commodity-related costs incurred up to the date of the utilities' PGA filing each fall. NW Natural <u>is</u> allowed to recover 100% of working gas costs for storage gas injected up to the time of the final PGA filing each year (about mid-October of each year). In addition, Avista's sharing ratio is 90%/10%, not the 80%/20% indicated by CUB's comments.

[5] On the fears of the current natural gas market see:

a. Business Week, January 17, 2007. "How Speculators Increase Oil [and Natural Gas] Volatility."
b. New York Times, January 15, 2006. "Energy Trading – Post Enron."
c. Natural Gas Intelligence, April 13, 2006. "Utility Hedging Against Gas Price Volatility Remains Essential, PG&E Fuel Manager Says."
d. Planalytics, Inside Edge, March 6, 2006. "The utilities today are faced with the unenviable task of trying to compete with the "professional gamblers" or hedge funds when they are managing the risk of natural gas exposure."
e. Issues Alert, October 13, 2006. "Energy Commodity Hedge Funds and Impacts on Energy Markets."

not impugning the abilities of the LDCs' gas supply departments, just pointing out how much more complex and unpredictable today's market is compared to the markets of the 1980s, 1990s or even earlier this decade.

CUB's comments ignore just how volatile, unsettled, and dangerous the current natural gas market is. In particular, CUB's comments show little understanding of the extremely high level of revenue risk LDCs face in purchasing gas in this market. Of the Oregon LDCs, NW Natural is best situated to deal with this risk. It has significant amounts of storage available to it, has a moderately high level of base load sales, some noticeable diversity in its load to help offset purchasing risks, and has the opportunity to shift among various financial and physical resource options, even late in the year. But even with the resources available to NW Natural, its ability to cope with and purchase gas effectively in this market, especially at prices below those in the market, is limited, at best. Avista and Cascade have no significant means to cope with, let alone "beat," this market. Generally, they must just take what the market (physical and financial) offers them, and thus face a greater level of risk than NW Natural. Clearly, CUB's view of the natural gas market leads it to the false conclusion that the current PGA mechanism is working but for the need to add a dead band mechanism.

- Finally, the addition of a dead band to the current PGA mechanism as proposed by CUB serves only to make the current PGA mechanism more ineffective and more counterproductive. The current PGA mechanism CUB wants to continue not only increases LDC risks for actions/decisions for which the LDC does not, and could not, earn a return, it removes the incentive for the LDC to seek to purchase gas at the lowest price possible compared to the prices available in the market. In addition, the current PGA mechanism makes it difficult or impossible to figure out if and when an LDC is purchasing at a price near, above, or below available market prices. Thus, not only does the current PGA send the wrong message to LDCs (focus on risk mitigation rather than finding and purchasing the lowest priced gas possible) but the mechanics of the PGA make it difficult to impossible to determine if and when the price paid for natural gas by an LDC is reasonable compared to available market prices.

  For example, the current PGA sets up a monthly comparison of an **annual** benchmark WACOG controlled by the LDC and established at the time of the **annual** PGA filing with the LDC's actual **monthly** WACOG for each **month** during the year. The results of this comparison are the variances that are shared between the LDC and customers. The results of this comparison are nonsense, since the items compared are not equivalent. What do any variances found actually

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f. Planalytics Symposium Presentation, August 16, 2006. "Hedge Funds Fuel Huge Growth in Gas Market."
g. New York Times, January 25, 2007. "Hedge Fund Chiefs, With Cash, Join Political Fray."
h. Midwest Attorneys General Natural Gas Working Group (Illinois, Iowa, Missouri, Wisconsin), March 2006. "The Role of Supply, Demand and Financial Commodity Markets in the Natural Gas Price Spiral."

represent? Staff submits these variances tells one nothing about how well or poorly the LDC is purchasing natural gas, or how the LDC's WACOG compares to available market prices. And ultimately purchasing near, below, or above available market prices is the test of how well the LDC is doing at procuring the lowest priced gas possible for customers. Secondly, the current PGA mechanism is set up so that the WACOG set in rates at the time of the PGA filing is computed using last year's weather-normalized sales volumes. This calculation inherently produces a PGA WACOG that does not reflect actual expected sales volumes for the upcoming PGA year. In a situation of growing LDC load, which has been and remains the case for Oregon LDCs, using normalized historical volumes for the PGA produces an artificially high PGA WACOG for the upcoming PGA year which, absent other changes, results in an overcollection from customers by the LDC. A third example is that there is no prohibition in the current PGA mechanism of the LDC using storage, excessive financial hedging, excessive spot (cash) daily and monthly purchases and renegotiated financial hedges, for example, to create variances between the annual benchmark WACOG and monthly WACOG that are not based on savings compared to market prices but still benefit the LDC and/or increase customers' gas costs.

<u>Although many of the parties oppose such a mechanism, should the Commission impose a dead band mechanism as CUB has proposed?</u>
No. The dead band proposed by CUB is the mechanism Staff commented on in its opening comments under the name, "PGE dead band". These comments identify and explain the many shortfalls and the incorrect incentive structure supported by the PGE dead band. The shortfalls and problems include pointed out in Staff's opening comments include:

- The PGE dead band applied to the LDCs suffers from all the problems associated with current Oregon sharing;
- The PGE dead band suffers from an additional problem as well. It places even greater pressure on the LDCs to fix the price of virtually all expected annual sales volumes;
- In adopting a dead band for PGE's power cost variations, the Commission concluded that PGE should absorb some normal variation of power costs. (Order No. 07-015 at 26) However, electric utilities have another advantage over LDCs: electric utilities deliver electricity. That electricity can be produced from a variety of sources. LDCs procure and sell only natural gas;
- These problems would generally eliminate portfolio natural gas purchasing by LDCs and, along with it, the protections it offers to LDC shareholders and customers; and
- In this environment, Staff expects the PGA filings, particularly the reviews of portfolio design and purchasing practices, will become difficult, complex, and extremely contentious, with frequent litigation and court appeals of Commission decisions.

Neither Avista nor Cascade directly comment on a dead band alternative. *Avista* “doesn’t see the need for *any* gas procurement incentive mechanism.” [Emphasis in original material]

NW Natural, like Staff, opposes adding the dead band proposed by CUB to the current PGA mechanism, saying that the “proposal fails to maintain alignment of customer and shareholder interests and fails to recognize the significant differences between electric and gas utilities, and therefore should be rejected.” (p. 4)

NWIGU does not support a dead band application to the gas LDCs, “given the fundamental differences between the natural gas LDC and electric utilities.” (p. 6) Industrial customers agree with Staff that a dead band on a gas LDC would not appear to incent optimum purchasing and planning. NWIGU believes that a benchmark should be tied to achieving the best deal for consumers, along with a financial incentive to achieve that goal. “A dead-band with a gas utility turns this concept on its head, and in comparison makes the gas utility more risky that it is today.” Finally, NWIGU agrees with the other LDCs and Staff that the gas utilities do not control the commodity market or other factors that influence natural gas commodity costs, and unlike an electric utility, a gas utility does not produce any of the commodity it is selling. (pp. 7-8)

So, Staff, NW Natural and NWIGU all oppose CUB’s proposal. But, what are we opposing? What is CUB’s proposal for a deadband? CUB proposes the following mechanism for all gas cost variations after the utilities’ PGA filing:

An earnings deadband of ±100 basis points ROE, a varying gas cost deadband depending on whether or not the utility is subject to SB 408 and a sharing arrangement of 90/10 (customer/utility). CUB does not provide any examples of how the mechanism works, but instead focuses on discussing the components, relying heavily on the Commission’s work in UE 180.

First, CUB finds that there is enough commonality between electric and natural gas utilities to simply propose a smaller deadband than what the Commission found to be appropriate for PGE in UE 184. Staff disagrees with this major assumption of CUB, and points to CUB’s own comment that “gas utilities can only supply natural gas with . . . natural gas.” (p. 10)

Second, CUB’s proposal is defined by its earnings deadband. As we noted in our opening comments, this dead band is not needed for LDCs. OAR 860-022-0070 has provided procedures and standards for reviewing gas utility rates in the context of the purchased gas adjustment mechanism since 1999. The earnings review is conducted on an annual basis independent of and in advance of the PGA filings. The purpose of such an earnings review is to determine whether the gas utility’s earnings are above an earnings threshold so as to require some sharing of revenue with customers before passing through base gas cost changes. Staff’s and NWIGU’s opening comments both indicate a need to review the earnings threshold, and in fact, the mechanism needs to be reviewed in 2008 because it would sunset after this year without provisions to extend it. CUB's proposal, as we understand it, adds another mechanism that could reduce the LDCs' earnings twice—the earnings review would act to reduce any overearnings by the LDC at the time of the spring review, and the dead band would also require the LDC to absorb significant differences in gas costs at the time of the PGA filing.

CUB also proposes to shift "more of the risk of significant commodity cost variations to customers, who are in a better financial position to absorb significant cost increases, and who should not be expected to over-pay when gas costs decrease significantly." CUB proposes that customers bear the bulk of these risks, while continuing to maintain a utility's stake in such cost excursions through the utility's 10% share.

Staff agrees that there may be large cost excursions as a result of major market or environmental disruptions. However, the effects of such disruptions on LDCs and their customers would be reduced greatly through portfolio purchasing practices.[6] CUB's dead band proposal will not achieve these objectives.

But CUB's proposal is fundamentally flawed; if for no other reason than it relies on the faulty premise that the current mechanism, the foundation of the proposal, is working reasonably well. Specifically,

❖ On pages 5 and 6, CUB compares natural gas prices for Oregon customers with those for customers in the nearby states of Washington, California, Idaho, and Nevada. CUB compares city gate gas prices for these states to reach the conclusion that "…Oregon's city gate natural gas prices were lower than the national average in every year except 2002 [and]… right in the middle of the pack" of the surrounding states, when 2002 data is removed. According to CUB, "Oregon's city gate gas price was lower than all but those in Idaho and Montana," when 2002 data is removed. However, if this data is examined more closely it reveals:

    - Gas prices for Oregon would be expected to be lower than the national average, since the price at the points through which Oregon LDCs purchase gas compared to the points through which Eastern and Midwestern LDCs purchase gas is almost always lower.

    - Consistently, the gas prices for Idaho and Washington customers are at or below those for Oregon. Neither state has a sharing arrangement like Oregon's.

    - Since 1998, in all years except 2001 (the year of California's energy crisis) and 2005 (the year the price of gas in the US topped $15/Dth) even California gas prices are, in general, near to or below those for Oregon. In 2006,

[6] Market disruptions large enough to overwhelm prudent portfolio purchasing practices and thereby significantly harm LDCs or their customers would likely signal either a watershed change in the structure of the market itself or a dramatic energy crisis (e.g., major supply disruption, failures of several major energy financial players, world war). Such disruptions are simply beyond the capacity of either LDCs or their customers to absorb or mitigate.

Oregon's price was significantly more than the price for California ($1.34) and for all the other states except Nevada, but this was, Staff believes, the result of a change in purchasing practices by Oregon LDCs that began in 2002. In 2002, Oregon's natural gas price was significantly higher than all the other states ($2.05 – CA; $1.42 – WA; $1.59 – ID; and $0.86 – NV). These differences were likely the result of Oregon LDCs locking in too-high prices during the run-up in gas price during 2001. Afterwards, the Oregon LDCs were more careful. During 2003, Oregon's price was less than that for Nevada, nearly the same as that for Washington and California, and higher than that for Idaho (with its easy access to Rockies lower-priced supplies). The situation improved in 2004 with only Idaho prices lower, and again in 2005 with Oregon's price being the lowest among all these states. But the situation reversed in 2006, with Oregon's price once again lower only than that for Nevada. This result was again likely caused by the LDCs entering too many financial hedge deals at the extraordinarily high 2005 prices and thus leaving themselves little space in their portfolios to purchase gas at the dramatically lower prices during 2006. Keeping up better with market intelligence and following proper portfolio purchasing practices would have alleviated much, if not all, of this price differential for the Oregon LDCs.

- Since 1998, Oregon's gas prices have been consistently lower only compared to prices for Nevada. But considering the insufficient pipeline access for Nevada and the large amount of new gas-fired electric generation being built in Nevada during this period, this result is not surprising.

For the comparison to be valid it would need to be done on a LDC-by-LDC basis. This would ensure that LDCs with like size and operational characteristics (e.g., demand, purchasing power) are compared to one another, rather than comparing state-wide averages.

❖ On page 7, CUB examines the credit status of NW Natural as represented by the company's debt and equity ratings from Standard and Poor's and Moody's and concludes, erroneously, that these results indicate, ". . . that Oregon's current PGA mechanism for NW Natural is not considered to be an enormous liability by the credit rating agencies." What CUB fails to mention in this analysis is that NW Natural has in place Commission-approved mechanisms specifically intended to protect the company from degradation of these ratings. These mechanisms include several deferral accounts, WARM, and, of course, revenue decoupling. These mechanisms, at least for now, more than compensate for the current risks involved with gas purchasing by NW Natural. This may change, however, if the current PGA sharing arrangement continues and gas market uncertainty continues to increase, or if the CUB-proposed PGE-like "dead band" mechanism is adopted by the Commission.

❖ Finally, on page 8, CUB's comments proclaim, "Removing Risk-Reward Sharing Won't Remove Need for Prudence Reviews." Staff concurs and has never made any assertion to the contrary. In fact, Staff proposes the Commission adopt two

> GPIM mechanisms designed to provide a reasonable revenue incentive to the LDC to purchase natural gas at the lowest price possible compared to the prices available in the market. But it's a truism in the regulation of utilities that no regulator can ever monitor and review each decision and action by the utility. Nor would a regulator want to do this. Thus, getting the regulatory incentives for utilities right is very important. Bluntly put, any regulatory prescription that places on a utility a high risk of substantial revenue loss must encourage the utility to protect against the risk before and often in place of going after the reward. The current PGA mechanism, mainly through its sharing arrangement, and certainly the replacement PGA proposed by CUB, are just such regulatory prescriptions. Their risks for the LDC clearly outweigh any reward that might be earned.

While CUB is correct that dead bands have often been utilized as a means to establish the level of normal business risk for utilities, a dead band of the type proposed by CUB has, to our knowledge, never been employed for this purpose for gas costs. Normal business risks refer to those risks over which the utility has some reasonable level of control and that directly affect the core operations of the utility to deliver natural gas to its customers. As Staff has argued elsewhere, purchasing natural gas does not meet this definition. Consequently, a dead band such as now is in place for PGE, and which CUB proposes to put in place for the LDCs, is not appropriate for this purpose. Staff's proposal is consistent with PGAs across the US and with regulatory efforts to (1) encourage utilities to purchase natural gas at the lowest possible price compared to the market prices available at the time of purchase and (2) follow appropriate portfolio practices in constructing natural gas supply portfolios.

Clearly, Oregon's current PGA sharing arrangement, combined with the natural gas market of the 2000s, is a substantial and continuous threat to LDC revenues. As a result, the LDCs spend a lot of time and effort searching for and carrying out actions to mitigate this risk. As explained above and in Staff's opening comments, the dead band proposed by CUB increases the risks faced by the LDCs with respect to gas purchasing. As a consequence, LDCs would focus even greater time and effort on finding and putting in place means to mitigate these increased risks. In such circumstances, it's difficult or impossible for the LDCs to serve two masters, risk mitigation and purchasing the lowest priced gas possible for customers. The prime objective of Staff's PGA and GPIM proposals is to re-focus the attention of LDCs away from mitigating the risk of the current PGA sharing arrangement and CUB's proposed dead band, and toward where it should be—purchasing gas for their customers at the lowest price possible. The CUB proposal pushes LDCs to continue to focus the lion's share of their attention and efforts on PGA sharing risk mitigation and away from low cost gas purchasing. This difference is a question the Commission needs to answer—what LDC actions and time commitments does the Commission want its PGA policies to encourage, reward, and penalize?

The Commission should not retain the sharing arrangement of the current mechanism and it should not adopt CUB's proposal

Although it is clear from its comments that *NWIGU* does not support CUB's proposal for a dead band mechanism, NWIGU does support two important features of an appropriate mechanism for the LDCs:

1. The Commission should look to protect customers with a modification to the earnings review mechanism. NWIGU urges the Commission to apply an appropriate adder in the range of 150 to 175 basis points under any incentive mechanism options or 100% pass-through mechanism.

Staff, as noted previously, supports a modification to the earnings review mechanism before the end of 2008.

2. NWIGU recommends that the Commission allow reasonable variations in allowed mechanisms provided that these "mechanisms utilize robust and evolving portfolio purchasing management strategies and provide for the lowest reasonable cost in a balanced portfolio." (p. 4)

Staff agrees with NWIGU that the PGA mechanism, including any incentive component should not be based on the notion that "one size fits all." Differences in LDC size, load characteristics, purchasing power and access to hubs should certainly be factored into mechanism design.

Throughout its opening and reply comments, Staff has placed a great deal of emphasis on the notion of risk-–for shareholders, customers, and the LDCs in general—involved with purchasing natural gas supplies. Staff contends that the current PGA mechanism, and even more so the changes to that mechanism proposed by CUB, increase risks for all stakeholders:

a. LDC shareholders are put at greater risk because the current mechanism and CUB's proposed changes to it increase the probability that LDC revenues will be reduced. Up to this point in time, the LDCs have countered the threats to revenues posed by the PGA sharing arrangement by frequently financially over-hedging their annual gas supply requirement. As explained in Staff's opening comments, this reduces any variation between the PGA embedded WACOG and actual LDC gas prices to zero or near zero and thus helps mitigate the threat to revenues of the PGA sharing arrangement. Similarly, under the current PGA sharing arrangement, LDCs are allowed to exercise a great deal of control over the benchmark for the sharing. This control has also been used by the LDCs to help mitigate the threat to revenues of the sharing arrangement. Staff proposes to end both these mitigation approaches. Staff proposes a requirement that LDCs must adhere to portfolio requirements in purchasing natural gas and that guidelines for purchasing be established. Secondly, Staff proposes that LDC control over the sharing benchmark be ended. This would be replaced with an exogenous market-based benchmark. With these mitigation strategies eliminated, if the current PGA sharing arrangement continues, LDC revenue losses are almost certain. CUB's proposed dead band increases both the chance of losses and their size. This would in turn likely lower LDC stock prices and credit ratings, both harmful to shareholders.

b. LDC customers are put at greater risk because the current mechanism and CUB's proposed changes to it both increase the likelihood that customers' price for natural gas commodity will be higher and that the LDC will not take sufficient or appropriate steps to mitigate price volatility.[7] Such actions by LDCs are simply discouraged by the existing PGA arrangements and even more so with the changes proposed by CUB. In addition, the situation of harm to shareholders described above would also harm customers by increasing the cost of debt and equity for the LDC. The result would be additional costs that would likely be passed along to customers, in one form or another.

c. Compounding the problem further is the threat to prudent portfolio purchasing of gas supply created by the greater risk to LDC revenues from the current PGA mechanism and CUB's proposed changes to it. As Staff has already noted, portfolio purchasing is the only workable and practical long-term strategy available to the LDCs for protection of both customers and shareholders from the risks of the current natural gas market. When the LDCs choose to focus more effort and attention on mitigating the threat to revenues posed by the current PGA and (if implemented) CUB's proposed changes to it, as they must in light of their legal obligations to their shareholders, portfolio purchasing is often pushed to a secondary position or sometimes actually opposes these mitigation activities. Thus, both customers and shareholders are harmed in the long-term.

d. Finally, the current PGA mechanism and CUB's proposed changes to it make it more difficult for Staff, and the Commissioners, to assess LDC gas purchase prices in terms of market prices for natural gas available to the LDC. As Staff has already noted, this is the only relevant comparison for assessing the reasonableness of LDC gas prices. In all instances this comparative price information should be transparently available to Staff and the Commissioners. But this cannot be the case where, as with the current PGA and CUB's changes to it, the relationship between the PGA embedded price of gas and actual market prices is not clear and likely cannot be made comprehensible.[8] This increases regulatory risks in evaluating LDC purchasing practices and prices, and thus adds further risks for shareholders and customers.

[7] For example, tracking natural gas market intelligence and prices on a daily basis, making purchasing decisions in real-time and holding sufficient volumes open to the physical market.
[8] Page 8, first full bullet

If the Commission decided to adopt one or more incentives for LDCs to purchase gas at the lowest price possible, compared to market, should the incentive(s) be consistent with the NRRI GPIM principles and characteristics, including a benchmark for the incentive(s) based on market prices?

As fully explained in its opening comments, *Staff* strongly recommends that one or both of the two GPIMs be put into place on a pilot basis, both to assess the operation of these GPIMs and for data collection to improve these and future GPIMs. GPIMs have proven their worth in helping LDCs reduce costs for customers. This monitoring and data collection for the GPIMs will help the Commission determine whether such GPIMs can continue to function in this way in the current skewed and inflexible natural gas market. But even with this uncertainty, it remains Staff's view that including a GPIM(s) with the 100% recovery PGA is essential. Furthermore, it remains Staff's position that any GPIM adopted must be consistent with the NRRI GPIM Principles and Characteristics laid out in Attachment A of our initial comments.

As we noted above, *Avista* suggests that while the "GPIM presented by Staff is a preferable incentive alternative as compared to the present gas cost sharing mechanism," the company does not believe any incentive is needed for an LDC to pursue the lowest possible gas costs. Avista notes that higher gas costs result in higher rates with no additional margin which "negatively affect customers, and ultimately the Company." The company further states that these higher rates attract the attention of "customers, as well as the media, who want to know that the Company is doing everything it can to keep its purchased gas costs as low as possible." (p. 5) Staff respectfully disagrees that this increased attention is enough to keep gas costs as low as possible.

Cascade's opening comments do not address an incentive mechanism, including any of the proposals that Staff made during informal workshops last year. The company simply contends that the LDCs would purchase natural gas at the lowest price under a cost recovery scheme that allowed the company to recover all its prudently-incurred gas costs. Cascade states that "focusing on the prudency of an LDC's purchasing practices . . . is the best way to ensure that customers pay the most reasonable price for gas." Staff disagrees with both Avista and Cascade that no incentive mechanism is needed. Staff has stated a number of times that their small size, load characteristics, lack of market purchasing power, and lesser availability of storage reduces significantly their options in gas purchasing, and thus, their ability to purchase gas at prices below those offered in the market. Further, we believe that the GPIM mechanisms we discuss in our opening comments and throughout these reply comments may not materially affect either of these companies, i.e., neither company will likely earn rewards or be assessed penalties related to its natural gas purchasing. Still, we want to have a mechanism in place to account for those times when these LDCs purchase gas at prices significantly above a threshold market price. Staff has proposed that any incentive mechanism be designed to be LDC-specific. This would address varying characteristics among the LDCs.

NW Natural contends that the current mechanism is a "hybrid PGA/GPIM mechanism" (p.4) in that a cost recovery component (whereby the LDC recovers its gas expenses in customer rates) and an incentive mechanism (where by LDCs are encouraged to purchase gas at the lowest possible cost) were "blurred" by the Commission's addition of a sharing component in the 1989 proceeding. Staff agrees with this portrayal of the current mechanism. However, we disagree with the company's further characterization that this current PGA is "sound," but for the need to tweak the sharing arrangement. We've already noted elsewhere in these comments that the current mechanism is not "sound," and our reasons for stating so.

Staff agrees with NW Natural that "a properly-designed PGA mechanism should incent an LDC to pursue the following goals in developing a gas supply portfolio: reliability, lowest reasonable cost, price stability for customers and cost recovery for shareholders." (p. 5) However, we point out that no single PGA-GPIM combination can achieve all these goals, including the mechanism favored by NW Natural. The PGA generally provides for reliability and, if the PGA is based on a well-designed portfolio, creates a particular balance of lowest price and price stability. Any particular GPIM can encourage lowest price or price stability, but it's very difficult, from a design perspective, to create a GPIM that achieves both optimum price and optimum price stability. Staff's proposal—100% recovery combined with an incentive mechanism to encourage purchasing gas at the lowest possible cost is the best alternative when combined with a robust prudence review process, along with carefully worded guidelines for assessing that prudence.

NW Natural spends a great deal of time in its comments setting out and discussing the NRRI GPIM guidelines and principles and does not appear to oppose the characterization of the components of a good GPIM defined in the report (and included as Attachment A in our opening comments). While Staff does not necessarily disagree with NW Natural's description of the NRRI GPIM guidelines and principles, it does wish to make two points about these guidelines/principles that NW Natural omits:

1. NW Natural argues that its <u>forecasted</u> WACOG is an appropriate benchmark. The only GPIM benchmark acceptable to Staff is market price. The basic function of a GPIM is to compare the LDCs cost of gas with market price for that same gas. Based on this comparison, the LDC is either rewarded (if the LDC's price is outside the tolerance band and below the market price), penalized (if the LDC's price is outside the tolerance band and above the market price), or neither rewarded nor penalized (if the LDC price is not outside the tolerance band). Portfolio construction, forecasting, and planning have no part in either the functioning or calculation of a GPIM.

2. Portfolio construction, on the other hand, must include forecasting and planning, and many other types of analysis. The portfolio constructed may lead to reward or penalty through a GPIM, and certainly the GPIM should affect how and why a portfolio is constructed. But the reverse should not occur; the portfolio should not determine the form or operation of the GPIM.

NW Natural also points out that it is important to properly balance the risks of the natural gas market between shareholder and customers.

> . . . if shareholders are exposed to too little risk, the LDC will have too weak an incentive to pursue savings on behalf of its customers. On the other hand, if shareholders are exposed to too much risk, the LDC might be inclined to mitigate risk to the detriment of customers.
> The goal then is to strike the best balance of risk between shareholders and customers to ensure that their interests remain in alignment. (p. 7)

Staff concurs with this goal and, like NW Natural, considers it essential. However, for the reasons already cited, Staff is convinced that the current PGA and its sharing arrangement do not achieve this goal. Among the more important reasons the current PGA-sharing fails to achieve this goal is that the benchmark for this mechanism is neither exogenous nor market-based, this PGA fails to incorporate the requirements of portfolio purchasing, and the mechanism fails to take into account the realities of the current natural gas market. This mechanism also fails to incorporate most of the other NRRI principles for GPIMs, e.g., elimination of manipulation of the results by altering use of storage, setting realistic baselines for volumes purchased at different hubs and transported over different pipelines.

NWIGU is correctly concerned that setting a benchmark correctly for any incentive mechanism is critical. It notes that ". . . benchmarks set in the wrong place do not motivate proper behavior or worse yet, reward mediocre performance." (pp. 6-7) In this regard, Staff has provided a number of reasons (in these closing comments, in addition to our opening comments) why a dead band mechanism is not justified for the Oregon LDCs and why Staff's proposed GPIMs can be effective incentives for LDCs to purchase lowest gas at lowest possible price.

<u>What is Staff's proposal?</u>
Through meetings with the LDCs after initial comments were filed, it became apparent that Staff had not adequately explained its approach to the calculation and use of the benchmark in the GPIMs proposed by Staff. These comments attempt to address that shortfall.

Staff is proposing a formulaic approach to the benchmark calculations. The table at the top of the next page presents the elements of the calculations and the equations for the benchmark and difference calculation for the spot (cash) gas WACOG GPIM proposed by Staff. There are fifteen (15) defined elements, A through O, and two (2) equations using these elements. These calculations would be applied each month during the PGA year with market price and LDC purchase price data for the month. Thus, the data would change each month but not the formula into which that data was placed. The results would be accumulated at the end of the year.

Monthly Benchmark WACOG and WACOG Difference Calculations for Staff's Spot (Cash) GPIM (FOR ILLUSTRATIVE PURPOSES ONLY)[9]

Monthly Spot (Cash) WACOG Comparison[10]		
Element	Description	Comments[11]
A	Share of month's total spot purchases at First of Month (FOM)	Value of this weight is 0.65 of total spot purchase volumes (based on historical split between FOM and daily purchase volumes, and firm transportation rights).
B	First of Month Price at Sumas	Prices from Inside FERC for US and Platts for Canada.
C	First of Month Price at AECO	"
D	First of Month Price at Rockies	"
E	First of Month Volumes at Sumas	Volumes based on LDC historical spot purchase volumes, forecasted spot purchased, and firm transportation rights.
F	First of Month Volumes at AECO	"
G	First of Month Volumes at Rockies	"
H	Share of month's total spot purchases at daily price	Value of this weight is 0.35 of total spot purchase volumes (Based on historical splint between FOM and daily purchase volumes, and firm transportation rights.)
I	Daily Price at Sumas	Prices from Gas Daily for and Platts for Canadian gas.
J	Daily Price at AECO	"
K	Daily Price at Rockies	"
L	Daily Volumes at Sumas	Volumes based on LDC historical spot purchase volumes, forecasted spot purchased, and firm transportation rights.
M	Daily Volumes at AECO	"
N	Daily Volumes at Rockies	"
O	LDC Actual WACOG for the Month	Defined by LDCs' tariff, subject to modification in this docket
P	Benchmark equation = P	((((B*E)+(C*F)+(D*G))/(E+F+G))*A)+ ((((I*L)+(J*M)+(K*N))/(L+M+N))*H)
	Difference equation	O – P

The calculation of the benchmark and WACOG difference for Staff's total WACOG GPIM[12] would follow the same general process as that in the table. However, the calculation would involve more data and longer equations since this GPIM includes hedged (financial and physical) gas purchasing as well as possible intra-day gas purchases, storage operational ratchet requirements, and perhaps even limits on the

[9] This is the GPIM we discussed in our Opening Comments, Attachments B and B-1.
[10] This is an example only. Actual weights would be based on LDC specific historical and forecasted data.
[11] These weights will vary between LDCs, based on historical/forecasted data and actual firm transportation rights.
[12] This is the GPIM we discussed in our Opening Comments, Attachments C and C-1.

mix and level of financial hedges an LDC could enter during the PGA year. Staff's illustrative effect of this mechanism is included in its opening comments, Attachments B-1 and C-1. Staff suggests that, due to their complexity and data intensity, the equations for the total WACOG GPIM are best worked out in face-to-face meetings among all the parties.

In addition, Staff proposes that for the initial two years of the implementation of the GPIMs an annual cap be placed on the penalties for the LDCs. Staff proposes a cap of approximately 10% of each LDC's authorized net operating income, or about a $7,000,000 cap for NW Natural, an $800,000 cap for Avista, and a $500,000 cap for Cascade. This seems a prudent precaution during the initial examination and testing of the operation and results of these GPIMs by the Commission. At the end of two years the Commission would be able to consider whether to continue, terminate, or in some way modify these caps.

Should the Commission formally support and require LDCs to follow portfolio principles in gas supply purchasing?

Yes. Staff has made clear its support for portfolio purchasing principles and the essential need that LDCs follow these principles in gas purchasing. The application of such principles provides the only long-term workable and effective protection for customers and shareholders from the risks inherent in today's natural gas market. Portfolio purchasing emphasizes goals other than price, most notably reliability, diversity, balance, and flexibility. These ensure gas is available to meet customer needs and that the LDC retains the ability to cope with the uncertainties and changes in the natural gas market in both the short- and long-term. No LDC should attempt to purchase gas in today's market without applying prudent portfolio purchasing principles. Staff will discuss in more detail its proposed portfolio purchasing principles and guidelines in Phase 2 of this docket. However, it's important to note that all three LDCs have strayed from what might be described as optimal practices simply to avoid the revenue risks inherent in the current PGA mechanism, in particular its sharing component.

Avista and Cascade both propose to eliminate the sharing component of the PGA, thus removing any disincentive to adherence to portfolio purchasing principles.

Avista says that "the establishment of reasonable guidelines regarding gas procurement practices and documentation, including hedging levels and practices, eliminate any real or perceived need for an incentive mechanism." Staff disagrees with this conclusion, but clearly the company believes that guidelines are an important part of the PGA process and is committed to addressing those guidelines in Phase 2 of this docket.

Cascade states that in order to help ensure that LDCs pay the lowest reasonable amount for natural gas, the Commission should focus its efforts on monitoring the LDCs' purchasing practices. Staff agrees. While Staff has carefully reviewed PGA filings for more than two decades, it has just been in the last three years that we have diligently analyzed and commented on the companies' purchasing practices and inputs to the WACOG, not only at the time of the annual PGA filings, but also throughout the ensuing year.

NW Natural clearly understands and generally adheres to portfolio purchasing principles. But even NW Natural has deviated from these principles, as it notes in its comments. The company states that its current sharing arrangement of 67/33 is excessive and leads to a potential loss of company revenues that is unacceptable. Portfolio purchasing resolves the problem set out by NW Natural over the long term. Thus, it should be the first solution offered by NW Natural. Instead, NW Natural proposes to retain the existing PGA arrangement, which impedes portfolio purchasing, and merely change its sharing obligation under that arrangement. There is no way to interpret this stance by NW Natural as support for portfolio purchasing. We agree with the statement of the problem, but emphatically disagree with NW Natural's solution.

The solution to the problem according to NW Natural is to change the sharing arrangement to 80/20 within the context of continuing the current PGA mechanism. The problem with NW Natural's "solution" is that it is data specific. That is, when market prices and risks change, as they inevitably will, the 80/20 arrangement may also lead to revenue losses that are in NW Natural's view unacceptable, thus requiring a further proposed modification of the sharing arrangement, perhaps to 85/15 or 90/10. With 100% recovery of prudently incurred costs in place in combination with Staff's proposed GPIMs this result cannot occur. This ensures meeting three of the goals for a PGA NW Natural says are necessary, "…simple to understand and easy to administer" (p. 19), alignment of "…customer and shareholder interests" (p. 17), and "…risks will be shared by customers and shareholders on a fair and sustainable basis." (p. 18). Neither the current PGA, nor NW Natural's proposal to modify its sharing arrangement within that PGA can ensure these goals are met.

NWIGU clearly supports portfolio purchasing principles and their application by LDCs.

> Industrial customers do not think that the Commission necessarily has to endorse a singular mechanism from this docket for the recovery of gas costs, provided that all allowed mechanisms utilize robust and evolving portfolio purchasing management strategies and provide for the lowest reasonable cost in a balanced portfolio. NWIGU recommends that the OPUC allow reasonable options but require all three of the utilities to proactively manage their natural gas supply portfolios and acquire a balanced and diverse portfolio of physical and financial contracts with stable and reasonable prices without regard to any incentive mechanism chosen by the utility among the options the Commission deems reasonable. (p. 4)

Staff concurs with the comments from NWIGU. However, Staff wants to point out that there is nothing inherent in a PGA tariff that ensures either the lowest reasonable cost or a balanced portfolio unless these requirements are added by the Commission and no way to enforce such requirements except by Staff reviews of the prudence of purchasing practices and price. Also, like NWIGU, Staff favors optionality in the PGA mechanisms and GPIMs available to LDCs. However, this is truly a situation in which the “devil is in the details.” Achieving these objectives will require a great deal more negotiation and design work from all the Parties in Phase 2 of this docket.

CUB correctly notes that “…Staff has expressed its opinion that the utilities’ experts need to be proactively monitoring and managing their gas portfolios.” (p. 14) However, CUB expresses no view about the need for or desirability that LDCs be required to follow portfolio purchasing guidelines in procuring natural gas for customers.

CUB has “yet to be convinced that the utilities are completely at the mercy of the gas market.” (p. 14) When Staff says that LDCs are “at the mercy of the market” and cannot control the market, it is stating that not only is the current natural gas market beyond the control of any particular participant but, more importantly, that LDCs have no ability to change either the prices offered or the types of contracts offered in the market. Staff does not mean that LDCs should give up attempts to construct balanced, diverse, and flexible gas supply portfolios based on the options the market offers that focus on reliability in conjunction with lowest possible price and mitigation of price volatility. As Staff has indicated, this is a very difficult job in today’s natural gas market, requiring LDC personnel to take positive actions on a monthly and sometimes daily basis during the entire year, and particularly during the peak season, to locate and implement whatever opportunities the market offers. It is also important that the Commission remove obstacles that impede the LDCs in carrying out such actions. Among these obstacles is the current PGA sharing arrangement. If CUB’s proposed dead band addition to the current PGA were implemented, it too would be an obstacle to such actions by the LDCs.

Is it necessary for the Commission to reach a decision about the Phase 1 questions in this docket or can the Commission wait until after the second phase of the docket, addressing LDC gas procurement guidelines, to make decisions for both phases?

The Commission should reach a decision in Phase 1 now. Staff believes a formal review of the PGA mechanism must address purchasing and portfolio guidelines to guide the LDCs, modify the PGA mechanism so that it does not interfere with LDC adherence to these guidelines, and construct and implement GPIMs that provide realistic and workable incentives for LDCs to purchase gas at the lowest price possible relative to the prices offered in the market in conjunction with the need to meet price volatility and reliability goals. The current phase of this docket addresses only the second of these objectives.

This docket was bifurcated at the request of the LDCs, NWIGU, and CUB based on their assertion that a decision from the Commission regarding the form of the PGA and PGA incentive mechanisms (Phase 1) was necessary before the parties could go forward on developing gas purchasing guidelines. These parties appear to continue to maintain this position. While Staff does not share these parties' position on this issue, Staff is concerned that in light of this position by these parties, work on purchasing guidelines without a definitive decision from the Commission in Phase 1 will be difficult, if not impossible, and will, in the end, either be unproductive or lead to a tangled and complex contested process.

What other PGA-related issues should the Commission resolve?

Should the Commission ultimately conclude, as does NW Natural, and to some extent CUB, that the current PGA mechanism should be retained, Staff strongly recommends that several proposals presented in its opening and reply comments still be implemented:

- More frequent PGA filings,
- Required adherence to portfolio purchasing by LDCs,
- Increased scrutiny of LDC procurement practices (particularly the commodity supply portfolio in relation to expected load and market conditions),
- More detailed gas accounting audits,
- Incentives designed to provide a reasonable revenue incentive to the LDC to purchase natural gas at the lowest price possible compared to the prices available in the market. GPIMs would need to be consistent with the NRRI guidelines set out in Attachments A, B, B-1, and C-1 included in Staff's opening comments, including exogenous market benchmarks as defined in footnotes 7 and 10 of Staff's opening comments, and
- Correction of the technical deficiencies in the PGA described in these reply comments.

These changes would signal to the LDCs that the Commission wants them to focus on lowest cost gas supply within the context of a balanced, diverse, and flexible portfolio and a GPIM consistent with NRRI GPIM Principles and Characteristics.

NWIGU's comments are consistent with Staff's when it indicates that the current earnings review mechanism should be modified as part of any cost recovery options the Commission approves in this docket. We have not provided a specific modification, but agree with the industrial customers with regard to changes to the earnings threshold that should be discussed more thoroughly with the Parties before any new mechanism is implemented. NW Natural supports the current earnings review mechanism and proposes no modifications to it.

Several parties (NWIGU, NW Natural, Avista, and Cascade) comment that the Commission should be cautious in making changes to the existing PGA, including its sharing arrangement, both to help avoid unintended consequences and to create the correct incentives for LDCs in gas purchasing. This has been Staff's position since the inception of the informal review of the PGA that began in 2005, up to the current time in the formal review of this docket. Staff's comments attempt to support this conservative view of changing the current PGA mechanism, but at the same time point out the harm the current PGA is causing and will cause in the future if it is continued.

CLOSING REMARKS

This docket raises important policy and operational questions for the Commission to address. Staff's comments outline these questions. In summary, the major questions before the Commission are:

1. Should the LDCs be allowed to recover 100% of prudently-incurred natural gas purchase costs?

   Yes. Historically, this was the situation in every state and remains so today in virtually all states. Considering the high level of risk involved with gas purchasing today and the fact that LDCs do not earn a return on this activity, returning to the historical arrangement of 100% recovery seems reasonable.

2. Should the Commission continue the existing PGA sharing arrangement or put in place the alternative to this arrangement proposed by CUB?

   No, neither option is appropriate. Clearly the current arrangement increases risk for LDCs and their shareholders compared to 100% recovery of prudently-incurred gas costs coupled with a well designed GPIM. Staff's proposal focuses simultaneously on lowering gas costs and gas cost volatility, while fostering portfolio purchasing and supply reliability. It also removes threats to LDCs revenues which prevent LDCs from actively managing gas purchasing to achieve these goals. CUB's proposed alternative increases risk for the LDCs even beyond that in the current arrangement. History shows that when faced with such high risk LDCs focus on risk mitigation, not on procuring natural gas for their customers at the lowest price possible. In light of the LDCs' obligations to their shareholders, this is rational behavior on the LDCs' part. However, it leaves customers partially or wholly unprotected.

3. If the Commission decided to adopt one or more incentives for LDCs to purchase gas at the lowest price possible, compared to market, should the incentive(s) be consistent with the NRRI GPIM principles and characteristics, including a benchmark for the incentive(s) based on market prices?

   Along with 100% recovery of prudently-incurred gas costs, the LDCs should be incented to purchase natural gas at the lowest possible price relative to the market price at the time of purchase. Market prices should <u>always</u> be the benchmark to which LDC gas purchase prices are compared. Market prices reflect the results of the interactions of the multiple participants, and physical and financial elements involved in the natural gas industry. From a purchasing perspective, in today's natural gas sector, these interactions produce the only real prices. Purchasing at a price significantly below market is an action for which the LDC deserves to be rewarded; purchasing at a price significantly above market is an action for which the LDC should be subject to penalties.

4. Should the Commission formally support and require LDCs to follow portfolio principles in gas supply purchasing?

   Yes. Since such principles are the only workable and practical long-term protection from gas price changes (particularly unexpected or unusually large changes) available to customers and LDC shareholders, it would be imprudent for any LDC not to apply such principles in gas purchasing. Unfortunately, both the current PGA sharing arrangement and, even more so, CUB's alternative to that arrangement, interfere with this goal by forcing LDCs to focus more attention on risk mitigation than on portfolio purchasing practices. Although formal consideration of portfolio purchasing guidelines is the subject for Phase 2 of this docket, Staff believes it very important for the Commission in this initial phase to give its full support to the need for LDCs in Oregon to follow portfolio purchasing practices and guidelines.

5. Is it necessary for the Commission to reach a decision about the Phase 1 questions in this docket or can the Commission wait until after the second, and final phase of the docket, addressing LDC gas procurement guidelines, to make decisions for both phases?

   As we noted above, a decision in Phase 1 of the docket is needed to lead to a more productive process in Phase 2. In the absence of a decision, work on creating effective purchasing guidelines will be difficult and would likely be another contested proceeding.

6. Are there other PGA-related issues the Commission should resolve in this docket?

   Yes. As Staff points out, regardless of the decision the Commission makes with regard to the form and components of the PGA cost recovery and incentive mechanisms, it should require: more frequent PGA filings, adherence to portfolio purchasing by LDCs, increased scrutiny of LDC procurement practices, more detailed gas accounting audits, and correction of the technical deficiencies in the PGA described in these reply comments.

Staff looks forward to the opportunity to discuss our opening and closing comments with the Commissioners at the February 4, 2008, workshop. If there are still unanswered questions at that time, Staff will avail itself of the opportunity to respond to these questions in a third round of comments by February 14, 2008.

Dated at Salem, Oregon this ~~28th~~ day of January, 2008

Kenneth R. Zimmerman, PhD
Senior Utility Analyst
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CERTIFICATE OF SERVICE

UM 1286

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 28th day of January, 2008.

Kay Barnes

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UM 1286
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