Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry

Docket No. UG-940778

Reference Volume 2: Written Reply Comments

STATE OF WASHINGTON
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
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Reference Volume 2: Written Reply Comments

On November 3, 1995 the Washington Utilities and Transportation Commission offered all interested persons the opportunity to submit written comments in response or reply to the first round of comments we received in our inquiry on the natural gas industry.

The Commission was pleased to receive eight sets of reply comments. This volume contains the text of these replies. Written responses have been arranged alphabetically and are separated by a yellow title page.

The analysis and opinions included in this volume are the responsibility of commentors and do not necessarily represent the opinions, position, policy, or analysis of the Commission or its staff.

Questions concerning the Inquiry should be directed to Jeffrey Showman (360/586-1196) of the Commission's policy and planning section.

Steve McLellan
Secretary

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Docket No. UG-940778

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February 1, 1996

Steve McLellan, Secretary
Washington Utilities and
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Olympia, WA 98054-7250

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Re: Natural Gas Industry NOI
Docket No. UG-940778

Dear Mr. McLellan:

Enclosed are the Reply Comments of Public Counsel in the above referenced docket. We have enclosed ten copies and a diskette formatted in Wordperfect 5.1.

Very truly yours,

Donald T. Trotter
Assistant Attorney General
Public Counsel

DTT/ljb
Enclosures

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry	)	DOCKET NO. UG-940778

REPLY COMMENTS OF PUBLIC COUNSEL

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February 2, 1996

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I. OVERVIEW OF FIRST ROUND COMMENTS

The first round comments of many parties were informative, interesting, and revealing. While numerous topics were addressed, nearly all of the comments fall into the following general categories:

1) Comments by local distribution companies requesting additional flexibility to price services to meet customer needs, but opposing the blanket establishment of exit fees, entrance fees, or other revenue stabilizing mechanisms;

2) Comments by gas marketers seeking open access to the retail customers of LDCs, and seeking to prevent "unfair competition" in the gas supply market by LDCs holding portfolios for core market customers;

3) Comments by public interest representatives seeking to ensure that core market customers are not adversely affected by emerging competitive trends in the industry.

4) Comments by industrial customers seeking additional opportunities to purchase only those unbundled services they require, and to pay only embedded cost-based prices for those specific services.

5) Comments by LDCs and the financial community urging that the purchased gas adjustment (PGA) mechanisms be preserved and/or improved.

6) Other issues, including confidentiality, demand-side management, and technological evolution.

II. PRINCIPLES FOR ANALYSIS OF MAJOR ISSUES

In general, Public Counsel finds the majority of the initial comments constructive and helpful to the Commission in preparing for the next decade of regulatory evolution in the natural gas industry. Our reply comments will be limited to specific areas addressed by others where we feel the Commission will benefit from additional perspectives on certain issues.

We begin, however, by reasserting the basic principles we set forth in our original comments. These principles are still crucial, appropriate, and complete:

1) Markets should work for the benefit of all consumers.

2) There is no forgiveness in a truly competitive marketplace; if there are changes needed in the regulatory scheme to "promote competition," this fact should be recognized.

3) No discrimination should be permitted which allows any customer to pay less or forces any customer to pay more than any other customers for substantially similar products as a result of competitive forces.

4) All customers must share in the cost of the system.

5) A fair allocation of embedded costs, which make up the utility revenue requirement, should be the guide to pricing equity for natural gas.

6) Long-run marginal costs, not short-run market conditions, should be the guide to pricing efficiency for natural gas.

7) There are efficiency benefits to having a utility system.

8) The benefits of utility operations in competitive markets should be used to reduce prices for "full service" customers of regulated utilities.

9) New customers should contribute at least as much to revenue as they do to long run marginal cost.

10) Utilities should enable consumers to choose the least costly means of meeting their energy needs, including demand-side management alternatives.

11) Large customers that exercise competitive options should only be allowed to do so in a way that does not jeopardize utility planning efforts for core customers.

With these principles in mind, we offer the following comments on the submissions received by the Commission to date. The general categories of issues we address are:

A) Pricing Flexibility;
B) "Fair" Competition in the Gas Supply Market;
C) Preserving Fair Rates for Core Market Customers;
D) Undbundled Services Pricing;
E) Purchased Gas Adjustment Clauses;
F) Other DSM Issues.

III. REPLY COMMENTS OF PUBLIC COUNSEL

A. PRICING FLEXIBILITY FOR UTILITIES

Nearly all of the LDC commenters have requested the flexibility to price services for competitive-sector customers to attract and retain loads. In general, we agree that it is desirable for utilities to retain loads which more fully utilize system facilities, allow administrative and other expenses to be spread more fully over all system users, and prevent uneconomic bypass.

However, as we discuss in section (D) below, one tool to accomplish this is to establish rates for unbundled services based on market conditions (not embedded costs) which will encourage large users to remain full customers of the LDCs. It would be a serious mistake to underprice unbundled services, allowing large users to economically switch to transportation service or bypass, and then offer below-cost prices to entice them back onto the system.

1. NWNG'S LRIC PROPOSAL

Northwest Natural Gas has gone a step further than the other LDC Commenters, by requesting the consideration of long-run incremental cost pricing for <u>all</u> gas services, arguing that these prices will best enable the Company to attract and retain loads which are subject to competitive pressures.

This Commission has never conducted a generic investigation into the proper way to allocate gas utility costs (as it did for the electric industry in Cause U-78-05), but rather has established principles guiding cost allocation in specific proceedings involving Cascade (U-86-100), WWP (UG-901459), and WNG (UG-940814).

NWNG appears to mix principles of <u>cost allocation</u> with those of <u>rate design</u>. In the electric industry, this Commission has consistently approved embedded cost of service methods which reflect forward-looking costs, while designing rates within customer classes based upon long-run incremental costs and/or concepts. The same approach can operate in the gas industry. Indeed, the "efficiencies" which NWNG notes on pages 20-22 of its comments have more to do with rate design than with cost allocation.

In any event, we anticipate that we will disagree sharply with NWNG on the proper calculation of long-run incremental costs. We say this because we anticipate that NWNG will seek to have principles similar to those employed in its Oregon jurisdiction adopted in Washington. We have examined the Oregon methods, and find them fundamentally flawed in the classification and allocation of long-run incremental distribution and administrative costs.

NWNG's Oregon core market rates are much <u>higher</u> than those in Washington, while its non-core rates in Oregon are <u>lower</u> than those in Washington. Conversely, NWNG's core market rates in Washington are <u>higher</u> than those for other LDCs, and its noncore market rates are lower than those for the other Washington LDCs. We are concerned that NWNG's request to change costing methods is little more than a thinly veiled proposal to adjust relative class contributions to margins in a direction which is exactly the opposite of what would result if one adhered to the cost allocation principles adopted by this Commission over the last decade.

The issue of cost allocation between classes based on long-run incremental costs has not been raised in proceedings involving the other LDCs in Washington. We note even that NWIGU seeks embedded cost prices, not LRIC-based prices (see page 4 of its comments).

We do not object to NWNG's request that long-run incremental pricing be considered as an alternative to embedded cost pricing in a future docket, but until that time, the Commission should establish by rule the methods it has consistently ordered to be used for computing embedded cost of service.

2. LINE EXTENSION POLICIES

One area addressed by the LDCs deals with line extension policies. NWNG proposes a change to rate levels in order to be able to justify extending service to additional customers, while WWP and WNG have indicated that their existing line extension policies are reasonable. NWNG's proposal should be dismissed, and the Company be directed to examine the optional form of "new customer" contribution recently implemented for WNG, in which new customers with higher-than-average line extension costs can pay the additional cost over a period of years. This allows existing customers to pay only for the costs of serving their needs, while allowing new customers access to gas without large up-front charges which may be a barrier to the choice of gas as a fuel.

A proper forum to address NWNG's concerns about its line extension policy may be its integrated resource planning process. That is, if gas service is indeed the lowest-cost option for the consumer and for society, including line extension costs, then methods to assure customer access and efficient customer choice should be developed. On the other hand, because NWNG competes with a low-cost, non-profit electric utility in Washington, there may be more situations where it is not cost-effective to extend gas service than the Company experiences in Oregon.

B. "FAIR COMPETITION" IN THE GAS SUPPLY MARKET

The comments of the gas marketers, including Enron, Natural Gas Supply Association, and Mock Resources, all reflect their hopes for unfettered access to gas consumers in order to market their products. We believe the commenters have overstated the benefits, and understated the risks, of such a system.

1. FAIR AND UNFAIR COMPETITIVE ACCESS

Prior to FERC Order 436, nearly all pipeline fixed costs were embedded in commodity gas prices, and all customers shared these costs equitably. The conversion to fixed/variable pricing, together with the emergence of very low cost "capacity release" programs has dramatically shifted the recovery of these costs to firm core market customers. A decade ago, there was less than a 10% difference between the gas supply costs for firm and interruptible customers. By contrast, today firm customers served by LDCs pay up to twice as much for gas supply as do interruptible transportation customers.

There is no question that in the current market environment, the "optimal" level of pipeline capacity is much lower than that currently held by any of the LDCs in Washington; we surmise that the optimal level of capacity is zero. The reason for this is that the purchase of interruptible gas, plus the cost of storage to firm it, is much lower than the cost of pipeline capacity. A transportation customer who is able to take advantage of capacity release can enjoy much lower gas costs than a sales customer who is locked into an LDC's rate schedule containing a full ration of pipeline capacity costs. Any system which allows transportation customers to continue to get a "free ride," or "hitchhike" on a pipeline system which is paid for by the core market is unacceptable, yet this is precisely what the gas marketers are seeking -- the ability to sell gas to any customer, and have that customer exempted from any of the LDC's gas supply costs (see, e.g. comments of Enron, page 5).

Enron has noted (comments, page 3) that commissions in other states have found ways to mitigate stranged costs for both pipeline demand charges and gas supplies. This issue needs to be addressed before any more fixed pipeline costs are shifted to core market consumers. In general, it is our view that all customers should pay equally for pipeline capacity, regardless of how they secure that access. An evaluation of the methods cited by Enron would be appropriate.

Currently, transportation customers are purchasing capacity release at less than $.01/therm through the open market, while core market customers are paying $.03 - $.10/therm for pipeline transportation through LDCs. We do indeed have a stranded commitment problem which needs to be addressed. Until this stranded commitment problem is addressed in a fair and equitable manner, it is appropriate for sales and transportation customers to share equally the uneconomic component (i.e., the difference between pipeline TF rates and capacity release rates) of pipeline charges.

2. AFFILIATE MARKETING OF GAS

Enron, in particular, has noted the potential for abuse when an LDC-affiliate is marketing on the utility's own system (Enron comments page 4). We agree. In Washington, as we understand it, only Cascade has been given permission to market gas to its own transportation customers. Both WNG and WWP were explicitly directed NOT to do so.

At the same time, given the pricing structure of the industry, with high discounts associated with high load factors, the LDCs may have very economical gas supplies available which can be sold at prices which benefit the core customers. We do not want to dissuade LDCs from taking actions to minimize the cost of service to core customers.

The standards of conduct suggested by Enron appear reasonable. If the Commission is to continue to allow Cascade to market to its own customers, we suggest that the Commission adopt standards of conduct for this activity. Similarly, if NWNG, WWP, or WNG are interested in marketing gas to their own customers, these or similar standards should also be applied.

3. IMPACT OF TRANSPORTATION ON CORE CUSTOMERS

The marketers, and Enron in particular, assert that competition in the gas industry for the loads of large customers does not affect small customers. Such assertions are plainly incorrect. The gas system is integrated. Increased demand by some customers causes increased prices for all customers as the system moves along a supply curve. A shortage caused by diversion of supplies to a formerly interruptible customer can adversely affect a firm customer.

The fact that there is no regulatory "obligation to serve" propane or heating oil customers (as noted by Enron on page 5 of its comments) does not affect the obligation to serve gas customers. If one heating oil customer runs out of fuel because its supplier does not deliver, that does not immediately affect other heating oil customers, since the fuel is in separate storage tanks. By contrast, if the gas supply system goes "under-pressure" because transportation customer gas supplies do not deliver gas to the LDC, all customers face a crisis.

All gas customers are tied together on a single system. The role of regulation in the public interest is to ensure that all customers are subject to reasonable rules which protect the integrity of that system, assure fair allocation of the costs of that system, and protect the interests of those who pay a premium for reliable service. The assertion that increased transportation of gas will not affect core market customers is plainly incorrect and could lead to irresponsible and unfair results.

C. PRESERVING FAIR RATES FOR CORE MARKET CUSTOMERS

Our own comments, and those of WSEO, dealt with means to preserve fair rates for customers without competitive options. Enron has proposed that small customers have access to competitive gas supplies, which would be one way to prevent LDCs from charging uneconomic gas supplies disproportionately to one group of customers. The proposal to allow competitive gas suppliers for all classes of customers should be explored, perhaps through educational workshops.

If, in fact, the "transaction costs" are not so high as to obviate any economic benefits of competition, we would generally agree that all customers should be allowed access to the market. Alternatively, however, if small customers must first incur the transaction costs of finding a gas supplier, and then also pay the LDC to provide standby firm gas supply (on the theory that it would be socially unacceptable to "valve off" residential or small commercial customers - NWNG, comments, page 10), there is unlikely to be any economic benefit. Gas marketers must provide a reliable supply, including a commitment to pay any emergency supply costs (such as the pipeline $2.00/therm overtake penalty) in order to meet their customers' needs. In this manner, there would be no need for the LDC to maintain any standby or reserve capacity.

We have no certainty that market pricing would benefit core customers. For this reason, we suggest educational workshops, rather than regulatory experiments, until more is known from experiences in other areas such as those cited by Enron.

D. UNBUNDLED SERVICES PRICING

NWIGU (comments, pages 5-8), the Natural Gas Supply Association (comments, page 2), and Enron (comments, page 5) have argued that customers should be allowed to select only those services they desire, and pay only embedded-cost based prices for those services. We could not disagree more with such self-serving proposals. Customers who elect to leave firm or interruptible service assume the risk that competitive LDC services will reflect the value of those services. Margins above cost should be flowed through to benefit core customers.

Utilities provide a broad range of services, not all of which are desired or desirable, or economic or necessary at any given point in time. For example, during the summer, firm pipeline capacity is a surplus commodity, and interruptible service is equally reliable. Storage costs are incurred year-round, but storage benefits accrue in the winter. In a warm year, not all of the pipeline capacity or storage facilities are necessary. Literally interpreted, the proposal of NWIGU and Enron would allow customers to pick and choose the facilities and service they want at cost-based prices, and bear <u>none</u> of the costs of the facilities and services they do not need at any point in time. We are concerned that all of the remaining costs will be borne by the core market.

We believe that at the present time, utilities have uneconomic levels of pipeline capacity. In the past, they had uneconomic levels of gas supply commitments (recovered through take-or-pay charges). In the future, they may have excess transmission capacity, excess storage capacity, or uneconomic meter reading techniques. Unless the system is always precisely optimally configured for the needs imposed on it at that instant, there will be some cost for which there is no current benefit. Allowing unbundled services to be priced on a cost of service basis allows customers with effectively competitive options to buy at market-based prices when those are lower than utility costs, and then to buy the remaining services they need, for which utility costs are lower, from the utility, leaving the utility stranded with uneconomic products and services (which we are concerned will be charged to the remaining core market customers).

In an effectively competitive market, when competitive market prices are higher than embedded costs, utilities, like any other competitor, should collect market-based prices for unbundled products and services, and use the net proceeds of those market activities to reduce the cost of service for captive core market customers.

It is common in the competitive market economy that unbundled pricing is more expensive than bundled pricing. Ordering a salad, entree, drink, and dessert "a la carte" is more expensive that the "full meal deal." Purchasing a Ford Taurus one component at a time over the parts counter is vastly more expensive than purchasing a fully assembled car. Purchasing the individual components of a computer system costs more than buying a fully-assembled unit with a software package included. The gas industry should be no different.

We recommend that the Commission adopt the following specific principle in this docket:

> Customers purchasing the full array of firm or interruptible sales service from a utility will be accorded cost of service based prices. Customers purchasing only transportation or other unbundled products and services will be allowed to do so if market-based prices exceed both short-run and long-run incremental costs, and therefore the offering of those services at market-based prices results in net revenues which can be used to reduce the costs paid by customers purchasing the full array of services from the utility. Customers purchasing unbundled services have no entitlement to cost-based prices for the individual products and services they choose.

E. PURCHASED GAS ADJUSTMENT CLAUSES

Several commenters took various positions on purchased gas adjustment clauses. While Paine Webber, Cascade, WNG, and WWP have advocated little or no change to the current 100% pass-through PGA mechanism, NWNG has advocated an incentive-based purchased gas mechanism which has been operating in Oregon for some time.

In a recent WNG proceeding, Public Counsel also advocated an incentive-based PGA mechanism. We believe that an incentive mechanism is appropriate, since these costs represent about half of the cost of serving core market customers. With a 100% pass-through, LDCs have little incentive either to minimize gas supply costs or maximize capacity release and off-market sales revenues.

WNG has correctly noted that the large number of transactions makes it difficult, if not impossible, for the Commission (and other parties) to examine every transaction for prudence. For this reason, a PGA mechanism based on some index of performance (i.e., daily spot market prices at Sumas) may be a more workable approach to determining what gas costs are allowable than a contract-by-contract analysis.

Since an active market for gas supply and pipeline capacity exists, it would be reasonable to compare what LDCs actually pay for gas delivered to their system to the prices paid by transportation customers situated in and near their systems. If the LDCs are paying higher prices, an adjustment may be appropriate, while if the LDCs are achieving lower costs, some reward mechanism may be appropriate. In this manner, the utilities will be put at risk for the level of firm pipeline capacity they retain, but will be able to achieve higher profits if they "beat the market" on gas supply costs.

The appropriate venue to examine the PGA mechanisms would be an informal series of workshops, followed by either individual utility general rate proceedings, or else a generic proceeding involving all of the LDCs. We recommend that the Commission convene a forum for the examination of the future of the PGA mechanism.

We are not prepared at this time to endorse NWNG's methodology, but recommend that the Commission convene a generic investigation into the proper way to reflect dynamic gas supply costs in rates. The mechanism should be fair to utilities and consumers, mitigate much of the risk to utilities while preserving incentives, and assure ease of administration.

F. OTHER ISSUES

Below we offer comments on only a limited number of the plethora of other issues raised by the submissions to the Commission. If other comments lead to proposed Commission action or rulemaking, we, of course, reserve the right to comment at the appropriate time on other issues.

1. DEMAND SIDE MANAGEMENT

Among the services which LDCs provide are demand side management measures and information. In general, the Commission's least cost planning rule is reasonable, and is having a desired impact on the supply and demand side resource acquisition activity of utilities.

We are concerned about one of the assertions made by NWIGU (comments, pages 10-11) about the impact of DSM activity on transportation customers, in which NWIGU asserts that the benefit of DSM activities to transportation customers is zero, and the share of DSM costs which transportation customers should bear is zero. NWIGU fundamentally misunderstands the purpose of DSM investments, and the benefits which those benefits bring to the system.

DSM investments reduce energy loads at the point of use. This helps the utility to avoid both gas supply purchases and gas distribution capacity investments. If transportation customers are served by the distribution system, they directly benefit from the reduced capacity needs on that distribution system, and should share in the cost of the DSM measures. About half of the cost of the utility system is gas supply, and half is distribution-related. Thus about half of the cost of DSM investments should be classified and allocated in the same manner as distribution plant investments, and transportation customers should share in this portion of DSM costs.

DSM investments also help to reduce total regional natural gas demand, and this has a beneficial downward effect on gas prices given any gas supply curve. It is widely recognized that improved motor vehicle fuel economy was the largest contributor to the collapse of OPEC and the relatively stable oil prices we have enjoyed for a decade. Similarly, more efficient building codes, appliances, and utility DSM programs help to hold down the demand for gas and the price for gas for <u>all</u> gas users, not just for the participants in the programs. The assertions preferred by NWIGU that transportation customers derive <u>zero</u> benefit from utility DSM programs is myopic, unrealistic, and incorrect. Such assertions should be rejected categorically.

G. CONFIDENTIALITY

Several parties commented on the importance of preserving confidentiality of information in a competitive environment. We are generally concerned about the increasing level of confidentiality in regulation. It impairs the ability of the parties to fully participate in the regulatory process, it impairs the ability of the Commission to regulate in the public interest, and it impairs the ability of the public to participate in and even understand the results of regulation. A recent extreme case is that of a confidential <u>tariff</u> which now applies to one electric customer (whether such a tariff is even legal has yet to be tested).

There is also a concern about how the current system works. We have found utilities increasingly asserting "confidentiality claims" over data which has little or no proprietary nature. Often, when challenged, the documents are "declassified."

We recommend that the Commission modify its position on confidentiality, from the current "confidential unless proven otherwise" to a position of "non-confidential unless proven otherwise."

IV. SUMMARY

Our reply comments above are intended to provide the Commission additional information to evaluate the comments made by all parties in the first round. If the Commission desires to take action to change the manner in which LDCs are regulated, we anticipate participating in informal or formal workshops, rulemakings, or contested case proceedings as these issues emerge. We hope our initial and reply comments are useful to the Commission.

DATED: February 2, 1996

Respectfully submitted,

CHRISTINE O. GREGOIRE
Attorney General

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Cascade Natural Gas

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February 1, 1996

Mr. Steve McLellan
Secretary
Washington Utilities and
Transportation Commission
Post Office Box 47250
Olympia, Washington 98504-7450

Subject: Notice of Inquiry Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry
Docket No. UG-940778

Dear Mr. McLellan:

Cascade Natural Gas Corporation ("Cascade") offers the following reply comments to the NOI. This letter is filed together with ten copies and a 3½ diskette.

1. Special contracts.

In a recent Wednesday morning meeting the subject of rate treatment for special contracts was discussed briefly. The Commission suggested that this issue was appropriate for consideration in the NOI process. At present, rate treatment for special contracts is considered as part of a general rate case. Cascade filed for rate consideration for its first four special contracts, dating back to 1990, in March 1995. As of January 1996, none of these contracts has been considered for rate treatment.

Cascade believes it is in the interests of ratepayers, shareholders and regulators that rate treatment for special contracts be established earlier in the process, while the best information is available so that the best decisions can be reached. Delay in determining rate treatment necessarily implies risk. Markets for equity and debt charge a premium where the risk of uncertainty is involved. A part of this burden of risk falls on Cascade's shareholders, since if Cascade's cost of capital increases it dilutes the investment of existing shareholders.

The interests of ratepayers and regulators also would appear to be served by prompt rate determination. Risk to shareholders leads to higher costs to Cascade for its capital to serve ratepayers. If Cascade's cost of debt increases, it requires higher rates to support Cascade's financing of system growth and maintenance. Uncertainty on the part of Cascade, how far it should go in entering special contracts, may also be to the disadvantage of ratepayers and shareholders, or both, if mistakes result in loss of margin. The expense of regulation is increased when fact investigations are conducted years after events occur, when memories have faded, and when Cascade and staff personnel responsible for negotiations or decisions have changed positions or are no longer available. The quality of decision-making is degraded where relevant facts and details are missing, since they may be impossible to recreate at a later time.

Now that Cascade has had several years of experience in negotiating and entering into special contracts, and Commission staff has had an equal amount of experience in considering whether to recommend contracts for approval (rate treatment aside), perhaps the knowledge gained has resulted in a comfort level of both the company and the staff high enough to allow a much more streamlined and efficient approval process. Cascade suggests that this approval process might include objective standards for determining the prudency of special contracts and their rate treatment.

If these objective standards are met, prudency might be presumed at the time of the next following rate case. Expenditures of regulatory and company resources to establish rate treatment would be greatly reduced where the objective standards and a presumption of prudency apply. Risks to ratepayers and shareholders would be reduced to the benefit of both.

One possible proposal for an objective standard could be demonstrated benefit to ratepayers generally, i.e., contribution to margin above long run incremental costs. If the special contract margin more than recovers cost of embedded plant and operating costs to serve the customer, and the alternate is complete loss of margin, ratepayers in general benefit. However, this determination is one of degree. Ratepayers are better off with some contribution to margin above long run incremental cost if their alternative is no margin at all. The troublesome issue is whether the margin from the special contract has been maximized. This is a difficult determination to make without objective standards. Unless objective standards can be agreed upon, this may be an evaluation that must be done on a case by case basis.

This evaluation is even more difficult when conducted years after the fact. These difficult issues point to having a current determination of rate treatment at the time a special contract is proposed, a set of previously agreed objective standards (or alternatively, a case by case evaluation) and perhaps consideration of a sharing of benefits approach to bind together the interest of ratepayers and shareholders.

Another alternative is to place all the risk and all of the benefits on Cascade and its shareholders, with all special contracts being taken "below the line." Cascade is willing to work with staff on these and other possible solutions to this difficult problem. Cascade's belief is that the present method for setting rate treatment needs improvement.

2. <u>Reply comments to comment letters submitted by others</u>.

Cascade wishes to give some specific reply comments on two of the comment letters. These are selected observations, and failure to reply to all letters or to all points should not be taken as agreement with them.

a. <u>Washington State Energy Office ("WSEO")</u>.

Cascade believes the automatic pass-through process of the PGA is important to both ratepayers and shareholders. LDCs have no control over general market prices for gas. Market prices can fluctuate rapidly and with great impact on the cost of gas service. The transactional costs of conducting a rate case should not be imposed on gas companies, ratepayers, shareholders, and the tax paying public without good reason. Cascade believes that rate cases should focus on other issues than fluctuations in the gas supply market. More appropriate for rate case investigation are controllable costs.

Cascade also believes that other issues such as cost of money could be handled on an automatic objective standard basis, such as a market index, if agreement could be held on an applicable and proper standard. The interests of all stakeholders seem to support expansion of automatic objective standard type rate mechanisms like the PGA.

Cascade agrees that objective standards such as those suggested by WSEO should be evaluated and could be useful to determine the market price of gas and to establish a presumption of prudence for purchases at or below this objective market price. Cascade also sees that there may be additional factors, such as the benefit of fixed contracts, rather than all indexed based pricing, which are worthy of consideration. Similarly, Cascade supports incentives under which an LDC might retain a portion of the benefit if actual gas costs are lower than the objective market index. Cascade supports the idea of incentives since they serve to bind together the interests of ratepayers generally and shareholders.

On page 8 of its comment letter, WSEO addresses line extension policies. Cascade is reluctant to embrace line extension policies that may result in the installation of facilities in locations that do not currently have any existing applicants, unless it is based on a prior agreement as to alternative objective standards, since this may raise difficult prudency issues. The existence of potential customer, along with a historically based estimated consumption level, offers an objective standard on which prudency can be based. Without an identified customer or other objective standard, issues such as prediction of specific growth pattern and rates of market growth may result in reduced ability to establish prudency should predictions be incorrect in either timing or rate of market growth. Cascade currently has a policy that allows a developer of a project to apply for lines to be extended into his development by contractually guaranteeing that an adequate number of dwellings will be built with gas equipment installed to make Cascade's line expenditure economic under its currently effective Main Extension Tariff. Cascade's approach seems to accomplish what the WSEO was suggesting without the introduction of undue prudency concerns.

On page 14 of WSEO's letter, it addresses DSM as a means of delaying or avoiding expensive distribution system upgrades. Cascade concurs with this comment. Where expensive upgrades are imminent, the higher cost alternative to DSM may serve to raise the threshold of economic effectiveness of DSM measures. There is still the question of judgment as to when and if the expensive system upgrades will be necessary regardless of the DSM measures. Issues remain as to the prudency of DSM expenditures if the upgrade delay is for a short period of time only. Difficulties remain in predicting timing, as well as the amount of growth which drives the system upgrade.

b. Public counsel.

Cascade supports the establishment of agreed principles or interests of various stakeholders and seeking solutions to administrative and other problems with an eye toward these principles. The difficult part is in deciding on what the principles should be on a reasoned and reasonable basis. Beginning at page 3 of public counsel's comments is a list of its recommended principles and concepts. Cascade agrees that these should be considered and examined and additional reasoning applied in refining and developing them. The following comments address the numbered paragraphs beginning on page 3 of public counsel's letter.

(2) The final sentence in this section is puzzling as a principle because of the number of questions it raises. The conclusion that costs should be borne equally by all customers apparently has as its basis the assumption that all customers were equally responsible for the incurring of the costs. Unclear is the relationship between the incurring of the costs, the benefits to various customer groups and the benefits to utility shareholders. It would seem that only after evaluating all of these issues could one establish a "principle" such as reflected in the subject sentence.

(3) The final sentence in this section raises similar questions. Cascade believes one needs to address whether customers are similarly situated in

the first instance. If they are not similarly situated, equal treatment is not necessarily fair, just, and equitable. Cascade believes that regulatory policy requires reasonable distinctions based on differences among customers and customer classes and that this established principle applies generally. Principle No. 3 appears to be applicable only to similarly situated customers.

(5) The final sentence in this section requires close analysis of the word "equitably." One might also consider whether a market driven alternative available to one customer is sufficient basis to forego an entire regulatory scheme (cost based rates for example) for other customers who do not share market based alternatives. Cascade might agree with such a concept if it were to apply to "similarly situated" customers. However, as a blanket statement without further clarification, it appears incomplete.

(6) Another factor to consider in this principle is whether some classes of customers are or could be served on an interruptible basis. This could have the effect of reducing unused capacity below the 99.97 percent of the time referred to. This statement may be correct in certain circumstances. However, as a statement of principle, it may benefit from a fuller explanation of the alternatives.

Beginning on page 6 of public counsel's letter, it comments on providing appropriate financial incentives relating to gas costs. As stated above with respect to WSEO's comments, Cascade supports this concept. Cascade is ready and willing to participate in negotiations toward establishing appropriate financial incentives with the goal of binding together the interests of ratepayers and shareholders.

At the top of page 7, public counsel notes that rate of return should be adjusted to reflect a shift of risk. Cascade agrees in principle that all changes in risks should be appropriately reflected in rate of return. The recent past has seen both increases and decreases in risk to ratepayers and shareholders. In some cases, risk has been shifted to both groups from external sources such as pipelines where such risk had resided for years before. Finding objective standards identifying the amount and timing of these shifts of risk might be an impossible task.

Cascade suggests that the ultimate arbitrator of risk for an LDC is the market for investment in its equity and debt. Regardless of the dynamics of risks shifting between ratepayers, shareholders and external parties, the only way for an LDC to obtain financing in order to serve ratepayers is through the financial markets. Many times occurrences in financial markets--not the gas markets--will dictate the appropriate rate of return. For example, during times of double digit inflation, rates of return must necessarily be higher than in times of a more stable economy. To focus too precisely on a risk shift among two or more groups, may well miss the point. It is in the interests of neither ratepayers nor shareholders to have LDCs unable to acquire financing due to inadequate and ultimately unfair rates of return.

Paragraph 3 on page 8 of public counsel's letter, raises the issue of distance based rates. Cascade supports consideration of this alternative. Recognizing the by-pass phenomenon is a complex one and not only tied to geographical distance, use of distance as a means of measuring expense of bypass is at least one factor to consider. In Cascade's experience, distance from the pipeline has had a fairly low correlation with willingness of a customer to construct bypass facilities, however.

Paragraph 4 on page 8 of public counsel's letter discusses stranded costs. Definition of stranded costs may become an issue in future rate proceedings as it has before. Commission approved depreciation schedules are usually longer than the duration of any specific gas service contract. In the case of bypass by a long time customer for example, the costs of facilities to serve the bypassing customer's plant would have been fully covered by margins charged while the contract was in effect. After the contract expired and the bypasser builds its bypass line, a portion of the facilities formerly used to serve the bypasser might remain on Cascade's books.

Since the margin paid by the bypasser under its contract was received by Cascade at a faster rate than the facilities were depreciated, and the rate of return received by Cascade on the contract exceeded Cascade's average rate of return, ratepayers paid rates lower during the contract term than they would have paid had the margin received under the contract and the depreciation rates been identical. Since ratepayers had received the benefit of higher margins (and lower rates) already, it seems reasonable that if necessary they should bear the burden of the continued depreciation in rates after the contract expired and after the bypass.

Cascade therefore would not consider the undepreciated facilities on the books after the bypass as "stranded" costs even if additional customers to use the facilities have not been added. The facilities were fully paid for by the bypasser as required under the original contract. There might be circumstances in which Cascade might agree that stranded costs should not be the responsibility of ratepayers generally, but absent more specific facts, a generalization as to responsibility might be incorrect.

Finally, addressing the last two paragraphs on page 9 of public counsel's letter, its observation seems to be that: (1) Many core customers are forced to pay for services they do not need; and (2) that the sum of individual prices for unbundled portions of a bundled service should always exceed the total price for the bundled service.

The assumption that core customers are forced to pay for services they do not "need" might be questioned. One could argue that it is not proper to retrospectively evaluate the "need" for a peaking service in a past winter when the weather was warmer than normal, and to conclude based on that information that the peaking service was not needed. A peaking service does not have to be used to be "needed." Need must be established prospectively, not retrospectively, when one is buying a peaking service. Cascade believes that part of its duty is to purchase only needed services for its core customer. Need must be established in advance and resources must often be purchased in advance due to the nature of some services. They may have to be purchased in larger increments than are required for a particular winter in order to be available for future periods. To do less leaves a utility open to criticism for failure to have adequate services available, and places unwarranted disadvantages on ratepayers and shareholders alike. If one questions the premise that "unneeded" services are forced upon core customers, then the principle expressed by public council does not necessarily follow.

As to the relationship between the price of a bundled service and the prices of its components, there seem to be other questions to consider before concluding that the bundled service should cost less than the sum of its parts. For example, if each individual portion of a bundled service had a ready market alternative, the bundled price might be the same as the sum of the unbundled prices. Furthermore, if the bundled price were determined on a cost of service basis and there were no practical alternative markets for portions of the bundled service (e.g., cost of facilities to connect a small volume weather sensitive customer to distant gas supplies) such a comparison might be meaningless and impractical. The logic of "unbundling for all if any may unbundle" does not seem compelling. Unbundling is a market driven response where alternatives exist. Unbundling is not necessary and is in fact meaningless where alternatives do not exist. Where there are no market price alternatives, cost of service regulated pricing is established. It would seem irrelevant to discuss a relationship between market-based and nonmarket-based rates and attempt to draw a principle of general application from them.

Cascade appreciates this opportunity to reply to comments of others and to raise a new subject under the NOI. Cascade looks forward to continuing the dialogue.

Very truly yours,

Jon T. Stoltz
Senior Vice President
Planning and Rates

ZWS041B1

Natural Resources Defense Council

STATE OF WASHINGTON
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
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Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry

Docket No. UG-940778

Reference Volume 2: Written Reply Comments

On November 3, 1995 the Washington Utilities and Transportation Commission offered all interested persons the opportunity to submit written comments in response or reply to the first round of comments we received in our inquiry on the natural gas industry.

The Commission was pleased to receive eight sets of reply comments. This volume contains the text of these replies. Written responses have been arranged alphabetically and are separated by a yellow title page.

The analysis and opinions included in this volume are the responsibility of commentors and do not necessarily represent the opinions, position, policy, or analysis of the Commission or its staff.

Questions concerning the Inquiry should be directed to Jeffrey Showman (360/586-1196) of the Commission's policy and planning section.

Steve McLellan
Secretary

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Reference Volume 2: Second Phase Written Comments
Docket No. UG-940778

Written Comments:

Attorney General: Public Counsel

Christine O. Gregoire
ATTORNEY GENERAL OF WASHINGTON
900 Fourth Avenue #2000 • Seattle WA 98164-1012

February 1, 1996

Steve McLellan, Secretary
Washington Utilities and
Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98054-7250

Re: Natural Gas Industry NOI
Docket No. UG-940778

Dear Mr. McLellan:

Enclosed are the Reply Comments of Public Counsel in the above referenced docket. We have enclosed ten copies and a diskette formatted in Wordperfect 5.1.

Very truly yours,

Donald T. Trotter
Assistant Attorney General
Public Counsel

DTT/ljb
Enclosures

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry	)	DOCKET NO. UG-940778

REPLY COMMENTS OF PUBLIC COUNSEL

CHRISTINE O. GREGOIRE
ATTORNEY GENERAL

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Assistant Attorney General

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Public Counsel Section

February 2, 1996

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I. OVERVIEW OF FIRST ROUND COMMENTS

The first round comments of many parties were informative, interesting, and revealing. While numerous topics were addressed, nearly all of the comments fall into the following general categories:

1) Comments by local distribution companies requesting additional flexibility to price services to meet customer needs, but opposing the blanket establishment of exit fees, entrance fees, or other revenue stabilizing mechanisms;

2) Comments by gas marketers seeking open access to the retail customers of LDCs, and seeking to prevent "unfair competition" in the gas supply market by LDCs holding portfolios for core market customers;

3) Comments by public interest representatives seeking to ensure that core market customers are not adversely affected by emerging competitive trends in the industry.

4) Comments by industrial customers seeking additional opportunities to purchase only those unbundled services they require, and to pay only embedded cost-based prices for those specific services.

5) Comments by LDCs and the financial community urging that the purchased gas adjustment (PGA) mechanisms be preserved and/or improved.

6) Other issues, including confidentiality, demand-side management, and technological evolution.

II. PRINCIPLES FOR ANALYSIS OF MAJOR ISSUES

In general, Public Counsel finds the majority of the initial comments constructive and helpful to the Commission in preparing for the next decade of regulatory evolution in the natural gas industry. Our reply comments will be limited to specific areas addressed by others where we feel the Commission will benefit from additional perspectives on certain issues.

We begin, however, by reasserting the basic principles we set forth in our original comments. These principles are still crucial, appropriate, and complete:

1) Markets should work for the benefit of all consumers.

2) There is no forgiveness in a truly competitive marketplace; if there are changes needed in the regulatory scheme to "promote competition," this fact should be recognized.

3) No discrimination should be permitted which allows any customer to pay less or forces any customer to pay more than any other customers for substantially similar products as a result of competitive forces.

4) All customers must share in the cost of the system.

5) A fair allocation of embedded costs, which make up the utility revenue requirement, should be the guide to pricing equity for natural gas.

6) Long-run marginal costs, not short-run market conditions, should be the guide to pricing efficiency for natural gas.

7) There are efficiency benefits to having a utility system.

8) The benefits of utility operations in competitive markets should be used to reduce prices for "full service" customers of regulated utilities.

9) New customers should contribute at least as much to revenue as they do to long run marginal cost.

10) Utilities should enable consumers to choose the least costly means of meeting their energy needs, including demand-side management alternatives.

11) Large customers that exercise competitive options should only be allowed to do so in a way that does not jeopardize utility planning efforts for core customers.

With these principles in mind, we offer the following comments on the submissions received by the Commission to date. The general categories of issues we address are:

A) Pricing Flexibility;
B) "Fair" Competition in the Gas Supply Market;
C) Preserving Fair Rates for Core Market Customers;
D) Undbundled Services Pricing;
E) Purchased Gas Adjustment Clauses;
F) Other DSM Issues.

III. REPLY COMMENTS OF PUBLIC COUNSEL

A. PRICING FLEXIBILITY FOR UTILITIES

Nearly all of the LDC commenters have requested the flexibility to price services for competitive-sector customers to attract and retain loads. In general, we agree that it is desirable for utilities to retain loads which more fully utilize system facilities, allow administrative and other expenses to be spread more fully over all system users, and prevent uneconomic bypass.

However, as we discuss in section (D) below, one tool to accomplish this is to establish rates for unbundled services based on market conditions (not embedded costs) which will encourage large users to remain full customers of the LDCs. It would be a serious mistake to underprice unbundled services, allowing large users to economically switch to transportation service or bypass, and then offer below-cost prices to entice them back onto the system.

1. NWNG'S LRIC PROPOSAL

Northwest Natural Gas has gone a step further than the other LDC Commenters, by requesting the consideration of long-run incremental cost pricing for <u>all</u> gas services, arguing that these prices will best enable the Company to attract and retain loads which are subject to competitive pressures.

This Commission has never conducted a generic investigation into the proper way to allocate gas utility costs (as it did for the electric industry in Cause U-78-05), but rather has established principles guiding cost allocation in specific proceedings involving Cascade (U-86-100), WWP (UG-901459), and WNG (UG-940814).

NWNG appears to mix principles of <u>cost allocation</u> with those of <u>rate design</u>. In the electric industry, this Commission has consistently approved embedded cost of service methods which reflect forward-looking costs, while designing rates within customer classes based upon long-run incremental costs and/or concepts. The same approach can operate in the gas industry. Indeed, the "efficiencies" which NWNG notes on pages 20-22 of its comments have more to do with rate design than with cost allocation.

In any event, we anticipate that we will disagree sharply with NWNG on the proper calculation of long-run incremental costs. We say this because we anticipate that NWNG will seek to have principles similar to those employed in its Oregon jurisdiction adopted in Washington. We have examined the Oregon methods, and find them fundamentally flawed in the classification and allocation of long-run incremental distribution and administrative costs.

NWNG's Oregon core market rates are much <u>higher</u> than those in Washington, while its non-core rates in Oregon are <u>lower</u> than those in Washington. Conversely, NWNG's core market rates in Washington are <u>higher</u> than those for other LDCs, and its noncore market rates are <u>lower</u> than those for the other Washington LDCs. We are concerned that NWNG's request to change costing methods is little more than a thinly veiled proposal to adjust relative class contributions to margins in a direction which is exactly the <u>opposite</u> of what would result if one adhered to the cost allocation principles adopted by this Commission over the last decade.

The issue of cost allocation between classes based on long-run incremental costs has not been raised in proceedings involving the other LDCs in Washington. We note even that NWIGU seeks embedded cost prices, not LRIC-based prices (see page 4 of its comments).

We do not object to NWNG's request that long-run incremental pricing be considered as an alternative to embedded cost pricing in a future docket, but until that time, the Commission should establish by rule the methods it has consistently ordered to be used for computing embedded cost of service.

2. LINE EXTENSION POLICIES

One area addressed by the LDCs deals with line extension policies. NWNG proposes a change to <u>rate levels</u> in order to be able to justify extending service to additional customers, while WWP and WNG have indicated that their existing line extension policies are reasonable. NWNG's proposal should be dismissed, and the Company be directed to examine the optional form of "new customer" contribution recently implemented for WNG, in which new customers with higher-than-average line extension costs can pay the additional cost over a period of years. This allows existing customers to pay only for the costs of serving their needs, while allowing new customers access to gas without large up-front charges which may be a barrier to the choice of gas as a fuel.

A proper forum to address NWNG's concerns about its line extension policy may be its integrated resource planning process. That is, if gas service is <u>indeed</u> the lowest-cost option for the consumer and for society, including line extension costs, then methods to assure customer access and efficient customer choice should be developed. On the other hand, because NWNG competes with a low-cost, non-profit electric utility in Washington, there may be more situations where it is not cost-effective to extend gas service than the Company experiences in Oregon.

B. "FAIR COMPETITION" IN THE GAS SUPPLY MARKET

The comments of the gas marketers, including Enron, Natural Gas Supply Association, and Mock Resources, all reflect their hopes for unfettered access to gas consumers in order to market their products. We believe the commenters have overstated the benefits, and understated the risks, of such a system.

1. FAIR AND UNFAIR COMPETITIVE ACCESS

Prior to FERC Order 436, nearly all pipeline fixed costs were embedded in commodity gas prices, and all customers shared these costs equitably. The conversion to fixed/variable pricing, together with the emergence of very low cost "capacity release" programs has dramatically shifted the recovery of these costs to firm core market customers. A decade ago, there was less than a 10% difference between the gas supply costs for firm and interruptible customers. By contrast, today firm customers served by LDCs pay up to twice as much for gas supply as do interruptible transportation customers.

There is no question that in the current market environment, the "optimal" level of pipeline capacity is much lower than that currently held by any of the LDCs in Washington; we surmise that the optimal level of capacity is zero. The reason for this is that the purchase of interruptible gas, plus the cost of storage to firm it, is much lower than the cost of pipeline capacity. A transportation customer who is able to take advantage of capacity release can enjoy much lower gas costs than a sales customer who is locked into an LDC's rate schedule containing a full ration of pipeline capacity costs. Any system which allows transportation customers to continue to get a "free ride," or "hitchhike" on a pipeline system which is paid for by the core market is unacceptable, yet this is precisely what the gas marketers are seeking -- the ability to sell gas to any customer, and have that customer exempted from any of the LDC's gas supply costs (see, e.g. comments of Enron, page 5).

Enron has noted (comments, page 3) that commissions in other states have found ways to mitigate stranged costs for both pipeline demand charges and gas supplies. This issue needs to be addressed before any more fixed pipeline costs are shifted to core market consumers. In general, it is our view that all customers should pay equally for pipeline capacity, regardless of how they secure that access. An evaluation of the methods cited by Enron would be appropriate.

Currently, transportation customers are purchasing capacity release at less than \$.01/therm through the open market, while core market customers are paying \$.03 - \$.10/therm for pipeline transportation through LDCs. We do indeed have a stranded commitment problem which needs to be addressed. Until this stranded commitment problem is addressed in a fair and equitable manner, it is appropriate for sales and transportation customers to share equally the uneconomic component (i.e., the difference between pipeline TF rates and capacity release rates) of pipeline charges.

2. AFFILIATE MARKETING OF GAS

Enron, in particular, has noted the potential for abuse when an LDC-affiliate is marketing on the utility's own system (Enron comments page 4). We agree. In Washington, as we understand it, only Cascade has been given permission to market gas to its own transportation customers. Both WNG and WWP were explicitly directed NOT to do so.

At the same time, given the pricing structure of the industry, with high discounts associated with high load factors, the LDCs may have very economical gas supplies available which can be sold at prices which benefit the core customers. We do not want to dissuade LDCs from taking actions to minimize the cost of service to core customers.

The standards of conduct suggested by Enron appear reasonable. If the Commission is to continue to allow Cascade to market to its own customers, we suggest that the Commission adopt standards of conduct for this activity. Similarly, if NWNG, WWP, or WNG are interested in marketing gas to their own customers, these or similar standards should also be applied.

3. IMPACT OF TRANSPORTATION ON CORE CUSTOMERS

The marketers, and Enron in particular, assert that competition in the gas industry for the loads of large customers does not affect small customers. Such assertions are plainly incorrect. The gas system is integrated. Increased demand by some customers causes increased prices for all customers as the system moves along a supply curve. A shortage caused by diversion of supplies to a formerly interruptible customer can adversely affect a firm customer.

The fact that there is no regulatory "obligation to serve" propane or heating oil customers (as noted by Enron on page 5 of its comments) does not affect the obligation to serve gas customers. If one heating oil customer runs out of fuel because its supplier does not deliver, that does not immediately affect other heating oil customers, since the fuel is in separate storage tanks. By contrast, if the gas supply system goes "under-pressure" because transportation customer gas supplies do not deliver gas to the LDC, all customers face a crisis.

All gas customers are tied together on a single system. The role of regulation in the public interest is to ensure that all customers are subject to reasonable rules which protect the integrity of that system, assure fair allocation of the costs of that system, and protect the interests of those who pay a premium for reliable service. The assertion that increased transportation of gas will not affect core market customers is plainly incorrect and could lead to irresponsible and unfair results.

C. PRESERVING FAIR RATES FOR CORE MARKET CUSTOMERS

Our own comments, and those of WSEO, dealt with means to preserve fair rates for customers without competitive options. Enron has proposed that small customers have access to competitive gas supplies, which would be one way to prevent LDCs from charging uneconomic gas supplies disproportionately to one group of customers. The proposal to allow competitive gas suppliers for all classes of customers should be explored, perhaps through educational workshops.

If, in fact, the "transaction costs" are not so high as to obviate any economic benefits of competition, we would generally agree that all customers should be allowed access to the market. Alternatively, however, if small customers must first incur the transaction costs of finding a gas supplier, and then also pay the LDC to provide standby firm gas supply (on the theory that it would be socially unacceptable to "valve off" residential or small commercial customers - NWNG, comments, page 10), there is unlikely to be any economic benefit. Gas marketers must provide a reliable supply, including a commitment to pay any emergency supply costs (such as the pipeline $2.00/therm overtake penalty) in order to meet their customers' needs. In this manner, there would be no need for the LDC to maintain any standby or reserve capacity.

We have no certainty that market pricing would benefit core customers. For this reason, we suggest educational workshops, rather than regulatory experiments, until more is known from experiences in other areas such as those cited by Enron.

D. UNBUNDLED SERVICES PRICING

NWIGU (comments, pages 5-8), the Natural Gas Supply Association (comments, page 2), and Enron (comments, page 5) have argued that customers should be allowed to select only those services they desire, and pay only embedded-cost based prices for those services. We could not disagree more with such self-serving proposals. Customers who elect to leave firm or interruptible service assume the risk that competitive LDC services will reflect the value of those services. Margins above cost should be flowed through to benefit core customers.

Utilities provide a broad range of services, not all of which are desired or desirable, or economic or necessary at any given point in time. For example, during the summer, firm pipeline capacity is a surplus commodity, and interruptible service is equally reliable. Storage costs are incurred year-round, but storage benefits accrue in the winter. In a warm year, not all of the pipeline capacity or storage facilities are necessary. Literally interpreted, the proposal of NWIGU and Enron would allow customers to pick and choose the facilities and service they want at cost-based prices, and bear <u>none</u> of the costs of the facilities and services they do not need at any point in time. We are concerned that all of the remaining costs will be borne by the core market.

We believe that at the present time, utilities have uneconomic levels of pipeline capacity. In the past, they had uneconomic levels of gas supply commitments (recovered through take-or-pay charges). In the future, they may have excess transmission capacity, excess storage capacity, or uneconomic meter reading techniques. Unless the system is always precisely optimally configured for the needs imposed on it at that instant, there will be some cost for which there is no current benefit. Allowing unbundled services to be priced on a cost of service basis allows customers with effectively competitive options to buy at market-based prices when those are lower than utility costs, and then to buy the remaining services they need, for which utility costs are lower, from the utility, leaving the utility stranded with uneconomic products and services (which we are concerned will be charged to the remaining core market customers).

In an effectively competitive market, when competitive market prices are higher than embedded costs, utilities, like any other competitor, should collect market-based prices for unbundled products and services, and use the net proceeds of those market activities to reduce the cost of service for captive core market customers.

It is common in the competitive market economy that unbundled pricing is more expensive than bundled pricing. Ordering a salad, entree, drink, and dessert "a la carte" is more expensive that the "full meal deal." Purchasing a Ford Taurus one component at a time over the parts counter is vastly more expensive than purchasing a fully assembled car. Purchasing the individual components of a computer system costs more than buying a fully-assembled unit with a software package included. The gas industry should be no different.

We recommend that the Commission adopt the following specific principle in this docket:

> Customers purchasing the full array of firm or interruptible sales service from a utility will be accorded cost of service based prices. Customers purchasing only transportation or other unbundled products and services will be allowed to do so if market-based prices exceed both short-run and long-run incremental costs, and therefore the offering of those services at market-based prices results in net revenues which can be used to reduce the costs paid by customers purchasing the full array of services from the utility. Customers purchasing unbundled services have no entitlement to cost-based prices for the individual products and services they choose.

E. PURCHASED GAS ADJUSTMENT CLAUSES

Several commenters took various positions on purchased gas adjustment clauses. While Paine Webber, Cascade, WNG, and WWP have advocated little or no change to the current 100% pass-through PGA mechanism, NWNG has advocated an incentive-based purchased gas mechanism which has been operating in Oregon for some time.

In a recent WNG proceeding, Public Counsel also advocated an incentive-based PGA mechanism. We believe that an incentive mechanism is appropriate, since these costs represent about half of the cost of serving core market customers. With a 100% pass-through, LDCs have little incentive either to minimize gas supply costs or maximize capacity release and off-market sales revenues.

WNG has correctly noted that the large number of transactions makes it difficult, if not impossible, for the Commission (and other parties) to examine every transaction for prudence. For this reason, a PGA mechanism based on some index of performance (i.e., daily spot market prices at Sumas) may be a more workable approach to determining what gas costs are allowable than a contract-by-contract analysis.

Since an active market for gas supply and pipeline capacity exists, it would be reasonable to compare what LDCs actually pay for gas delivered to their system to the prices paid by transportation customers situated in and near their systems. If the LDCs are paying higher prices, an adjustment may be appropriate, while if the LDCs are achieving lower costs, some reward mechanism may be appropriate. In this manner, the utilities will be put at risk for the level of firm pipeline capacity they retain, but will be able to achieve higher profits if they "beat the market" on gas supply costs.

The appropriate venue to examine the PGA mechanisms would be an informal series of workshops, followed by either individual utility general rate proceedings, or else a generic proceeding involving all of the LDCs. We recommend that the Commission convene a forum for the examination of the future of the PGA mechanism.

We are not prepared at this time to endorse NWNG's methodology, but recommend that the Commission convene a generic investigation into the proper way to reflect dynamic gas supply costs in rates. The mechanism should be fair to utilities and consumers, mitigate much of the risk to utilities while preserving incentives, and assure ease of administration.

F. OTHER ISSUES

Below we offer comments on only a limited number of the plethora of other issues raised by the submissions to the Commission. If other comments lead to proposed Commission action or rulemaking, we, of course, reserve the right to comment at the appropriate time on other issues.

1. DEMAND SIDE MANAGEMENT

Among the services which LDCs provide are demand side management measures and information. In general, the Commission's least cost planning rule is reasonable, and is having a desired impact on the supply and demand side resource acquisition activity of utilities.

We are concerned about one of the assertions made by NWIGU (comments, pages 10-11) about the impact of DSM activity on transportation customers, in which NWIGU asserts that the benefit of DSM activities to transportation customers is zero, and the share of DSM costs which transportation customers should bear is zero. NWIGU fundamentally misunderstands the purpose of DSM investments, and the benefits which those benefits bring to the system.

DSM investments reduce energy loads at the point of use. This helps the utility to avoid <u>both</u> gas supply purchases <u>and</u> gas distribution capacity investments. If transportation customers are served by the distribution system, they <u>directly</u> benefit from the reduced capacity needs on that distribution system, and should share in the cost of the DSM measures. About half of the cost of the utility system is gas supply, and half is distribution-related. Thus about half of the cost of DSM investments should be classified and allocated in the same manner as distribution plant investments, and transportation customers should share in this portion of DSM costs.

DSM investments also help to reduce total regional natural gas demand, and this has a beneficial downward effect on gas prices given any gas supply curve. It is widely recognized that improved motor vehicle fuel economy was the largest contributor to the collapse of OPEC and the relatively stable oil prices we have enjoyed for a decade. Similarly, more efficient building codes, appliances, and utility DSM programs help to hold down the demand for gas and the price for gas for <u>all</u> gas users, not just for the participants in the programs. The assertions preferred by NWIGU that transportation customers derive <u>zero</u> benefit from utility DSM programs is myopic, unrealistic, and incorrect. Such assertions should be rejected categorically.

G. CONFIDENTIALITY

Several parties commented on the importance of preserving confidentiality of information in a competitive environment. We are generally concerned about the increasing level of confidentiality in regulation. It impairs the ability of the parties to fully participate in the regulatory process, it impairs the ability of the Commission to regulate in the public interest, and it impairs the ability of the public to participate in and even understand the results of regulation. A recent extreme case is that of a confidential <u>tariff</u> which now applies to one electric customer (whether such a tariff is even legal has yet to be tested).

There is also a concern about how the current system works. We have found utilities increasingly asserting "confidentiality claims" over data which has little or no proprietary nature. Often, when challenged, the documents are "declassified."

We recommend that the Commission modify its position on confidentiality, from the current "confidential unless proven otherwise" to a position of "non-confidential unless proven otherwise."

IV. SUMMARY

Our reply comments above are intended to provide the Commission additional information to evaluate the comments made by all parties in the first round. If the Commission desires to take action to change the manner in which LDCs are regulated, we anticipate participating in informal or formal workshops, rulemakings, or contested case proceedings as these issues emerge. We hope our initial and reply comments are useful to the Commission.

DATED: February 2, 1996

Respectfully submitted,

CHRISTINE O. GREGOIRE
Attorney General

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Assistant Attorney General

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Cascade Natural Gas

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COMMISSION

February 1, 1996

Mr. Steve McLellan
Secretary
Washington Utilities and
Transportation Commission
Post Office Box 47250
Olympia, Washington 98504-7450

Subject: Notice of Inquiry Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry
Docket No. UG-940778

Dear Mr. McLellan:

Cascade Natural Gas Corporation ("Cascade") offers the following reply comments to the NOI. This letter is filed together with ten copies and a 3½ diskette.

1. Special contracts.

In a recent Wednesday morning meeting the subject of rate treatment for special contracts was discussed briefly. The Commission suggested that this issue was appropriate for consideration in the NOI process. At present, rate treatment for special contracts is considered as part of a general rate case. Cascade filed for rate consideration for its first four special contracts, dating back to 1990, in March 1995. As of January 1996, none of these contracts has been considered for rate treatment.

Cascade believes it is in the interests of ratepayers, shareholders and regulators that rate treatment for special contracts be established earlier in the process, while the best information is available so that the best decisions can be reached. Delay in determining rate treatment necessarily implies risk. Markets for equity and debt charge a premium where the risk of uncertainty is involved. A part of this burden of risk falls on Cascade's shareholders, since if Cascade's cost of capital increases it dilutes the investment of existing shareholders.

The interests of ratepayers and regulators also would appear to be served by prompt rate determination. Risk to shareholders leads to higher costs to Cascade for its capital to serve ratepayers. If Cascade's cost of debt increases, it requires higher rates to support Cascade's financing of system growth and maintenance. Uncertainty on the part of Cascade, how far it should go in entering special contracts, may also be to the disadvantage of ratepayers and shareholders, or both, if mistakes result in loss of margin. The expense of regulation is increased when fact investigations are conducted years after events occur, when memories have faded, and when Cascade and staff personnel responsible for negotiations or decisions have changed positions or are no longer available. The quality of decision-making is degraded where relevant facts and details are missing, since they may be impossible to recreate at a later time.

Now that Cascade has had several years of experience in negotiating and entering into special contracts, and Commission staff has had an equal amount of experience in considering whether to recommend contracts for approval (rate treatment aside), perhaps the knowledge gained has resulted in a comfort level of both the company and the staff high enough to allow a much more streamlined and efficient approval process. Cascade suggests that this approval process might include objective standards for determining the prudency of special contracts and their rate treatment.

If these objective standards are met, prudency might be presumed at the time of the next following rate case. Expenditures of regulatory and company resources to establish rate treatment would be greatly reduced where the objective standards and a presumption of prudency apply. Risks to ratepayers and shareholders would be reduced to the benefit of both.

One possible proposal for an objective standard could be demonstrated benefit to ratepayers generally, i.e., contribution to margin above long run incremental costs. If the special contract margin more than recovers cost of embedded plant and operating costs to serve the customer, and the alternate is complete loss of margin, ratepayers in general benefit. However, this determination is one of degree. Ratepayers are better off with some contribution to margin above long run incremental cost if their alternative is no margin at all. The troublesome issue is whether the margin from the special contract has been maximized. This is a difficult determination to make without objective standards. Unless objective standards can be agreed upon, this may be an evaluation that must be done on a case by case basis.

This evaluation is even more difficult when conducted years after the fact. These difficult issues point to having a current determination of rate treatment at the time a special contract is proposed, a set of previously agreed objective standards (or alternatively, a case by case evaluation) and perhaps consideration of a sharing of benefits approach to bind together the interest of ratepayers and shareholders.

Another alternative is to place all the risk and all of the benefits on Cascade and its shareholders, with all special contracts being taken "below the line." Cascade is willing to work with staff on these and other possible solutions to this difficult problem. Cascade's belief is that the present method for setting rate treatment needs improvement.

2. Reply comments to comment letters submitted by others.

Cascade wishes to give some specific reply comments on two of the comment letters. These are selected observations, and failure to reply to all letters or to all points should not be taken as agreement with them.

a. Washington State Energy Office ("WSEO").

Cascade believes the automatic pass-through process of the PGA is important to both ratepayers and shareholders. LDCs have no control over general market prices for gas. Market prices can fluctuate rapidly and with great impact on the cost of gas service. The transactional costs of conducting a rate case should not be imposed on gas companies, ratepayers, shareholders, and the tax paying public without good reason. Cascade believes that rate cases should focus on other issues than fluctuations in the gas supply market. More appropriate for rate case investigation are controllable costs.

Cascade also believes that other issues such as cost of money could be handled on an automatic objective standard basis, such as a market index, if agreement could be held on an applicable and proper standard. The interests of all stakeholders seem to support expansion of automatic objective standard type rate mechanisms like the PGA.

Cascade agrees that objective standards such as those suggested by WSEO should be evaluated and could be useful to determine the market price of gas and to establish a presumption of prudence for purchases at or below this objective market price. Cascade also sees that there may be additional factors, such as the benefit of fixed contracts, rather than all indexed based pricing, which are worthy of consideration. Similarly, Cascade supports incentives under which an LDC might retain a portion of the benefit if actual gas costs are lower than the objective market index. Cascade supports the idea of incentives since they serve to bind together the interests of ratepayers generally and shareholders.

On page 8 of its comment letter, WSEO addresses line extension policies. Cascade is reluctant to embrace line extension policies that may result in the installation of facilities in locations that do not currently have any existing applicants, unless it is based on a prior agreement as to alternative objective standards, since this may raise difficult prudency issues. The existence of potential customer, along with a historically based estimated consumption level, offers an objective standard on which prudency can be based. Without an identified customer or other objective standard, issues such as prediction of specific growth pattern and rates of market growth may result in reduced ability to establish prudency should predictions be incorrect in either timing or rate of market growth. Cascade currently has a policy that allows a developer of a project to apply for lines to be extended into his development by contractually guaranteeing that an adequate number of dwellings will be built with gas equipment installed to make Cascade's line expenditure economic under its currently effective Main Extension Tariff. Cascade's approach seems to accomplish what the WSEO was suggesting without the introduction of undue prudency concerns.

On page 14 of WSEO's letter, it addresses DSM as a means of delaying or avoiding expensive distribution system upgrades. Cascade concurs with this comment. Where expensive upgrades are imminent, the higher cost alternative to DSM may serve to raise the threshold of economic effectiveness of DSM measures. There is still the question of judgment as to when and if the expensive system upgrades will be necessary regardless of the DSM measures. Issues remain as to the prudency of DSM expenditures if the upgrade delay is for a short period of time only. Difficulties remain in predicting timing, as well as the amount of growth which drives the system upgrade.

b. Public counsel.

Cascade supports the establishment of agreed principles or interests of various stakeholders and seeking solutions to administrative and other problems with an eye toward these principles. The difficult part is in deciding on what the principles should be on a reasoned and reasonable basis. Beginning at page 3 of public counsel's comments is a list of its recommended principles and concepts. Cascade agrees that these should be considered and examined and additional reasoning applied in refining and developing them. The following comments address the numbered paragraphs beginning on page 3 of public counsel's letter.

(2) The final sentence in this section is puzzling as a principle because of the number of questions it raises. The conclusion that costs should be borne equally by all customers apparently has as its basis the assumption that all customers were equally responsible for the incurring of the costs. Unclear is the relationship between the incurring of the costs, the benefits to various customer groups and the benefits to utility shareholders. It would seem that only after evaluating all of these issues could one establish a "principle" such as reflected in the subject sentence.

(3) The final sentence in this section raises similar questions. Cascade believes one needs to address whether customers are similarly situated in

the first instance. If they are not similarly situated, equal treatment is not necessarily fair, just, and equitable. Cascade believes that regulatory policy requires reasonable distinctions based on differences among customers and customer classes and that this established principle applies generally. Principle No. 3 appears to be applicable only to similarly situated customers.

(5) The final sentence in this section requires close analysis of the word "equitably." One might also consider whether a market driven alternative available to one customer is sufficient basis to forego an entire regulatory scheme (cost based rates for example) for other customers who do not share market based alternatives. Cascade might agree with such a concept if it were to apply to "similarly situated" customers. However, as a blanket statement without further clarification, it appears incomplete.

(6) Another factor to consider in this principle is whether some classes of customers are or could be served on an interruptible basis. This could have the effect of reducing unused capacity below the 99.97 percent of the time referred to. This statement may be correct in certain circumstances. However, as a statement of principle, it may benefit from a fuller explanation of the alternatives.

Beginning on page 6 of public counsel's letter, it comments on providing appropriate financial incentives relating to gas costs. As stated above with respect to WSEO's comments, Cascade supports this concept. Cascade is ready and willing to participate in negotiations toward establishing appropriate financial incentives with the goal of binding together the interests of ratepayers and shareholders.

At the top of page 7, public counsel notes that rate of return should be adjusted to reflect a shift of risk. Cascade agrees in principle that all changes in risks should be appropriately reflected in rate of return. The recent past has seen both increases and decreases in risk to ratepayers and shareholders. In some cases, risk has been shifted to both groups from external sources such as pipelines where such risk had resided for years before. Finding objective standards identifying the amount and timing of these shifts of risk might be an impossible task.

Cascade suggests that the ultimate arbitrator of risk for an LDC is the market for investment in its equity and debt. Regardless of the dynamics of risks shifting between ratepayers, shareholders and external parties, the only way for an LDC to obtain financing in order to serve ratepayers is through the financial markets. Many times occurrences in financial markets--not the gas markets--will dictate the appropriate rate of return. For example, during times of double digit inflation, rates of return must necessarily be higher than in times of a more stable economy. To focus too precisely on a risk shift among two or more groups, may well miss the point. It is in the interests of neither ratepayers nor shareholders to have LDCs unable to acquire financing due to inadequate and ultimately unfair rates of return.

Paragraph 3 on page 8 of public counsel's letter, raises the issue of distance based rates. Cascade supports consideration of this alternative. Recognizing the by-pass phenomenon is a complex one and not only tied to geographical distance, use of distance as a means of measuring expense of bypass is at least one factor to consider. In Cascade's experience, distance from the pipeline has had a fairly low correlation with willingness of a customer to construct bypass facilities, however.

Paragraph 4 on page 8 of public counsel's letter discusses stranded costs. Definition of stranded costs may become an issue in future rate proceedings as it has before. Commission approved depreciation schedules are usually longer than the duration of any specific gas service contract. In the case of bypass by a long time customer for example, the costs of facilities to serve the bypassing customer's plant would have been fully covered by margins charged while the contract was in effect. After the contract expired and the bypasser builds its bypass line, a portion of the facilities formerly used to serve the bypasser might remain on Cascade's books.

Since the margin paid by the bypasser under its contract was received by Cascade at a faster rate than the facilities were depreciated, and the rate of return received by Cascade on the contract exceeded Cascade's average rate of return, ratepayers paid rates lower during the contract term than they would have paid had the margin received under the contract and the depreciation rates been identical. Since ratepayers had received the benefit of higher margins (and lower rates) already, it seems reasonable that if necessary they should bear the burden of the continued depreciation in rates after the contract expired and after the bypass.

Cascade therefore would not consider the undepreciated facilities on the books after the bypass as "stranded" costs even if additional customers to use the facilities have not been added. The facilities were fully paid for by the bypasser as required under the original contract. There might be circumstances in which Cascade might agree that stranded costs should not be the responsibility of ratepayers generally, but absent more specific facts, a generalization as to responsibility might be incorrect.

Finally, addressing the last two paragraphs on page 9 of public counsel's letter, its observation seems to be that: (1) Many core customers are forced to pay for services they do not need; and (2) that the sum of individual prices for unbundled portions of a bundled service should always exceed the total price for the bundled service.

The assumption that core customers are forced to pay for services they do not "need" might be questioned. One could argue that it is not proper to retrospectively evaluate the "need" for a peaking service in a past winter when the weather was warmer than normal, and to conclude based on that information that the peaking service was not needed. A peaking service does not have to be used to be "needed." Need must be established prospectively, not retrospectively, when one is buying a peaking service. Cascade believes that part of its duty is to purchase only needed services for its core customer. Need must be established in advance and resources must often be purchased in advance due to the nature of some services. They may have to be purchased in larger increments than are required for a particular winter in order to be available for future periods. To do less leaves a utility open to criticism for failure to have adequate services available, and places unwarranted disadvantages on ratepayers and shareholders alike. If one questions the premise that "unneeded" services are forced upon core customers, then the principle expressed by public council does not necessarily follow.

As to the relationship between the price of a bundled service and the prices of its components, there seem to be other questions to consider before concluding that the bundled service should cost less than the sum of its parts. For example, if each individual portion of a bundled service had a ready market alternative, the bundled price might be the same as the sum of the unbundled prices. Furthermore, if the bundled price were determined on a cost of service basis and there were no practical alternative markets for portions of the bundled service (e.g., cost of facilities to connect a small volume weather sensitive customer to distant gas supplies) such a comparison might be meaningless and impractical. The logic of "unbundling for all if any may unbundle" does not seem compelling. Unbundling is a market driven response where alternatives exist. Unbundling is not necessary and is in fact meaningless where alternatives do not exist. Where there are no market price alternatives, cost of service regulated pricing is established. It would seem irrelevant to discuss a relationship between market-based and nonmarket-based rates and attempt to draw a principle of general application from them.

Cascade appreciates this opportunity to reply to comments of others and to raise a new subject under the NOI. Cascade looks forward to continuing the dialogue.

Very truly yours,

Jon T. Stoltz
Senior Vice President
Planning and Rates

ZWS041B1

Natural Resources Defense Council

Natural Resources
Defense Council

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February 1, 1996

Steve McLellan, Secretary
Washington Utilities and Transportation Commission
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Olympia, WA 98054-7250

RE: **Comments of the Natural Resources Defense Council on the Notice of Inquiry Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry. Docket No. UG-940778.**

Dear Mr. McLellan:

Enclosed, please find ten (10) copies and a diskette formatted in Wordperfect 5.1 of the Natural Resources Defense Council's (NRDC) comments in the above referenced proceeding. NRDC appreciates the opportunity to contribute to this Inquiry in the second round of comments. If there are any questions concerning the enclosed comments, please contact me at (415) 777-0220.

Sincerely,

Sheryl Carter

Sheryl Carter, Policy Analyst
Natural Resources Defense Council

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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of Examining Regulation of Local) Distribution Companies in the Face of Change) in the Natural Gas Industry))	DOCKET NO. UG-940778

COMMENTS OF THE NATURAL RESOURCES DEFENSE COUNCIL ON THE NOTICE OF INQUIRY EXAMINING REGULATION OF LOCAL DISTRIBUTION COMPANIES IN THE FACE OF CHANGE IN THE NATURAL GAS INDUSTRY.

Sheryl Carter

February 1, 1996

Natural Resources Defense Council
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I. Introduction

The Natural Resources Defense Council (NRDC) appreciates the opportunity to participate in this very timely discussion on the regulation of Washington's local distribution companies (LDCs) in the rapidly changing natural gas industry. This particular Inquiry is especially timely not only in determining how the changing gas industry will affect regulation of LDCs, but also in exploring how the current restructuring of the electric industry could alter the natural gas market. Although there were many important issues explored in the WUTC's Inquiry, we focus our comments here on the questions posed by the WUTC as they relate to integrated resource planning, investments in energy efficiency, and EPACT. We urge the WUTC to continue and strengthen its commitment to integrated resource planning. In addition, NRDC recommends consideration of the adoption of a performance-based DSM incentive mechanism and a decoupling mechanism to encourage effective least-cost planning implementation. Finally, we urge the WUTC to adopt the conservation standard proposed in EPACT Section 115.

II. A Changing Industry

There are several reasons why comprehensive and consistent planning is essential for natural gas utilities:

1. Natural gas is forecasted to play a more prominent role in future national and state energy policy. Its popularity is due primarily to the fact that it is largely a domestic fuel source that is more attractive economically and environmentally than other fossil fuels.

2. Competition in energy markets from electrotechnologies is on the rise. The high cost of new nuclear plants and wide-spread public opposition to nuclear power, growing concern about the environmental impact of coal combustion and the difficulty of locating sites for new coal-fired plants, and improvements in gas turbine technology - have been apparent for many years. As a result, there is projected to be more use of natural gas-fired generators, and a sharp increase in gas consumption at electric utilities during the late 1990s and the early twenty-first century. This puts electric utilities in more direct competition with gas utilities for the supply of natural gas. In addition to the struggle for existing market share, competition for emerging markets such as alternative fueled vehicles is rapidly developing.

3. Deregulation in the natural gas industry has created more challenges and opportunities for natural gas utilities. The most notable and recent development is Order 636 which focused on comprehensive unbundling and eliminating the monopoly power of pipelines. Because of the changes in the market resulting from deregulation:

* gas utilities now face an expanded array of options for securing gas supplies and transportation, and face increased competition from bypass alternatives;

* due to deregulation of well-head pricing and unbundling of pipeline services, resource planners within gas utilities now develop their supply mix using a portfolio of resources assembled from individual components including: production (gas wells, propane-air plant), transportation (pipeline), and storage (storage fields, LNG); and

* gas utilities will more closely examine and rationalize their capacity holdings and look for alternative and more inexpensive ways to obtain the same level of service due to higher reservation fees for peak day capacity.

One major question emerging from the market response to deregulation is the relative availability and cost of different combinations of these components in the utility's portfolio because there is no industry-wide standard. The potential for natural gas as a prominent player in future energy policy hinges in part on industry and federal and state regulators ensuring that gas is used efficiently and that barriers to its efficient use are removed.

In contemplating changes to the regulation of LDCs to foster greater competition and customer choice, it is imperative that the fundamental differences that remain between the wholesale gas business and continuing natural monopoly functions are recognized. Real customer choice involves a much larger bundle of activities than just therms, and market barriers still stand in the way of many of those activities such as efficiency and other public interest goals.

III. Integrated Resource Planning

Although the actual rules may need to be updated or modified, it is imperative that the WUTC maintain some type of integrated resource planning requirement. System expansion and refurbishment, supply and demand-side resource acquisition should continue to be evaluated. Integrated Resource Planning (IRP):

* can be a useful tool for systematic comparison between DSM measures and supply of gas. It minimizes the life-cycle costs of adequate utility services to gas customers to obtain the optimal mix of resources;

* enables gas utilities to thrive in a more competitive environment by allowing it to avert costly mistakes;

* provides a framework for treatment of uncertainty and risk management;

* facilitates public participation and stakeholder input which provides a source of risk sharing on resource acquisitions and decisions;

* facilitates coordinated energy and environmental planning;

* has a long planning horizon; and

* can provide service at minimum cost to society as opposed to rates.

Not all costs of a supply- or demand-side resources are necessarily borne by the utility and the billpayers. Nor are all costs readily quantifiable. Therefore, it is important that the long-run public interest be included as part of the goal for IRP. The WUTC must take care not to make the IRP process so complex and formal that it becomes difficult to realize potential benefits. Therefore, if it is not the practice of the LDCs already, integrated resource planning should be aligned more closely with other LDC business planning to simplify and streamline the process.

IV. Demand-Side Management and Conservation

Removing Barriers to Cost-Effective Investment

It is necessary for the WUTC to explore mechanisms to put long-term, cost-effective DSM investments on equal footing with gas supply due to existing market barriers and regulatory disincentives. One way to accomplish this is through a performance-based incentive mechanism that rewards utilities and their shareholders for cost-effective investments in DSM. Spending on DSM does not necessarily equal energy savings or effective programs. Therefore, incentives for DSM (if given) must be tied to performance. Since the purpose of most DSM programs is to reduce energy and peak use, goals and targets for evaluating program performance should be based on these same criteria.

However, performance-based incentives may not be adequate since current regulation discourages development of DSM through incentives to sell gas. Another and perhaps complimentary solution is establishing a decoupling mechanism, or separating the linkage between gas throughput and revenues. Decoupling is the most important step to removing disincentives, thereby encouraging the successful implementation of the least-cost process. Decoupling is preferable to lost margin recovery for reasons that go well beyond inevitable disputes over measurement results. The principal problem with the lost revenues approach is that it fails to break the link between utility sales and revenues. Under such a system (lost revenues), utility profits are enhanced to the extent that the company is able to game the system by overstating energy savings attributable to its conservation programs, without actually reducing sales relative to what would have occurred. Such programs would leave overall net revenues unimpaired (since sales would not drop), while yielding utilities a windfall in the form of restored lost revenues that were never really lost. At a minimum, reliance on net lost revenue adjustments will require a higher level of regulatory oversight to ensure that all cost-effective savings are achieved and that consumers are charged only for revenues actually lost. By removing the incentive to maximize actual sales, decoupling substantially reduces the disincentives to effective implementation and accurate reporting of the results of conservation and load management programs.

Market transformation programs provide an example of another problem posed by the lost revenue mechanism. These programs change the mix of products available in the market and selected by consumers through normal market transactions, such that cost-effective, energy efficient products are produced and sold. By providing direct economic incentives to a relatively limited portion of the market, these programs affect a much larger - potentially 100% - share of the market. Lost revenue adjustments require a demonstration that reductions in load are specifically tied to utility conservation programs. As a result, under a lost revenue adjustment, a utility can lose money when energy consumption declines as a result of utility support for improvements in energy efficiency which cannot be quantified and demonstrated to the satisfaction of the regulators to be the result of the utility's programs. Uncertainty regarding regulatory acceptance of the link between market transformation effects and utility initiatives will continue to be a significant disincentive to effective utility support for market transformation in the absence of decoupling.

NRDC urges the WUTC to explore adoption of a decoupling mechanism as well as a performance-based DSM incentive mechanism to encourage implementation of least-cost planning. The decoupling mechanism is currently in use in Washington. In 1993 the WUTC reviewed and reaffirmed its decoupling system which applies to Puget Power. In that order they said that the mechanism has achieved its primary goal and that the decoupling experiment should continue for at least another three year cycle. A similar mechanism could be established for Washington's LDCs.

Non-Energy Benefits

The non-energy benefits from energy efficiency and other DSM - quantifiable or not - are often times much larger than the energy benefits themselves. These non-energy benefits include increased comfort and productivity as well as environmental improvements. Environmental externality costs are not included in the observed price of gas, but are still experienced by society. Therefore, avoided gas requirements have a value in terms of avoiding environmental externalities such as air emissions and land use impacts, which could increase the value of DSM relative to traditional gas supply resources. With societal avoided costs, the costs occur at the wellhead and throughout the total system. Unlike electric utilities which tend to be vertically integrated (although that, too, is changing), natural gas industry functions are generally not integrated and local gas utilities do not see all of the effects on society of the use of natural gas. Avoided cost components for gas utilities should include: commodity costs (long-term contracts, multi-month contracts, spot contracts); capacity costs (pipeline capacity, on-system storage, liquid natural gas or propane-air plants); local transmission and distribution costs (may only apply to new developments); and environmental externality costs.

Future Competitiveness

Finally, the WUTC asks if there is a risk of DSM being a threat to future competitiveness, or DSM assets being stranded. Whether or not DSM is currently or will be a real threat is not important since we have seen that the mere perceived threat of this competition has caused many utilities to cut back on current and planned cost-effective investment. The threat of stranded benefits is currently being realized. The WUTC has approved a DSM tariff rider for Washington Water and Power which provides DSM funding as a distribution charge. NRDC proposes adopting a similar system benefits charge to avoid future stranded benefits. Such a mechanism would effectively mitigate the competitive impacts (real or perceived) of DSM cost recovery. The charge would not create competitive disadvantages and would avoid creation of regulatory assets and stranded investment.

V. EPACT Issues

1. *Should the Commission adopt the integrated resource planning standard proposed and defined in EPACT Section 115?*

The current resource planning rule appears largely to incorporate the primary IRP standards. At this time, NRDC does not believe it is necessary to formally adopt the IRP standard defined in EPACT Section 115. However, we do stress that the deficiencies in the current regulatory structure should be addressed through strengthening and modification of the WUTC IRP rules.

2. *Should the Commission adopt the standard pertaining to utility investment in conservation and demand-side management proposed in EPACT Section 115?*

NRDC believes that the adoption of this standard would carry out the purposes of Title III of PURPA. Although some work has already begun toward its adoption by encouraging DSM investment, many barriers still need to be addressed. Providing incentives for investment based on performance and removing disincentives through decoupling, discussed above, would address these barriers. Adoption of this standard would be an official confirmation of the direction in which Washington is already headed, and could better serve to focus future actions.

3. *If the Commission adopts the EPACT standards, how should these be implemented so utilities would not have an unfair competitive advantage over small businesses engaged in design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures?*

As long as the WUTC continues to ensure that these small businesses are allowed access to the regulatory process and the ability to compete to provide products and services, then legitimate small energy businesses should benefit from increased DSM investment.

Northwest Industrial Gas Users

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EDWARD A. FINKLEA

February 2, 1996

VIA FEDERAL EXPRESS OVERNIGHT DELIVERY

Mr. Steve McLellan, Secretary
Washington Utilities and Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive, SW
Olympia, WA 98504

Re: In re Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry, Docket No. UG-940778, Reply Comments of the Northwest Industrial Gas Users

Dear Mr. McLellan:

Enclosed please find the original and ten copies of the Reply Comments of the Northwest Industrial Gas Users in the above-referenced proceeding. As requested by the Commission, I have also enclosed an electronic copy of the Reply Comments in a WordPerfect 5.2 for Windows format. Also enclosed is one additional copy to be file-stamped and returned to us in the enclosed, postage-prepaid, self-addressed envelope.

Pursuant to our request and Mr. Showman's agreement, we are sending the original and file copies today via federal express for filing and sending a copy of the Reply Comments via facsimile today to Mr. Showman.

If you have any questions regarding this filing, please call me at (503) 228-2525. Thank you for your assistance with this matter.

Very truly yours,

Edward A Finklea

Edward A. Finklea
Counsel for the Northwest
Industrial Gas Users

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STATE OF WASH.
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STATE OF WASHINGTON

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In re Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry	Docket No. UG-940778

REPLY COMMENTS OF THE NORTHWEST INDUSTRIAL GAS USERS

The Northwest Industrial Gas Users (NWIGU) are in general agreement with many of the comments filed by the four local distribution companies (LDCs) regulated by the Commission. Gas marketing companies and others have also provided the Commission with useful input on the policy questions posed in this notice of inquiry. The overwhelming message voiced by the initial comments is that the regulatory changes in the gas industry that have taken place over the past ten years have been positive for all gas consumers. No credible arguments have been advanced to make radical changes to the policies the Commission has adopted through proceedings governing specific local distribution companies.

A. Unbundling and Customer Choice Issues

The recent decision in Washington Natural Gas Company's (WNG's) Docket No. UG-940814 addressed many important policy and technical issues regarding how gas transportation service should be provided and priced in Washington. Nothing raised in the initial comments in this docket should cause the Commission to reverse the policies it adopted in the Fifth Supplemental Order in that docket.

NWIGU strongly endorses the availability of unbundled services from the Washington LDCs at cost-based rates. Since the late 1980s, Washington LDCs have been providing unbundled transportation services to a greater or lesser extent. The availability of transportation service from interstate pipelines and LDCs has brought about fundamental change to the natural gas industry.

1. All Customers Are Beneficiaries of the Gas Industry Restructuring

All gas consumers, residential, commercial and industrial, have been beneficiaries of the changes brought about by the restructuring of the natural gas industry. Public Counsel, and to a lesser extent the State Energy Office, have proffered the mistaken view that only industrial customers have benefitted from the introduction of competition in the gas industry. (Initial Comments of Public Counsel at 2, 13-15). The belief, as asserted by Public Counsel (Initial Comments at 2), that "the vast majority of the benefits of competition have accrued to large gas consumers, with cost shifts to small consumers..." is not borne out by the facts.

The following chart compares the price of natural gas for Washington residential customers in 1984 with the price for Washington residential customers in 1995. The facts show an astonishing result: The delivered price of natural gas is **__lower__** today for the residential consumers of all four Washington LDCs than it was before the Federal Energy Regulatory Commission embarked on the course of natural gas deregulation in 1985.

RESIDENTIAL NATURAL GAS PRICES IN WASHINGTON
1984 v. 1995
COMPARISON

1984 Rates	**1995 Rates**[1]
CASCADE NATURAL GAS: Monthly service charge: **$1.20** First 50 therms/mo.: **$0.64089** per month Over 50 therms/mo.: **$0.60541**[2]	Monthly service charge: **$1.50** Per therm: **$0.55836**[3]
NORTHWEST NATURAL GAS: Monthly service charge plus first 6 therms: **$5.80** Next 34 therms: **68.283¢** per therm Additional therms: **64.328¢** per therm[4]	Monthly service charge plus first 6 therms: **$5.62** Next 34 therms: **55.954¢** per therm Additional therms: **50.958¢** per therm[5]

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[1]1995 Tariff Sheets as approved by the Commission reflecting actual billing rates including all temporary surcharges and refunds for the bulk of 1995.

[2]CNG Schedule 501 issued 11/30/84 approved by the Commission to be effective 1/1/85.

[3]CNG Schedule 501 issued 1/6/94, approved by the Commission to be effective 2/6/94. Subject to adjustments from Schedules 595, 596, 597, 598 and 599 (when applicable).

[4]NNG Schedule 2 issued 5/21/84, approved by the Commission to be effective with service on and after 6/22/84.

[5]NNG Schedule 2 issued 12/13/94, approved by the Commission to be effective with service on and after 2/1/95. Subject to adjustments from Schedules 25, 25A, 103, 105, 107, 109 and 113 (when applicable).

WASHINGTON NATURAL GAS: Monthly service charge: **$4.51** First 25 therms per mo.: **68.446¢** per therm Over 25 therms per mo.: **57.327¢** per therm[6]	Monthly service charge: **$4.50** Per therm: **49.179¢**[7]
WASHINGTON WATER POWER: Monthly service charge: **$3.00** Per therm: **56.191¢**[8]	Monthly service charge: **$3.25** Per therm: **42.523¢**[9]

It is undeniable that delivered gas prices for industrial customers have declined in the 11 years since deregulation began. The above chart shows, however, that residential customers have also benefitted substantially from deregulation. Gas-on-gas competition brought about by industrial users purchasing their own supplies has enabled LDCs to purchase gas supplies at significantly lower prices than were available when pipelines sold regulated, bundled wholesale service.

Despite the fact that every Washington LDC has had general rate increases since 1984 that have increased their margins, gas-

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[6]WNG Schedule 23 issued 6/28/84, approved by the Commission to be effective with all consumption on and after 7/6/84.

[7]WNG Schedule 23 issued 5/12/95, approved by the Commission to be effective with all service on and after 5/15/95. Subject to adjustments from Schedules 1, 102 and other supplemental schedules (when applicable).

[8]WWP Schedule 101 issued 2/29/84, approved by the Commission to be effective 4/1/84.

[9]WWP Schedule 101 approved by the Commission to be effective 1/1/95 subject to adjustments from Schedule 150, 155 and 191 (when applicable).

on-gas competition has more than offset margin increases and actually brought down the delivered price of natural gas for residential customers. Natural gas producers in Canada and the United States compete for the gas purchasing business of LDCs and end-users that are free to purchase the commodity on the open market. That competition has brought down prices for all consumers to levels no one would have predicted in 1984.

The fact that industrial gas consumers have seen larger percentage decreases in gas prices than residential consumers is not an indication that the competitive market has been "unfair" to residential consumers. Industrial consumers have year-round demands for gas, in many cases have alternate fuel capability and many purchase interruptible service. Residential customers typically are low load factor purchasers who require highly reliable firm service. These two types of consumers are not buying the same product.

The costs of serving residential and industrial gas consumers differ greatly because of the varying demands they place on pipeline and distribution systems. In addition, the commodity cost of gas is a larger percentage of the industrial customer's delivered price of gas than it is for the residential customer. Thus, even an equivalent reduction in the cost of gas for both types of customers translates into a large percentage decrease in the industrial customer's delivered price. These facts largely explain why industrial customers have seen higher percentage price decreases than residential customers since restructuring began.

To suggest that deregulation has harmed any consumers is to ignore reality. Restructuring is working for all consumers as evidenced by the dramatic price decreases experienced by Washington residential consumers over the past 11 years despite general inflation. Any suggestion that we should go back to the heavy regulation present before FERC's initiatives of the mid-80s should be summarily rejected.

2. Transportation Service Should Be Available to All Customers at Cost-Based Rates

NWIGU has consistently advocated before this Commission that transportation service should be available on LDCs' systems on a nondiscriminatory basis to all customers. There is no reason to categorically exclude any class of customers from purchasing their own gas and then transporting that gas over the LDCs' distribution systems.

NWIGU urges the Commission to articulate as a result of this Notice of Inquiry that transportation service will be available to all customers on a cost basis from all Washington LDCs. Economic realities will then dictate which customers choose bundled service and which customers choose to buy their own natural gas. Offering customers more choices of service with different reliability standards and associated different cost-based prices allows the customers to better match their particular requirements in the marketplace.

B. Recommended Commission Findings on Cost of Service

Local distribution has remained a monopoly service even though it has been unbundled in the course of the restructuring that has occurred since 1984. For the foreseeable future, NWIGU would anticipate that distribution service would remain a monopoly, regulated service. The Commission should continue to apply cost-based rate making principles to govern how monopoly distribution services are provided to all customers, sales and transportation.

Much is made by Public Counsel of the so-called cost shifts that have occurred during the process of restructuring. The unbundling process has focused consumers and the Commission on how the fixed costs of the distribution system were allocated in the past and how they should be allocated to reflect cost-causation principles more accurately. Some fixed costs have been shifted from industrial to residential and small commercial customers <u>in order to reflect current cost causation properly</u>. This realignment is a positive and necessary adjustment to the new, restructured gas market. To contend, however, that the cost shifts have been unfair is to ignore why the costs are incurred and which customer classes should properly bear those costs.

The Commission addressed many important cost-of-service issues in the recent Fifth Supplemental Order in the Washington Natural Gas proceeding (Docket No. UG-940814). In that Order, the Commission resolved important policy questions concerning cost allocation, including the decision to use a peak and average allocation method of allocating distribution service costs to the various customer classes and the use of a direct assignment methodology for LDC distribution mains to reflect the cost of serving different classes of customers more accurately. The WNG decision came after many years of policy debate before the Commission in company-specific cases concerning how costs should be allocated to the various customer classes. The Commission did not adopt wholesale any party's position on these issues, but rather reached a middle ground.

Through the Fifth Supplemental Order in the WNG case, the Commission has given the policy guidance that was so necessary in order to bring a sense of stability to the gas industry and gas consumers in Washington. There will undoubtedly be a need for refinements and adjustments to address specific issues regarding the other three LDCs' cost incurrence.

This proceeding should affirm that LDC services will remain regulated using embedded cost-of-service principles. The basic cost allocation methods adopted in the WNG Fifth Supplemental Order provide the policy guidance that is necessary for the foreseeable future. The Commission, however, should not invite relitigation of the basic issues that were debated and resolved in that proceeding. Instead, the Commission should give the industry the signal through this proceeding that all players can be assured that the Commission has resolved many basic policy issues through the WNG Order. Workable compromises among the various interested parties will be more achievable if the state of flux that existed over the past several years is substituted with a sense of policy stability.

C. Transportation Operational Issues

Operational issues will continue to arise before the Commission. Many operational issues, such as balancing rules and minimum terms of service for sales and transportation customers, were debated in the WNG proceeding. WNG now has transportation tariffs in place that reflect the Commission's decision in the Fifth Supplemental Order.

NWIGU notes that operational concerns are likely to vary from LDC to LDC, and therefore the Commission should not expect that all LDCs in the state must have identical operating provisions. NWIGU urges the Commission to clarify in this notice of inquiry that it will address and resolve transportation operational issues on each of the LDCs' systems when those issues arise. In general, operating conditions should assure that transporters have the flexibility needed to move gas over the distribution system in an efficient manner with a minimum of obstacles, without imposing costs on sales customers from transporters' activities. Northwest Pipeline Corporation has, for example, maintained flexible operating conditions since the onset of transportation with no insurmountable problems being created. LDC operating conditions should not artificially create obstacles to the full utilization of their systems.

D. Demand Side Management Issues

As articulated in our opening comments in this proceeding, cost-effective demand side management (DSM) programs can be a useful part of an LDC's resource portfolio for meeting the needs of its firm sales customers. To the extent that a DSM measure avoids the purchase of firm gas supplies or firm pipeline capacity, DSM programs can lower the overall cost of providing firm sales service to customers.

The purpose of DSM measures is to lower the price of acquiring energy resources now and in the future for firm sales customers. Interruptible sales customers and transportation customers do not purchase firm gas supplies through LDCs and hence should not pay for DSM resources that are purchased as a substitute for firm gas resources. The Commission should clarify through this proceeding, or through company-specific proceedings, that DSM costs will be allocated the same way that firm gas supply resources are allocated: to those purchasing firm sales service. To do otherwise simply masks the cost of meeting firm sales customers' demands for gas supplies and pipeline capacity.

Through its opening comments, Public Counsel raised the notion of replacing utility-run DSM programs with a state owned and operated program. The proposal goes far outside the scope of this NOI and instead raises broad public policy issues that could only be resolved by the State legislature. The proposal should be dismissed by the Commission in this docket.

CONCLUSION

NWIGU appreciates the opportunity to participate in this inquiry and desires to participate in any further comments or workshops established to address the issues. NWIGU appreciates the effort of the Commission in launching this inquiry and looks forward to a constructive resolution of these regulatory issues in a manner that protects the interests of all consumers without obstructing the benefits of market competition.

DATED this 2nd day of February, 1996.

Respectfully submitted

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Reply Comments of the Northwest Industrial Gas Users upon all parties of record in Docket No. UG-940778 by placing a true copy of the document properly addressed to each party in the United States mail first class postage prepaid thereon.

DATED at Portland, Oregon, this 2nd day of February, 1996.

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February 1, 1996

Mr. Steve McLellan, Secretary
Washington Utilities & Transportation
Commission
1300 S. Evergreen Park Dr., SW
Olympia, WA 98504

Re: **DOCKET NO. UG-940778/NOI: EXAMINING REGULATION OF LOCAL DISTRIBUTION COMPANIES IN THE FACE OF CHANGE IN THE NATURAL GAS INDUSTRY**

Northwest Natural Gas Company hereby submits an original and 10 copies of its reply comments on the above-referenced matter. A diskette of the company's reply comments is also enclosed.

The company thanks the Commission for this opportunity to participate in its Notice of Inquiry. If any questions should arise, please feel free to call me.

Sincerely,

Susan Ackerman

Susan K. Ackerman
Manager, Regulatory Affairs
& Associate Counsel

SKA/cmt
enclosures

cc: Jeffrey Showman, WUTC
Bruce Samson
Bruce DeBolt
John Hanson
Randy Friedman
Brian McCabe
[All w/enc. (hard copies only)]

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

NOTICE OF INQUIRY (NOI)
Examining Regulation of Local Distribution Companies
In the Face of Change in the Natural Gas Industry

Docket No. UG-940778

REPLY COMMENTS OF NORTHWEST NATURAL GAS COMPANY

Northwest Natural Gas Company (Northwest Natural or NNG) submits the following reply comments in this docket. These reply comments address only the initial comments of Public Counsel.

1. ***All Natural Gas Customers, Large and Small, Have Been Advantaged By Increased Competition in the Natural Gas Industry.***

In its initial comments, the Public Counsel paints a picture of the emerging competitive climate in which small natural gas users have not benefited. Specifically, Public Counsel makes much of the economic self-interest of large natural gas customers, their market power, and their competitive options, and contrasts that with the inability of smaller customers to exercise the same level of market power. Public Counsel concludes that the Commission should be wary about assuming "that 'stimulating competition' will result in benefits for all consumers".[1] Comments, pp. 1-3. NNG agrees with Public Counsel that "markets should work for the benefit of all customers." NNG disagrees with Public Counsel's apparent conclusion that markets have not worked for all customers.

First, under the old scheme of natural gas regulation, where no natural gas user could choose any supplier other than the pipeline, natural gas prices climbed to as much as $4.00 an MMBtu in the early 1980's (over $7.20 at 1995 prices). With deregulation, prices have fallen steadily, reaching as low as $0.80 an MMBtu 1995. This price reduction results directly from the competition achieved with Order 436 and its successors. The benefits of these commodity gas cost reductions have, despite Public Counsel's comments, flowed equally to all natural gas customers, large or small.

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[1]Public Counsel argues that gas LDCs fall outside the definition of competitive entities, but Counsel fails to appreciate that the market in question is not simply natural gas, but energy; a market in which natural gas LDCs face stiff competition at all levels.

Second, while customer-owned transportation and LDC bypass have to date benefited the larger, more sophisticated customers, there is no reason to expect this to continue. In time, all customers may use transportation and alternative gas supplies. It is inappropriate to assume that residential and commercial customers are too ill-informed and unsophisticated to choose these alternatives. Marketers will happily inform smaller customers of their options, and will develop new ones, as yet unimagined. Certainly large customers benefited first from transportation, but they are unlikely to benefit exclusively.

Third, NNG challenges Public Counsel's claims regarding the "monopoly position" of LDCs with respect to gas users. Natural gas has always competed with electricity, oil, wood, and propane for residential and commercial users: unlike electricity, there is always an alternative to natural gas. Further, competition has reduced what limited market power LDCs had in all markets. Large customers can and do bypass the local utility, taking service directly from an interstate pipeline. For large industrial business, the utility has no monopoly franchise. The same will be increasingly true for other classes of utility business. Nationally, residential and commercial customers are already sampling "core market" transportation, buying their gas from competing independent suppliers. Eventually, groups of favorably situated residential or commercial customers will undertake utility bypass. They could form gas distribution cooperatives to bring gas from the pipeline to coop members. Under this circumstance, the utility would face competition for even its small customer distribution business.

In sum, small customers still need regulatory protection, but they need protection that is consistent with the realities of a progressively more competitive market.

2. ***Marginal Cost-Based Rates Are The Best Method For Assuring that All Customers Fairly Share in the LDC's System Cost.***

Public Counsel takes the position that "all customers must share in the cost of the [LDC] system". Northwest Natural agrees. Public Counsel, however, does not identify the appropriate pricing concepts for a competitive environment except to demarcate instances when an LDC's revenue requirement should be disallowed. Thus, Public Counsel's comments address only the first question of traditional regulation: what is the "reasonable cost" of utility operations? Once that question is answered, however, the next question is how utilities and regulators should allocate these costs in a "fair, just and reasonable" manner among the various users of the LDC system. Public Counsel does not answer this question, which is really the most important question. **As LDCs serve increasingly competitive markets, NNG urges the**

Commission to consider an approach to determining rate spread and rate design that is guided by marginal cost concepts.

The public debate surrounding deregulation of electric and gas utilities emphasizes knowledge of costs -- your costs, your competitors' costs, the cost of your customers' options. In no case is it suggested that understanding a competitor's Fully Allocated historic Costs has any strategic value. Only in the traditional regulatory environment (and even here only in general rate case proceedings) is any emphasis placed on a utility's fully allocated costs (FAC). In all other business decisions, the utility is guided by incremental costs and incremental revenues: the evaluation of new service offerings, the pricing of unbundled services, and the determination of the best mix of supply-side and demand-side resources to meet load growth are all evaluations which are made by comparing marginal costs to marginal revenue. Thus, while historic embedded costs are relevant to a utility's revenue requirement, all other important economic decisions must start afresh with the comparison of alternatives at the economic margin of choice.

A reasonable, and ultimately necessary, departure from FAC approaches using historical costs would allow forward-looking incremental capacity costs to play a greater role in determining retail rates. For instance, evaluating the cost effectiveness of DSM stands out in bold relief. Here it is not the historic depreciated cost of pipeline capacity and gas storage facilities that matter, but rather the incremental cost of optimized capacity to meet load growth. NNG's 30-year levelized cost of capacity and infrastructure to meet future load growth is approximately $0.03 per therm at a 100 percent load factor. For an average residential customer with a 20 percent load factor, this amounts to $0.15 per therm which should be reflected in retail rates in addition to incremental O&M expense and the annualized cost of distribution system investments. The historic cost of existing capacity may be above or below this level when allocated on the basis of contribution to peak day requirements. Capacity cost allocation conventions approved by the Commission in the past would be far below the $0.15 level, which is not efficient.

Achieving efficient price signals requires a forward-looking focus on both the utility's cost incurrence and avoidance and on the challenger's (or third party provider's) incremental cost of providing discrete services on a stand-alone basis. Retail rates based on optimized avoidable capacity costs prevent loss of load to competitors, and discourage provision of gas service to customers with lower cost alternatives.

The desirability of using marginal cost pricing concepts to establish rate spread and rate design in core markets is an issue that NNG believes the Commission should examine further. NNG recommends that a workshop following reply comments in this docket should focus on developing new ratemaking guidelines for efficient pricing of energy services in a competitive environment.

3. ***Regulators Can Best Protect Core Customers By Encouraging Utilities To Retain Customers in Highly Competitive Markets.***

Public Counsel argues that "a special rate...offered to one customer to attract or retain load...should be applied to...all other customers"; and that "if markets do not permit the recovery of [Commission determined] embedded costs,...then those costs should not be recovered from any customers". Comments, p. 4.

Competitive rates are determined by markets, not by committees. The rate which will attract and retain load in highly contested gas markets is a rate which meets the customer's next best energy option. The competitive rate probably will not be equal to one determined in a regulatory hearing, and failing such a rate the customer is lost. In order for customers to contribute to system costs, they must remain customers.

Over the last several years, Northwest Natural has struggled to provide competitive rates to large, multifuel customers and has done so with relative success. Northwest Natural has priced gas service to match the price of alternate fuels, and where appropriate, to mirror the customer's cost of bypass. In all cases, however, the company has competed with an eye to covering its long run incremental cost of service.

Where a customer threatens bypass, for example, the company attempts to measure the cost of building and operating the proposed bypass facility. A rate is then offered which matches the customer's bypass cost. The result is a pure, long run incremental cost of service rate. The utility cost of serving such a customer equals, at most, the cost of building a new, direct connection to the interstate pipeline. Actual, historic utility costs might be lower since the company may already have facilities close by or even connected to the customer. But, the pure long run incremental cost of serving such a customer can well be measured by the customer's cost of bypass. If the utility can charge this higher incremental bypass cost as a competitive rate, then the utility benefits core customers by earning more than its historic cost of service in this market, and it benefits the large customer by offering a rate equaling the customers best competitive option.

Public Counsel argues that losses associated with competitively stranded costs should be born by the LDC shareholders alone. By way of example, Counsel suggests that Airlines that buy too many airplanes cannot charge customers a higher price for its product. NNG agrees: utilities should not be able to, either. Healthy airlines, however, will charge cost-covering, competitive rates that maximize the contribution of each of its customer classes. The same should be true of LDCs, with contributions constrained only by the utility's overall revenue requirement. Regulators can best protect core ratepayers by encouraging utilities to compete vigorously to retain customers in highly competitive markets. By doing so, these customers will make a contribution towards utility operating costs and earnings, and provide rate relief for the more captive customers.

It does little good to assign arbitrarily determined, "fully allocated costs" to be recovered in competitive market sectors. Any attempt by the utility to collect such costs will simply result in an unnecessary loss of profitable business for the utility, an economically or environmentally disadvantageous decision by the customer, and potentially higher costs for remaining customers. To argue that the failure to recover fully allocated costs is a shareholder responsibility unfairly and unwisely harms core customers, large customers and shareholders alike.

4. Washington's Current PGA is Adequate and Should be Augmented With Incentive Mechanisms which Suit Each LDC Individually.

Public Counsel argues that since gas prices are no longer FERC-regulated, but rather are market-determined, the Commission needs a mechanism to determine that gas costs are reasonable. Comments, 6. NNG does not disagree that the Commission may review the reasonableness of gas purchasing practices, but NNG believes that Public Counsel fundamentally misperceives the natural gas commodity markets and the need for regulation with respect to these markets.

The fundamental reason why Congress and FERC relinquished regulatory control over wellhead natural gas prices was because regulation here simply did not work. Prices were artificially constrained, which led to shortages in the 1970s. And, until open access, there were limited buyers competing to purchase supplies. Interstate pipelines were the sole market for producers, and the sole source of natural gas for LDCs. Clearly under this structure, FERC oversight was needed to control monopoly power. With wellhead price decontrol and open access transportation, however, competition was introduced into the market for natural gas, and since then gas prices have never been as high as they were when they were FERC-regulated. **Competition and open access transportation have assured a market in which natural prices**

are reasonable. Where competition grows, the need for regulatory oversight declines. Given this, the question to be asked is whether intensive regulatory scrutiny of LDCs' gas purchases for "reasonableness" has any value. NNG believes that it does not. More likely, whatever value there is to such an endeavor would probably be overwhelmed by its cost.

PGA mechanisms, though, have merit still. Gas costs are a big component of the cost of natural gas service, and LDCs have limited control over the general up and down trending of natural gas prices. This, however, does not suggest that utilities have no need to keep these costs low or to try to negotiate the best possible deals for their customers. Gas utilities have strong incentives to purchase gas at the lowest price consistent with appropriate reliability of supply. Natural gas is not a monopoly product; electricity, oil and wood are clear competitors of natural gas in energy markets. Failure to maintain low gas prices weakens the ability of gas utilities to gain and keep customers of all kinds. This market imperative alone is sufficient to cause LDCs to shop wisely for gas supplies. As well, the overall competitiveness of the natural gas markets has produced great benefits to all natural gas users. These two factors are the reasons why the Commission's current PGA mechanisms have worked reasonably well.

An improvement to the current practice, however, would be to permit LDCs to develop their own incentive mechanisms which would assure further purchase efficiency. For Northwest Natural, the Oregon purchased gas cost adjustment mechanism includes a built-in incentive wherein gas cost increases and decreases are shared by customers and the company on an 80/20 split. If the company achieves savings by purchasing gas at an average cost which is lower than the estimated average gas cost (WACOG) contained in the preceding PGA filing, then 80% of these savings flow back to benefit customers, and NNG keeps 20%. If the company cannot achieve savings and actual gas costs exceed the published WACOG, then the company is allowed to collect only 80% of the cost over run and is required to absorb the remaining 20%. This mechanism provides a very real incentive for vigorous competitive gas shopping, and it does not require additional regulatory scrutiny which attempts to "second guess" gas markets or gas purchasing practices. And, because NNG does not purchase gas separately for Washington and Oregon customers, Washington customers have been the beneficiaries of this mechanism.

Public Counsel proposes that an "index" of gas cost be established by the Commission in general rate case proceedings and that utility performance be assessed against that standard. NNG believes that this approach requires more work of the Commission than is necessary, and the results will not be worth the effort. First, the suggestion places the Commission in the unfortunate position of having to constantly present a price which "captures" the essence of market conditions--a difficult if not impossible project. The operation of gas commodity markets insures that prices will be competitive. Prices in these markets reflect the demand and supply of natural gas, and move constantly in order to reflect changes in these conditions. Any attempt to set a gas price index in a general rate case will succeed only in establishing an index which does not reflect ongoing market conditions. The odds are overwhelming that such an index will focus on the wrong gas prices, in the wrong markets, for the wrong time period, and will be "stale" as soon as it is created.

Second, utilizing an index of "spot" prices presents similar problems. In general, spot prices are not the prices which gas utilities focus on in arranging gas supplies. Gas utilities may look to somewhat more costly sources in order to achieve the degree of reliability which is needed for core customer service. Spot prices, further, are often published for delivery points vastly different from those actually used by a gas LDC. In order for these prices to be used, they would need to be adjusted for the relevant market area, a process which is open to different interpretations by different parties to the PGA process.

Rather than attempt to index gas prices, regulators should examine the utility's gas purchase history at general rate filing times, and see how their performance compares to overall, historic gas market prices. Gross inefficiency should be easy to spot. More minor instances of what seem less than aggressive performance could be negotiated by the regulators and the company in order that a rational decision be made on the merits of the case.

5. Transportation Is Here to Stay.

Public Counsel expresses its concern that transportation has adversely affected sales customers. Comments, pp. 7-8. Public Counsel argues that transportation needs careful study, and that transporting customers need to accept long-term contracts for service and give three-years' notice of intent to come back to sales service. Public Counsel goes so far as to question whether the Commission should permit transportation service at all. Public Counsel's comments here can only be understood if one accepts Public Counsel's initial premise that competition has benefited only large natural customers, and has hurt small natural gas customers. First, NNG disagrees with this premise; small customers have also benefitted from competition. See above at pp. 1-2. Second, it is incongruous that a response to increased competition should be a call for more regulation.

At its best, regulation is not an end in itself, nor is it a tool to serve ideological ends. Rather, it is a substitute for missing competition. Both economic theory and experience indicate that regulation is not needed for the sale of watches, marbles, televisions, or any of the millions of other products whose prices are set in competitive markets. As competition grows within an industry, less oversight is needed to assure that rational prices are being charged. This should also be true with natural gas. Customers should be allowed access to competitive options as they present themselves, and utilities should be encouraged to compete. In this way, all classes of service will be improved, and the need for regulatory oversight reduced.

While the move to competitive alternatives needs to be watched and studied by regulators, it should not be actively impeded. Natural gas distribution companies may suffer unsettling effects as customers increasingly move from sales to transportation service, but these effects will be temporary and should not lead to the conclusion that obstructing the process is the answer. In the final analysis, LDCs are essentially distribution companies. Their business is moving gas from the interstate pipeline to the customer's burner tip. Nothing in this requires that the gas being moved belong to the LDC, so ultimately all customers may become transportation customers.

Despite Public Counsel's concerns, customers intending to transport need only offer annual notice of their intention. This notice should be timed so as to allow the LDC an opportunity to adjust purchases accordingly. It would be awkward, for example, to have transporters shift to or from sales during peak, winter months. Ideally, notice would be required by spring or early summer, with a commitment to not change service type until the next notification period. Longer notice periods, as suggested by Public Counsel, are simply not necessary. As well, because the sale of commodity gas is not a necessary part of the local distribution company's business, penalties should not be applied either for leaving or returning to gas sales service. As noted above, LDCs need notice periods and service length commitments (in order to facilitate gas supply planning), but it will generally be more useful to all parties if competitive innovation is encouraged, not impeded.

6. *Unbundling is Here to Stay.*

Among the "rate innovations" which have emerged in recent years is "unbundling". While most gas company customers need all of the services offered by the local distribution company, there are some customers, usually interruptible customers, who are interested in subsets of LDC total services. Public Counsel is concerned that "if customers with competitive options are allowed to pick and choose the services they need...customers without competitive options will be forced to pay for...services they need...(and) also those they don't need, at full embedded price". Comments, pp. 9-10.

In fact, traditional utility rates have always allowed these "unbundled" choices. Interruptible customers have always received a subset of utility services, whether their rates were called "unbundled" or not. These customers have had no claim on LDC storage or peak day capacity, and logically should not be required to pay for these facilities. Standby service, too, has always been an unbundled service. With transportation, newer "unbundled" services have emerged, among these storage and balancing services.

The sale of storage services allows otherwise interruptible customers the opportunity to improve the "firmness" and reliability of their service. In theory, a customer could utilize storage to build a reliable gas supply from fairly unreliable third party sources potentially reducing their costs in the process. In fact, storage service sales have not proven popular with customers on the Northwest Natural system. Balancing service is another issue. Customers transporting on interstate pipelines need to assure, over time, that the gas they actually receive is equal to the gas they have committed to take. The process by which this is achieved is called balancing. Since pipelines and LDCs compete for large, transporting customers, the range and kind of balancing services the LDC offers tend to be limited by pipeline balancing requirements. Certainly, where pipelines offer liberal (low cost) balancing services, LDCs hoping to avoid bypass pressures will be reluctant to demand more onerous and costly balancing procedures.

In sum, despite all the hoopla and anxiety, unbundling is not new. The tariffs offered by utilities have for decades embodied most of the unbundling concept. Where new services are emerging, they are usually the product of increasing competitive pressure, a movement which is healthy for all utility customers. Public Counsel's fears are unwarranted.

7. Making Public Commercially Sensitive Information Will Only Work to the Disadvantage of Small Customers; The Commission Should Explicitly Recognize This Fact and Protect Commercially Sensitive Information.

Public Counsel rejects "the notion that there is 'commercially sensitive' information which must be protected; in an efficient market," Public Counsel claims, "all buyers and sellers have access to the same 'perfect' information about the market. The protection of confidential information inhibits the operation of an efficient market." Comments, p. 10. This argument is curious indeed. Where least cost planning involves, for example, discussions of resources for which a company might be actively negotiating, it would be needlessly damaging to force the LDC to publicly disclose how much value that resource has for the utility. Such information would only raise the price of the resource to the utility and ultimately to the utility's customers. To suggest that all buyers and sellers have access to the same information in an efficient market is not only wildly wrong, but it further ignores the bargaining process, a procedure well understood by anyone who has bought a new car. It benefits a seller immensely to know precisely how much a buyer is willing to pay. Fortunately, the car seller cannot compel the buyer to disclose such information.

These are the kinds of effects that protection of commercially sensitive information is intended to prevent, and rightfully so. Regulators should not force utilities to sabotage the interests of their customers and shareholders by requiring that commercially sensitive information be made public. The Commission should explicitly recognize this by amending the least cost planning rule to permit LDCs to seek protection for commercially sensitive information. And, the Commission should be willing to entertain a utility's arguments that information is sensitive, and determine sensitivity on the merits of the case.

8. CONSERVCO May be an Idea Whose Time Will Come, But in the Interim, The Commission Should Address the Lost Margin Disincentive Associated with DSM Acquisition.

The future may see the formation of an Energy Efficiency Trust Fund concept similar to the CONSERVCO approach described by Public Counsel in their initial comments. Comments, pp. 12-13. An energy tax to endow such a fund may prove difficult to sell politically. The current anti-tax mind set of state legislatures may only permit a token tax that produces limited funds. At low funding levels, conservation activities will be limited to customer information, and lobbying support for market transformation though regulatory approaches such as building codes.

During the period of time before and after formation of a unified approach to providing conservation services, strong disincentives for LDCs to pursue cost-effective energy efficiency investments will remain. The principal barrier to the pursuit of cost-effective energy efficiency by energy utilities is the lack of mechanisms for lost margin recovery. This problem is not addressed in Public Counsel's initial comments, and the problem is not eliminated by their CONSERVCO proposal. One of the planned workshops following from the Notice of Inquiry should focus on the lost margin disincentive.

9. *Environmental Externalities.*

As the Commission puts forward its "Policy Statement on Guiding Principles for Regulation in an Evolving Natural Gas Industry" it would seem appropriate to include a statement of the Commission's position on recognition of environmental externalities in energy planning and regulation.

10. *Conclusion.*

Radical departure from current regulation is not now required in Washington. Rather, the Commission should continue to watch and study the natural gas markets as they develop; fine tuning to regulation can take place as the markets indicate a need. Areas where the Commission should consider further study are (1) developing guidelines for the use of marginal cost concepts in rate spread and rate design, (2) addressing the lost margin disincentive to DSM acquisition, and (3) permitting LDCs to introduce incentive mechanisms into the PGA process, as deemed necessary by the LDC. Finally, but not least important, NNG urges the Commission to avoid the cookie-cutter approach to regulation which requires that solutions developed for one LDC be imposed on all LDCs uniformly.

Respectfully submitted,

NORTHWEST NATURAL GAS COMPANY

Susan K. Ackerman

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February 1, 1996
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Seattle Steam Company

SEATTLE STEAM
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January 31, 1996

Mr. Steve McLellan, Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

Dear Mr. McLellan:

RE: Docket No. UG-940778 - Response to First Phase Written Comments

Seattle Steam Company hereby responds to the first round of comments filed pursuant to the Notice of Inquiry (NOI) "Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry", Docket No. UG-940778, which was issued on August 2, 1995. Ten copies of our response are enclosed together with a 3-1/2" diskette formatted in WordPerfect 6.1.

As background, Seattle Steam is a large interruptible transportation customer of Washington Natural Gas Company (WNG) currently receiving service under WNG's Schedule No. 57. Seattle Steam operates a district heating system providing service to over 200 commercial, industrial and institutional customers in the downtown and First Hill areas of Seattle. Seattle Steam has been a transportation customer of WNG since such service was first made available in 1988. Prior to that Seattle Steam purchased interruptible natural gas service under WNG's Schedule No. 87. The cost of natural gas, including the cost of its transportation by WNG, is a very large component of our total annual costs. Accordingly, Seattle Steam has been an active participant in all WNG's recent general rate proceedings (Docket Nos. UG-920840, UG-931405 and UG-950278) and WNG's rate design proceeding (Docket No. UG-940814.)

Seattle Steam has reviewed the initial comments of all twelve respondents and is compelled to respond to certain of the initial comments.

Public Counsel on page 5 (No. 8) of its initial comments proposes that customers receiving unbundled services from an LDC should pay market-based or value-based prices for the unbundled services instead of cost based prices which is the foundation of current commission policy. Seattle Steam strenuously objects to such a proposal which would negate the efforts of the recent restructuring of WNG's rates in Docket No. UG-940814. This proposal would reinstitute potentially unjust and discriminatory rates having substantial cross class subsidies to the full service or bundled customer classes. Presumably Public Counsel would continue to advocate using cost of service as a cap or ceiling for an LDC's overall revenues.

One alternative to Public Counsel's proposal would be to have an LDC provide all customer classes just a delivery service from the pipeline to the customer's meter at cost based rates. This would allow all customers to purchase their own gas supplies at the pipeline city gate from a selection of supply pools offered by third party marketers. Such pools would be unregulated, operating in the free market, and could include a pool offered by the LDC in competition with at least two other unaffiliated marketers. Such an arrangement would be comparable to the choice of competitive long distance services with the telephone companies. This gas supply structure would eliminate the questions associated with PGA's, least cost planning, and demand side management. The LDC would simply own and operate the underground delivery system for which it would be allowed to earn a fair rate of return with each customer class paying its share of the cost of service. This gas supply structure would overcome the suggestion by Public Counsel that transportation customers are favored over sales customers and would also be consistent with Public Counsel's suggestion that distribution utilities cease offering gas supply services.

On page 8 (No. 3) Public Counsel is proposing discrimination against large customers which are located at a distance from the pipeline where bypass (i.e. direct connection) would be unlikely. This concept of distance based rates had been proposed previously by Public Counsel in UG-940814. Testimony submitted by Seattle Steam set forth the added operational benefits to an LDC having large interruptible customers located at some distance from the pipeline and downstream of a distribution system constraint compared to an interruptible customer located upstream of the constraint. Further, if distance is to be included as a cost factor why should it apply only to large customers and not all customer classes?

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Public Counsel on page 11 (No. 4) proposes a least cost planning rule involving firm curtailment as a gas supply resource for planning purposes. When a home owner installs gas for home heating, that owner expects to receive uninterrupted service even when a fifty year design day occurs, since it has no alternative other than freezing. To propose that an LDC plan to serve this customer on a design day by curtailing firm service to another customer (i.e. stealing their gas) is unconscionable. If firm service is subject to being interrupted, why pay a premium for it? In addition most large customers elect to pay a higher price for firm service only because they cannot discontinue their operations and either have no ability to use alternate fuel or have a process which is dependent on natural gas.

The DOT analogy of not building a 20 lane freeway is not comparable. With a smaller freeway, the motorist can just endure the delay or use one of many alternatives to avoid congestion and delays. These include public transportation, alternate driving times, car pools, or relocation. However, the firm customer has no alternatives. If the transportation customer knows its firm supplies would be confiscated in design weather to serve other customers, what incentive does that customer have to prudently acquire its supplies and pay a premium to assure their availability on a peak day? When a sufficient number of customers decide there is no advantage in acquiring premium priced firm supplies only to have them subject to being confiscated, and no longer acquire such premium priced supplies, would there be a supply for the LDC to confiscate to serve design condition demands?

Beginning on page 13, Public Counsel proposes several additional questions not included in the NOI. The first question is whether the experiment with gas transportation has provided benefits for all LDC customers. While initially admitting uncertainty to the exact answer, Public Counsel nevertheless asserts it has not been positive for core market customers without providing one shred of documentation. Instead, it is suggested that opponents to such an assertion provide a quantitative analysis to prove a negative. The reverse is necessary, and Public Counsel should be required to document its assertion. Instead of a reexamination of the benefits of transportation to specific customer classes, all parties should recognize that an LDC's investment in physical plant is designed to accomplish one basic function, the efficient transportation of gas from the pipeline to the end-user. The question then is how to allocate the costs of doing so between various customer classes. In Docket No. UG-940814, the rate design proposal by WNG's witness was to determine the delivery cost for each customer class which would be the cost of transportation. The

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rate for sales customers would be the same delivery cost plus the cost of the gas itself.

Secondly, to adopt a policy, as Public Counsel proposes on page 14, that the use of gas for electrical generation is a secondary use of gas which must be released to maintain core market service would be detrimental to the LDC. Any potential cogenerator seeing such a policy would locate its facility where it could obtain direct service from the pipeline, thus denying the LDC the opportunity for additional billing determinants over which to spread its costs. This would potentially deny the region the benefits of high efficiency cogeneration projects where direct connection is not feasible. Further, large end-users may view such a policy as the beginning of establishing end-use priorities where one after another end-use is regarded as secondary and the associated gas supplies become subject to being commandeered for the core market. If any end-user were contemplating a direct connection with the pipeline, such a policy, with the attendant likelihood of policy creep, could be sufficient justification to proceed immediately with direct connection. It should be noted there are no provisions in the pipeline tariffs serving Washington relating to differentiation in treatment due to the ultimate end-use of the gas.

Thirdly, as an attachment to its comments, Public Counsel outlines a proposal for the creation of a statewide surcharge funded entity to provide "cost effective" DSM (demand side management) programs. In analyzing any DSM program, it must be kept in mind that interruptible sales and all transportation customers do not "benefit" from LDC sponsored DSM. In fact, the reverse may be the case. Under successful DSM, the annual usage or annual billing determinants of the affected classes are reduced. Thus, where annual billing determinants are used to allocate costs in a rate proceeding, the net effect of DSM is to shift a greater portion of an LDC's costs to those classes with no DSM, i.e. interruptible and transportation customers.
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In response to the late filed Initial Comments of the Washington State Energy Office (WSEO), one area in particular requires clarification. On page 5 the WSEO suggests "a flat monthly distribution tariff" for non-core customers plus a market determined fee for the gas commodity. Is the WSEO suggesting that the monthly distribution charge be set by some manner in advance and not be related to actual volumetric consumption?

The policy issue which still needs to be kept in the forefront is maintaining the distinction between firm and interruptible service for <u>both</u> the commodity <u>and</u> crosstown LDC transportation service from the pipeline city gate to the customer's meter. However, the WSEO proposal blurs the distinction between firm and interruptible transportation for the "non-core" customer.

The WSEO proposal appears to be a purely theoretical concept and is lacking the specifics necessary to permit meaningful evaluation. In some respects it is internally inconsistent. For example, "a flat rate monthly distribution tariff" does not reflect a cost based rate for interruptible non-core customers. There are several questions which arise from the proposal: What is the basis for setting the fee? Is it the contract peak day or the projected monthly volume? For the commodity gas, will the market determined fee be applied to metered use or on some arbitrary basis?

The Commission is fully capable of evaluating complete proposals. If the WSEO has such a proposal, it can present and support it in a subsequent phase of this proceeding where other parties, including Commission staff, will have the opportunity to examine and test it.

The Commission has solicited comments regarding which procedural steps would be most successful. As noted earlier, Seattle Steam has participated in several recently litigated proceedings before the Commission, some of which were resolved by settlement. One, UG-940814, which was fully litigated, was preceded by a collaborative process prior to any filing with the Commission. While time consuming, Seattle Steam is of the opinion that the time was well spent with an improved filing by WNG the result. Based on this limited experience, Seattle Steam would encourage the use of a format permitting as much open and free discussion as possible both prior to the issuance of a formal notice of proposed rulemaking and subsequent to that notice as well.

If the Commission concludes that LDC's are a monopoly and as a result it must regulate the overall utility earnings from such a monopoly, then the following principles should apply:

(1) Whatever methodology is used to set the overall earnings of an LDC, that same methodology should be applied to each customer class without exception - e.g. if the LDC's earnings limit is determined on a cost basis, then the revenue responsibility for each customer class likewise should be cost based.

(2) Customer classes should be allocated only the costs related to the services they receive - e.g. (a) gas supply costs (the cost of the commodity plus pipeline transportation) should be allocated to sales customers only and (b) conservation programs and demand side management costs should be allocated to firm sales customers only.

(3) The actual "real world" operational characteristics which differentiate interruptible from firm service, both in sales and in transportation, should continue to be recognized and that the necessary concomitant rate differentials continue to reflect these differences.

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In conclusion, Seattle Steam's position is:

(1) The end result of LDC regulation should be the provision of service at just and reasonable rates to all customers. It should include policies which encourage customers to remain with LDC service instead of being driven to seek direct service to the ultimate detriment of the remaining customers which are unable to do so.

(2) Competition in the natural gas industry has been mandated at the Federal level. Local regulation of LDC's should not attempt to reverse this national policy goal.

Thank you for the opportunity to offer our comments. We look forward to participating in future proceedings.

Sincerely,

James G. Young

James G. Young
President

JGY/sh

Washington Natural Gas

Washington Natural Gas
A Washington Energy Company

February 22, 1996

Advice No. 876

Mr. Steve McLellan
Executive Secretary
Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive S.W.
P. O. Box 47250
Olympia, Washington 98504-7250

RE: Notice of Inquiry -
Examining Regulation of Local Distribution Companies

Dear Mr. McLellan:

Washington Natural Gas Company submits herewith an original and ten (10) copies of its written Reply Comments in the Commission's Notice of Inquiry (NOI) - Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry-Docket No. UG-940778. These comments include a discussion of some new concepts relating to regulation of the gas industry as well as specific reply to issues raised in the initial responses of other parties on each of the topics outlined in the NOI.

Please also find enclosed a 3 ½", high density "floppy" diskette, containing an electronic (Word for Windows) version of these comments.

Sincerely,

Ronald J. Amen

Ronald J. Amen
Director, Rates and Tariffs

enclosure

Washington Natural Gas Company
815 Mercer Street (P.O. Box 1869), Seattle, Washington 98111, (206) 464-1999, 1-800-999-4964

NOTICE OF INQUIRY (NOI)

Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry

Docket No. UG-940778

Reply Comments

February, 1996

Washington Natural Gas
A Washington Energy Company

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I. INTRODUCTION

Washington Natural Gas (WNG) is pleased to reply to the comments submitted by other parties in the Washington Utilities and Transportation Commission's (WUTC or Commission) Notice of Inquiry (NOI). We welcome the open and frank dialogue necessary for the re-evaluation of regulation of the natural gas Local Distribution Company (LDC) industry.

Certain parties have chosen to reargue rate design issues that were debated and resolved recently in Docket No. UG-940814. A cost of service methodology was adopted, and many other significant issues, especially related to unbundled transportation service, were resolved in that docket. WNG does not believe that it was the Commission's intent to revisit those issues here. Rather, the focus of this dialogue should be to address new evolving issues and the role of future regulation, given the realities of the competitive marketplace. WNG is, however, compelled to respond to certain of these broad philosophical issues so that the public record is clear.

It has been stated that take or pay costs should be paid for "equally by all customers equally." The premise of this declaration is untenable with Least Cost Plan (LCP) requirements. WNG firmly believes that take or pay or excess capacity costs should be paid for by those on whose behalf the resources were originally acquired. Demand charges (for pipeline, storage and gas supply) were incurred on behalf of firm customers and should be paid by them. The LDC must plan and acquire resources based on 20-year least cost considerations, in accordance with the law. The position presented by Public Counsel simply puts the LDC at an unacceptable risk.

The fact that some cost allocation is made for use of a given resource by non-firm customers is not an acknowledgment that the resource was purchased for them. It is simply the recognition that they may use a resource bought for and available to the firm sales market when that market does not need it. Clearly, it is sensible to make such resources available to interruptible customers at a price greater than marginal cost rather than simply hold the resource for the exclusive use of the firm sales customer and forego any contribution toward otherwise sunk costs. Further, the usage of the distribution system by transportation and interruptible sales customers (and the allocation of costs to these customers) is not evidence that the distribution system was designed for them.

Public Counsel asserts that no special rates should be allowed as these are discriminatory. The concept referenced by Public Counsel is generally described as prohibiting any <u>undue discrimination</u>. In fact, the Commission has approved high load factor and high volume rates, as well as banded rate rules and provisions, for special contracts for dealing with customers whose circumstances do not lend themselves to simple average pricing by the utility.

The proposal is again made to charge higher rates to certain large-volume customers that have, due to location, less chance of bypassing the services of the LDC, while charging lower rates to others having more options. Contrary to the premise advanced, the costs to provide transportation on the distribution system are not a function of mileage, as was noted in Docket No. UG-940814. WNG maintains that distance-based rates not supported by distance-based cost causation would indeed be unduly discriminatory.

It has also been argued that natural gas use for electric generation should be designated a second class use of the fuel, with special strings attached to transportation service related thereto. WNG observes that if this is done, all future electric generation load will connect directly to the pipeline where there is no discrimination against classes of firm customers based on their type of natural gas use. There is clearly no benefit to creating an artificial barrier to serving a potential customer. Such a policy simply eliminates the LDC as a competitor for potential service to these customers.

WNG struggles with Public Counsel's arguments that on one hand, the LDC should not provide a special rate or treatment to a specific customer or class based on customer size or usage quantity yet, on the other hand, the LDC should discriminate against a customer or class based on location on the distribution system or type of gas use.

It is also declared that if additional transportation service (beyond current levels) is offered, it should be offered only to "large" customers. The quantity restriction is an arbitrary limitation and an attempt to reargue an issue already resolved in Docket No. UG-940814.

The proposal to require the release of a transportation customer's gas supply to the LDC may, at best, be difficult to apply as the LDC is not, generally, a party to the gas supply arrangement between the transportation customer and his gas supplier. In most cases, the supplier reserves the right to the gas on days when the transportation customer cannot access the gas due to lack of LDC system capacity. The ability to obtain, at a negotiated cost, the right to use the firm gas supply of a transportation customer is properly an issue to consider in an LDC's Integrated Resource Plan (IRP).

The recent Commission decisions on cost of service and rate design can and should serve as a foundation for consideration of the issues raised in the NOI.

Finally, much has been said about what is required for effective competition. WNG believes Bonbright provides a useful description.

> ...effective competition requires that (1) consumers must be willing and able to change supplies if there is a change in price, and (2) competing carriers must be willing and able to increase output to meet the increased demand if another supplier raises its prices above costs. Alternatively, effective competition is said to exist when users have the ability to obtain comparable services and facilities at reasonable prices from alternative suppliers. Choice is a valued asset of a competitive market place.[1]

[1] Bonbright, James C. et al, Principles of Public Utility Rates (2nd ed.). Arlington, VA: Public Utilities Reports, Inc.,1988, p. 160.

II. REPLY COMMENTS AND DISCUSSION

A. SUPPLY-SIDE ISSUES

Most parties to this dialogue suggest the need for some sort of incentive for the LDC to diligently pursue lower gas supply costs. The growing complexities of the marketplace and the sheer volume of individual transactions make the existing method of regulatory oversight of gas supply costs (the audit of transactions) increasingly less efficient and effective.

New methods and techniques need to be developed to provide a responsible degree of regulatory oversight and yet assure a fair determination of prudence by recognizing that each LDC's portfolio selection options and portfolio management methods are unique. This is not an area where a cookie-cutter approach will suffice. The volatility of the natural gas marketplace is such that WNG (and most LDCs) do not see benefit to abandoning the current PGA process. The regulatory lag (which usually results when a PGA is not used) does a great disservice to the utility, in terms of lost cost recovery, and to the market, as gas cost changes are not communicated frequently enough for customers to respond to a price signal for their own benefit.

The establishment of a "reference gas cost" in a rate case with subsequent percentage pass-through is not an appropriate alternative. This method would not actually communicate the true cost to the consumer over time. This idea is particularly unfair to the LDC as it does not have a corresponding degree of control over total gas cost. The proposed method may require more frequent rate cases just to reset the reference price to reflect market price changes, much as the price escalation during the 1980s that gave rise to the PGA mechanism in the first place.

Establishment of an absolute reference price as an incentive benchmark, in any format--rate case or PGA--may elicit significant gamesmanship as LDC and intervenors each attempt to outwit the other. By the time a specific value for total gas cost is agreed to or ordered, it is no longer a fair representation of the current market value of gas. WNG believes it is better to measure an LDC's performance against the market, not some arbitrary value which is outdated by the time it is established.

WNG suggests that a better understanding of certain aspects of the current gas supply market will lead to a clearer vision for future regulation. Additional observations about the current marketplace are made here, as a recognition of these factors may serve as a basis for other regulatory options.

WNG observations regarding DEMAND COSTS :

- For most LDCs, demand costs for pipeline and storage service comprise 30% or more of total gas cost. Most of these charges are pursuant to tariffed rates set by FERC, and outside the LDC's direct control.
- Gas supply demand costs, which are individually negotiated with a producer, are influenced by reliability concerns and expectations regarding the long-term availability of the resource.
- For Canadian gas supplies, the demand charge is generally closely tied to tariffed rates for firm gathering, processing and transportation capacity on Canadian pipelines. These rates are established in a separate regulatory environment, again, without direct LDC control. Such costs may be 10% or more of total gas cost.
- Demand costs generally will change only once a year, or less frequently; and are not tied to any market index.
- Demand charges are paid to guarantee supply, and this cost of reliability is generally not reflected in spot prices.
- Demand costs are a direct result of the long-term resource selection process; and as such, their incurrence is generally driven by the entire least cost planning process.

WNG observations regarding COMMODITY COSTS :

- Most commodity gas is now bought by LDCs at or near index in one or more of the regional supply basins.
- Index prices can rise or fall in unpredictable fashion and not necessarily with strong correlation to each other.
- Regional prices are affected more by supply and demand dynamics, pipeline capacity availability and by the forward markets such as NYMEX (hedgers and speculators) than the purchasing efforts of any given LDC.
- Commodity prices change daily (even hourly), leaving significant opportunities for LDCs to achieve pricing benefits on behalf of customers.
- There are significant risks (credit, performance, reliability, etc.) associated with these opportunities which could be mitigated with a market-oriented incentive mechanism.

From the above observations, WNG concludes that dramatic differences exist between the two types of gas supply costs. Demand charges are related to and influenced by a long-term view of the market, tend to evolve more slowly, are triggered by a well-documented decision by the LDC, but are otherwise cost determined by others. By contrast, commodity costs are driven by short-term market expectations, change frequently and rapidly, and are somewhat beyond the control of the LDC. The use of any specific commodity resource is much more subject to the utility's ability to manage, in that so many other known and quantifiable purchase options exist at any given moment. A pattern emerges that demand charges are a long-term phenomenon and commodity costs are short-term.

Further, it could be concluded that in the gas supply market today, it is the access to firm capacity and firm peaking resources that largely dictate the reliability of supply at the city-gate. Commodity gas availability could then realistically be viewed as primarily a function of price. One could, therefore, conclude the need for a different form of regulatory scrutiny to evaluate commodity costs, given the changing nature of such costs.

Given the preceding, WNG concludes that firm capacity and peaking resources lend themselves to regulation by prudence reviews and review in the least cost planning process due to the reliability issues (i.e., how well the LDC selected its portfolio). Gas commodity costs are more appropriately regulated by comparison to the market (i.e., how well the LDC managed the portfolio). With these considerations in mind, WNG proposes a reconfigured and restated use of certain current regulatory tools and the introduction of an incentive PGA concept.

1. PGA-Demand Filings (generally at least once per year)

- Establishes demand cost recovery rates for the year.
- Includes demand (i.e., fixed) costs for pipeline capacity, storage, and gas supply demand charges.
- Provides details of the contracts in the portfolio and expected annual usage.
- Serves as the forum for prudence determination on the long-term resource. Filing is related to the portfolio selection process (as opposed to the day-to-day resource management process).
- Prudence is measured against standards of documentation and consistency of assumptions and methodology to LCP process.
- A fair prudence review of demand costs must give serious consideration to the least cost planning process and the applicable Integrated Resource Plan which formed the basis for the selection of that particular resource.
- As today, the LDC would continue the use of Account 191 and monthly deferrals for over- or under-recovery of demand costs.
- Allocate demand costs to individual rate schedules based on the methodology approved in the last rate case.

2. **PGA - Commodity Filings (annual, semi-annual or quarterly, as necessary)**

- Establishes commodity cost recovery rate expected for next (short-term) period.
- Follows pre-established consistent methodology of forecasting.
- Consists of a blend of resources optimized based on projected pricing by source location, including storage withdrawals.
- Provides reasonable and timely pricing signal to customers.
- Could be implemented on as little as one-day notice since it is just an estimate.
- Not used as a measure for incentive and therefore not prone to gamesmanship.
- All proceeds from off-system sales, exchanges, and other activities would be used to reduce the commodity gas costs.
- As today, the LDC would continue the use of Account 191 and monthly deferrals for over- or under- recovery of commodity costs.

3. **PGA - Incentive Results Filings (annual or semi-annual)**

- Reports monthly determination of incentive earned or lost by comparison of actual costs to a reference price.
- Reference commodity price needs to reflect the portfolio of the applicable LDC (e.g., weight factors to reflect commodity mix from different gas supply basins or storage resources).
- Methodology is pre-established, but the market determines the standard of reference for the incentive or penalty.
- Serves as the de facto prudence review for the day-to-day management of the resource portfolio (as opposed to the selection of the individual components of the portfolio).

With a properly designed incentive mechanism, WNG can better respond to the uncertainty inherent in market probability and lost opportunity risk in the supply market while providing lower gas costs to its core market customers than would otherwise be possible.

B. CUSTOMER CHOICE AND COMPETITIVE BYPASS ISSUES

It has been asserted that there is no need for regulation of the non-core gas supply market. WNG believes that unbundled commodity sales to customers within its service territory should be made in accordance with a tariff mechanism. WNG's understanding of this issue is based on how this issue was addressed by the Commission, when the banded rate rules were established. The banded rates mechanism is a regulatory tool that can be utilized to offer service to any market that is declared competitive. Surely, the unbundled sales of commodity to the transportation market could be considered competitive. The Commission should encourage LDCs to utilize the existing regulatory framework, when possible, to provide options to customers (and that also benefit core customers).

It is alleged that large industrial customers were the primary beneficiaries of unbundling in the industry. It is further argued that the availability of transportation service has adversely affected sales customers and ought to be reconsidered. WNG disagrees with both of these positions. The unbundling of the interstate market that gave rise to market demand for transportation at the LDC level has brought significant savings to all stakeholders in the industry. The relative impact on non-core customers is from a variety of sources. Non-core transportation and sales customers' distribution rates are now lower as they are more closely aligned with their associated cost of service. Non-core customers now have direct access to an active and competitive commodity market, where they are able to purchase only those resources they desire. Significant savings are possible for the high load-factor, interruptible customer today due to the surplus of both supply and pipeline capacity in the Pacific Northwest. The economic reality is that the relative price differential between core and non-core is more a function of differing cost causation factors, such as load factor and reliability, than it is a measure of relative "benefit."

While large-volume industrial customers may be the most visibly impacted group, all customer classes have benefited from the greater availability of capacity and significantly lower gas prices. Core customers benefit tremendously because WNG (and indeed most LDCs) have more opportunities than non-core customers to be efficient at buying resources. This is due to the economies of scale, bulk purchase and price arbitrage opportunities, the flexibility afforded by storage, and the diversity of complimentary resources possessed by the LDC. The LDC has access to the same commodity markets, but has greater flexibility and options to use those markets to their core market's advantage. The evidence of core-market benefit is the significantly lower gas costs embedded in WNG's core market rates today as compared to before unbundling of the interstate pipeline merchant function.

The Commission need not study whether or not transportation service should be eliminated. It is a reality of today's and tomorrow's energy industry. The natural gas industry has evolved beyond the possibility of FERC rebundling the interstate pipelines and limiting access to supply. The competitive environment will demand that transportation service continue to be provided. LDCs need to continue to develop new strategies and techniques to capture market opportunities for the benefit of all their customers.

It is argued that LDCs should not provide unbundled sales service to their transportation customers in competition with bundled sales services. WNG suggests that the establishment of rules limiting customer choice may also limit the availability of cost-reducing strategies that benefit core market customers. The actions of the FERC and the market in general have provided customers with one of the main tenants of an open economy – customer choice. As discussed above, the transportation market is already here, and it is not likely to disappear. Once acquired, customer choice will not be easily given up. The case is clear; non-core customers have been "lured away" to transportation for one primary reason: the costs of transportation plus commodity gas are <u>less than</u> the tariffed rates they would pay for a bundled sales service. This is largely, if not entirely, a function of load factor and rate design, in spite of the fact that LDCs are very efficient commodity purchasers.

The challenge then, for any LDC is how to achieve the system cost-reducing benefits of serving the non-core customer while recognizing the reality of customer choice. If it cannot be done by charging traditional bundled rates, then other methods should be explored. One of those options is to offer unbundled commodity sales as well as unbundled transportation service. WNG believes it is possible to develop an unbundled sales rate schedule that would indeed resolve this challenge for the ultimate benefit of both core and non-core customers.

C. UNBUNDLING

Several marketers propose that regulated LDCs should be prohibited from competing for industrial markets with unbundled gas supplies or services. The transparency of such an argument is obvious to all. The insistence of these parties that LDCs be forced to establish completely separate unregulated marketing affiliates (which have no day-to-day contact with the LDC) is born of so much self-interest as to be not credible. This scheme would do nothing more than create additional overhead costs while preventing the LDC from selling gas supplies for the benefit of its customers. The notion of prohibiting LDCs from serving their own end-use customers is simply an attempt at "cream-skimming" without having to compete.

It is self-serving for certain producers and marketers to claim that an LDC should be banned from competing for its own industrial customers. Many of the same producers and marketers already enjoy the benefit of the demand charge payment (made by the LDC to guarantee firm supply availability). They now wish to preclude the LDC from maximizing the value of that payment. If the LDC does not sell the marginal therm of gas (for which it has already paid the demand charge), the producer will sell that same unsold therm anyway, and often to the LDC's own customer. The producer/marketer is thus being paid twice for the same gas supply.

Many (non-LDC) parties support further unbundling and the exclusion of regulated LDCs from the unbundled sales market because they perceive a substantial profit potential in selling gas supply and pipeline capacity to the high load factor customer at the expense of the bundled sales service customer. The bundled sales service customer will be best served by the LDC being able to sell gas as a regulated entity to <u>any</u> customer.

WNG intends to stay in the gas supply merchant business for <u>all</u> of its market. WNG agrees with Public Counsel that "If there is a market for unbundled services such as storage, balancing, or standby, LDCs should be permitted to provide that service on a value-of-service basis..." Further, WNG believes that LDCs should <u>not only be permitted but encouraged</u> to compete to serve customers desiring unbundled gas supply sales whenever and wherever it benefits all customers. A properly structured unbundled sales service will complement the existing unbundled transportation service offerings and recoup benefits to the bundled sales service customer while providing additional customer choice. Customers who have chosen unbundled transportation service have clearly expressed their interest in having an unbundled commodity sales service available from WNG as an option in the marketplace.

It is important to minimize the total cost of the resource portfolio required to serve the bundled sales service customer. WNG makes significant sales of interruptible gas and/or transportation service in the off-system market, recovering a contribution to the fixed costs of its resources.

The right to provide unbundled sales service to transportation customers will greatly expand WNG's ability to lower costs even more. Therefore, WNG will work with its customers, regulators and other parties with legitimate standing, to develop a tariff for unbundled sales service as characterized below.

- Tariffed unbundled interruptible gas supply service to be provided to WNG's unbundled transportation customers.
- Contracts would contain either individually negotiated market-based pricing, as under the banded rate mechanism, or perhaps, a menu of pricing options.
- Use of temporarily underutilized firm supplies and/or capacity from existing resource portfolio, supplemented by incremental purchases, if advantageous.

- Contractual title transfer of gas from WNG to customer at the city-gate or any negotiated upstream point.

Because the agreed sale price for the unbundled commodity would always exceed marginal cost, this service would recoup a significant contribution to fixed system costs from customers who have elected unbundled transportation.

One party suggests that unbundling should be available to all classes of customers, if it is encouraged or made available for some classes; and several other parties argue to completely unbundle the core market. WNG's recently approved transportation tariff makes unbundled transportation service available on a strictly economic basis, without limitation based on issues such as size or minimum usage. The only potential issue to consider in further unbundling is the aggregation of small loads so as to make transportation accessible economically to all customers. Today, WNG has no indication that anyone, except would-be competitors, is interested in residential market aggregation. However, if a significant portion of our residential customers were interested in taking such a service, we are willing to work through the tariff, rate design and implementation issues with the Commission.

WNG believes that the important issues raised by Public Counsel, such as gate station aggregation, system and supplier balancing, etc., would need to be addressed and resolved. The question of reliability for core customers choosing other suppliers and the impact on those remaining with WNG will need to be resolved. WNG envisions the provision of a mandatory standby service for various customer classes, (i.e., firm standby charges). WNG will not willingly accept the role of becoming the supplier of last resort, and having the costs associated with that status borne solely by the remaining residential and small commercial customers. There are significant costs associated with maintaining service that must be considered if a standby service is not made mandatory.

In order to manage its gas supply portfolio effectively and for the protection of those customers choosing sales service, non-WNG suppliers would be required to install Automated Meter Reading so as to provide a basis for periodic system balancing. Maintaining a balance of supply to demand is, after all, a critical component of providing a reliable merchant function for one's customers. The costs of monitoring and maintaining this balance for customers choosing to purchase resources elsewhere should not be absorbed by WNG's remaining bundled sales service customers.

D. LEAST COST PLANNING

For the foreseeable future, WNG expects to be operating in a regulated, competitive environment. WNG's actions and policies need to be responsive to both regulation and competitive market forces. WNG has tried to align these two forces through its least cost planning process. By integrating the principles of least cost planning into its strategic and business planning processes, WNG believes it can better meet the expectations of both its regulators and the markets it serves.

It should be noted that least cost planning is not synonymous with Demand-Side Management (DSM). Integrated resource planning is one tool to minimize the long-run costs to customers. DSM is a strategy evaluated in the Integrated Resource Plan. WNG believes that incorporating least cost planning principles into facilities and operational decisions, in addition to resource decisions, is a critical element of its future success.

This approach appears generally consistent with the comments of other LDCs. One party argues, however, for the disclosure of the LDC's Strategic Plan as a supplement to the Integrated Resource Plan so as to provide a better framework for determining compliance with least cost planning principles. If its strategic plans are disclosed, the utility is put at a distinct disadvantage in the competitive environment, and will simply discontinue production of its Strategic Plan. This would be detrimental to comprehensive planning by utilities. It should be recognized, also, that the IRP is an integral part of the company's Strategic Plan, but not the reverse.

Various parties suggest that the economic market would function better if the LDC made a full public disclosure of the costs and details of all its resource options. We would agree with this suggestion if all other parties (producers, brokers, marketers, etc.) were to share the detail of all their resource options. That would certainly level the playing field. Until then, however, it must be considered that each LDC has built its resource portfolio (guided by least cost planning principles and documented strategies) to serve the needs of all its firm customers. In many cases, there is an expectation that some fixed costs could be recouped from non-core customers when such resources are not fully utilized by core customers. This results in overall lower costs to guarantee firm service to core customers than would otherwise be possible. Disclosure of sensitive information, such as pricing details, by an LDC to a third party competitor (who is generally not regulated, and thus not subject to the proposed rule) gives an advantage to that competitor. As a result, any contribution to recovery of core market gas supply costs that might have been possible are lost. The only beneficiary to such disclosure is the competitor's bottom-line. Disclosure of commercially sensitive data is not in the best interests of the LDC's core-market customers.

WNG does not agree with the assertion that an efficient market requires perfect information about competitive costs and business strategies. To expand on the analogy used by Public Counsel, a customer can make an informed buying decision regarding the purchase of a Taurus vs. purchase of an Accord without having information about how much Ford pays for heater motors or the terms under which Honda buys gas tanks.

As noted by Northwest Natural Gas, WUTC staff has demonstrated a good understanding of the LDC's concerns and has worked cooperatively with the LDCs to obtain commercially sensitive data subject to confidentially agreements. WNG would support the inclusion of language in the rule to document this latitude and to encourage utilities to strike an appropriate balance between necessary confidentially and an open process.

A distinction should be made between the selection of a long-term resource for inclusion in the portfolio, and the day-to-day management of that resource within the portfolio. The objective of each is obviously to achieve the least cost. The association of a significant fixed cost component with a given resource changes the economic options and time considerations for minimizing the cost of that resource.

WNG does not believe there is need to consider the adoption of "incentive mechanisms" to encourage an LDC to select resources to serve customers at the least cost as suggested by Public Counsel. In a regulated environment the incentive to select resources at least cost is the ability to seek recovery of the related demand costs in a subsequent PGA. WNG believes, however, that an incentive is appropriate to encourage the LDC to accept the added risk associated with utilizing all of the available tools to subsequently manage the selected resources.

WNG agrees with Northwest Natural Gas's comment that the requirement to provide estimates of DSM potential for interruptible sales customers should be deleted from the current rule. This customer group has the ability to bypass to other fuels and generally has a strong interest in sophisticated energy management. In some cases, however, it may be in all customers' interests to offer DSM measures to interruptible customers. Any changes to the rule should retain the flexibility to allow LDCs to investigate DSM opportunities with interruptible sales customers.

There is no need, as proposed by Public Counsel, for the Commission to direct LDCs to consider limited-term interruptible service, voluntary curtailment and firm curtailment for peak day supply planning. WNG and other LDCs are already investigating these alternatives along with all other options available to meet peak day demand. Public Counsel misses the point when arguing for relaxed peak day design standards and the use of untested theoretical planning criteria. System reliability is more a function of individual sections of distribution capacity than some simplified system average assumption. Even at near-peak days, for example, WNG requires peaking efforts at numerous locations throughout its distribution system. To arbitrarily reduce the design requirements would result in additional outages in the future. The establishment or modification of an individual LDC's peak day design standards is not an issue for generic rulemaking or this forum. Each LDC's supply portfolio and distribution system were and are developed based on the special characteristics of time, geography, and growth pattern unique to that company. As such, these are appropriate topics to be discussed and judged within the confines of the individual LDC's IRP.

Determining what constitutes an appropriate level of reliability, below system design criteria, for least-cost planning purposes is difficult. Implementing firm curtailment options could have life-threatening implications and be infeasible unless very carefully designed and implemented (i.e., voluntary contracts etc.). Also, based on preliminary WNG research, it appears that firm customers would prefer higher gas prices to curtailment of firm service. WNG believes the current rule (supplemented with continuing dialogue in this forum and our ongoing Technical Advisory Committee discussions) will give adequate direction in this area.

WNG would, however, welcome clearer guidelines from the Commission regarding distribution facilities planning in the least cost planning process. As stated in initial comments, WNG believes that the rule should more specifically address the issue of long-term least cost facilities planning.

E. DEMAND SIDE MANAGEMENT AND CONSERVATION

Even in an environment of increasing competitiveness, WNG believes DSM will continue to play a role in meeting customers' needs at the least cost. Issues of who should pay and how costs should be recovered will be critical in determining the success, and longevity, of such resource acquisition endeavors.

To be effective, DSM programs must balance least cost principles with the requirements of this competitive environment. Short-term and long-term rate impacts, ratemaking disincentives, potential stranded investments, customer needs, and the delicate task of balancing program costs among varying customer classes all represent challenges for which solutions are available. DSM programs need not be seen as a conflict of interest for a utility. Appropriate cost-recovery mechanisms, the careful balance of costs between participants and non-participants with a shift toward greater participant contributions, and the ability to hold commercial/industrial customers liable for as yet unrecovered demand side investments should they choose to leave sales service are the keys to continuing cost-effective DSM.

In an effort to avoid potential stranded DSM assets, utilities need a cost-recovery policy which encourages a short amortization period and provides recovery of lost margins. LDCs must be able to pull out of a program that is no longer cost-effective due to competitive pressures and avoided cost changes. Utilities must also be able to seek modifications to the mechanisms used to recover DSM costs if the impact causes non-core customers to leave the system, thus increasing costs to the core market. A mechanism such as WNG's current DSM tracker mitigates the risk of stranded assets by amortizing program costs over a 12-month timeframe. High quality and timely process and impact evaluations keep cost effectiveness at the forefront of the programs and allow an LDC to appropriately end or modify programs as needed before rate impacts become detrimental.

Along with this, however, arise questions of equity among participants and non-participants. Public Counsel asserts that DSM efforts of LDCs in the state have been "deminimus." Public Counsel then goes on to state that non-firm sales customers should share in the cost of DSM resources. The supporting rationale offered is that these "deminimus" efforts have softened the regional demand for gas, thus driving down the commodity price of gas for all users. The logic is flawed and inconsistent. In reality, the commodity price of gas has fallen primarily as a result of competitive wholesale markets brought about by federal deregulation, the "gas supply bubble" caused by the reaction of gas producers and new technologies.

WNG maintains that firm sales service requirements are the basis for DSM programs. And though the successful acquisition of demand-side resources benefits all firm sales customers with reduced energy costs (primarily peak-related demand costs), there is a need to strike a balance between the direct and indirect receivers of benefits (participants and non-participants). This can be achieved by providing programs which target varying customer classes within the firm sector and spreading the costs in accordance with the benefits, as well as developing cost-sharing mechanisms which transfer a larger share of the cost to the participant (while maintaining program goals).

Finally, for DSM to be plausible in a competitive market, company financial disincentives arising from ratemaking policies must be removed. This can be achieved through recovery of lost margins associated with program impacts and the development of a mechanism by which customers leaving the core market can be required to repay the unamortized portion of any DSM assets they have acquired from the company.

Reducing the risks associated with stranded DSM assets and eliminating the financial disincentives for the LDC negate concerns of conflict of interest between making a profit and reducing consumption. Consequently, the responsibility for running cost-effective and efficient DSM programs should remain in the hands of the utility.

The company, as the entity best able to determine the appropriate avoided energy cost for each customer, is able to implement programs specifically designed for its customers, keeping in mind both the financial and service issues at hand. Furthermore, it is the local utility that can best evaluate DSM initiatives as an alternative to new distribution facilities or upgrades. The increase in rates is directly associated with the particular utility's DSM costs, and that utility's customers can be confident in the knowledge that any increase in rates is paying for specific programs which reduce that utility's (and thus their own) long-term energy costs.

Customers are able to rely on their utility employees, with whom they already have contact, to work with them in obtaining demand-side measures, and an increasing number of partnerships with other local utilities can achieve DSM cost savings while still attributing costs and savings, as appropriate, to the specific utility. Finally, legislative involvement is not required, and DSM remains as it was designed: a least cost option and not a social tax.

DSM resources are acquired as part of an overall least cost strategy to meet the energy needs of firm sales service customers. The higher cost of alternative resources to meet those firm needs is the justification for DSM expenditures. Therefore, firm sales service customers should bear the cost of DSM resources.

WNG believes that a wide range of DSM strategies should be examined for firm sales customers. Candidate strategies should address opportunities within residential, commercial and industrial segments and for both small and large customers over a diverse range of end-use applications. However, we must not fall into the trap of trying to offer a DSM program to every single customer or class in the name of equity. In the end, the strategies selected for implementation <u>must be least cost</u>.

An alternative model for DSM resource acquisition was suggested by Public Counsel. WNG believes that the Conservco model does not represent a constructive evolution in DSM resource acquisition. It is disappointing that Public Counsel acknowledges the lost-margin disincentives but proposes no solution as part of the Conservco model.

Public Counsel questions "whether or not utilities are the best possible entity to operate DSM programs, due to the obvious internal conflict between the desire to provide best service at the lowest possible cost ... and the desire to secure gas sales margins which contribute to margin..." WNG believes that the Conservco model does not create the "best possible entity" to implement DSM strategies, or even one that is better than the LDC.

Here in the Northwest, examples of centralized energy agencies already exist. The Bonneville Power Administration (BPA) is certainly well recognized for its large staff and the size of its conservation programs but can hardly be viewed as a model for cost efficiency. Likewise, we should not forget the success the Washington Public Power Supply System enjoyed and the resulting impacts on ratepayers caused by that quasi-government agency. WNG strongly suggests that the energy consumers of the State of Washington do not need another public agency to tax all consumers in the name of the "public good." The proposed new agency would be a new monopoly provider with no competitive pressure to hold down costs.

Since natural gas avoided costs are low, the key to cost-effective DSM programs is controlling overheads and delivery costs. Today this is achieved by minimizing utility costs and securing outside services for design, implementation support and evaluation through competitively bidding. The proposed budget for Conservco is very troubling. The tax proposed of approximately $.42/MMBtu would raise nearly $100 million dollars across the state--each year--for gas DSM resources. It is hard to fathom what measures Conservco could possibly acquire for $100 million each year and still be cost effective. What incentive is there for Conservco to minimize the cost of resources acquired?

The funding mechanism itself is flawed. More specifically, the standardized funding proposal would penalize the customers of efficient utilities by forcing them to fund cost reduction programs of inefficient utilities. There is no discussion of a valid method for prioritizing DSM programs and relating the costs of those programs to the avoided costs of any specific utility. The funding from an individual LDC's customers should be in direct proportion to the reduced cost of service that LDC's customers realize.

Regional partnerships that make sense are already being formed. There is no need for Conservco to do the positive things which are already being done by utilities across the state. Code training and implementation, the Home Water Savers Program, THELMA (high efficiency laundry consortium) and In Concert with the Environment© (a high-school based resource education program) are all examples of joint utility cooperation.

Finally, the Washington State Energy Office asserts that Class 40 windows are cost effective for newly constructed, gas heated homes. WNG's analysis shows the upgrade from Class 65 to Class 50 to be cost effective. However, the increment from Class 50 to Class 40 was not found to be cost effective.

F. EPACT ISSUES

No further comments.

G. MISSED QUESTIONS

No further comments.

III. CONCLUDING REMARKS

The changing character of the gas industry makes it highly desirable that regulations be current, responsive and flexible in order to address emerging market conditions. Emerging competition is already redefining the LDCs' business. Customers are testing whether the LDCs can meet their needs for new service options.

We encourage the continuation of these open discussions. We look forward to a continuing forum to further refine some of the visions and proposals discussed in this document and the comments of others. We will continue development of proposals to further reduce costs and provide expanded service options to all customers.

Washington Water Power

Washington Water Power

February 1, 1996

Washington Utilities & Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98504-7250

Attention: Steve McLellan, Secretary

Re: Docket No. UE-940778 -- Reply Comments of the Washington Water Power Company

Enclosed are the reply comments of the Washington Water Power Company on the Commission's Notice of Inquiry on "Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry".

Sincerely,

Thomas D. Dukich

Thomas D. Dukich, Manager
Rates and Tariff Administration

enclosures: Ten copies
Electronic version (3.5 inch, high density diskette)

The Washington Water Power Company P.O. Box 3727 Spokane, Washington 99220 (509) 489-0500 / 1-800-727-9170
SERVING EASTERN WASHINGTON AND NORTHERN IDAHO WITH ELECTRICITY AND NATURAL GAS

Washington Water Power

REPLY COMMENTS TO NOTICE OF INQUIRY (NOI)
February 2, 1996

Examining Regulation of Local Distribution Companies
In the Face of Change in the Natural Gas Industry

WUTC Docket No. UG-940778

Introduction

The Washington Water Power Company (Water Power or WWP) provides the following reply comments regarding the Commission's Notice of Inquiry on the changing natural gas industry (Docket No. UG-940778). WWP's comments focus on two areas that have the potential to assist local distribution companies (LDCs) to better serve customers at low costs. These areas are an examination of the potential for limited gas procurement incentives and greater customer options (or limited unbundling) for some services.

To advance discussion, Water Power offers specific proposals as suggested by the Commission letter of December 22, 1995. These proposals are not a "filing" at this time, but are intended for discussion purposes.

In addition to these two discussion proposals, WWP offers one procedural suggestion and critiques one commentor's observations on the future role of integrated resource planning (IRP) for LDCs. The WUTC order authorizing the proposed merger with Sierra Pacific included a base rate freeze for five years and limited opportunity for rate design changes. With this base rate freeze as WWP's performance-based ratemaking alternative, other mechanisms are not addressed in our comments.

Incentive Mechanisms

Water Power has been hesitant in the past to recommend an incentive mechanism for natural gas purchases and transportation. The lack of a clear benchmark which could truly reward performance while avoiding the opportunity to "game" a mechanism has been problemmatic. However, experience gained from mechanisms around the country show that sound mechanisms can be proposed for the benefit of the customer and the company rather than waiting for the "perfect" mechanism which may never come. The following suggestions are offered in the spirit of discussion for appropriate gas cost incentive mechanisms that may be appropriate for Water Power. Its application to any other utility operating in the State of Washington is not being implied; while one mechanism may be appropriate for one utility, some other incentive may be more appropriate for a different utility.

Benchmark to index

There is sufficient data and experience in the Pacific Northwest to identify a set of receipt points where gas is purchased for delivery to utilities under the jurisdiction of the WUTC. These receipt points can be clearly identified and reported. Specifically, natural gas enters the Pacific Northwest through the Northwest Pipeline delivering gas to all utilities operating in the State of Washington. The supply is at a ratio of 58% from Sumas at the British Columbia border and 42% from receipt points collectively referred to as the Rocky Mountains. These points are measured and reported in publications such as McGraw Hill's *Inside F.E.R.C'.s Gas Market Report* as "Northwest Pipeline Corp. Rocky Mountains" and "Canadian border". A performance mechanism may be developed which utilizes these reported points as the benchmarks.

An acceptable incentive mechanism would use a benchmark based upon a weighted average cost of the commodity portion of the overall gas costs using 58% Canadian border and 42% Rocky Mountains with a percentage premium to reflect the necessity for firm supplies, supply and transportation demand charges and load factor implications upstream. This premium reflects that prices reported in *Inside F.E.R.C.* include spot interruptible purchases and that suppliers typically charge some premium to deliver firm. Any deviation from this weighted cost would be split with 80% tracked through to the customers and 20% being kept by the utility. This comparison would result in differences serving to benefit or penalize the utility based on improvements in gas procurement over an established norm. This mechanism is depicted in Attachment 1.

Net benefits of off-system sales, exchanges and other value added gas resource optimization activities could also be shared. Non-commodity costs for storage, whether underground storage such as Jackson Prairie or liquefied storage such as Plymouth LNG, would continue to be tracked under the current rate treatment. Net transportation cost reductions from a level determined to be prudent by the WUTC could also be shared as agreed to by the parties.

The advantage of this mechanism is that it rewards or penalizes performance below or above a clear and widely reported benchmark. While it may be possible to "lock in" some savings to the utility through innovative contracting or access to other pipelines and supply basins, the company's customers still retain 80% of those benefits. The disadvantage is that it might influence Water Power to abandon a diversified portfolio concept and purchase gas priced month to month. While this is easy to measure against the benchmark, it may cause more price instability than a diversified portfolio with a component of longer term fixed prices.

Pass-through of labor costs with sharing of benefits

One of the contradictions with current regulation is that many utilities have staffed up to pursue value-added opportunities in gas purchases and transportation. However, the costs of increased staffing are borne by the utility and the benefits of their labor are passed through to the customers. The argument that this can be handled through a general rate case is valid, but many factors go into the decision to file a general rate case. Water Power's proposed rate freeze for non-gas costs, and the expense of a general rate case speak against the Company filing for such a mechanism at this time through traditional rate case processes. Yet, 100% of the benefits flow to customers with 100% of the costs borne by the utility.

As a solution to this problem, Water Power suggests including in the tracker the cost of employees added to pursue market opportunities. The company would keep 100% of the gas commodity and transportation benefits up to the cost of the staff hired to pursue these market opportunities, and then all benefits above that amount would be split 80% to customers and 20% to the company. If the additional staff could not "pay their way" with demonstrated benefits, the company would incur the balance up to 100% the labor costs of those individuals. To avoid adding unneeded capacity for later release, this mechanism would be based on contracts in place as of a certain time of the year or based on contracts in place averaged over the previous three to five years. An example of this mechanism is illustrated in Attachment 2.

Benchmark to Industry

A potential, but less desirable, incentive mechanism is to benchmark utility performance to industry averages. For example, if the overall gas costs in the western United States increased three percent, but Water Power costs increased only two percent, Water Power would share in that differential. On the other hand, if western gas costs decreased by twelve percent and Water Power only decreased eight percent, it would be penalized for a portion of that differential.

The major shortcoming of this mechanism is that Water Power is not aware of a good statistical summary of true gas costs that accurately measures utility performance. Weather patterns may make costs in one utility service area in the western United States different from another utility's costs for reasons beyond the control of that utility. Additionally, because gas costs in the Pacific Northwest are so much lower than other areas of the west, a given price per therm change in Water Power's rates has a greater percentage impact than that same price per therm change for other utilities, especially in the southwest.

Mechanisms Not Recommended

Water Power is not recommending incentive mechanisms which simply split the difference between gas costs one year versus the next. Because of industry trends, Water Power may actually perform better in a year when its gas costs went up only five percent versus an industry average of ten percent. Conversely, Water Power probably should not benefit if its gas costs decrease only five percent instead of an industry average of ten percent. Yet a mechanism which shared 80/20 on year to year costs would send the opposite signal to the company and customers.

Water Power is also not recommending a mechanism which compares actual versus estimated gas costs. Because of the volatility of gas prices between the time in which estimates are made and the time gas is purchased as well as the opportunities for gaming the estimate, it is Water Power's belief that this kind of mechanism does not fairly reward or penalize actual performance.

Water Power encourages the Commission and its staff to continue to pursue reasonable purchased gas incentive mechanisms. The above recommendations are not set in stone, but are intended to offer alternatives specific enough to begin a dialogue which can lead to a reasonable mechanism being adopted during 1996.

Pricing Options and Unbundling

Many commentors, including WWP, touched on unbundling issues. Based on the initial comments, Water Power believes it is important to distinguish and contrast two general definitions of unbundling. One definition is full or "robust" unbundling. The second definition views unbundling to be more akin to "pricing options" within the existing framework, without functional separations of services.

This first definition starts with the premise that unbundling is full desegregation of functions accomplished by the separation of supply and transportation. To this is added separation of services within functions such as billing, nomination and balancing services. Each of these services is provided on a stand-alone basis with the requirement that specific prices support each of the associated costs. An example is transportation service by LDCs with third party marketers providing gas supply instead of or in competition with LDCs.

It is instructive to note that this "robust" unbundling has usually occurred in states which previously had high gas supply costs and high administrative costs. This unbundling was promoted by customers, and encouraged by regulators, who demanded lower cost service, either through absolute lower costs or through a "pick and choose" menu of services. Examples include LDCs in Pennsylvania, Maryland, and New Jersey in the mid-1980s. In the meantime, after substantial loss of load to third party marketers, these East Coast utilities have reduced their costs and won back many sales customers through lower costs and service options.

The situation now facing customers of LDCs in the Pacific Northwest is markedly different than what these East Coast LDCs faced in the mid-1980s. Washington State LDCs have low gas costs. Additionally, WUTC jurisdictional LDCs have offered increased services, or "choice", to those customers with alternatives to utility service. As evidenced by the initial comments to the Commission's NOI, LDCs are not hearing a request by customers for full unbundling. However, LDCs are examining various options due to the ongoing change in the industry and LDCs' focus on serving customers needs.

This leads to a second definition of unbundling which may be better termed "pricing options". This is an effort to meet customer needs within an existing premise of low costs in both gas supply and administrative costs. The principles under which new pricing options are considered include cost shifting concerns, margin impacts, and customer responsiveness to alternatives. WWP is examining pricing and service options that could be offered for all classes, athough some options may be more appropriate only at the commercial and industrial level. Options may include an industrial/commercial supply pool, fixing a certain portion of customers supply price or even offering a price per square foot concept.

In summary, WWP's initial comments on this issue noted that a certain level of gas unbundling has occurred in order to meet customers' needs and competitive alternatives. WWP noted that full unbundling for customers at all levels of service would present the Commission with a host of cost allocation issues. It is WWP's intention to continuously examine options which may be of benefit to all customers.

Future Role of IRP

The Washington State Energy Office recommends changes to the scope and process of the Commission's integrated resource planning (IRP) rule. The WSEO suggests that the IRP process include, among other issues, greater analysis of business strategy, wholesale opportunities, and environmental effects. The purpose of these requirements are stated to allow the Commission and the public to understand the benefits and costs of these activities.

WWP is concerned that WSEO's recommendations, if adopted, would lead to several undesirable consequences. First, WSEO's recommendation, if adopted, could lead to a lengthy process with the possibility that an IRP would be suspended and set for hearing. The level of detail and time necessary to meet the WSEO's apparent concerns would, in turn, require some form of Commission preapproval to make this process worthwhile.

Second, WSEO's purported enhancements would come with increased costs at a time when LDCs are looking to shed costs. Yet, this increased analysis and cost would probably not translate into improved actions compared to the existing process. This is because opportunity <u>currently</u> exists for individuals to suggest improvements to WWP's planning or ask questions about WWP's business. WWP has benefitted through suggestions for improvements under the existing IRP format.

Third, the examples cited by the WSEO do not lend themselves to inclusion in an IRP. For example, the WSEO undertook an environmental effects study in 1991 which was disbanded after difficulty in reaching consensus on quantifying and monetizing costs. Further, strategic business planning and wholesale market opportunities are based on expert market understanding. The current IRP process, in essence, allows WWP to portray "what" and "why" the company makes certain business decisions. The WSEO appears to be requesting that the "how" and "when" also be included in the IRP process. However, these are the proprietary actions performed by company experts that provide additional customer benefits. The "how" and "when" are best left to either market forces, if incentive ratemaking is in place, or to regulatory oversight under traditional ratemaking. All parties to the IRP process, including the company, need to recognize the balance of providing information and analysis while allowing the LDC to make and implement business decisions.

WWP understands that the WUTC's current rule has set the natural gas IRP standard nationally. The WUTC should resist the urge to expand the rule without assessing implications.

Lastly, if the Commission desires more information such as business strategy or environmental effects, WWP--and, we trust, other LDCs--would elaborate on such issues. As the Commission is aware, WWP and other LDCs regularly updates the Commission and its staff on emerging issues and business strategy. Similar updates are provided to those individuals attending the company's IRP TAC meetings. WWP also communicates costs and benefits of such activities to the Commission and, of course, the Company bears the risk of potential disallowances. WWP, and to our knowledge other LDCs, inform the public about a variety of issues and provide opportunities for input.

Procedure

The NOI invites suggestions for process or "next steps". Water Power offers two recommendations. First, WWP continues to advocate a "filing by filing" approach, enhanced by dialogue among parties as has occurred in this NOI. Issues have been framed that can be incorporated in LDCs filings.

Secondly, the Commission may wish to consider hosting periodic discussions among stakeholders through a semi-annual or annual forum such as a panel discussion based on current or emerging topics and questions. This forum would promote dialogue among industry stakeholders and would allow more "give and take" in an informal setting. All participants would gain insights on upcoming issues and stakeholders' concerns. Water Power would be a willing participant.

Conclusion

WWP hopes that the details embodied in the unbundling and incentive sections accomplish two objectives. First, we hope that this shows that customer benefits can result without significant risk and without major changes to regulation. Second, we hope that these concepts can be used to increase and "frame" discussion prior to any potential filing.

We appreciate the opportunity to comment on other parties' observations and believe that our response to potential uses of IRP illustrates likely problems which will occur without a thorough review of such impacts.

Lastly, the Commission may wish to continue this dialogue beyond the conclusion of the NOI through WUTC-sponsored forums on emerging issues.

Washington Water Power
Incentive Calculation

Example of January 1996

Commodity Cost of WWP Gas Delivered

	Total Cost (1)	Volume MMBtu	Cost/MMBtu
At: Sumas	$1,100,000	805,000	1.3665
Rockies	$500,000	370,000	1.3514
Kingsgate	$2,500,000	1,825,000	1.3699
Total	$4,100,000	3,000,000	1.3667

Calculation of Benchmark Index

	Inside FERC	% Allocation	Weighted Index
Sumas	1.24	0.58	0.7192
Rockies	1.25	0.42	0.5250
Subtotal			1.2442
Markup of 10%			0.1244
Adjusted Index			1.3686

Variance

WWP Unit Cost	1.3667
Adjusted Index	1.3686
Savings/MMBtu Delivered	-0.0020

Savings Calcuation

Volume (MMBtu)	3,000,000
Cost under Benchmark	($5,860.00)
80% to Customers	($4,688.00)
20% to Margin	($1,172.00)

(1) Includes all costs of gas delivered at to a WWP receipt points. Including supply or transportation demand charges and load factor implications of upstream transportation.

(Estimates, for illustrative purposes only.)

Washington Water Power
Incentive Calculation

Attachment 2

Example of 1996

Fully Loaded annual Cost of Additional Personnel		$150,000
Various Annual Savings Related to Additional Personnel		
Capacity Release	$500,000	
Off-System Sales Margin	$800,000	
Savings Available for Incentive		$1,300,000
Savings Calcuation		($1,150,000)
80% to Customers		($920,000)
20% to Margin		($230,000)

(Estimates for illustrative purposes only.)