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 Opening Comments

INTRODUCTION

On November 21, 2006, the Commission approved Staff's recommendation that an investigation be opened to review and modify, as appropriate, the Purchased Gas Adjustment (PGA) mechanism used by Oregon's three local distribution companies (LDCs). The mechanism currently in use in Oregon no longer serves well either LDCs or Oregon gas customers. During workshops leading up to this formal investigation all participants recognized this fact and discussed how the current PGA mechanism needed to be modified in order to better meet the needs of LDCs and customers in today's natural gas market.

In a letter to Judge Power, dated September 25, 2007, Staff's counsel described the Parties'[1] agreement regarding how they proposed to proceed in this case. The Parties agreed to split this docket into two phases. During the first phase, the Parties will address mechanisms for the recovery of gas costs, including any proposed incentive arrangements. During the second phase of the case, the Parties will address guidelines for implementing these mechanisms, portfolio purchasing of natural gas, and related documentation.

Staff's opening comments address the following issues identified by the Parties, and included in the aforementioned letter:

1. We will discuss what mechanism(s) the Commission should approve for the recovery of gas costs by Oregon's three natural gas utilities. Our proposed mechanism will address recovery of gas costs and will include an incentive mechanism as well.

2. We will explain our proposed cost recovery and incentive mechanisms, and

3. We will explain how our proposed mechanisms correct any deficiencies of the current mechanisms.

[1] The official UM 1286 Parties include Staff, Avista Utilities, Cascade Natural Gas Corporation, NW Natural, Citizens' Utility Board (CUB) and Northwest Industrial Gas Users (NWIGU).

Staff's initial comments focus on the form and content of costs to be recovered through a PGA mechanism and its associated tariff, including as necessary the mathematics of this recovery, and the form and operation of possible performance-based gas purchasing (PBGP) mechanisms that could be embedded in the PGA. Staff's comments include, as necessary, remarks regarding the basic gas purchasing practices and guidelines underlying its PGA and performance-based gas purchasing proposals. These are intended to form the foundations upon which the prudence of utility natural gas purchasing and natural gas supply portfolio construction would be judged.

The PGA is a tariff which "allows a utility to recover the changes in its wholesale gas costs on a periodic basis and without the need for a formal rate review."[2] In theory, the PGA is a fairly simple tariff, providing for pass through to customers of actual and prudently-incurred costs for natural gas purchases. The state regulatory commission determines both the actual level and prudence of gas costs for pass through to customers' bills. Also, since actual gas costs incurred during any particular time period are not always known when customer bills are prepared and because PBGP mechanisms can change the level of pass through, deferral accounting is required in conjunction with the PGA tariff. In practice, the PGA tariff and any associated PBGP mechanism do not always function as intended simply due to disputes over actual vs. current costs passed through to customers, and actual vs. prudent costs for natural gas purchases.

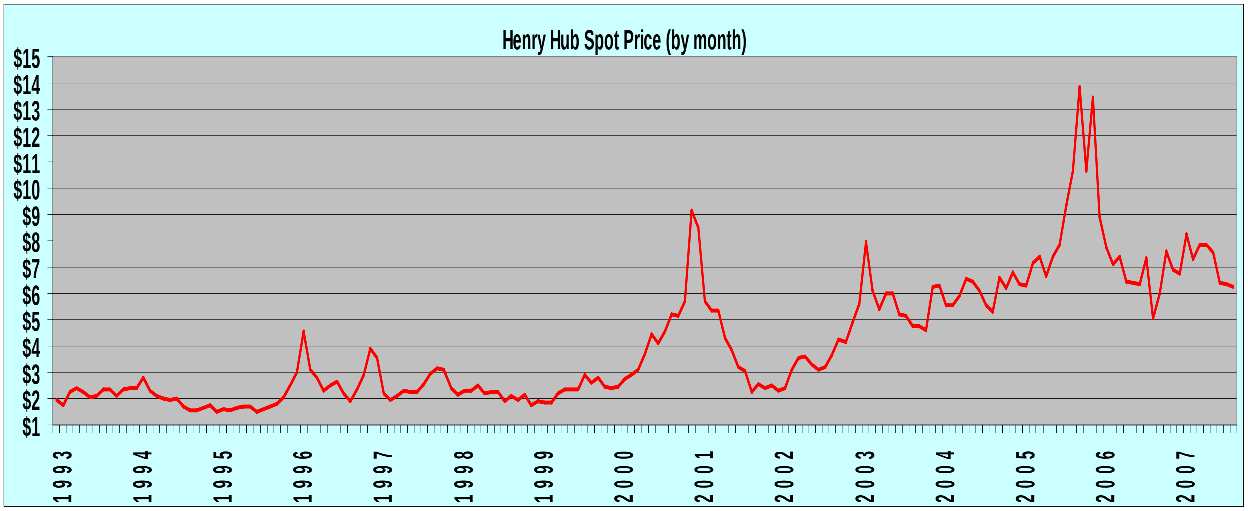
OREGON'S CURRENT PGA MECHANISM/PBGP AND MARKET PRICES

<u>INTRODUCTION AND HISTORY OF US NATURAL GAS MARKETS</u> Since 1989, the dynamics and operation of the US and Northwest natural gas markets have changed dramatically. Not only have prices increased exponentially, but price volatility has increased at an even greater pace (see Figure 1 on next page). The natural gas "bubble" of the 1980s ended in the 1990s. Market trading hubs for sales of natural gas were invented, as was the basis differential between these hubs. The "Henry Hub" in Louisiana was chosen as the benchmark point for all hubs, the point to which all other hubs' prices were compared. A financial derivatives market for natural gas has been established and gradually the common practice of fixing the price of natural gas purchases over time by entering into a physical fixed-priced contract with a producer or marketer was replaced by financial derivatives, generally purchased through NYMEX. Financial derivatives also came to dominate the market for the hedging of price for future gas supply needs, generally referred to as futures trading. Independent energy marketing companies emerged (e.g., Enron, Dynegy) who combined the physical and financial side of natural gas purchasing, often merging the two into a single transaction. The number of counterparties for natural gas financial instruments expanded geometrically, until finally today, even banks and stock brokerage houses are heavily involved in the financial and even physical side of the business. Also, in the last ten years hedge funds have pumped billions of dollars into energy markets, including the gas market, based purely on speculation about the direction and size of changes in the price of natural gas, oil,

[2] NARUC. 2003. *Natural Gas Information Toolkit*. Page 21.

electricity, and other energy products. In terms of “cash in play” these funds now dominate the natural gas market.

Figure 1: History of US Spot Natural Gas Prices at the Henry Hub, 1993 - 2007[3]



These visible changes are the result of systemic changes in US and Northwest natural gas markets. These markets have become complex in the sense that they are inter-dependent, not independent. Natural gas markets should be viewed as complex systems. Complex systems tend to be high-dimensional, non-linear, and hard to model. What we see in complex systems is the result of “emergence” and “self-organization.” In simpler lay person’s terminology, this means the rules for current US and Northwest natural gas markets are not fixed and not likely to be fixed for some time to come. These rules are in the process of being constructed, but do not yet exist in any firm form. Complex systems move in many directions simultaneously and the parts of the system do not always change in the same ways, at the same pace, or in the same direction. Such systems are thus difficult to model, to analyze, and to predict. The parties forced to sell and buy in the complex natural gas markets thus face great uncertainty when it comes to predicting market movement size and direction, which translates into great risk when attempting to minimize price or price volatility of purchases. LDCs, such as those that operate in Oregon, are among the parties facing this difficult situation.

This sort of natural gas market is intimidating for seasoned market traders; it has become exceedingly difficult for any LDC to protect either its customers or its shareholders from the large risks inherent in the gas markets of the last five to ten years. Adding to the difficulty of the situation for LDCs and electric utilities is the fact they also are faced with the unenviable task of trying to compete with "professional

[3] The data on this figure extend back only to 1993. Reliable data prior to that time for all the transactions at or around the Henry Hub is not available. However, general descriptions of the price of natural gas prior to 1993 at and around the Henry Hub indicate prices were not greater than those experienced in 1993 and in many instances were less.

gamblers" or hedge funds when they are managing the risk of natural gas exposure. The financial players have absolutely no interest in the underlying commodity, just the profits that can be made from speculation on price movements. The LDCs need to work closely with their regulators to effectively procure natural gas in the current complex and hard-to-analyze natural gas markets.

These changes in the natural gas sector have placed great pressure on state commissions as well as the LDCs. The state regulatory commissions that assess and review the operations, particularly the gas purchasing of these LDCs, are under great pressure to design natural gas cost recovery mechanisms for their LDCs that fit the circumstances of the changed natural gas market. The Oregon PGA mechanism in place today was designed to meet LDC needs in a stable, lower priced, and more predictable natural gas market. That market no longer exists. As we note below, the mechanism designed for that now extinct market no longer serves well either Oregon's LDCs or their customers. It is time to review that PGA mechanism and consider how it might be redesigned. The work in this docket needs to be completed as soon as possible and certainly in time to provide guidelines the LDCs will follow in constructing their gas supply portfolios for the 2008-2009 PGA year. Specific information on how we propose that the PGA and incentive mechanisms be implemented is presented later in these comments.

OREGON'S CURRENT PGA MECHANISM The PGA mechanism currently used by Oregon's LDCs was established by the Commission in 1989,[4] and certain provisions have since been modified.[5] The purpose of the Oregon PGA mechanism is two-fold: (1) to allow the LDCs to recover the costs associated with the purchase and transportation of natural gas to their systems without the need for a general rate review and (2) to provide an incentive to the LDCs to minimize the cost of natural gas purchases.

Currently, a percentage (33% for Cascade and NW Natural and 10% for Avista) of any variance between the LDC's weighted average cost of gas (WACOG) commodity included in rates and the actual WACOG for commodity is absorbed (if greater than the WACOG embedded in rates) or retained (if less than the WACOG embedded in rates) by the LDC.[6] For the natural gas supply sector that existed in 1989 this arrangement was certainly workable, and even for the gas supply sector of 1999 this arrangement made some sense. Prices were generally stable and less than $3/Dth. Price volatility did not begin to become a problem until about 1996. Thus, for the period up to 1996, there was no systematic reason to believe that the difference between the WACOG in rates and the actual WACOG experienced would be anything but small and randomly positive and negative. But even in this pre-1996 market some difference in the two was likely. This meant the LDCs using this PGA mechanism would, by design, never recover 100% of their actual gas costs. They would always recover more or less than

[4] *See* Order No. 89-1046, entered August 4, 1989 (Docket UG 73).
[5] *See* Order No. 99-272 (Docket No. UM 903) and Order No. 05-852 (Docket UG 73). Per these previous Commission PGA orders, PGAs are "automatic adjustment clauses" as defined in ORS 757.210(1).
[6] Demand charges for transportation of gas from the purchase points to the LDCs' system are recovered 100% by the LDCs. Staff's proposal does not modify cost recovery for demand charges.

100%. As long as the market prices remained low and stable, this difference was inconsequential in terms of the total cost of gas and level of overall revenue, even for the smaller of Oregon's LDCs.

As the risks in natural gas purchasing expanded beginning around 2001, due to higher and more volatile prices, Oregon's PGA mechanism passed these risks on to customers and shareholders. As a means to mitigate these risks, particularly for shareholders, the LDCs chose to enter financial and physical fixed-price hedges for nearly all of their expected annual supply needs. As physical hedging opportunities rapidly declined in the early 2000s, the LDCs shifted most of their hedging to the financial side. This strategy effectively reduced the variation to zero between the LDCs' WACOG included in rates and the actual cost of gas. While this result was probably not intended when the Commission drafted and issued its 1989 and 1999 PGA Orders, these actions by the LDCs are certainly in part the result of these Orders and could have been anticipated at the time of the Orders.

However, except in periods of extreme market emergency, fixing the price in advance for nearly all expected annual sales volumes is not consistent with portfolio purchasing. Even in periods of extreme emergency such hedging of prices is not likely to be available. Normally, LDCs fix the price in advance of base load gas supply (gas the LDC is certain it will sell). Sometimes this level is extended an additional 10%-15% of total annual sales volumes. Gas supply requirements above this level are usually purchased through shorter-term (less than one year) index priced contracts or through the daily or monthly spot (cash) markets. When these guidelines are violated customers experience more risk because they are denied the basic protections afforded by portfolio natural gas purchasing – the LDC's supply portfolio is not diverse, flexible, and balanced across all major dimensions affecting price (e.g., time, supply type, supply location, pricing type, take requirements). Barring absolutely accurate knowledge of future natural gas prices, which is never available, portfolio purchasing is the best tool for protecting customers and shareholders from changes in the price of natural gas. This purchasing approach requires that LDCs focus on selecting portfolios of gas supplies based on their overall risk-reward characteristics instead of merely compiling portfolios of purchases that each individually has attractive risk-reward characteristics. In a nutshell, in purchasing natural gas, LDCs should select portfolios not individual supply options. Such a portfolio should also display the three characteristics of balance, flexibility, and diversity; should be based on the particular circumstances in which the purchases are made; and should not impede the provision of reliable gas supply to core customers. The greater the risks of price change or supply availability, the greater the need to follow the diversity, flexibility, and balance requirements of portfolio theory.

Beginning with the 2005 PGA, Staff sought to move the Oregon LDCs away from the high levels of fixed-price financial hedging in which the LDCs had engaged over the several years prior to 2005. However, in making this Staff-requested change, the LDCs also removed the strategy they had utilized to mitigate the shift of risk to shareholders inherent in the Oregon PGA sharing arrangement. Oregon's current PGA mechanism is thus, not only ineffective in the today's natural gas market, it leads to increased risk for both LDC customers and shareholders by impeding the application of portfolio purchasing practices by LDCs.

<u>BUT WHAT, SPECIFICALLY, ARE THE DEFICIENCIES ASSOCIATED WITH THE CURRENT PGA MECHANISM APPROVED FOR USE BY THE OREGON LDCS?</u> Most PGA mechanisms approved by state commissions across the country provide for 100% recovery of prudently-incurred gas costs. Washington, for example, does so. Many states also include some type of sharing or incentive mechanism as part of the PGA. These mechanisms in all instances are intended to provide incentives for LDCs to purchase gas at the lowest price possible and/or take actions to control natural gas price volatility passed on to customers. The Oregon PGA includes a unique a sharing arrangement (Oregon sharing) between customers and the LDC of differences between the WACOG in rates and the actual WACOG for gas purchases. As already noted, among other things, Oregon sharing prevents full recovery or leads to over recovery of gas costs by the LDCs.

Few other states include a sharing arrangement like this in their PGA, and no state's sharing or incentive arrangement is designed like Oregon sharing. The Oregon sharing is problematic for several reasons. Most important among these are:

Oregon sharing violates several of the Gas Purchase Incentive Mechanisms (GPIM) design principles (see Attachment A).

- Oregon sharing allows the benchmark for the sharing to be established by the LDC. The benchmark is the PGA allowed to go into rates at the time of the annual PGA filing. The GPIM principles in Attachment A recommend keeping the benchmark exogenous[7] to avoid weak or distorted incentives and gaming**.** In Staff's view this is sound advice.

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[7] By "exogenous" benchmark, Staff means values for price that are outside the control or influence of the LDC or the Commission. Regarding purchase volumes, exogenous means determined by load, firm transportation capacity rights, and planned storage injection and withdrawal quantities. Staff's position is consistent with that of the NRRI report from which the Attachment A GPIM Principles and Guidelines are taken. Staff's proposed benchmark approach translates to a formulaic approach. Before the beginning of the PGA year, all parties would have the opportunity to participate in creating a benchmark formula, including the data inputs. The formula must meet the following criteria:

1. The final result of the formula's application cannot be controlled by any single party or group of parties.
2. The data/information for the formula must be from sources external to any party or the Commission.

Once approved by the Commission the benchmark formula would operate throughout the PGA year without change. Changes to the formula could be considered prior to the beginning of the PGA year subsequent to the year the current formula is applied.

- The principles indicate that “All inter-related and substitutable actions, costs and revenues should have equal incentives applied to them.” Oregon sharing places greater stress on fixing the price of as much of the annual gas supply as possible prior to or at the time of the annual PGA filing. This is a simple precaution by the LDC to protect itself from the potential impacts of natural gas price volatility in combination with Oregon sharing. But it also has the effect of reducing the incentive to keep overall gas cost for the LDC as low as possible, especially as market volatility expands.

- Oregon sharing does not focus on what the principles indicate is the prime objective of any GPIM, low gas cost. “[I]ncentives for achieving other objectives, such as reliability or price stability, cannot effectively be created within a GPIM, nor should a GPIM create incentives that jeopardize or conflict with these other objectives.” Yet Oregon sharing seeks both price stability and lowest price, objectives that no single GPIM, of any sort, can achieve.

- Finally, the principles indicate that the exogenous benchmark should approximate the results of “reasonable” purchasing strategies but should not be “too easy to beat.” Oregon sharing’s benchmark not only fails to be exogenous but is actually set-up by each LDC. In this situation making the benchmark “too easy to beat” becomes a central issue.

Oregon sharing creates an incentive for LDCs to move away from the requirements of portfolio purchasing (see above) if and when the complex natural gas markets change unexpectedly in directions that threaten the LDC.

It does so by:

- placing greater stress on fixing the price of natural gas,
- expecting this to also result in the lowest possible price,
- forgoing an exogenous benchmark, and
- placing no limits on fixed-price hedging of gas volumes.

Natural gas market changes include, but are not limited to, significant expansions in price volatility, significant decreases/increases in the price level over any sustained period after the billing rates have been approved for the PGA year, loss of financial hedging counterparties, and unexpected increases/decreases in demand or annual load.

In Oregon, like most other states, LDCs are forbidden from making a profit on gas supply purchases. Oregon sharing, however, allows such a profit to be made.

Even if the above problems with Oregon sharing are ignored there is one overriding problem that remains. How does one go about verifying that Oregon sharing actually produces the lowest possible price of gas for Oregon's LDC customers? This goal can be achieved only when LDC pricing is compared directly to an external and independent benchmark that reflects the results of the operation of Pacific Northwest natural gas markets.

STAFF'S PROPOSED COST RECOVERY AND INCENTIVE MECHANISMS

STAFF'S PURCHASED GAS COST RECOVERY PROPOSAL As we noted above, the first purpose of the current PGA mechanism, embodied in the LDCs' tariffs, is to allow the LDCs to recover the costs associated with the purchase and transportation of natural gas to their systems without the need for a general rate review. It is Staff's view that the PGA tariff itself should be as simple as possible. Large scale costs are passed through to customers via this tariff. The tariff should be clear and precise about which costs are eligible for pass through and how the prudence of those costs will be assessed. The tariff should also include only direct gas costs.

Direct gas costs include:

- commodity costs,
- transportation fees,
- costs for storage gas supply, and
- other costs related directly to gas supply itself and gas purchases (e.g., odorization).

It is Staff's view that barring a finding of imprudence in gas purchasing by the Commission, 100% of the LDC's actual gas costs should be passed through to customers. As noted above, the current Oregon PGA mechanism's sharing component ensures that an LDC never recovers its actual gas costs, is not an effective incentive for achieving lowest gas cost in today's markets, and could push LDCs away from the requirements of portfolio purchasing. Deferral accounting and Commission oversight would ensure that no more and no less than 100% of prudently-incurred gas costs are passed on to customers. As explained in more detail beginning on page 14, prudence is determined through:

1. Rigorous review of purchasing practices and portfolio design during the PGA filing review to determine that these are consistent with "best practices" portfolio purchasing;

2. Frequent and detailed audits by the Commission of the gas cost accounting records of the LDCs; and

3. PBGP mechanisms that continually test the purchasing decisions of the LDCs (both short- and long-term) against market price index and hedging benchmarks.

To further strengthen the review of the prudence of LDC gas purchasing practices and portfolio design, Staff recommends the LDCs be required to make PGA filings on a more frequent basis. This change would improve the effectiveness of conservation programs by providing nearer to “real-time” pricing signals to customers; would allow the Commission greater opportunity to obtain information about, examine, and have input into LDC purchasing practices and decisions; and would add more impetus for the LDCs to measure their purchasing actions against current market pricing (both short- and long-term pricing).

Staff’s PGA proposal is presented in Table 1 below, including the GPIM requirements.

Table 1: Staff’s PGA Proposal

Gas Cost Recovery	100% of prudently-incurred gas costs, subject to gas purchase incentive mechanisms and detailed PGA purchasing practices reviews. Regular and detailed accounting audits of gas costs and deferral accounting would ensure no more and no less than 100% of prudently-incurred costs are recovered from customers.
Gas costs mean:	1. Cost of gas commodity, including reservation fees; 2. All costs related to transporting LDC gas supply from purchase points and storage to the LDC distribution system, including compressor fuel; 3. Lost and Unaccounted For Gas (LUFG); 4. Gas treatment (e.g., odorization); and, 5. All non-rate based costs related to emergency provision of gas to core customers.
Deferrals	Short-term – For adjustments during the PGA year.
	Long-term – For adjustments from one PGA year to another.
Audits of gas costs by the Commission	At least semi-annually.
Quarterly meetings between LDC and Staff	Set up in the PGA tariff.
Portfolio guidelines	Expectation included in the PGA tariff that LDC will follow portfolio guidelines approved by the Commission in UM 1286.
PGA guidelines	Expectation included in the PGA tariff that LDC will follow PGA guidelines approved by the Commission in UM 1286.
Incentives for lowest price possible	See Attachments B and C. Both these designs are acceptable to Staff.

INCENTIVE MECHANISMS Any PBGP mechanism should work with the PGA, adding or deducting costs to the pass through to customers based on the operation and structure of that mechanism. Such mechanisms allow purchased gas costs to be recovered from consumers on the basis of a pre-determined cost-sharing formula. Such cost-sharing arrangements are intended to provide an incentive to the utility to keep overall gas costs as low as reasonably possible while at the same time appropriately managing gas price volatility and reliability of gas supplies to core customers. During 2006, the National Regulatory Research Institute (NRRI) completed a comprehensive review and analysis of existing and possible PBGPs.[8] The NRRI analysis refers to such mechanisms as GPIMs. Based on this research, NRRI proposed the GPIM principles in Attachment A.

STAFF'S INCENTIVE MECHANISM PROPOSALS Staff agrees with these principles and recommends that any GPIMs adopted in Oregon be consistent with these principles. There are many potential GPIM designs consistent with these principles that could be implemented in Oregon. It is also important to recall that, as noted above, the second purpose of Oregon's PGA is to provide an incentive to the LDCs to minimize the cost of natural gas purchases. Staff's GPIM originally proposed during the UM 1286 workshops is such an incentive. This GPIM is designed to be limited to short-term (less than one year) index-priced purchases only. It is Attachment B to these comments. We have also included a numerical example (see Attachment B-1) of how this incentive mechanism would work.

This GPIM focuses only on spot (cash) purchases by the LDCs in the daily and monthly markets. The reward/penalty for the LDC is computed monthly and totaled for the entire PGA year. The benchmark is computed based on published and publicly available spot gas prices for each of the three hubs from which Oregon LDCs purchase natural gas (Sumas, AECO, and Rockies), weighted by the historical amount of gas transportation capacity each LDC has from each hub. The LDC's price for spot purchased gas during a month is compared to the benchmark price for that month. As long as the LDC has not violated the storage ratchet[9] for the month, it has an opportunity to earn a reward. The tolerance band is based on 100 basis points of ROE. In the numerical example (see Attachment B-1), Staff used $180,000 for the annual value of this 100 basis points and then spread that total through the months of the year, weighted so that greatest revenue was during the winter months, second greatest during the shoulder months, and least revenue during the summer months. If the savings from the benchmark for any month is outside the tolerance band but less than $50,000, the LDC retains 25% of this savings; if the savings for the month is outside the tolerance band and exceeds $50,000, the LDC retains 50% of the savings. The GPIM is symmetrical so the same level of penalty applies to the LDC for spot prices that are outside the tolerance band and below or above $50,000.

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[8] Costello, Ken and James F. Wilson. NRRI. *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*. 2006.

[9] Storage ratchet as used here refers to the storage injection and withdrawal schedule and levels of working gas available to the LDC during each month of the PGA year according to that schedule. This schedule is submitted and approved in conjunction with the annual (or more frequent) PGA filing(s) by the LDC.

There are two possible difficulties that we identify with the design of this GPIM. One is that the hub weighting will vary by LDC and the other is that storage ratchet levels will vary by LDC. These are not insurmountable problems. Through meetings and workshops with the LDCs, agreements can be reached regarding the expected future percentage of natural gas each company will purchase at the Sumas, AECO, and Rockies hubs for the upcoming PGA year. These weights can then be placed into the formulas for this GPIM for the upcoming PGA year. Similarly, Staff, the LDCs, and the other interested parties can reach an understanding, prior to the upcoming PGA year, about the appropriate storage injections and withdrawals for each month during that PGA year. Also, different designs for the tolerance band and sharing percentages in this GPIM will need to be put in place for large, medium, and smaller-sized LDCs.

A design based on a variation of the current Oregon sharing arrangement is found in Attachment C, along with its numerical example in Attachment C-1. This GPIM is considerably more complex than the mechanism described in Attachment B. On a monthly basis, the difference between the LDC's total WACOG and the benchmark WACOG is computed. The benchmark WACOG is based on both spot (cash) purchases and firm gas purchases of more than a month in duration, both priced at index and hedged either physically or financially. Again, for the LDC to have the opportunity to receive any reward, its storage ratchets must be met. Within ±2% of the benchmark WACOG, the LDC recovers 100% of actual (prudently-incurred) costs, with no reward or penalty. After a savings from the benchmark of more than 2.5%, the LDC receives a reward of:

- 2% of the cost difference if the total difference from the benchmark WACOG is up to 5%;
- 5% of the cost difference if the total difference from the benchmark WACOG is between 5% and 10%; or
- 7.5% of the cost difference if the total difference from the benchmark WACOG is greater than 10%.

Again, the GPIM is symmetrical. So, if the total difference from the benchmark WACOG is above the levels described above, the LDC receives a penalty of 2%, 5% or 7.5% each month. This GPIM has the same potential problems as described above. That is, the hub weighting will vary by LDC and the storage ratchet levels will vary by LDC. Also, different design for the tolerance band and sharing percentages in this GPIM will need to be put in place for large, medium, and smaller-sized LDCs. In addition, unlike the GPIM in Attachment A, much of the information relating to available physical and financial hedging prices needed to calculate the benchmark is not public information and may be beyond the access of the Commission, without orders from the FERC mandating State Commission access to this information. NARUC and several states have already asked FERC to require State Commission access to this information. To implement this GPIM, agreements to protect confidential hedging information contained in various third party offers to the LDCs and other market participants will be necessary.

Staff recommends these two GPIMs be adopted by the Commission and implemented by the LDCs on a pilot basis for a period of five years to test their benefits for Oregon LDCs and their customers. Staff also recommends the performance of these GPIMs be reviewed annually to determine whether they should continue in place as is, be modified and continue, or be terminated. It is Staff's intention that these and other possible designs be discussed more fully in the second phase of UM 1286 comments. As changes to Oregon's PGA mechanism are made, additional GPIM proposals could be considered. Staff hopes that all parties to UM 1286 will participate fully in the consideration of all GPIMs that might be beneficial for Oregon LDCs and their customers. Staff is fully willing to consider and support GPIM designs different from those described here so long as they are:

- workable in the Oregon situation;
- able to be demonstrated to have the potential to provide benefits for Oregon LDC customers;
- able to be transparently implemented and results can be fully monitored and assessed; and
- consistent with the NRRI GPIM principles and characteristics.

HOW DO STAFF'S PROPOSED MECHANISMS CORRECT THE DEFICIENCIES STAFF NOTED?

Staff does not contend that its PGA and GPIM mechanisms are perfect, but it does assert that these mechanisms cure many of the problems with the current Oregon PGA and GPIM mechanisms:

- The general principles and purposes underlying Staff's mechanisms are simple, direct, and easy to understand for customers and the general public. This is not the case with current PGA and GPIM mechanisms.
- Staff's PGA mechanism provides for recovery of 100% of gas costs, subject to demonstrated prudent purchasing by the LDC. This, in turn, places greater emphasis on LDC decisions and actions in purchasing natural gas for its customers.
- Staff's GPIMs are consistent with the NRRI design principles and characteristics for GPIMs found in Attachment A. These principles and characteristics constitute the "state of the art" for GPIM structure and operation. This means LDC gas prices can be directly and easily compared to market prices (both short- and long-term). Also, consistent with these principles and characteristics, Staff's GPIMs focus exclusively on lowest price for natural gas purchases.
- Staff's PGA and GPIM mechanisms are consistent with full commitment to and implementation of portfolio purchasing. Portfolio purchasing protects customers (and LDC shareholders) from both singular natural gas price spikes and also the negative impacts of gas price volatility increases.
- Staff's PGA and GPIM mechanisms hold LDCs responsible for their gas purchasing decisions and actions. Staff's proposed mechanisms provide LDCs with the opportunity to earn "incentive" payments for exceptional gas purchasing decisions and actions that reduce gas costs for customers below currently available market prices, but also impose penalties if purchasing decisions result in actual gas costs that are significantly higher than market prices.

- And to repeat once more a key point: the benchmarks for Staff's GPIMs are external, beyond any control by LDCs or the Commission. Thus these benchmarks are a robust test of LDCs' natural gas pricing.

<u>WHY NOT A "DEAD BAND" APPROACH FOR THE PGA MECHANISM?</u> Some parties have suggested that a "dead band" like that approved by the Commission for Portland General Electric (PGE) and other electric utilities would be appropriate for the LDCs. Staff disagrees. Staff asserts that the PGE dead band approach would not be appropriate because:

1. The PGE dead band applied to the LDCs suffers from all the problems associated with current Oregon sharing.

2. 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. Within the bounds of the dead band the LDCs would not be allowed to make any adjustments in the gas costs placed into rates for recovery from customers. So within the dead band all differences (above or below) the gas cost in rates would be absorbed or retained by the LDC. Current Oregon sharing only requires the LDC to absorb or retain 33% (Cascade and NW Natural) or 10% (Avista) of these differences. Unlike PGE and most other large to middle-size electric utilities, LDCs (even larger ones) simply do not have a level or flexibility in revenue sufficient to absorb even a 150 basis point loss through a dead band mechanism. LDC revenues on a per unit of delivered commodity are generally lower than electric. This is the result of the cost structure of the two industries: it costs more to produce/procure/deliver electricity on average than it does natural gas. One result of this situation is that financial analysts treat LDCs and electric utilities differently for rating purposes. Simply put, electric utilities are allowed larger revenue disallowances than LDCs, even beyond the difference in the general rate base and cost structure of the two industries, before the disallowances begin to have an effect on stock price and cost of equity assessments.

3. 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. It can be generated from company-owned plants using several fossil fuels, generated from renewable facilities (including hydro), or purchased on spot and longer-term wholesale markets. A dead band for power costs includes all these options. Having this flexibility of electricity procurement options means the electric utility has a great deal more control on where its power costs fall within the dead band than do LDCs who procure and sell only natural gas. With this threat hanging over their heads, LDCs would do all they could to ensure no such loss occurred. This is easily done by fixing the price of virtually all expected sales volumes prior to the PGA filing. But again we return

to the need for the LDCs to engage in portfolio purchasing, which prohibits fixing in advance pricing for such a large share of sales volumes.

4. Obviously, the above problems with a dead band mechanism and the LDCs reactions to such a mechanism would hamper, if not altogether eliminate, portfolio purchasing by the LDCs for gas supply. Thus, the protections such purchasing provides to LDC customers would be lost.

5. With such a dead band in place for LDCs in Oregon, Staff expects the PGA filings, particularly the reviews of portfolio design and purchasing practices, will become difficult, complex, and extremely contentious. The process will be buffeted between LDC actions to protect their revenues from the dead band and Commission efforts to ensure that LDC portfolios are properly designed and their purchasing practices produce the lowest gas price possible for customers.

Staff does not disagree with some parties' positions that the LDCs should share "excessive earnings" with their customers. In OAR 860-022-0070, such a mechanism and procedures already exist. In Section (7) of that rule, the earnings review mechanism established under the rule "will be reviewed for potential extension" after earnings reviews are conducted in 2008. At such time, Staff will initiate a proceeding to review the risk sharing mechanism and its various components. Until this rule is completely reviewed, Staff recommends any rewards earned or penalties imposed under Staff's proposed incentive mechanism not be subject to an earnings test.

ASSESSING PRUDENCE FOR THE PGA

With any PGA mechanism it is important to properly assess the prudence of natural gas purchase planning and execution. Staff proposes the following criteria and action for making that assessment.

1. Staff's first recommendation for assessing the prudence of LDC natural gas purchasing as reflected in the PGA is that the purchases are carried out in accordance with the requirements of "best practices" portfolio purchasing. As noted above, portfolio purchasing is the strategy generally accepted as best for purchasing under current natural gas market conditions—purchasing a portfolio of supply resources rather than any one type, over a limited time period, at a limited number of trading hubs, or from a single or limited number of counterparties. This strategy is generally accepted in the industry as providing the greatest level of risk mitigation for both shareholders and customers over the long-term in terms of gas price and price volatility while not impeding the goal of reliable gas supply for core customers. In this context, financial hedging of natural gas volumes is only one resource among many for meeting customers' gas supply needs reliably, at the lowest reasonable price, while managing price volatility. Financial hedging should not be overused. Other resources include storage; firm multi-month index purchases of natural gas; spot purchases (daily

and monthly); city gate purchases; gas exchanges; and purchases at multiple hubs over varying time periods of varying volume packages across the entire PGA year.

2. Secondly, Staff recommends that LDCs' gas cost accounting records be regularly audited by Commission-selected auditors. Such audits should be carried out at least semi-annually. The auditors selected by the Commission to carry out these audits should have at least five years of prior experience in conducting fuel audits of utilities, including LDCs. Annually, Oregon LDCs pass through to their customers approximately $650 million in natural gas costs. Such a level of pass through demands regular audits of the accounting for natural gas costs. Staff recommends the auditors be allowed to bill their time for auditing an LDC to that LDC. Staff also recommends that the LDCs be allowed to recover these auditing costs as part of normal operating expenses.

3. Finally, as we noted above, Staff recommends more frequent PGA filings by Oregon's LDCs. There are several benefits related to more frequent PGA filings:

    a. More frequent PGA filings provide more "real time" pricing signals to customers. This helps customers adjust their usage accordingly and makes energy efficiency and conservation programs more effective.

    b. More frequent PGA filings provide the Commission more opportunity and information to assess the prudence of gas purchase costs and LDC purchasing practices.

    c. More frequent PGA filings allow more time and opportunity for Staff to recommend and review implementation of necessary changes to purchasing practices and portfolios.

    d. More frequent PGA filings provide an opportunity for the Commissioners to question LDCs about natural gas markets and natural gas purchasing practices.

    e. Finally, more frequent PGA filings allow customers and the press more opportunity to develop proper understanding of natural gas markets and pricing and the purchasing actions of the LDCs.

Staff's preference is that LDCs make PGA filings on a quarterly basis during the November through October PGA year. Staff could also support monthly filings. Staff feels less comfortable with semi-annual filings, but even this would be an improvement over the current annual filing arrangement. Changing to more frequent PGA filings would have little impact on gas cost deferrals. For example, if PGA filings were made quarterly, each such filing would re-set the gas cost charged through to customers. Any over/under in recovery from such changes during the PGA year would be "trued up" at the end of the year and returned/recovered during the next PGA year. A separate deferral account would deal with rewards and penalties from any incentive mechanism put in place.

SUMMARY OF STAFF'S RECOMMENDATIONS

Staff proposes the Commission adopt a cost recovery mechanism that is fair, simple, and easy to understand, but more importantly, a mechanism that reflects the nature of natural gas purchasing and risks in today's natural gas marketplace. We have provided herein the backdrop for how we got where we are today and why Oregon's current PGA mechanism and sharing arrangement for natural gas costs are no longer tenable. We have also provided support for our recommendation that natural gas utilities be allowed to recover 100% of their prudently-incurred natural gas costs.

Staff has also proposed two incentive mechanisms that allow the LDCs an opportunity to earn a reward for the purchase of natural gas at prices better than an exogenous market-based benchmark. Staff was careful in building its proposed incentive mechanisms to be consistent with principles and characteristics outlined in an NRRI paper investigating such mechanisms, published in 2006. Our mechanisms clearly focus on the objectives of low gas cost, avoid undue exposure to uncertainties outside of the LDCs' control and, most importantly, define a benchmark so that awards are earned only by an LDC's efforts to lower its gas costs. Either mechanism could be adopted by the Commission. The first mechanism (shown in Attachments B and B-1) provides an opportunity to earn a reward, or symmetrically, a penalty, for purchasing natural gas in the daily or monthly spot market for less, or more, than an exogenous market-based benchmark for that spot gas for that LDC. The second mechanism (shown in Attachments C and C-1) provides an opportunity to earn a reward, or symmetrically, a penalty, for purchasing an LDC's total gas supply for less, or more, than an exogenous market-based benchmark for that natural gas supply for that LDC.

Staff's opening comments also discuss how the proposed mechanisms correct the deficiencies inherent in the PGA mechanism in place today. Specifically, Staff's proposed cost recovery will place greater emphasis on LDC decisions and actions in purchasing natural gas for its customers. Staff mechanisms provide LDCs with the opportunity to earn incentive payments for exceptional gas purchasing decisions and actions that reduce gas costs for customers below currently available market prices, but also impose penalties if purchasing decisions result in actual gas costs that are significantly higher than market prices.

Staff proposes specific and detailed criteria and means for assessing the prudence of LDC gas purchase planning and decision making. These include:

1. Purchases must be carried out in accordance with the requirements of "best practices" portfolio purchasing; and
2. LDCs' gas cost accounting records must be regularly audited by Commission-selected auditors.

Staff recommends more frequent PGA filings by Oregon's LDCs. More frequent filings have multiple benefits in addition to improving assessment of the prudence of LDC purchase planning and decision making. Staff's preference is that LDCs make PGA filings on a quarterly basis during the November through October PGA year.

Finally, Staff proposes that the PGA cost recovery and incentive mechanisms be implemented beginning November 1, 2008. For cost recovery, that would mean that the mechanism would true up, through a deferral process, the difference between the WACOG embedded in rates beginning November 1, 2008, and the actual WACOG experienced by the LDC. For the incentive mechanism, that would mean that the LDCs would be subject to the incentive mechanism for purchases relating to the PGA year beginning November 1, 2008.

Dated at Salem, Oregon this 4th day of December, 2007

Kenneth R. Zimmerman, PhD
Senior Utility Analyst
Market & Resource Analysis
Electric & Natural Gas Division

Attachment A
NRRI Recommended GPIM Design Principles and Characteristics

Provide Equal Incentives For Interrelated Costs and Revenues: All inter-related and substitutable actions, costs and revenues should have equal incentives applied to them; this provides broad-ranging incentives, and avoids creating opportunities where the utility may be able to maximize less-incented costs to allow optimization of costs or revenues to which stronger incentives apply.

But Focus on Objective of Low Gas Cost; Exclude, or Include Targets For, Hedging: GPIMs are about low gas cost; incentives for achieving other objectives, such as reliability or price stability, cannot effectively be created within a GPIM, nor should a GPIM create incentives that jeopardize or conflict with these other objectives. Consequently, firm capacity holdings for reliability, and target quantities and a schedule for hedging, should be agreed upon in advance and reflected in the GPIM benchmark (so that holding the required capacity and meeting the targets result in no award or penalty). Or, hedging costs and results can remain entirely outside of the incentive mechanism.

Define the Benchmark to Adapt to Uncertain External Conditions: The goal should be to provide incentives for actions under utility control while avoiding undue exposure to uncertainties outside of utility control, such as load levels and market prices. That would lead to undeserved "windfall" awards or large penalties, and the exposure to risk could adversely affect utility decision-making.

Define the Benchmark To Approximate a Reasonable Strategy -- Not Too Easy to Beat: Avoid rigid assumptions about purchase locations; include estimates of offsetting revenues from capacity release and off-system gas sales; etc.

But Keep the Benchmark Exogenous To Avoid Weak or Distorted Incentives, Gaming:[10] The benchmark calculation should be invariant to actions of the utility, so that awards are earned only by lowering gas cost, not raising the benchmark, and incentives are created for all aspects of procurement decision-making. Avoid reflecting the actual locations, timing or types of purchases in the benchmark, or use of other parameters that are affected by the utility's actual choices.

Set Sharing Rules to Provide Strong, Symmetric Incentives Under All Conditions: The sharing rules should be set to balance the strength of incentives, the likelihood of relatively large deviations between actual and benchmark gas costs, the utility's risk attitude, and other factors. Variable or asymmetric sharing rules, tolerance bands, and caps distort and blunt incentives, and should be avoided.

Meanwhile, Try To Keep It Simple: A less complex approach will be less costly to monitor and may reduce the chance of misunderstandings, disputes and unintended incentives.

[10] While it is important for a GPIM benchmark to reflect external conditions, such as load and prices, which are outside of utility control, it is also important that a GPIM benchmark not use parameters that are under utility control. It is a fundamental principle of the design of incentive mechanisms that a benchmark should provide an external and independent basis for evaluating company performance. This means that the benchmark calculation should use only parameters and assumptions that are independent of the utility's actual purchasing decisions (we call this an exogenous benchmark). If the benchmark is exogenous, the utility can only increase its award by lowering actual gas cost, not by raising the benchmark; as a result, utility and customer interests are aligned. (p. 7 of the NRRI Report)

Attachment B

Staff's Proposed PGA Incentive Mechanism for Short-term Purchases at Index Prices

<table>
<tr><td>1</td><td>Scope</td><td colspan="4">Gas commodity purchased in monthly and daily spot markets</td></tr>
<tr><td>2</td><td>Period for which incentives computed</td><td colspan="4">Annual (for current PGA year), computed on a monthly basis</td></tr>
<tr><td rowspan="3">3</td><td rowspan="3">Benchmark - Index locations and weights</td><td>Index locations</td><td>Sumas</td><td>AECO</td><td>Rockies</td></tr>
<tr><td>Formula weight</td><td>1.2</td><td>0.95</td><td>0.85</td></tr>
<tr><td>Comment</td><td colspan="3">Based on available firm transportation capacity, historical purchasing practices, and projected future purchasing practices. Computed on a monthly basis with the results summed for an annual benchmark.</td></tr>
<tr><td>4</td><td>Benchmark - Source for spot prices</td><td colspan="4">Published FOM prices for monthly contracts; published daily index prices for daily purchases</td></tr>
<tr><td>5</td><td>Benchmark - Volumes for spot natural gas</td><td colspan="4">Based on weights from line 3</td></tr>
<tr><td>6</td><td>Benchmark – Treatment of storage</td><td colspan="4">Ratable injection pattern as follows:
• 20% fill complete by May 1;
• 50% fill complete by July 1;
• 75% fill complete by September 1; and,
• 100% fill complete by November 1.
Ratable withdrawal pattern as follows:
• Maximum withdrawal total by January 1, 25%;
• Maximum withdrawal total by February 1, 50%;
• Maximum withdrawal total by March 1, 75%; and
• Maximum withdrawal total by April 1, 100%.
Violations of ratchets:
• For months during which these ratchets are violated by more than then 5% the LDC will not recover additional gas costs above actual.
• For months during which these ratchets are violated by more than 5% but less than 10% the LDC will reduce gas costs to customers by 2.5%.
• For months during which these ratchets are violated by more than 10% the LDC will reduce gas costs to customers by 5%.
• LDC may request waiver of penalty for good cause shown.</td></tr>
<tr><td>7</td><td>Benchmark exogenous?</td><td colspan="4">Yes</td></tr>
<tr><td>8</td><td>Tolerance band</td><td colspan="4">±100 basis points for monthly revenue (based on ROE from most recently completed OPUC earnings review).</td></tr>
<tr><td>9</td><td>Sharing rule (%) – utility share</td><td colspan="4">• 25% for monthly savings from the benchmark outside the tolerance band up to $50,000; and,
• 50% for monthly savings from the benchmark outside the tolerance band above $50,000.</td></tr>
<tr><td>10</td><td>Sharing rule (%) – customer share</td><td colspan="4">• Pay 25% of monthly costs above the benchmark outside the tolerance band up to $50,000; and,
• Pay 50% of monthly costs above the benchmark outside the tolerance band by greater than $50,000.</td></tr>
<tr><td>11</td><td>Treatment of hedging</td><td colspan="4">Costs and impacts excluded from benchmark and actual gas cost calculations.</td></tr>
<tr><td>12</td><td>Treatment of off-system natural gas sales</td><td colspan="4">All revenue gains and losses will be included in monthly gas cost.</td></tr>
<tr><td>13</td><td>Accounting</td><td colspan="4">All gas cost and volume adjustments for the PGA year must be included in the calculation of actual cost for each month during the PGA year. No such adjustments may be accounted for in prior or subsequent months during the current PGA year or during subsequent PGA years for purposes of the GPIM.</td></tr>
</table>

Attachment B-1

Numerical Example

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Month	**Benchmark**	**LDC WACOG**	**Difference**	**Spot Gas Vols. (Dth)**	**Total Value of Difference**	**Tolerance Band Value (± value)**	**Difference for Sharing (Note 1)**	**Rewards To LDC**	**Penalties to LDC**	**Net Result to LDC (Note 2)**	**Net Result to Customers (Note 3)**
Jan	$8.05	$7.80	-$0.25	750,000	($187,500)	$21,600	($165,900)	$82,950	$0	$82,950	($104,550)
Feb	$8.50	$8.05	-$0.45	625,000	($281,250)	$23,400	($257,850)	$128,925	$0	$128,925	($152,325)
Mar	$8.25	$8.35	$0.10	240,000	$24,000	$12,600	$11,400	$0	($2,850)	($2,850)	$21,150
Apr	$7.50	$7.60	$0.10	160,000	$16,000	$14,137	$1,863	$0	($466)	($466)	$15,534
May	$7.00	$6.80	-$0.20	90,000	($18,000)	$14,137	($3,863)	$966	$0	$966	($17,034)
Jun	$6.50	$6.35	-$0.15	33,000	($4,950)	$12,852	$0	$0	$0	$0	($4,950)
Jul	$6.00	$6.00	$0.00	17,500	$0	$11,567	$0	$0	$0	$0	$0
Aug	$6.00	$6.05	$0.05	12,000	$600	$10,282	$0	$0	$0	$0	$600
Sep	$6.20	$6.05	-$0.15	162,500	($24,375)	$12,852	($11,523)	$2,881	$0	$2,881	($21,494)
Oct	$6.10	$5.90	-$0.20	193,750	($38,750)	$14,137	($24,613)	$6,153	$0	$6,153	($32,597)
Nov	$7.60	$7.20	-$0.40	237,500	($95,000)	$14,400	($80,600)	$40,300	$0	$40,300	($54,700)
Dec	$7.50	$7.60	$0.10	475,000	$47,500	$18,000	$29,500	$0	($7,375)	($7,375)	$40,125
Totals				2,996,250	($561,725)	$179,964	**($501,586)**	$262,175	($10,691)	**$251,484**	**($310,241)**

Note 1: This is the level of savings from or costs above the benchmark outside the tolerance band.

Note 2: Added earnings to LDC.

Note 3: (Savings)/Cost to customers.

Attachment C

Staff's Proposed PGA Incentive Mechanism for Monthly WACOG to Customers

<table>
<tr><td>1</td><td>Scope</td><td colspan="4">Monthly WACOG for all gas sales to core customers</td></tr>
<tr><td>2</td><td>Period for which incentives computed</td><td colspan="4">Monthly (for current PGA year), accumulated annually</td></tr>
<tr><td rowspan="3">3</td><td rowspan="3">Benchmark - Index locations and weights</td><td>Index locations</td><td>Sumas</td><td>AECO</td><td>Rockies</td></tr>
<tr><td>Formula weight</td><td>1.2</td><td>0.95</td><td>0.85</td></tr>
<tr><td>Comment</td><td colspan="3">Based on available firm transportation capacity, historical purchasing practices, and projected future purchasing practices. Computed on a monthly basis with the results summed for an annual benchmark.</td></tr>
<tr><td>4</td><td>Benchmark - Source for hedged and spot prices</td><td colspan="4">Published FOM prices for monthly contracts; published daily index prices for daily purchases. Published (often confidential) NYMEX and Pacific Northwest fixed-price hedging prices for the monthly period, averaged by NWP hub for all counterparties for which information is available.</td></tr>
<tr><td>5</td><td>Benchmark - Volumes for spot natural gas</td><td colspan="4">Based on weights from line 3</td></tr>
<tr><td>6</td><td>Benchmark – Treatment of storage</td><td colspan="4">Ratable injection pattern as follows:
• 20% fill complete by May 1;
• 50% fill complete by July 1;
• 75% fill complete by September 1; and,
• 100% fill complete by November 1.
Ratable withdrawal pattern as follows:
• Maximum withdrawal total by January 1, 25%;
• Maximum withdrawal total by February 1, 50%;
• Maximum withdrawal total by March 1, 75%; and
• Maximum withdrawal total by April 1, 100%.
Violations of ratchets:
• For months during which these ratchets are violated by 5% or less the LDC will not recover additional gas costs above actual.
• For months during which these ratchets are violated by more than 5% but less than 10% the LDC will reduce gas costs to customers by 2.5%.
• For months during which these ratchets are violated by more than 10% the LDC will reduce gas costs to customers by 5%.
• LDC may request waiver of penalty for good cause shown.</td></tr>
<tr><td>7</td><td>Benchmark exogenous?</td><td colspan="4">Yes</td></tr>
<tr><td>8</td><td>Tolerance band</td><td colspan="4">± 2% of benchmark is a dead band (LDC recovers 100% of actual prudent gas costs only)</td></tr>
<tr><td>9</td><td>Sharing rule (%)</td><td colspan="4">• If the monthly percentage variance between LDC WACOG and the benchmark (see Column 8 in Attachment C-1) is greater than or equal to 2.5% and less than 5%, the LDC is penalized 2% of the variance between the benchmark and the LDC WACOG available for sharing (see Column 9 in Attachment C-1), if LDC WACOG is above the benchmark or is rewarded 2% of the variance shown in Column 9 if LDC WACOG is below the benchmark.
• If the monthly percentage variance between LDC WACOG and the benchmark is greater than or equal to 5% and less than 10%, the LDC is penalized 5% of the variance between the benchmark and the LDC WACOG available for sharing, if LDC WACOG is above the benchmark or is rewarded 5% of the variance if LDC WACOG is below the benchmark.
• If the monthly percentage variance between LDC WACOG and the benchmark is greater than or equal to 10%, the LDC is penalized 7.5% of the variance between the benchmark and the LDC WACOG available for sharing, if LDC WACOG is above the benchmark or is rewarded 7.5% of the variance if LDC WACOG is below the benchmark.</td></tr>
<tr><td>10</td><td>Treatment of hedging</td><td colspan="4">Costs and impacts included in benchmark and actual gas cost calculations.</td></tr>
<tr><td>11</td><td>Treatment of off-system natural gas sales</td><td colspan="4">All revenue gains and losses will be included in monthly gas cost.</td></tr>
<tr><td>12</td><td>Accounting</td><td colspan="4">All gas cost and volume adjustments for the PGA year must be included in the calculation of actual cost for each month during the PGA year. No such adjustments may be accounted for in prior or subsequent months during the current PGA year or during subsequent PGA years for purchases of the GPIM.</td></tr>
</table>

Attachment C-1

Numerical Example

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Month	**Bench-mark**	**LDC WACOG**	**Difference**	**Sales Vols. (Dth)**	**Total Value of Difference**	**Tolerance Band Value (± 2%) (This is not shared, but sets the threshold for sharing to begin.)**	**Percentage Variance of LDC WACOG from Benchmark WACOG**	**Variance Between Benchmark and LDC WACOGs Available for Sharing (Note 1)**	**Difference for Sharing to LDC (± 2.5% of Benchmark) Sharing Level 2%**	**Difference for Sharing to LDC (± 5% of Benchmark) Sharing Level 5%**	**Difference for Sharing to LDC (± 10% of Benchmark) Sharing Level 7.5%**	**Rewards To LDC**	**Penalties to LDC**	**Net Result to LDC (Note 2)**	**Net Result to Customers (Note 3)**
Jan	$7.90	$7.00	-$0.90	3,000,000	($2,700,000)	$474,000	-11.39%	($2,226,000)	($44,520)	($111,300)	($166,950)	($166,950)	$0	$166,950	($2,533,050)
Feb	$8.10	$7.50	-$0.60	2,500,000	($1,500,000)	$405,000	-7.41%	($1,095,000)	($21,900)	($54,750)	$0	($54,750)	$0	$54,750	($1,445,250)
Mar	$7.95	$8.25	$0.30	1,200,000	$360,000	$190,800	3.77%	$169,200	$3,384	$0	$0	$0	$3,384	($3,384)	$356,616
Apr	$7.20	$7.30	$0.10	800,000	$80,000	$115,200	1.39%	$0	$0	$0	$0	$0	$0	$0	$80,000
May	$6.70	$6.35	-$0.35	450,000	($157,500)	$60,300	-5.22%	($97,200)	($1,944)	($4,860)	$0	($4,860)	$0	$4,860	($152,640)
Jun	$6.20	$6.00	-$0.20	220,000	($44,000)	$27,280	-3.23%	($16,720)	($334)	$0	$0	($334)	$0	$334	($43,666)
Jul	$5.80	$5.80	$0.00	175,000	$0	$20,300	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$5.55	$5.60	$0.05	150,000	$7,500	$16,650	0.90%	$0	$0	$0	$0	$0	$0	$0	$7,500
Sep	$5.60	$5.25	-$0.35	650,000	($227,500)	$72,800	-6.25%	($154,700)	($3,094)	($7,735)	$0	($7,735)	$0	$7,735	($219,765)
Oct	$6.21	$6.05	-$0.16	775,000	($124,000)	$96,255	-2.58%	($27,745)	($555)	$0	$0	($555)	$0	$555	($123,445)
Nov	$7.50	$7.30	-$0.20	950,000	($190,000)	$142,500	-2.67%	($47,500)	($950)	$0	$0	($950)	$0	$950	($189,050)
Dec	$7.85	$7.60	-$0.25	1,900,000	($475,000)	$298,300	-3.18%	($176,700)	($3,534)	$0	$0	($3,534)	$0	$3,534	($471,466)
Totals				12,770,000	($4,970,500)			**($3,672,365)**	**($73,447)**	**($178,645)**	**($166,950)**	**($239,668)**	**$3,384**	**$236,284**	**($4,734,216)**
Source of column data	See Attachment C for calculation inputs	Actual monthly LDC-specific WACOG	Column (2) less Column (3)	LDC-specific monthly sales volumes	Column (4) times Column (5)	Column (2) times 2.0% Time Column (5)	Column (4) Divided by Column (2)	**Column (6) plus or minus Column (7)**	**If Column (8) is between 2.5% and 5%, the reward or penalty is ±2% times Column (9)**	**If Column (8) is between 5.0% and 10%, the reward or penalty is ±5% times Column (9)**	**If Column (8) is greater than or equal to 10%, the reward or penalty is ±7.5% times Column (9)**	**The largest of the values in Columns (10), (11), or (12), if negative**	**The largest of the values in Columns (10), (11) or (12), if positive**	**Opposite signed value of Column (13) is a reward, Opposite signed value of Column (14) is a penalty**	**Column (6) plus Column (15)**

Note 1: This is the value for sharing outside the tolerance band; or is zero if the total value of the difference for sharing does not exceed the tolerance band level.

Note 2: Added earnings to LDC.

Note 3: (Savings)/Cost to customers.

UM 1286 - Staff Comments
Attachment B-1 - Numercial Example

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Month	**Benchmark**	**LDC WACOG**	**Difference**	**Spot GasVols. (Dth)**	**Total Value of Difference**	**Tolerance Band Value (± value)**	**Difference for Sharing (Note 1)**	**Rewards To LDC**	**Penalties to LDC**	**Net Result to LDC (Note 2)**	**Net Result to Customers (Note 3)**
Jan	$8.05	$7.80	-$0.25	750,000	($187,500)	$21,600	($165,900)	$82,950	$0	$82,950	($104,550)
Feb	$8.50	$8.05	-$0.45	625,000	($281,250)	$23,400	($257,850)	$128,925	$0	$128,925	($152,325)
Mar	$8.25	$8.35	$0.10	240,000	$24,000	$12,600	$11,400	$0	($2,850)	($2,850)	$21,150
Apr	$7.50	$7.60	$0.10	160,000	$16,000	$14,137	$1,863	$0	($466)	($466)	$15,534
May	$7.00	$6.80	-$0.20	90,000	($18,000)	$14,137	($3,863)	$966	$0	$966	($17,034)
Jun	$6.50	$6.35	-$0.15	33,000	($4,950)	$12,852	$0	$0	$0	$0	($4,950)
Jul	$6.00	$6.00	$0.00	17,500	$0	$11,567	$0	$0	$0	$0	$0
Aug	$6.00	$6.05	$0.05	12,000	$600	$10,282	$0	$0	$0	$0	$600
Sep	$6.20	$6.05	-$0.15	162,500	($24,375)	$12,852	($11,523)	$2,881	$0	$2,881	($21,494)
Oct	$6.10	$5.90	-$0.20	193,750	($38,750)	$14,137	($24,613)	$6,153	$0	$6,153	($32,597)
Nov	$7.60	$7.20	-$0.40	237,500	($95,000)	$14,400	($80,600)	$40,300	$0	$40,300	($54,700)
Dec	$7.50	$7.60	$0.10	475,000	$47,500	$18,000	$29,500	$0	($7,375)	($7,375)	$40,125
Totals				2,996,250	($561,725)	$179,964	**($501,586)**	$262,175	($10,691)	**$251,484**	**($310,241)**

Note 1: This is the level of savings from or costs above the benchmark outside the tolerance band.

Note 2: Added earnings to LDC.

Note 3: (Savings)/Cost to customers.

UM 1286 - Staff Comments

Attachment C-1 - Numercial Example

(1) Month	(2) Benchmark	(3) LDC WACOG	(4) Difference	(5) Sales Vols. (Dth)	(6) Total Value of Difference	(7) Tolerance Band Value (± 2%) (This is not shared, but sets the threshold for sharing to begin.)	(8) Percentage Variance of LDC WACOG from Benchmark WACOG	(9) Variance Between Benchmark and LDC WACOGs Available for Sharing (Note 1)	(10) Difference for Sharing to LDC (± 2.5% of Benchmark) Sharing Level 2%	(11) Difference for Sharing to LDC (± 5% of Benchmark) Sharing Level 5%	(12) Difference for Sharing to LDC (± 10% of Benchmark) Sharing Level 7.5%	(13) Rewards To LDC	(14) Penalties to LDC	(15) Net Result to LDC (Note2)	(16) Net Result to Customers (Note 3)
Jan	$7.90	$7.00	-$0.90	3,000,000	($2,700,000)	$474,000	-11.39%	($2,226,000)	($44,520)	($111,300)	($166,950)	($166,950)	$0	$166,950	($2,059,050)
Feb	$8.10	$7.50	-$0.60	2,500,000	($1,500,000)	$405,000	-7.41%	($1,095,000)	($21,900)	($54,750)	$0	($54,750)	$0	$54,750	($1,040,250)
Mar	$7.95	$8.25	$0.30	1,200,000	$360,000	$190,800	3.77%	$169,200	$3,384	$0	$0	$0	$3,384	($3,384)	$165,816
Apr	$7.20	$7.30	$0.10	800,000	$80,000	$115,200	1.39%	$0	$0	$0	$0	$0	$0	$0	$0
May	$6.70	$6.35	-$0.35	450,000	($157,500)	$60,300	-5.22%	($97,200)	($1,944)	($4,860)	$0	($4,860)	$0	$4,860	($92,340)
Jun	$6.20	$6.00	-$0.20	220,000	($44,000)	$27,280	-3.23%	($16,720)	($334)	$0	$0	($334)	$0	$334	($16,386)
Jul	$5.80	$5.80	$0.00	175,000	$0	$20,300	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$5.55	$5.60	$0.05	150,000	$7,500	$16,650	0.90%	$0	$0	$0	$0	$0	$0	$0	$0
Sep	$5.60	$5.25	-$0.35	650,000	($227,500)	$72,800	-6.25%	($154,700)	($3,094)	($7,735)	$0	($7,735)	$0	$7,735	($146,965)
Oct	$6.21	$6.05	-$0.16	775,000	($124,000)	$96,255	-2.58%	($27,745)	($555)	$0	$0	($555)	$0	$555	($27,190)
Nov	$7.50	$7.30	-$0.20	950,000	($190,000)	$142,500	-2.67%	($47,500)	($950)	$0	$0	($950)	$0	$950	($46,550)
Dec	$7.85	$7.60	-$0.25	1,900,000	($475,000)	$298,300	-3.18%	($176,700)	($3,534)	$0	$0	($3,534)	$0	$3,534	($173,166)
Totals				12,770,000	($4,970,500)			**($3,672,365)**	**($73,447)**	**($178,645)**	**($166,950)**	**($239,668)**	**$3,384**	**$236,284**	**($3,436,081)**

Note 1: This is the value for sharing outside the tolerance band; or is zero if the total value of the difference for sharing does not exceed the tolerance band level.

Note 2: Added earnings to LDC.

Note 3: (Savings)/Cost to customers.

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 4th day of December, 2007.

Kay Barnes

Kay Barnes
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UM 1286
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