IV.
GAS COST RECOVERY

A. Factors To Be Considered In Evaluating The Appropriateness Of The Use Of Automatic PGA Clauses

Purchased gas adjustment clauses have been generally accepted in Missouri as a part of an LDC's tariff for four major reasons. What follows is a discussion of the Team's perception of how each of these major reasons contributed to the regulatory acceptance of automatic purchased gas adjustment clauses, as well as how they have changed with the advent of Order 636.

1. Gas Purchase Costs Were And Are Significant

The purchased gas costs tracked by automatic adjustment clauses (payments for natural gas as well as for the transmission of that gas) constitute a significant or large portion of an LDC's operating cost and corresponding revenue requirement.

Fuel purchases reported by Missouri LDCs are in the 60%-70% range of total gas operating expenses and 55%-65% range of total gas operating revenues. In comparison, fuel expenses for electric companies are in the 25%-45% range of total electric operating expenses and 20%-35% range of total electric operating revenues for those companies that generate their own power. The percentage levels will be higher for an electric company which has a greater dependence on purchased power.[36] If these percentages are used as a basis for comparison, then gas purchase costs can range from 2 to 3 times higher for the LDC than fuel expenses are for a utility that both generates and distributes electricity. Since electric utilities typically are more capital-intensive than gas utilities, the relative impact of gas purchases on gas utility revenue requirements is greater than the impact of fuel purchases on electric utility revenue requirements.

2. Gas Purchase Costs Remain Volatile

One component of gas purchase costs relates to spot market prices for natural gas. Spot market prices can be very volatile, which makes it extremely difficult, if not impossible, to predict this cost component within any acceptable degree of accuracy.

With the implementation of Order 636, the pipelines will no longer provide LDCs with sales service. When sales service from pipelines was available to LDCs, the change in gas prices was linked to approved rate changes before the FERC. This provided some degree of stability to gas prices. With open access, LDCs began purchasing gas supplies on the spot market when these prices were below the tariff sales gas prices of the pipelines. One of the inherent "costs" of these lower gas prices through the spot market was a higher degree of price volatility. (Refer to **Attachment 4**, pp. 1-2)

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[36] It should also be noted that as independent power producers (IPPs) and electric wholesale generators (EWGs) become more prominent in the electric industry, electric companies' dependence upon purchased power will likely increase.

In the "new" world of Order 636, Missouri LDCs claim to have little or no experience with entering into long-term contracts with producers or marketers. Missouri LDCs indicate that due to the existence of a formal futures market, the majority of available long-term contracts[37] are directly or indirectly indexed to that market. Gas prices based on indexing to a formal futures market would be subject to the same volatility that occurs in the actual futures market. At this point, the lack of LDC experience with long-term contracts would make any definitive conclusions concerning gas cost volatility premature. It is unlikely that before the next heating season the LDCs will have gained much of a sense as to what extent long-term natural gas contracts will be a viable economic option for reducing the amount of volatility in natural gas prices.

In comparison, electric utilities appear to have long-term coal contracts with fairly stable prices, which are augmented with purchases on the spot markets. The spot market prices for coal appear to be much more stable than those for natural gas. (Refer to **Attachment 4**, p. 3) The main similarity between natural gas and electric appears to be that buyers must pay a premium (higher price) to get long term contracts with greater price stability.

3. Gas Purchase Costs Were Outside LDC Control

The prices paid for natural gas have historically been outside the control of the buying utility. Thus, gas purchase costs were viewed at the state regulatory level as "pass through" in the sense that there was no issue of prudence regarding the level of these rates. The sales rates for natural gas were set by the FERC, and accordingly states were arguably precluded from examining their prudence.[38]

With open access on pipelines came the opportunity for transportation customers to contract directly with wellhead producers or marketers. LDCs also participated in buying natural gas on the spot market, and regulators began to review these purchases with respect to whether or not they were prudent; e.g., in Missouri the ACA review was not only a vehicle for true-up on PGA filings, it has also been the forum in which the purchasing practices of LDCs are reviewed.[39]

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[37] "Long-term contracts" have been defined by the LDCs as those contracts with a term of 12-18 months.

[38] Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 106 S. Ct. 2349 (1986); Mississippi Power & Light Co. v. Mississippi ex. rel. Moore, 487 U.S. 354, 108 S. Ct. 2428 (1988).

[39] In reviewing ACA cases which have been completed over the past 4-5 years, there have been three instances where the MoPSC Staff has submitted testimony questioning the prudence of an LDC's decisions related to the acquisition of gas for system supply.

In GR-88-31, Staff took the position that the LDC had not sufficiently reduced its sales contract demand levels with its sole pipeline supplier and also was imprudent in its decision to renew a particular storage contract with the pipeline. The Commission found the LDC had been imprudent in establishing its sales contract demand levels and required an adjustment be made to prevent the

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After implementation of Order 636, sales gas from the pipelines will no longer be available at a tariffed FERC rate. Any gas sold by pipelines will be at negotiated, unregulated prices. More than likely, most LDCs will directly contract with wellhead producers or marketers for supplies of natural gas. The LDCs still view the market price as being beyond their direct control. While lack of price control is true in theory for all competitive markets, there remains the practical question of whether or not the LDC has entered into prudent day-to-day transactions in that market. The question of prudence will also deal with the utility's gas purchasing strategy with regard to the portfolio mix of various contract lengths for firm gas supplies--from very long term down to spot market (day-to-day) purchases.

With Order 636, the price of unbundled pipeline services will continue to be FERC tariffed rates and therefore beyond the direct control of the LDC. However, the LDC will be required to make choices regarding the mix of pipeline services. The mix of pipeline services is completely within the control of each individual LDC. Therefore, these costs should now be subject to regulatory prudence review.

4. Gas Purchase Costs Were Easily Identifiable By FERC Tariffs

Before Order 436 open access, an LDC purchased all of its gas from pipelines. Therefore, gas costs included in PGA filings were based upon pipeline tariffed prices approved by FERC. These tariffs typically had only a few billing components, such as: Demands (D1, D2, etc.) and Commodity Volumes. The PGA was basically a formula that calculated certain costs based on FERC rates and long term contractual billing units, and then allocated those costs between firm and interruptible service. This meant the primary function of the review of a PGA filing was to compare its rates to pipeline tariffs and verify its computational accuracy.

With open access and the development of the spot market, LDCs began purchasing some of their gas on the spot market. Spot market prices are not FERC authorized tariffs; rather, they are market-based prices which vary from month to month, or day to day. Having non-tariffed gas prices as part of the overall cost of gas complicated the PGA review process.

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[39](...continued)
collection of the related costs in future years. The Commission determined that renewal of the storage contract was not imprudent.

In GR-89-48, Staff proposed an adjustment to the LDC's gas cost recovery. The Staff identified three defects in the LDC's gas purchasing procedures which had kept the LDC from being able to take advantage of spot gas markets. The Commission found that although there were deficiencies in the LDC's preparation and implementation of Order 436 open access transportation, the deficiencies did not rise to the level of imprudence. Although no adjustment was made, the Commission indicated the LDC needed to improve its gas acquisition procedures and records.

In consolidated cases GR-90-40 and GR-91-149, Staff in its prepared testimony questioned the prudence of the price contained in a particular gas supply contract negotiated by the LDC. This case was settled prior to hearing with no adjustment being made to the company's purchased gas costs.

With Order 636's unbundling of services, pipelines will no longer package and sell the gas commodity together with pipeline capacity for a total pipeline price. Instead, pipelines will now offer a variety of separate transportation and storage services in their FERC tariffs. Therefore, even the complexity of piecing together tariffed rates for pipeline service will increase. LDCs will pay different rates depending on: the receipt point from which they ship the gas, the delivery point to which they ship the gas (e.g., city gate versus storage facility), the amount of pipeline capacity and storage capacity under contract, the location of the storage (e.g., field or market area), the storage deliverability needed, and the number of units injected and withdrawn from storage. Instead of a few billing determinants (demand and commodity), there is now an entire strategy involved for contracting pipeline services, and an associated determination of multiple billing determinants.

The Team believes circumstances have changed enough to warrant some modifications to the method of reviewing and allowing recovery of gas purchase costs.

B. Gas Cost Recovery Mechanisms To Be Considered

The Team has debated whether the PGA mechanism currently utilized by Missouri LDCs should be continued with a limited amount of modification, substantially revised, or eliminated. A discussion of the various options considered by the Team follows.

1. Maintain PGA Mechanism With Order 636 Accommodations

All PGA clauses currently in effect for regulated utilities in Missouri have some items in common. The PGA clauses are all designed to create a rate per unit of gas sold. The clauses provide for the recovery of costs associated with delivering gas (supply and transportation costs) to the distribution system of the LDC for delivery or sale to the customer. Gas costs are the only costs that are allowed to be included in the computation of the PGA rate and that are allowed an expedited tariff (less than 30 day) treatment by the Commission.[40]

PGA clauses contain three basic sections: the PGA factor; the actual cost adjustment (ACA) factor and the refund factor. Larger LDCs have addressed or are in the process of addressing the allocation of Order 500/528 take-or-pay (TOP) costs and Order 636 restructuring costs.

<u>The PGA Factor</u>

The PGA factor is the rate developed to estimate a per unit price that will generate revenues needed to recover actual gas costs. LDCs estimate their costs of gas, by PGA rate classification, and then divide by an annualized sales level to develop this factor.

An LDC is required to make revisions in its PGA rate when its cost changes exceed the "trigger" amount specified in its PGA clause. These "trigger" or threshold amounts are stated in terms of absolute dollar values or as a percentage change and vary for each LDC.

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[40] Section 393.140(11), RSMo 1986.

The ACA Factor

The ACA factor provisions call for an annual reconciliation of gas supply costs to the gas cost revenues received from billing the PGA rates. The resulting over or undercollection by the LDC is divided by the estimated annual sales volumes in the following year, yielding an ACA factor for each gas cost class of sales. This ACA factor is applied during the subsequent year to recover or refund the deferred ACA gas cost balance. This annual review is also the time when final allocations of gas costs among firm, interruptible, and backup customers occur.

The Refund Factor

The FERC operates by approving most wholesale supplier and transportation rates on an "interim subject to refund" basis. This usually results in overcollections of costs by interstate pipelines. Once the final rates are determined by the FERC, the pipelines then return the overcollections to their customers, including the applicable LDCs. The return of these FERC authorized refunds to an LDC's customers is accomplished by the application of a refund factor mechanism contained in the LDC's PGA clause. In general, the amounts refunded by the interstate pipelines are divided by the LDC's estimated annual sales amount to develop a refund factor. Approval of this factor affects refunding during a subsequent annual period, with the exception that some LDCs return refunds to larger customers by one-time credits or checks.

The Order 500/528 Take-Or-Pay and Order 636 Restructuring Cost Factors

Recovery from the LDC's customers of the FERC approved direct billed Order 500/528 TOP costs is accomplished currently on a total throughput basis, not just on a sales basis. This has the effect of holding transportation customers responsible for a portion of these costs. The MoPSC has concluded that TOP costs are a cost of gas, that they are transitional in nature and that they should be recovered from all throughput.[41] To date, the Commission has not determined who will pay for direct billed Order 636 restructuring costs.

These factors are currently developed by taking the direct billed amounts and dividing them by estimated annual total throughput (sales and transportation volumes). These rates are then applied to throughput of all customers for a subsequent annual period. Not all LDCs have these factors as separate items in their PGA clauses.

As the implementation dates for restructured services on various pipelines have arisen, the affected LDCs have made filings proposing "definitional" changes to their PGA tariffs. These filings adapt the existing PGA mechanism for changes necessitated by Order 636 so that the LDCs are able to continue business as much as usual. Given the significant operational changes that are being made at the pipeline level, the short amount of time for LDCs to deal with these

[41] American National Can Co., et al. v. Laclede, 30 MoPSC N.S. 32, 36 (Oct., 1989).

changes, and the need to have a smooth "uneventful" transition right now, these filings have been reviewed by the Staff and other interested parties and processed by the Commission as quickly as possible.

Perceived Advantages of Maintaining The PGA Mechanism

- The current mechanism allows LDCs to manage significant swings in price without putting their financial standing in jeopardy. Consideration must be given to the possibility that a poor credit standing could impair the LDC's ability to buy reliable supplies.

- PGAs provide automatic passthrough of price decreases as well as price increases. This gives consumers the benefit of decreases in price in a timely manner as well as providing an early recovery for the LDC in the event of price increases.

- Under the current scheme, all refunds are automatically passed on to consumers.

- LDCs are encouraged, or at least not discouraged, to give adequate consideration to reliability of gas supplies. Currently, LDCs are entitled to recovery of all gas costs associated with obtaining reliable supplies at reasonable prices. LDCs do not have to sacrifice reliability in order to meet a target price or go for the lowest price.

- The schedule for Staff reviews is known to all parties. This allows for adequate planning of resources on the part of both LDC and Staff.

Perceived Disadvantages Of Maintaining The PGA Mechanism

- Upon implementation of Order 636, there is no longer a FERC regulated sales rate. FERC is regulating only pipeline transportation rates which appear to be in the range of 15-35% of the total cost. Under the current scheme, the PGA rates charged to customers are "subject to refund" until Staff completes its ACA review process. Accordingly, there is only a cursory review by the Commission prior to customers' rates being changed. It is questionable whether the Commission sufficiently meets its responsibility for establishing reasonable rates when it makes its determination in retrospect. This type of review arguably requires the MoPSC to engage in retroactive adjustments and billings.

- Arguments could be made that it is improper to allow PGA treatment because it represents single issue ratemaking, i.e., viewing purchased gas costs in isolation without considering variations which may be occurring in other components of an LDC's cost of service. The legal merits of this argument may be quite strong. However, as a practical matter, Missouri's major LDCs have routinely found it necessary to file rate cases over the past 5-10 years. This is despite the fact LDCs have had use of the PGA and inflation has been fairly low during this period. While the future is not bound to follow this pattern, the likelihood of an LDC staying away and keeping its other cost of service components from Commission purview for prolonged periods of time seems rather slim.

- Under the current PGA mechanisms, LDCs have limited incentives to contain costs because they are permitted to completely pass through the cost of gas. With LDCs now having more alternatives available to them for acquiring gas supplies, it will be important for the Commission to consider the use of incentive mechanisms to encourage LDCs to perform these responsibilities well.

- With the changes that are occurring in both the electric and natural gas industries, the differences between the fuel adjustment clause and the PGA clause will narrow. Therefore there will be increasing pressure on the Commission to afford consistent treatment in terms of risk and accountability applicable to gas and electric companies.

- Current ACA procedures have not effected timely closure of ACA cases. Past experience shows that ACA cases have been permitted to languish for extended periods of time. Although the statutory operation law date applicable to LDC rate increase filings does not apply to ACA cases, the Commission should implement revised procedures to effect a more timely resolution of contested issues in these dockets.

- There is concern that frequent changes in PGA rates cause public confusion.

- Although timely tracking of costs can be an advantage, price spikes can cause public concern.

Additional Issues

If some form of the PGA mechanism is retained, there are several additional issues which would need to be addressed. Some of these issues may have already arisen in the context of the Order 636 PGA tariff change filings. However, it may be necessary to revisit them in conjunction with these other issues in the context of each LDC's next ACA or rate case, whichever comes first. While it is unreasonable to expect identical tariffs and treatment of these items by all LDCs, it seems important for there to be consistency in the principles applied to the resolution of these issues.

<u>Cost Eligibility</u>

There needs to be a clear understanding of the types of costs which are eligible for pass through treatment. Obviously, gas commodity costs and demand-related gas costs, such as producer minimum bills and take-or-pay type costs would be included, as well as pipeline service costs. However storage costs can pose a dilemma. Should customers be charged gas costs when it is injected or withdrawn from storage? Should carrying costs on storage inventory be allowed to run through the PGA or should they be considered as part of working capital and therefore reflected in the LDC's margin instead? What kind of treatment should hedging costs, i.e., costs associated with NYMEX futures transactions, be given? Is it appropriate to afford PGA treatment for expenses associated with fuel procurement?

Generally, the Team believes the definition of purchased gas costs to be afforded PGA pass through treatment needs to be strictly applied. The concept of providing LDCs the opportunity to recover general costs of doing business becomes one of guaranteed recovery if LDCs are allowed to begin tracking various expenses.

Monitoring Costs and Collections

Although deferred accounts currently exist for accumulating the difference between costs and collections, during the past few years over-recovery of an LDC's actual gas cost account has become a common occurrence for most LDCs. This can be due to a variety of factors, including significant abnormal weather fluctuations, inflated estimates of costs by LDCs, and restrictive rate components tying PGA rates to historical pipeline costs.

Most PGA tariffs do not provide for the accumulation of interest on over or under collections. This may be appropriate when an LDC's PGA rate is based upon elements the LDC cannot freely change. If the LDC has very little or no control over the level of its over/under collections, the application of interest on overrecoveries would penalize the LDC for random weather fluctuations unless a tolerance is built in.

However, some current PGA clauses provide the LDC discretion to change its PGA rate regardless of whether or not its costs have changed. In these situations, it may be appropriate and effective to accrue interest on the ACA account balance. This would hopefully have the effect of minimizing an LDC's incentive to manipulate the timing of "booking" certain costs for the purpose of obtaining cash working capital.

Rate Design

As previously discussed in Section III. B, rate design issues need to be examined closely. Although a preliminary deliberation of rate design issues will have already transpired with each LDC's tariff filing implementing Order 636 definitional changes, cost allocation and rate design for purchased gas costs would need to be revisited and/or fine-tuned within each LDC's next ACA case or rate case, whichever comes first.

2. Eliminate PGA Mechanism And Establish/Review Gas Costs In The Context Of LDC's Rate Case Or Complaint Case

A likely alternative to the current PGA mechanism for review of purchased gas costs would be a review in the context of a general rate proceeding. Under traditional rate of return/rate base regulation, a utility's revenue requirement equals the total of: (a) prudent operation and maintenance expenses, including depreciation and taxes, and (b) allowed earnings on the utility's rate base. Currently, because rate recovery of LDCs' purchased gas costs are handled through the PGA/ACA process, gas cost revenues are set equal to the LDC's purchased gas costs in general rate proceedings, resulting in gas costs having no net impact on utilities' rate requests. Under the rate case/complaint case option, gas costs and LDC purchasing practices would be reviewed at the same time as other expenses, revenues and rate base. An annualized level of purchased gas expense would be built into the utility's cost of service calculation in rate cases, to allow LDCs the opportunity to recover their gas costs on a prospective basis. In rate cases, the Staff would propose a prospective level of rates based upon a rigorous examination of test year gas cost expenses incurred by utilities. If gas costs were to be examined in the rate case/complaint case format, a fundamental audit step would be to examine the prudence of the LDC's historical gas purchasing practices in the test year, with the Staff proposing to eliminate any imprudently incurred gas costs so that excessive levels are not reflected in the utility's ongoing cost of service.

Perceived Advantages of Rate Case Option

- Handling of gas costs in rate cases would lead to a proper matching of revenues, expenses and investment in setting rates. The perception of "single issue" and "retroactive" ratemaking in the current PGA/ACA process would be eliminated. Gas costs would not be reviewed in a vacuum, but would be examined in the framework of the LDC's overall revenue requirement, with all relevant factors considered.

- Movement of gas purchasing practice review into a rate case format would allow more efficient use of the Staff's time, requiring less time to be spent on administrative matters, such as processing monthly PGA changes, and allowing more time for substantive review of the gas costs.

  The actual field work portion of rate audits usually takes place in an approximate three to four month period. That period in and of itself would not be sufficient to allow for a thorough review of the prudence of an LDC's gas purchases and determination of a reasonable gas cost level for setting of prospective rates. However, it is the current intent that the auditors in the newly created Procurement Analysis Department will devote 100% of their time to this area. Presumably they would be able to perform considerable work outside of filed rate cases keeping track of utility gas purchasing developments and any potential concerns that may arise. This up-front knowledge would allow for a more efficient and concentrated review of utility purchasing practices when a rate case/complaint case is filed.

- In a rate case setting, it is clear the burden of proof belongs to the utility proposing the rates. Under the current PGA/ACA process, the Staff, as a practical matter, bears the burden of proof. The Staff bears the burden of coming forward and proposing any adjustments to the utility's actual gas costs based on its review in the ACA audit. Also, in the current PGA/ACA format, the LDC is able to present evidence in both direct and surrebuttal filings, while the Staff has only one opportunity in testimony to address the utility's purchasing practices. Based on these considerations, the rate case/complaint case format more clearly places the burden of proof on the appropriate party, i.e. the party requesting the change in rates.

- In a general rate proceeding, new rates will not go into effect until the rates have been established to be "just and reasonable" by the Commission. Normally, prior to adjudication by the Commission, the Staff has conducted a detailed audit and provided written testimony regarding all elements of the LDC's cost of service. Thus, in a rate case format, the portion of a rate comprising an LDC's gas costs levels will be reviewed in advance of being charged to the LDC's ratepayers. This is fundamentally different than what currently occurs under the PGA/ACA mechanism, wherein the LDC's purchased gas costs are not reviewed until after such rates have been charged to customers on an "interim subject to refund" basis.

- Since rates wouldnot be changed as often, there would be less consumer confusion.

Perceived Disadvantages of Rate Case Option

- The shifting of the LDC's recovery of gas costs to a rate or complaint case format may expose the LDC to the risk of a significant impact of regulatory lag on a large portion of its total operating costs. The rate case format, which can take up to 11 months to complete, could cause LDCs to incur large losses related to unrecovered gas costs, with potential harm to the financial integrity of the LDC. It is not clear to what extent provision for emergency rate proceedings would meaningfully address this potential problem for all the state's LDCs. Of course, it is equally true that the regulatory lag inherent in general rate proceedings may also allow LDCs to incur windfall profits for a significant period of time if their actual gas costs are significantly less than the gas cost levels on which their current rates are based.

- If the current PGA clause is eliminated, the Staff would have to rely upon its surveillance reports to detect over-earnings, and use the complaint procedures contained with the current Commission rules to pursue rate adjustments to correct over-earnings situations. At any point in time, resource and time constraints may prevent the Staff from initiating complaint procedures on a timely basis to prevent the LDCs from incurring excess profits related to gas costs.

- The Commission would have little control over its caseload and the scheduling of cases. Only those LDCs in an under-earning situation would be filing a rate case. Those LDCs in over-earning situations would not be filing any cases. If gas prices were rising significantly, it is conceivable that rate cases by all LDCs could be filed within several months of each other.

- The current PGA/ACA process provides the ratepayer with a timely reimbursement of any LDC over-recovery in interim rates for gas costs. However, the outcome of any complaint proceeding would be applied only on a "prospective" basis to the LDC. Unlike a rate case, complaint cases do not have the statutory 11-month timeframe within which a case must be resolved. If Staff or another party were to file an over-earnings complaint case, an LDC could prolong the proceeding in order to delay a decision requiring it to reduce its rates. If an LDC is in an over-earning situation, the ratepayer will never recover past dollars that have been over-earned in relation to purchased gas costs. It should be noted that, if this is in fact a valid criticism of treatment of gas costs in a rate case format, this criticism is also fully applicable to rate case treatment of all other elements of an LDC's cost of service determination.

- The burden of proof in a complaint case would be on the party filing the complaint, i.e., the Staff, Office of Public Counsel, or customer(s).

- If Staff did initiate complaint proceedings against an LDC because of over-earnings related to gas costs, the LDC would be able to assert that it is under recovering other elements of cost of service that would serve to offset any gas purchasing over-earnings. Under the current PGA/ACA process, utilities cannot propose offsets to any PGA over-recoveries that it may incur. (Consideration of all relevant factors is, of course, required in general rate proceedings. Whether this is a virtue or defect is dependent upon one's point of view at a particular time).

- If gas purchasing practices are handled in general rate proceedings, LDCs would presumably be inclined not to base its rate requests on actual gas costs, but to inflate them by various means in order to allegedly derive an appropriate prospective level of rates. Significant amounts of audit time may need to be devoted toward an examination of any adjustments LDCs may propose to their actual gas costs in the rate case format, and determining the appropriateness of such adjustments in light of past Commission policy, particularly use of the "known and measurable" standard.

- The current PGA/ACA mechanism transmits "price signals" regarding purchased gas costs to the consumer on a more timely basis than would occur under the rate case/complaint case format. However, it is not clear how significant this concern is, as many LDC customers choose to have their monthly gas bills "levelized", which would have the impact of dulling any price signal. In addition, those customers which are sensitive to pricing signals are presumably the customers already transporting LDC gas, and acquiring their own supply sources.

- Implementation problems could result with change from the current PGA/ACA mechanism to the handling of gas purchased costs in a rate case format. If such a transition is implemented abruptly, concurrent rate cases by all of Missouri's LDCs may be a possibility, causing resource and timing constraints on the Staff. This problem can be mitigated with the Commission implementing a "phased" transition period of several years to the rate case option. For example, two or three of the state's LDCs could be changed over to a rate case approach in a given year, with another two to three utilities changing over the next year, and so on.

- Refunds related to LDCs' gas purchases from pipelines or other entities would not be flowed through automatically to ratepayers under this approach as is currently provided with the current PGA/ACA mechanisms.

  Refunds related to pipeline rate reductions can be quite significant. An LDC could manipulate the timing of its rate case filing and influence the timing of refunds in order to avoid returning them to consumers. There are, however, techniques which can be used to effect simple fairness and equity in these situations. It is possible for pipeline refunds and gas supply cost adjustments to be handled in a rate case context. Refunds which occur within an LDC's rate case test period can be flowed through to customers all at once, or spread out (amortized) in rates over a long period of time. For refunds which occur outside the test period for LDC rate cases/earnings complaints, a normalization analysis (i.e., a three or five year average) could be utilized by the Staff and other parties to ensure that customers gain the benefit of such refunds on an ongoing basis. It should be made clear, however, that rate case methods for handling gas purchase refunds will not, in all likelihood, lead to as precise a flow back of refunds as currently accomplished in the PGA/ACA format.

Additional Issues

Several additional issues which would need to be addressed if the rate case approach is adopted by the Commission include, but are not necessarily limited to:

(a) possible use of forecasted gas prices in the rate case format, similar to what was done for electric utility fuel costs in the early 1980s;

(b) procedures for handling emergency rate proceedings which may be necessitated by future price volatility of gas costs; and

(c) the overall impact on LDC's cost of capital, if any, of a change from the current PGA/ACA mechanism to a rate case/complaint case approach.

3. Scheduled Cases To Establish/Review Base Gas Cost Rates

As with the other alternatives being discussed, there are numerous variations which could come from this approach. The fundamental aspect of this method is that some sort of "scheduled" filing and preliminary review process takes place for the purpose of establishing a reasonable estimate of gas costs before base gas cost recovery rates are implemented. As part of this preliminary review process and/or as part of an ongoing supply planning process, a significant piece of the required LDC filing would need to include the LDC's gas purchasing plan and underlying documents such as demand and customer studies; gas supply, transportation, and storage contracts; gas cost forecasts; and the LDC's identification and analyses of its various supply and service options. Also, some type of incentive mechanism could be coupled with this method so as to encourage LDCs to be accountable, i.e., take their supply and service planning seriously and to have them affect their acquisition decisions in a responsible manner.

These scheduled reviews could be mandatory rate case filings where all aspects of an LDC's revenue requirement are considered. Or these reviews could be limited to only gas supply costs, or something in between these two extremes. The established frequency of these reviews could be the same for all LDCs or could vary based on certain criteria, such as LDC size.

A true-up mechanism, i.e., a formal comparison of estimated costs to actual costs, could be used in conjunction with this approach, but would not have to be.

Perceived Advantages And Disadvantages Of Using Scheduled Cases To Establish Base Gas Cost Rates

- If no true-up were attached to this procedure, then the advantages and disadvantages accompanying the rate case method (identified above) would be similar here. One difference would be that rate risks, i.e., the problems associated with actual rates varying significantly from the base rate, could be mitigated to some extent by shortening the time interval between scheduled reviews. Also, the Commission could control the timing of these reviews and stagger these examinations rather than be confronted with the possibility of having many of the LDCs filing rate cases at the same time.

- If a true-up is used, the problems associated with rate risks would be greatly reduced. However, several of the concerns connected with the pass through of purchased gas costs also appear here. One, when LDCs are permitted complete pass through of gas purchase costs, there is limited incentive for the LDCs to contain costs. Two, the Staff seems to have the burden of proving an LDC was imprudent in its acquisition of supplies and services rather than the burden being on the LDC to prove that its purchases were prudent. Therefore, it may be particularly appropriate to combine this technique with some type of incentive(s).

- There likely would be a debate as to what extent the MoPSC's preliminary review of purchasing plans and costs represents "pre-approval" of transactions. Depending upon the Commission's desire, its "approval" could range from one of merely collecting information, to making certain all the blanks are filled in and everything adds up, to providing timely feedback regarding the LDC's evaluation of risks and identification of alternatives, to actually approving the plan and establishing a rate which comes from the plan. The rate setting process could be dependent or independent of the purchase planning review process as the Commission deemed appropriate.

- If the Commission were to adopt this type of mechanism, consideration would need to be given to its structure in order to affirm the Commission's authority to establish such a process and to take care of any single issue ratemaking concerns that may appear.

- There would also need to be thought given as to how to make the transition from current practices to this method. The phase-in could be handled in a manner similar to what was done in the electric IRP rule or the gas and electric USOA filing rule.

Following is a description of a system used by the State of Michigan which has a blend of some of the techniques described above. In 1982, Michigan's PGA mechanism was abolished by voter referendum and state legislation. Michigan's Gas Cost Recovery Act of 1982 (the relevant Michigan statute is provided as **Attachment 5**) established a 2-phase process for those LDCs wishing to have a separate gas cost recovery clause.

Phase I requires each LDC to file a gas cost recovery plan and a 5-year forecast 3 months prior to the beginning of a new supply year. The gas cost recovery plan contains computations of and support for specific gas cost recovery factors for each month and includes a copy of <u>all</u> supplier contracts. The 5-year forecast includes current and contemplated contracts as well as identification of any contracts or items within a contract that may be subject to renegotiation in the next 5 years.

The Michigan PSC conducts a proceeding for the purpose of evaluating the reasonableness and prudence of the plan, and establishing the monthly gas cost recovery factors. This is a process where a hearing transpires and a commission order is issued before the new year begins or early in the new year. In its final order, the Michigan PSC evaluates the reasonableness and prudence of the decisions underlying the gas cost recovery plan filed and approves, disapproves, or amends the proposed 12 monthly gas cost recovery factors accordingly.[42] The Michigan PSC may also indicate any cost items in the 5-year forecast which on the basis of present evidence, the Commission would be unlikely to permit the LDC to recover in its rates in the future. LDCs are also required to submit periodic reports comparing actual purchases to planned purchases.

Phase II is the review and reconciliation process. Not less than once a year, and not later than 3 months after the end of the 12-month period covered by the LDC's gas cost recovery plan, the Michigan Commission commences a proceeding, to be known as a gas cost reconciliation case. During the year, LDCs are required to supply monthly reconciliations comparing actual costs to revenues collected. When the LDC underrecovers, it receives interest at the short-term interest

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[42] The gas cost recovery factors may be revised at midyear.

rate. When it overrecovers, it must pay customer interest at its last approved ROE rate. In addition, if the LDC deviates from its plan, it must explain why. If the deviation is found to be detrimental to customers and not justified, an adjustment is made to the LDC's revenue recovery.

4. Incentive Mechanisms - Cost/Benefit Sharing

An incentive mechanism sets a target level of purchased gas cost that when exceeded results in a loss to the LDC and when bettered results in a gain to the LDC. The purpose of such a mechanism is to provide the LDC with an incentive to minimize its gas purchasing costs subject to providing reliable service to its customers. In part, the incentive mechanism is meant to be a substitute for regulatory review of the prudence of LDC implementation of its gas purchasing plan. In order to provide reasonable rates to customers and a reasonable likelihood for shareholders to earn a fair rate of return, limits or sharing mechanisms need to be placed on losses and profits.

Any incentive/sharing mechanism must be specifically designed to mesh with the ratemaking approach being used for purchased gas costs. What follows are fairly specific examples of such mechanisms for each of the three ratemaking approaches: PGA; Rate/Complaint Case; and Scheduled Cases. These examples are illustrations meant to convey the nature of incentive/ sharing mechanisms and as such should not be viewed as proposals by the Team. Moreover, a definitive proposal would require more detail than has been included in these illustrations.

Incentive Mechanisms with the PGA Approach

As presently designed, the PGA reflects a best guess at what gas purchase costs will be during the future period in which it is in effect. To interface the PGA/ACA procedure with an incentive mechanism, the established PGA rate would reflect the target level for purchased gas costs and the ACA mechanism would be used to calculate the cost/benefit sharing when actual gas purchasing costs are measured relative to actual revenues recovered in the PGA.

In order to prevent large losses or profits from occurring, adjustments to the PGA rates could be made on either a regular or triggered basis. Regular adjustments could be made to the PGA by using certain market based indices (e.g., the spot market or futures price of natural gas) which are reflective of average costs or reflective of the LDC's contracts with suppliers. Triggered adjustments could be made for recognizable events such as a change in the FERC tariffed rates for pipeline services. Alternatively, an ongoing tracking system could be designed to measure the month-to-month differences between revenues collected via the PGA rates and the costs incurred by the LDC. The trigger for changing the PGA rate would be limits set on the cumulative levels of profits and losses.

The ACA mechanism would become the means by which a prescribed level of sharing would be applied to the profits or losses incurred over the ACA period. The result would be a refund or surcharge to customers over the next ACA period. It appears that such a practice could be interpreted as retroactive ratemaking unless either the surcharge (loss sharing) mechanism is not used or specific legislation is obtained providing for a surcharge.

An alternative view of the ACA adjustment for cost/benefit sharing would be to maintain some percent of the cumulative profits or losses for the purpose of prospectively setting the PGA level. Suppose for example the trigger for the PGA is two million dollars in profits or losses. This would mean that on a cumulative basis, if either of these limits is reached, the PGA rate would be changed by a prescribed formula. At the time of the ACA adjustment, the cumulative profits or losses would be reduced by one half (50-50 sharing), thereby delaying the future point in time at which the PGA rate would change. At the same time, half of the normally prescribed formula change could be applied to the existing PGA rate.

Incentive Mechanisms with the Rate/Complaint Case Approach

In the rate/complaint case approach, the rate for purchased gas costs is set prospectively based on known and measurable changes. Assuming all other costs are as allowed in the setting of rates, if the rate for purchased gas is too high, the LDC will earn an above normal profit, or if the rate is set too low the LDC will earn a below normal profit. The first instance would trigger a complaint case; the second would trigger a rate case. With the time required to put these cases together and to go through the judicial process (regulatory lag), there may be a substantial accumulation of profits or losses. In essence, this regulatory lag in and of itself provides an incentive for the LDC to minimize its costs.

To prevent significant profits or losses, the FERC approach could be taken which allows rates to go into effect at the time of filing subject to refund. Moreover, this interim rate approach would work much like the trigger mechanism on the PGA, and the ensuing rate/complaint case would work much like the ACA. The primary difference would be that all of the LDC's costs would be subject to audit, not just its purchased gas costs, and more importantly, there would be no tracking mechanism for cumulative profits and losses.

Incentive Mechanisms with Scheduled Rate Cases

As with the rate/complaint case, an emergency interim rate approach could be used to limit extreme profits and losses between scheduled rate cases. What is unclear in this approach is what, if any, incentive mechanism exists. Very much like the PGA approach, the scheduled rate case approach would have to be modified in order to give LDCs an incentive to minimize costs. It appears that any sort of incentive approach would require some type of tracking mechanism for cumulative profits and losses. While such tracking mechanisms are feasible when dealing with specific items of costs and revenues (e.g., actual purchased gas costs measured against actual PGA revenues), the inclusion of all costs and revenues in a tracking mechanism would be unwieldy at best.

A possible alternative is analogous to the forecasted fuel price method which was used by the Commission during the early 1980's. In the rate case, rates were set based on a forecast of the prices of various fuels and a fixed fuel mix. These prices were subject to audit six months after they went into effect. If the actual prices in effect at that point resulted in a lower than forecasted fuel cost, then rates were lowered to reflect these lower costs and customers were refunded the difference in rates times their actual usage over the six month period. If fuel costs were above their forecasted costs, then rates were left unchanged. The electric utilities certainly had an incentive to keep down their fuel costs, but there were no profit incentives in this mechanism.

A profit sharing mechanism could have been added by allowing the electric utilities to keep half of the profits, but this had little meaning with a fixed fuel mix and where the only item being considered was the fuel price which was beyond the utility's control.

For the LDC, the case is somewhat different than for the electric utility. The question is the extent to which the LDC does have control over the price. Presumably, rates would in part be based on forecasts of the average spot market price six months into the future. Such a forecast would involve an average spot market price recorded at a specific location. At the time of the true-up audit, that average spot market price could be above or below the forecasted level. In addition, the LDC will have made actual purchases on the spot market at prices that could be above or below the average price. A modification could be made to allow the LDC to keep a portion of its profits from gas purchases made below the average spot market price.

Perceived Advantages Of Incentive Mechanisms

- Traditional regulation is designed to ultimately pass on to the customer all the benefits accruing from increased efficiencies brought about by the utility, as well as pass on to customers the impact of all increased costs (if prudently incurred). By contrast incentive mechanisms are intended to lead to the sharing of risks and rewards between the LDC and its customers.

- Incentive mechanisms will provide strong positive (sharing of rewards) and negative (sharing of detriments) incentives for LDCs to aggressively take measures to minimize their purchased gas costs. The explicit incentive mechanisms presumably will have a stronger impact on the utility's behavior as compared to whatever incentives exist under traditional rate base regulation or the PGA/ACA process as it now exists.

Perceived Disadvantages Of Incentive Mechanisms

- Rewards for cutting gas costs may encourage LDCs to inordinately reduce supply reliability to maximize potential sharing gains. Therefore, strict reliability standards for LDCs would have to be developed and enforced if explicit incentive mechanisms are to be seriously considered.

- Incentive regulation is theoretically designed to encourage utilities to maximize their rewards by providing more efficient service to customers. However, almost certainly there will be events impacting the cost of gas paid by utilities which are more or less out of their direct control. Incentive regulation under these circumstances might give utilities unwarranted windfalls or detriments. To attempt to differentiate between events under and outside a utility's control in the context of an incentive regulation scheme would be very difficult.

- The incentive mechanisms themselves and the follow-up comparisons can be quite complicated to develop and maintain. Agreement between the LDC, the Staff/Commission and other parties may be very difficult to attain in any effort to reach an incentive format that is acceptable to all parties.

C. Project Team Recommendations Concerning Gas Cost Recovery Method

1. Retain The PGA/ACA Recovery Mechanism For The Short Term

The Team recommends the PGA/ACA recovery mechanism be retained for the 1994-95 heating season. This recommendation is based on the belief that gas prices will remain volatile in the near term and the fact that gas costs are a large component of an LDC's operating costs. This will also allow for a smooth transition to the Order 636 environment and will enable all parties to gain experience with this new environment. The effectiveness of the PGA/ACA mechanism should then be re-evaluated to determine whether its continued use is appropriate.

As was pointed out in Chapter IV.B.1., we have significant concerns with the current PGA/ACA procedure. Therefore, the Team believes the Commission and LDCs need to make a cooperative effort in the near term to improve the present system. The progress that is made in regard to the Commission's review of LDC gas purchasing practices and improving ACA procedures will certainly be significant considerations when the viability of the PGA is revisited. This includes making provisions for LDCs to develop longer term purchasing strategies and shorter term purchasing plans and for these items and supporting documentation to be submitted to the Commission. As is discussed later in this report, the Team believes the supply-side aspect of gas IRP planning may be the best method for developing and reviewing purchasing strategies and plans. Therefore it seems the status of the gas IRP rule may also be a consideration. In addition, the extent to which LDCs have developed and proposed good, viable incentive mechanisms could also have a bearing on whether or not the PGA mechanism should be retained.

One of the major concerns is the argument that PGA treatment constitutes single issue and retroactive ratemaking. Clearly, the Commission may view the PGA mechanism as lawful until a court rules to the contrary. Practically speaking, should an interested party with standing decide to challenge the use of the PGA clause, the judicial process would provide an absolute determination only after several years of litigation, at best. Undoubtedly the Commission will continually evaluate the litigation risks associated with this. If the Commission finds there is a serious problem with the legality of the PGA because of the single issue ratemaking aspects of the mechanism, it seems the Commission would have basically three alternatives to choose from: 1) obtain a statutory change which would allow the current mechanism to continue, 2) retain the PGA/ACA mechanism along with a requirement for LDCs to submit periodic cost of service studies for Commission review (scheduled rate cases), or 3) eliminate the PGA and leave gas cost recovery issues to be handled through rate cases and/or complaint cases. However, for the reasons cited above in the first paragraph, it seems appropriate to retain the PGA/ACA during the near term.

THE PROJECT TEAM RECOMMENDS:

23. *The current PGA/ACA recovery mechanism be retained for the 1994-95 heating season.*

24. *The Commission initiate a process whereby the appropriateness of the PGA/ACA mechanism is reassessed. The process used could either be in the form of another project team made up of various Staff members or a task force which would include representation from interested sectors*

of the industry. This process should begin in the 1st quarter of 1995 with recommendations to be presented to the Commission by the Fall of 1995.

2. Commission Review Of LDC Gas Purchasing Practices

The second significant concern which needs to be addressed lies in the increasing difficulty for the Commission to fulfill its responsibility for determining the just and reasonableness of a PGA rate prior to the rate being charged.

It is clear that none of the prices for natural gas purchased by the LDCs will be subject to prior FERC review. In part, this has been the case for the past several years as Missouri LDCs have been involved in procuring their own gas supplies and pipeline transportation for a portion of their system supply. However, subsequent to Order 636, the LDCs no longer have any FERC regulated pipeline sales gas available to them. LDCs now have to actively seek not only spot market purchases, but also a mix of various long-term gas contracts, and may even choose to become involved in the futures and options market. The pipelines do not have a FERC approved tariff for sales gas which in the past provided a base level for the PGA and some measure of the reasonableness of gas costs.

Without the FERC approved tariff, ideally the Commission should find a way to fulfill its statutory mandate to ascertain whether or not rates are just and reasonable prior to permitting recovery of purchased gas costs. To accomplish this in theory, an LDC's gas purchasing practices[43] need to be reviewed by the Commission to provide assurance that those practices appear reasonable before it allows recovery of purchased gas costs by the LDC.

In reality, however, the Commission Staff continues to struggle to obtain from the LDCs the information the Staff believes necessary to evaluate LDC gas purchasing practices in the current "after-the-fact" review process. Generally, the urgency with which most LDCs address rate case data requests is lacking in the current ACA process. Unlike rate cases where LDCs must prove that their proposed rates are reasonable and those rates are suspended until a final Commission decision on their reasonableness is made; in the ACA process, LDCs receive recovery of gas costs up-front and retain those revenues unless the Staff or an intervenor puts forth sufficient evidence to prove that an adjustment to those gas cost recoveries is warranted. Thus it is not surprising that in a number of ACA proceedings, adequate documentation of gas purchasing decisions has not been maintained or that LDCs attempt to limit discovery to very narrow time periods.

As a practical matter, the Team believes the Commission's access to LDCs' gas purchasing strategies and plans in order to evaluate initial PGA rates will best be achieved through implementing gas IRP rules. However, during this interim period, i.e. until a gas IRP rule goes into effect, the most pragmatic response to these problems is for the Commission to direct LDCs to provide their gas purchasing strategies and plans, including load forecasts and gas supply and pipeline service contracts, when they file their new ACA rate in their GR-94 dockets. This

[43] Gas purchasing practices as used here includes both the LDC's longer-term gas purchasing strategy which may be planning 3-5 years in the future and its near-term gas purchasing plans (for a one year period of time) supported by gas supply and pipeline service contracts.

information should help provide more complete[44] and timely ACA reviews and also provide a smoother transition to implementing a gas IRP rule. It would serve to "jump start" the Commission's need to place a greater emphasis upon LDC planning functions, the evaluation of alternatives and potential results, and the continual reassessment of the environment that affects their decisions. It will convey the message that the Commission expects such processes to be performed by LDCs.

The Team wishes to point out that if the Commission desires a meaningful review of LDC supply plans in order to evaluate initial PGA rates, and make adjustments to those initial rates based on this review, existing PGA tariffs will likely need to be revised. Also additional staffing resources or changes in emphasis will be required since the current process is structured to make after-the-fact reviews. It is anticipated that such a shift in emphasis may actually evolve as the gas IRP process matures.

As noted previously, the Team recognizes that the Commission and Staff are currently not in position to do comprehensive upfront reviews of gas purchasing strategies and plans. However, for informational purposes, and in case the Commission and Staff are able to move at a quicker pace than anticipated, an explanation of the scope for such upfront comprehensive reviews follows. These descriptions are not intended to be all encompassing and therefore should not in any way limit the scope of any such reviews which may be performed in the future.

Gas Purchasing Strategy

Each LDC's gas purchasing strategy should be reviewed by the Commission for determination of whether or not there is a proper balance between minimizing short run cost and long run risk to the ratepayer. The review of the gas purchasing strategy should include an analysis of the factors which the LDC considers important in its decision-making process in regard to possible natural gas contracts, including the reliability of supply at a stable price, as well as any other reasons which support the mix of spot market, short-term and long-term contract gas. The analysis should also consider the use of hedging tools to mitigate price risk.

A significant component of the gas purchasing strategy should be a formal load forecast of peak day and annual requirements anticipated for the next 3-5 years. The Commission should be interested in the reasonableness of the underlying assumptions used in the preparation of the load study.

Gas Purchasing Plan

The LDC's near-term gas purchasing plan should also be subject to the review of the Commission. The review of this short-term gas purchasing plan should include an analysis of how the LDC sought out suppliers to bid on contract gas, a summary of the results of the negotiation process and an explanation as to why certain contracts were accepted and others were rejected. An

[44] Poorly documented plans, unjustified inconsistencies between the purchasing plan and the LDC's initial ACA filing, and questionable affiliate contracts with a material effect on gas costs are examples of items that would be addressed in the subsequent ACA reviews.

important part of the review would involve any affiliate transactions, with explicit comparisons to be provided in the form of market place documentation contrasting the cost and terms of purchases of gas from affiliated and non-affiliated entities. In addition, the review should include an analysis of gas supply flexibility with an indication of at what price and in what quantities the LDC would expect to substitute spot market gas for contract gas and use price hedging tools.

LDC Pipeline Services

With the advent of Order 636, LDCs have to contract for a mix of pipeline services. These services include contract demands for transmission services, as well as storage capacity, demand, injection and withdrawal services. These services interact with the LDC's mix of gas purchases and will, therefore, be a major element in the overall strategy for providing reliable gas supply to the burner tip at a reasonable price to the ratepayer. While the prices of these unbundled services are set by FERC, the LDC must choose the mix of services. Therefore, the Commission should be satisfied with the LDC's rationale for its mix of various pipeline services and that there is a proper balance between minimizing short-run cost and long-run risk to the ratepayer. Additionally, the relationship of these services to gas purchases must be clearly understood. This means the review must also include an analysis of how the LDC plans to operate (dispatch) its system.

THE PROJECT TEAM RECOMMENDS:

25. *The Staff file a motion two months before each LDC's GR-94 ACA filing is due, requesting the Commission a) open a GR-95 docket for that LDC, and b) direct the LDC to provide, at the time of filing its new ACA rates, certain information relative to its gas purchasing strategies and plans, including load forecasts and gas supply and pipeline service contracts for both the GR-94 and GR-95 periods.*

    In the case where an LDC has already filed its GR-94 ACA (Union Electric and St. Joseph Light & Power) the LDC should be directed to provide the foregoing information 30 days after such motion is filed. (In regards to Union Electric's GR-94-353 docket, where a GR-94 case number has been used for the 1994-95 period, the Team is treating this docket as being analogous to a GR-95 docket for purposes of this recommendation.)

26. *The Staff perform an annual audit comparing all aspects of an LDC's actual gas supply and pipeline services to its purchasing plan and indicate its findings to the Commission as part of its overall ACA recommendation.*

27. *The Commission require LDCs, via the IRP process, to file a current gas procurement strategy with the Commission at least every three years and an updated gas supply plan annually. If at a subsequent time there is a significant change in either the LDC's long-term strategy or short-term plan, the LDC should be required to amend its most recent filing with the Commission. Ultimately, each LDC's gas purchasing practices should be reviewed by the Commission to provide assurance that those practices appear reasonable before it allows final recovery of purchased gas costs by the LDC.*

3. Change ACA Procedures

Timely Resolution

Generally, Staff is expected to file its Recommendation Memorandum summarizing the results of its audit within six to nine months of the LDC's ACA filing. Extensions for the ACA memorandums have been sought routinely. Customarily, once Staff's Recommendation Memorandum is filed, the LDC then has 10 days to answer the findings contained in Staff's memorandum. Parties are then expected to either resolve contested issues and seek to have the docket closed or to propose a procedural schedule for a hearing. Unfortunately, as many as four ACA cases/periods have accumulated for an LDC at one time before the process is completed. Recently the Commission established a separate department, the Procurement Analysis Department, for the purpose of performing ACA audits. While there may still arise some unusual circumstances which would justify extension of the ACA memorandum filing deadlines, with Staff dedicated expressly for this purpose, the timeliness of the ACA memorandums should generally improve.

However, to further elicit timely closure of these cases, the Team makes the following suggestions. The Commission should issue an initial order which (1) recognizes the LDC's ACA filing, (2) establishes a nine month filing deadline for the Staff's Recommendation Memorandum, and (3) requires the LDC to answer the audit's findings within 30 days of the filing of Staff's Memorandum. Then 15 days after receiving the LDC's response (or 45 days after Staff's recommendation is filed if no LDC response is received), the Commission should issue a second order either dismissing the case or establishing an early prehearing conference within 20-25 days of the second order. Parties attending the prehearing conference should then be required to submit to the Commission within 7 days a Hearing Memorandum identifying the contested issues and a recommended procedural schedule for these issues. The Team believes all parties involved would strive to meet these guidelines, especially if the Commission has expressed its expectations ahead of time.

Refund Account

Most of the FERC-tariffed pipeline rates billed to LDCs and paid by LDC customers through the PGA/ACA are not final rates, rather they are subject to the ultimate outcome of a rate proceeding at FERC. When a settlement is reached or a final decision is issued by FERC, any refunds received by the LDC, which can amount to millions and millions of dollars, are placed in its Refund Account. This Refund Account is separate from the ACA Account. Although the balances in both these accounts affect the ultimate rate to be paid by LDC customers, not all LDC tariffs provide for the Refund Account activity to be reconciled at the same time the ACA Account is closed out. LDC tariffs as well as ACA audit procedures should be revised to allow for the Refund and ACA Accounts to be reconciled simultaneously.

Capacity Release Revenues

With the establishment of pipeline capacity release programs, LDCs will have the opportunity to offer to resell, either permanently or temporarily, any of their unneeded pipeline (transmission or storage) capacity to other customers. Since the costs related to pipeline capacity currently pass through the PGA, the ACA review will need to include an analysis of capacity release revenues to ascertain whether the LDC has taken appropriate advantage of these opportunities and whether these revenues have been properly flowed through to LDC customers.

THE PROJECT TEAM RECOMMENDS:

28. *The Commission establish procedures to bring about a more timely resolution of contested issues in ACA dockets.*

29. *LDC tariffs and ACA audit procedures be revised to allow for the Refund and ACA Accounts to be reconciled simultaneously.*

30. *ACA audit procedures include an analysis of capacity release revenues to determine whether LDCs have taken appropriate advantage of capacity release opportunities and whether these revenues have been properly flowed through to LDC customers.*

4. Encourage The Development Of Incentive Mechanisms

LDCs should be encouraged to propose modifications to existing PGA tariff provisions which provide them with incentives to <u>properly balance</u> the economic and reliability considerations when acquiring gas supplies and pipeline services. With the PGA mechanisms currently in effect providing for complete pass through of gas costs, LDCs are able to concentrate on or are at least not discouraged from seeking reliable supplies. However, the current PGA mechanisms may cause LDCs to be complacent or not be motivated to aggressively minimize purchased gas costs while providing reliable gas service. It is for this reason the Team would like for the Commission to give due consideration to any incentive proposals offered by LDCs that relate to purchased gas costs and collections in the context of their current PGA docket or by separate PGA tariff change filings. Staff and interested parties should then have the opportunity to address those proposals or to present alternative proposals.[45] Ideally, the Team would like to see this process begin so that the Commission would have time to hold hearings to consider whether any such proposals can be tested during the 94-95 ACA period.

Also, even if an LDC is not in a position to put forth an incentive proposal shortly, Staff should consider suggesting tariff changes to apply and refund interest on overcollections in those instances where the LDC has some discretion to change its PGA rate regardless of whether or not its costs have changed. This would hopefully have the effect of minimizing an LDC's incentive to manipulate the timing of "booking" certain costs for the purpose of obtaining cash working capital.

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[45] Generally, the goal of performance-based ratemaking (use of incentives) is to improve the current regulatory approach so as to provide lower gas costs to ratepayers. To achieve this goal, incentive mechanisms should be developed so as to reduce regulatory burden and complexity.

THE PROJECT TEAM RECOMMENDS:

31. *The Commission encourage LDCs to develop incentive mechanisms that relate to purchased gas costs and collections and to offer such proposals in the context of their current PGA dockets or by separate PGA tariff change filings.*

32. *In instances where an LDC's tariffs are structured in a manner allowing the LDC flexibility in the PGA rate it can bill, Staff propose tariff modifications providing for interest to be applied and refunded to customers on purchased gas cost overcollections.*

5. Rulemaking For Natural Gas Resource Planning

On December 7, 1993, the Commission issued an Order Establishing A Docket And Setting An Early Prehearing Conference in Case No. GO-94-171[46]. This docket was created to consider whether it is appropriate to establish integrated resource planning (IRP) regulation for LDCs under Section 115 of the Federal Energy Policy Act of 1992 (EPACT).[47] On March 4, 1994 the Commission approved a stipulation and agreement in Case No. GO-94-171 whereby parties agreed that the Commission has attained compliance with Section 115 of the EPACT and Section 303 of PURPA by having (1) considered before October 24, 1994, the two new natural gas standards established by Section 115 of EPACT, and (2) determined before October 24, 1994, that it will implement IRP for gas utilities through a future rulemaking. The stipulation and agreement also stated that the "breadth of the coverage" of the Commission's anticipated gas IRP rules has not been determined. Although the Team recognizes that extensive discussions and investigation into gas IRP are just beginning, it wishes to make several general observations and comments on this topic.

By definition, IRP involves both supply and demand side management issues. For gas IRP, the supply side would involve examining natural gas supply, transportation and storage issues while the demand side would focus upon evaluating such things as energy conservation and load shifting alternatives. Even though the Commission and participants will rightfully be looking to the Commission's recent experience in establishing electric IRP rules for guidance here, there are several distinct differences between the gas and electric industries which should cause gas IRP to not mirror the results of electric IRP. First, the planning horizon for LDCs will be significantly shorter than for electric companies. This is because the lead time required for planning, constructing and completing electric generation facilities can be as long as 10-20 years, where time frames for LDC construction projects are generally in the range of 1-5 years. Second, there will be greater emphasis on the supply side aspect of gas IRP since the major portion of the costs paid by an LDC's customers is driven by gas supply costs, whereas significant weight falls on the demand side of electric IRP because of the capital intensive nature of the electric industry and the large impact of that on consumers' electric rates.

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[46] Case No. GO-94-171 <u>Investigation of Section 115 Standards of the Energy Policy Act of 1992</u>

[47] 15 USC §3203(b)(3)(4)

As noted previously in this report, the Team believes it is extremely important for LDCs to develop, document, and provide to the Commission for review their gas supply strategy and purchasing plans and is hoping to get this started procedurally through the individual PGA dockets. In fact, load forecasting and gas supply information obtained in the context of the individual PGA dockets would help Staff understand supply side issues and formulate its position and approach to gas IRP. Since the biggest part of gas IRP relates to evaluating supply alternatives, ultimately it may be most efficient and effective for the Commission to link or coordinate the IRP process with its responsibilities for evaluating gas costs. For this reason, even if the Commission were to determine that there is very little value to demand side planning for gas, a formal IRP process emphasizing the gas supply side of the equation may still be beneficial.

The Team does not believe it is feasible to have IRP rules completed and in effect soon enough to have the LDCs make their IRP filings before the 94-95 heating season and, therefore, the issues raised by LDC gas procurement should not be deferred to the IRP rulemaking.

THE PROJECT TEAM RECOMMENDS:

33. *The Commission allow investigations into recovery of gas purchase costs and gas IRP to proceed on separate tracks at this point in time. To combine them right now may unnecessarily slow down either process by allowing one to become captive to the other.*

V.
METHODS AND SUMMARY OF INFORMATION GATHERING EFFORTS

The Project Team conducted a survey in April, 1993 of state regulatory commissions regarding their gas cost recovery practices and received responses from 44 states. A summary of the survey responses accompanies this document as **Attachment 6**. Following are some general observations made from the survey results.

All but two states[48] presently utilize some type of purchased gas cost mechanisms allowing LDCs to pass through purchased gas costs with a reconciling of actual gas costs incurred to revenue recoveries of these costs from their customers. However, as shown in the summary in **Attachment 6**, these mechanisms take different forms and require a broad range of reviews.

Michigan and Vermont are the two states which do not utilize an automatic adjustment or pass through mechanism. In Michigan, the Commission utilizes contested case gas cost recovery proceedings in which LDCs submit a supply plan for the upcoming year and conduct an after-the-fact reconciliation. Michigan's PGA was abolished in 1982 by referendum approved by voters and by legislation enacted by the state legislature. Vermont abolished its PGA in 1985. It is utilizing a 2-year phase-in formula, that includes the exchange rate for money, for its gas costs from its only supplier, a Canadian company.

The other pass through mechanisms take a number of different forms. Eight states responded that they also use rate cases for gas cost recovery. Massachusetts, for example, embeds gas costs in base rates, at the time of a rate case and then adjusts these costs through a Cost of Gas Adjustment (CGA) factor every six months.

Seventeen of the respondents indicated that FERC's Order 636 had already prompted a reexamination of their practices. An additional five states indicated that this examination would probably be conducted in the near future. Several of the states such as New Jersey, West Virginia and Wisconsin have already received formal comments from their utilities, producer representatives, industrial customers and marketers as to the potential effects of Order 636.

The frequency of these adjustments vary tremendously with some states utilizing a different frequency for adjustments based on the size of the LDCs. The majority of the states utilize an annual adjustment (fourteen states) or semiannual adjustment (twelve states). Others tie these adjustments to a trigger mechanism or specified level.

The majority of the states cited rules and regulations as their authority for the PGA as well as basic statutory authority. Twenty-two states have very company-specific clauses.

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[48] California requires a truing up of actual costs for purchases of supply for core customers and for non-core customers who have agreed to a 1-year purchase commitment with the LDCs. There is no PGA process for the LDCs' 30-day spot market portfolio selected by non-core customers.

Thirteen of the respondents reported that they believed that commission staffs have been very effective in dealing with prudence issues. A similar number stated that at this time, prudence has not been an issue in gas cost recovery mechanisms.

The Staff responsibility for monitoring of gas costs and recovery has primarily been placed under the Energy Division (twelve instances) or the Accounting Division (ten instances). Most of the states utilize a multi-disciplinary team approach of accounting and engineering/rates expertise.

All but six of the respondents handle PGA work activities as a part-time function of these employees. The states that do utilize devoted Staff positions for gas cost recovery have from one to nine employees involved.

The Project Team held a workshop with the LDCs on June 23 and 24, 1993, to discuss the purchased gas adjustment clause in light of restructuring under Order 636. The LDCs were allowed the opportunity to send formal comments to the Project Team. Formal comments were received from seven of the participating LDCs. These comments generally focused on their concerns over issues such as:

- the volatility of prices
- changes in the time frames of contracts
- an increased focus on reliability

The Project Team has included several charts provided by Laclede Gas Company in its comments to illustrate the volatility of recent prices. These are included as **Attachment 4**.

On June 8, 1994 a draft of the Project Team's report was mailed to interested parties. Those parties were invited to participate in a second workshop held June 27, 1994, where they were given an opportunity to present their views on the contents of the draft report and also encouraged to submit written comments to the Team. (See **Attachment** 7 - Listing of June 27, 1994 Workshop Participants.) The Team reviewed these comments and made the changes it deemed necessary before issuing its final report.

The Project Team sincerely appreciates the time, effort, and information others have provided to help it complete this project.

BIBLIOGRAPHY/REFERENCES

1. Natural Gas Contracts, 1992 Thompson Publishing Group.

2. Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure, December 1991, The National Regulatory Research Institute.

3. "Federal Natural Gas Policy and the Energy Policy Act of 1992", Energy Law Journal, Volume 14, No. 1, 1993.

4. Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets, November 1991, The National Regulatory Research Institute.

ATTACHMENT 1

ANALYSIS OF A RESIDENTIAL CUSTOMER'S ANNUAL NATURAL GAS COSTS

Annual costs and related percentages for a residential customer using 120 Mcf per year based on current rates and the following pipeline rate structures:

Gas Service (Williams)

Before Open Access

Type of Cost	TOTAL COST				
	Federally Regulated	Unreg.	Mo PSC Regulated	$ Total	% Total
Demand 1/				$0.00	0.00%
Gas Costs 2/	$229.58			$229.58	39.45%
Transportation Costs				$0.00	0.00%
Pipeline Margin 1/	$158.82			$158.82	27.29%
Storage Costs 1/				$0.00	0.00%
LDC Margin & Loss			$193.57	$193.57	33.26%
Total	$388.40		$193.57	$581.97	100.00%
Percent of Total	**66.74%**	**0.00%**	**33.26%**	100.00%	

After Order 636

Type of Cost	TOTAL COST				
	Federally Regulated	Unreg.	Mo PSC Regulated	$ Total	% Total
Demand 1/				$0.00	0.00%
Gas Costs 2/		$229.58		$229.58	39.45%
Transportation Costs				$0.00	0.00%
Pipeline Margin 1/	$158.82			$158.82	27.29%
Storage Costs 1/				$0.00	0.00%
LDC Margin & Loss			$193.57	$193.57	33.26%
Total	$158.82	$229.58	$193.57	$581.97	100.00%
Percent of Total	**27.29%**	**39.45%**	**33.26%**	100.00%	

Laclede (Miss. River)

Before Open Access

Type of Cost	TOTAL COST				
	Federally Regulated	Unreg.	Mo PSC Regulated	$ Total	% Total
Demand 3/	$59.82			$59.82	9.86%
Gas Costs 4/	$250.80			$250.80	41.35%
Transportation Costs	$11.63			$11.63	1.92%
Pipeline Margin 3/	$18.74			$18.74	3.09%
Storage Costs 3/				$0.00	0.00%
LDC Margin & Loss			$265.54	$265.54	43.78%
Total	$340.99		$265.54	$606.53	100.00%
Percent of Total	**56.22%**	**0.00%**	**43.78%**	100.00%	

After Order 636

Type of Cost	TOTAL COST				
	Federally Regulated	Unreg.	Mo PSC Regulated	$ Total	% Total
Demand 3/	$59.82			$59.82	9.86%
Gas Costs 4/		$250.80		$250.80	41.35%
Transportation Costs	$11.63			$11.63	1.92%
Pipeline Margin 3/	$18.74			$18.74	3.09%
Storage Costs 3/				$0.00	0.00%
LDC Margin & Loss			$265.54	$265.54	43.78%
Total	$90.19	$250.80	$265.54	$606.53	100.00%
Percent of Total	**14.87%**	**41.35%**	**43.78%**	100.00%	

UE (Panhandle)

Before Open Access

Type of Cost	TOTAL COST				
	Federally Regulated	Unreg.	Mo PSC Regulated	$ Total	% Total
Demand 5/	$249.67			$249.67	30.88%
Gas Costs 6/	$280.63			$280.63	34.71%
Transportation Costs				$0.00	0.00%
Pipeline Margin 5/	$60.62			$60.62	7.50%
Storage Costs 5/	$0.73			$0.73	0.09%
LDC Margin & Loss			$216.94	$216.94	26.83%
Total	$591.66		$216.94	$808.60	100.00%
Percent of Total	**73.17%**	**0.00%**	**26.83%**	100.00%	

After Order 636

Type of Cost	TOTAL COST				
	Federally Regulated	Unreg.	Mo PSC Regulated	$ Total	% Total
Demand 5/	$249.67			$249.67	30.88%
Gas Costs 6/		$280.63		$280.63	34.71%
Transportation Costs				$0.00	0.00%
Pipeline Margin 5/	$60.62			$60.62	7.50%
Storage Costs 5/	$0.73			$0.73	0.09%
LDC Margin & Loss			$216.94	$216.94	26.83%
Total	$311.03	$280.63	$216.94	$808.60	100.00%
Percent of Total	**38.47%**	**34.71%**	**26.83%**	100.00%	

1/ Williams Natural Gas' (WNG) 1 Revised Fourteenth Revised Sheet No. 6 & 1 Revised Fifteenth Revised Sheet No. 6A, effective January 1, 1993.
2/ Used average cost of gas reflected in WNG's latest annual PGA filing (TA93-1-43), Schedule A1, Part 1.
3/ Mississippi River Transmission Corporation's (MRT) 8 Revised Eighty-Third Revised Sheet No. 4, effective March 1, 1993.
4/ Used average cost of gas reflected in MRT's latest annual PGA filing (TA93-1-25), Schedule A1, Part 1.
5/ Panhandle Eastern Pipe Line Company's (PEPL) Substitute Ninty-Fourth Revised Sheet No. 3-A, effective January 1, 1993.
6/ Used average cost of gas reflected in PEPL's latest annual PGA filing (TA93-1-28), Schedule A1, Part 1.

LDC SERVICE TARIFFS

SERVICES CURRENTLY OFFERED / CURTAILMENT RELATED PROVISIONS

Company	Sales		Transportation	Backup		Flex Rate Provisions	Curtailment Provisions in Tariffs	Do Tariffs Contain Emergency Exception Provisions?
	Firm	Interruptible		Firm	Interruptible			
Associated Natural Gas	Yes	Yes-Comm, Ind & Lg Ind	Yes-Avg usage of 2,000 Mcf/mo.	No	Yes-Comm, Ind & Lg Ind	No	Yes-old style-applies to supply deficiencies	No
Fidelity Natural Gas, Inc.	Yes	Yes	Yes-3,500 Mcf of usage in any 1 month of prior 12 months	No	Yes	Yes, for sales and transportation	Yes-very general	No
Greeley Gas Company	Yes	No	No	No	No	No	None	No
Laclede Gas Company	Yes	Yes-With demand ≥ 10 Mcf/hr	Yes-Billing demand > 1500 therms and annual usage > 300,000 therms	Yes	Yes	No	Yes-applies to both suppy & capacity curtailments	Yes-customer exemption only
Missouri Gas Energy	Yes	No	Yes-1,500 Mcf of usage in any 1 month of prior 12 mos. ended Feb.	Yes	Yes	Yes, for transportation	Yes-old style-applies to supply deficiencies	Yes-customer exemption only
Missouri Public Service	Yes	Yes-Usage > 15,000 Mcf/yr	Yes-Not firm. Usage > 15,000 Mcf annually	No	Yes	Yes, for transportation	Yes-old style-applies to supply deficiencies	Yes-customer exemption only
St. Joseph Light & Power Co.	Yes	No	Yes->50 Dth/day min. usage during the 6 highest usage months	Yes	No	No	Yes-very general	No
Union Electric Company	Yes	Yes-With standby fac. & alt. fuel	Yes-No minimum (available to any non-residential customer)	Yes	Yes	Yes, for sales and transportation	Yes-very general	No
United Cities Gas	Yes	Yes-Min 24,000 Mcf/yr with standby fac. & alt. fuel	Yes-Minimum of 24,000 Mcf/yr.	Yes	Yes	Yes, for sales and transportation	Yes-general old style	No

ATTACHMENT 2

PROPOSED MINIMUM FILING REQUIREMENTS

1. Supporting documentation (diskettes, workpapers, calculations, etc.), including descriptive narratives and source references for verifying the amounts included in the Company's current ACA filing.

2. A schedule listing the Company's gas supply contracts in effect for the current ACA period. The schedule should be provided in tabular format and include a summary of the major pertinent information relevant to the contract including the following:

A. Contract term
B. Contract demand
C. Minimum take provisions, both monthly and annually if applicable
D. Reservation or demand levels and charges if applicable
E. Commodity charge and any premiums paid
F. Force majeure provisions
G. Type of service; i.e. firm or as available
H. Warrantee provisions
I. Provisions regarding pricing methodology
J. Other

3. A schedule listing the Company's transportation contracts in effect for the current ACA. The schedule should be presented in tabular format and include a summary of the major pertinent information relevant to the contract including the following:

A. Contract term
B. Maximum contract quantity per day
C. Type of service; firm or interruptible
D. Customer class served by the contract
E. Receipt and delivery points
F. Other

4. A schedule listing the Company's storage and other contracts utilized for meeting system demand. The schedule should be presented in tabular format and include a summary of the major pertinent information relevant to the contract including the following:

A. Contract term
B. Maximum Daily Withdrawal Quantity and period
C. Maximum Daily Injection Quantity and period
D. Capacity level and requirements
E. Type of service (peaking, seasonal, balancing, etc.)
F. Customer class served by the contract
G. Other

5. A copy of the Company's gas supply plan in effect for both the current and subsequent ACA period.

6. A schedule listing the Company's forecasted monthly usage by customer class for both the current & subsequent ACA period. The Schedule completed should also include a narrative regarding the method and major assumptions utilized for calculating the monthly usages.

7. A schedule listing the Company's forecasted monthly storage injections and/or withdrawals for both the current & subsequent ACA periods.

8. A copy of all invoices supporting the Company's current ACA filing.

9. A summary of all gas bids for contracts entered into during the current ACA period. A brief narrative should also be included which explains the Company's bid evaluation process and criteria for accepting and/or rejecting supplier bids

10. A schedule listing any curtailments that occurred during the current ACA period. A brief narrative regarding the reason for the curtailments and the group of customers affected should also be included.

11. A schedule listing any penalties incurred for imbalances exceeding pipeline tolerance levels. A brief narrative regarding the Company's explanation for the imbalance exceeding tolerance levels should also be included.

12. A copy of the Company's gas dispatch model. The information provided should include information regarding basic assumptions, computer logic engineering constraints, inputs, outputs, and interpretation of outputs.

13. A copy of the Company's procedures manual for optimizing released capacity revenues.

14. A calculation of the Company's lost and unaccounted for factor during the current ACA period. The information provided should include a brief narrative of how the factor was calculated and the Company's methodology for allocating the L/U costs to each customer class.

15. A schedule listing all purchases from affiliates for each month of the Company's current ACA period.

16. A copy of the Company's procedures manual for analyzing hedging opportunities available for reducing price risk. A brief narrative should also be included which lists the hedging contracts utilized during the current ACA period and the impact on actual gas costs.

17. Company evaluations of all gas/transport/storage contract decisions made for the current ACA period.

18. A summary of the Company's participation of FERC cases having an impact on the Company or its customers.

19. A summary of all options under evaluation for alternative pipelines, supply alternatives, new interconnects, capacity expansion, propane air additions, etc.

20. A comparison of peak day demand versus supply sources used to meet that peak day demand.

21. A description of the reliability standard used by the Company along with a quantification and description of any reserve margin the Company uses.

22. A listing of the all alternative sources of gas available for meeting peak day such as underground storage, LNG, Propane Air, Propane Vaporization Facilities. Also to be included is the design capacity of the facility and the capacity actually considered available to meet peak day.

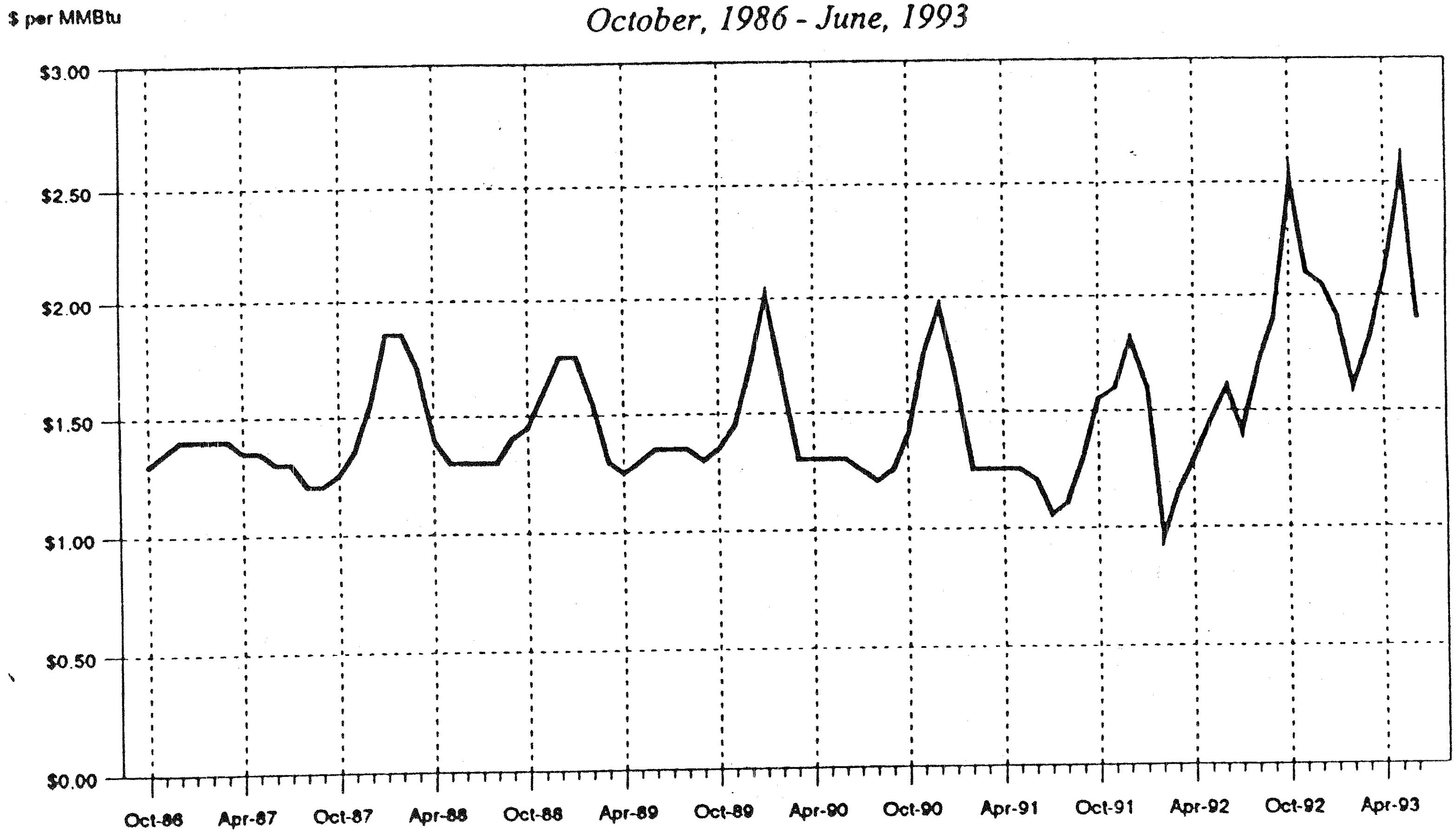
23. A description of all off-system sales activity performed during the ACA period. If such transactions occurred, also provide copies of the related contracts and documentation to support the contract price(s) and revenues received under such agreements.

Chart No. 1

Price Volatility

ANR - Custer Cty., Oklahoma Spot Market Prices

October, 1986 - June, 1993



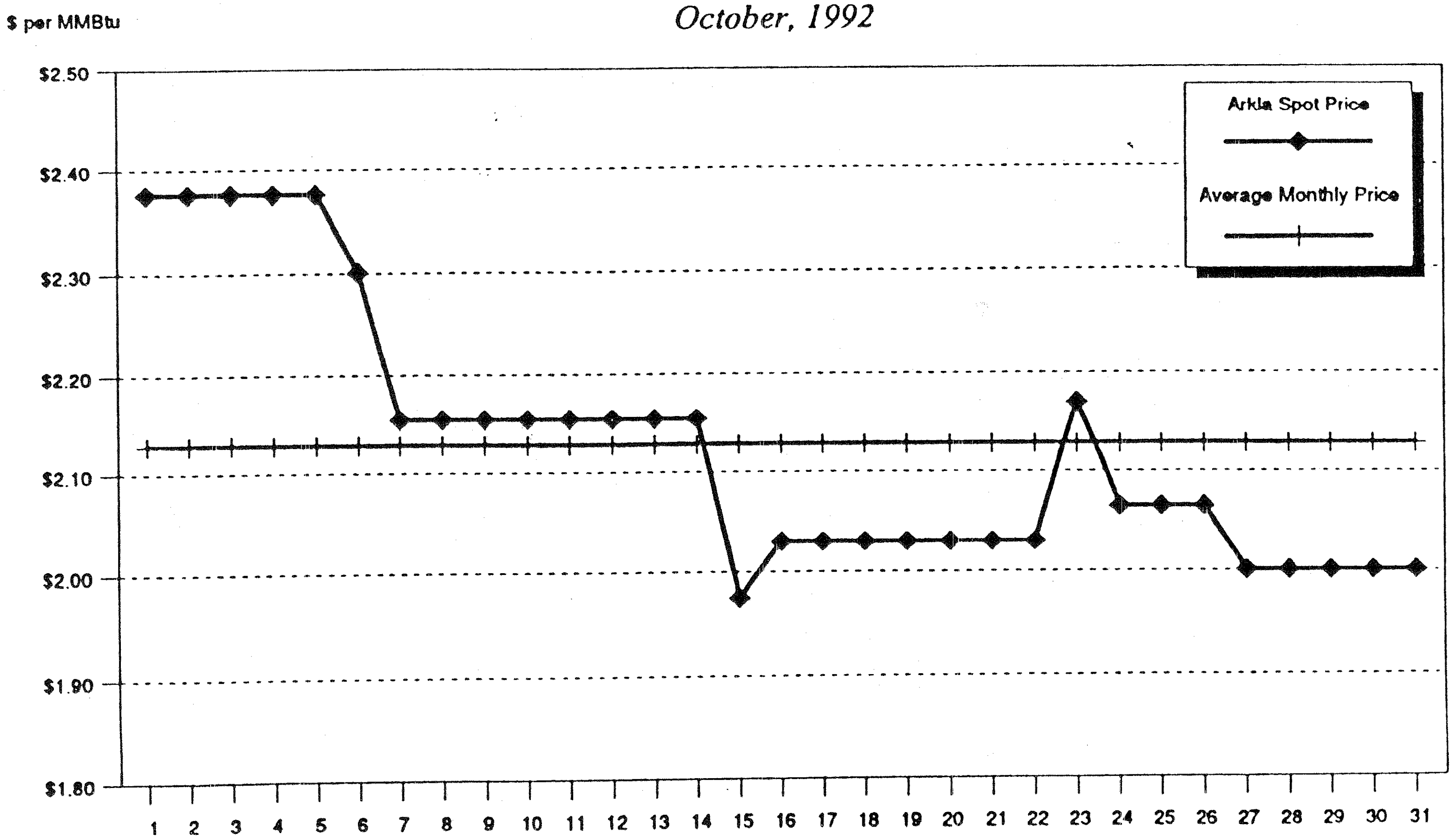
Source: Foster Natural Gas Report

Note: Submitted by Laclede Gas Company in its written comments dated July 8, 1993.

Price Volatility

Natural Gas Spot Prices

October, 1992



Source: Gas Daily

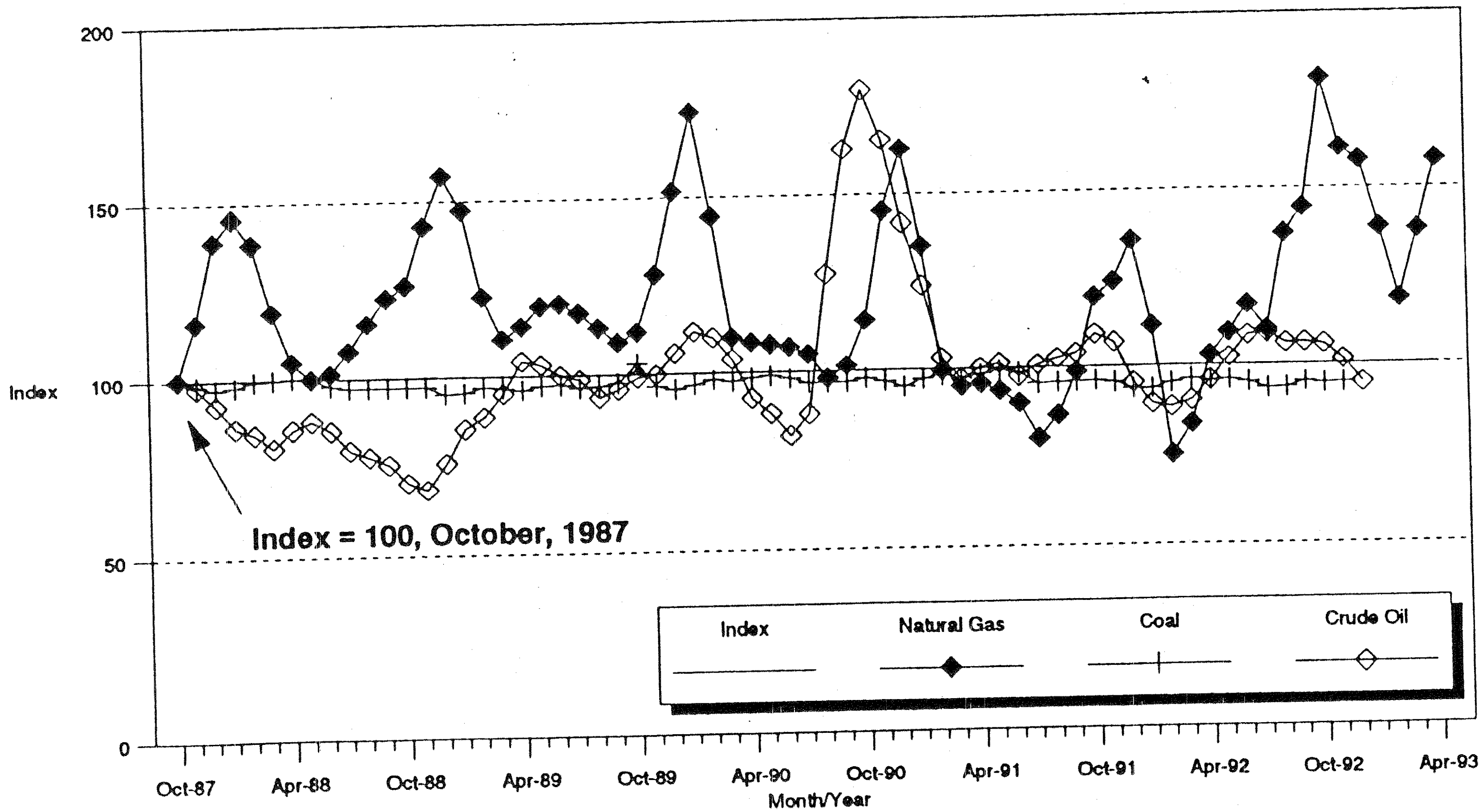
Note: Submitted by Laclede Gas Company in its written comments dated July 8, 1993.

Chart No. 3

Price Volatility

Comparison of Price Changes: Coal, Natural Gas, Oil

October, 1987 - April, 1993



Sources: Natural Gas - Natural Gas Week Coal - Energy Information Administration ("EIA"), Electric Power Monthly Crude Oil - EIA, Monthly Energy Review

Note: Submitted by Laclede Gas Company in its written comments dated July 8, 1993.

Michigan's Gas Cost Recovery Statute

Act 304, Public Acts of 1982, abolished automatic adjustment clauses and provided for a Gas Cost Recovery process. It also amended Act 3, Public Acts of 1939, which is Michigan's general rate regulation statute. The attached Section 6h of Act 3 contains the Gas Cost Recovery requirements.

(b) "Attachment" means any wire, cable, facility, or apparatus for the transmission of writing, signs, signals, pictures, sounds, or other forms of intelligence or for the transmission of electricity for light, heat, or power, installed by an attaching party upon any pole or in any duct or conduit owned or controlled, in whole or in part, by 1 or more utilities.

(c) "Commission" means the Michigan public service commission created in section 1.[1]

(d) "Utility" means any public utility subject to the regulation and control of the commission that owns or controls, or shares ownership or control of poles, ducts, or conduits used or useful, in whole or in part, for supporting or enclosing wires, cables, or other facilities or apparatus for the transmission of writing, signs, signals, pictures, sounds, or other forms of intelligence, or for the transmission of electricity for light, heat, or power.

(2) The commission shall regulate the rates, terms, and conditions of attachments by attaching parties. The commission, in regulating the rates, terms, and conditions of attachments by attaching parties, shall not require a hearing when approving the rates, terms, and conditions unless the attaching party or utility petitions the commission for a hearing. The commission shall ensure that the rates, terms, and conditions are just and reasonable and shall consider the interests of the attaching parties' customers as well as the utility and its customers.

(3) An attaching party shall obtain any necessary authorization before occupying public ways or private rights of way with its attachment.

(4) Procedures under this section shall be those applicable to any utility whose rates charged its customers are regulated by the commission, including the right to appeal a final decision of the commission to the courts.

P.A.1939, No. 3, § 6g, added by P.A.1980, No. 470, § 1, Eff. March 31, 1981.

[1] Section 460.1.

Library References

Public Utilities ⇐145.
WESTLAW Topic No. 317A.
C.J.S. Public Utilities §§ 18, 65 to 67.

460.6h. Definitions; gas cost recovery clause; review; gas cost reconciliation

Sec. 6h. (1) As used in this act:

(a) "Commission" or "public service commission" means the Michigan public service commission created in section 1.[1]

(b) "Gas cost recovery clause" means an adjustment clause in the rates or rate schedule of a gas utility which permits the monthly adjustment of rates for gas in order to allow the utility to recover the booked costs of gas sold by the utility if incurred under reasonable and prudent policies and practices.

(c) "Gas cost recovery factor" means that element of the rates to be charged for gas service to reflect gas costs incurred by a gas utility and made pursuant to a gas cost recovery clause incorporated in the rates or rate schedules of a gas utility.

(d) "General rate case" means a proceeding before the commission in which interested parties are given notice and a reasonable opportunity for a full and complete hearing on a utility's total cost of service and all other lawful elements properly to be considered in determining just and reasonable rates.

(e) "Interested persons" means the attorney general, the technical staff of the commission, any intervenor admitted to 1 of the utility's 2 previous general rate cases, any intervenor admitted to 1 of the utility's 2 previous reconciliation hearings, or any association of utility customers which meets the requirements to intervene in a reconciliation hearing under the rules of practice and procedure of the commission as applicable.

(2) Pursuant to its authority under this act, the public service commission may incorporate a gas cost recovery clause in the rates or rate schedule of a gas utility, but is not required to do so. Any order incorporating a gas cost recovery clause shall be as a result of a hearing solely on the question of the inclusion of the clause in the rates or rate schedule, which hearing shall be conducted as a contested case pursuant to chapter 4 of Act No. 306 of the Public Acts of 1969, being sections 24.271 to 24.287 of the Michigan Compiled Laws, or, pursuant to subsection (17), as a result of a general rate case. Any order incorporating a gas cost recovery clause shall replace and rescind any previous purchased gas adjustment clause incorporated in the rates of the utility upon the effective date of the first gas cost recovery factor authorized for the utility under its gas cost recovery clause.

(3) In order to implement the gas cost recovery clause established pursuant to subsection (2), a utility annually shall file, pursuant to procedures established by the commission, if any, a complete gas cost recovery plan describing the expected sources and volumes of its gas supply and changes in the cost of gas anticipated over a future 12-month period specified by the commission and requesting for each of those 12 months a specific gas cost recovery factor. The plan shall be filed not less than 3 months before the beginning of the 12-month period covered by the plan. The plan shall describe all major contracts and gas supply arrangements entered into by the utility for obtaining gas during the specified 12-month period. The description of the major contracts and arrangements shall include the price of the gas, the duration of the contract or arrangement, and an explanation or description of any other term or provision as required by the commission. The plan shall also include the gas utility's evaluation of the reasonableness and prudence of its decisions to obtain gas in the manner described in the plan, in light of the major alternative gas supplies available to the utility, and an explanation of the legal and regulatory actions taken by the utility to minimize the cost of gas purchased by the utility.

(4) In order to implement the gas cost recovery clause established pursuant to subsection (2), a gas utility shall file, contemporaneously with the gas cost recovery plan described in subsection (3), a 5-year forecast of the gas require-

ments of its customers, its anticipated sources of supply, and projections of gas costs. The forecast shall include a description of all relevant major contracts and gas supply arrangements entered into or contemplated between the gas utility and its suppliers, a description of all major gas supply arrangements which the gas utility knows have been, or expects will be, entered into between the gas utility's principal pipeline suppliers and their major sources of gas, and such other information as the commission may require.

(5) If a utility files a gas cost recovery plan and a 5-year forecast as provided in subsections (3) and (4), the commission shall conduct a proceeding, to be known as a gas supply and cost review, for the purpose of evaluating the reasonableness and prudence of the plan, and establishing the gas cost recovery factors to implement a gas cost recovery clause incorporated in the rates or rate schedule of the gas utility. The gas supply and cost review shall be conducted as a contested case pursuant to chapter 4 of Act No. 306 of the Public Acts of 1969.

(6) In its final order in a gas supply and cost review, the commission shall evaluate the reasonableness and prudence of the decisions underlying the gas cost recovery plan filed by the gas utility pursuant to subsection (3), and shall approve, disapprove, or amend the gas cost recovery plan accordingly. In evaluating the decisions underlying the gas cost recovery plan, the commission shall consider the volume, cost, and reliability of the major alternative gas supplies available to the utility; the cost of alternative fuels available to some or all of the utility's customers; the availability of gas in storage; the ability of the utility to reduce or to eliminate any sales to out-of-state customers; whether the utility has taken all appropriate legal and regulatory actions to minimize the cost of purchased gas; and other relevant factors. The commission shall approve, reject, or amend the 12 monthly gas cost recovery factors requested by the utility in its gas cost recovery plan. The factors ordered shall be described in fixed dollar amounts per unit of gas, but may include specific amounts contingent on future events, including proceedings of the federal energy regulatory commission or its successor agency.

(7) In its final order in a gas supply and cost review, the commission shall evaluate the decisions underlying the 5-year forecast filed by a gas utility pursuant to subsection (4). The commission may also indicate any cost items in the 5-year forecast that on the basis of present evidence, the commission would be unlikely to permit the gas utility to recover from its customers in rates, rate schedules, or gas cost recovery factors established in the future.

(8) The commission, on its own motion or the motion of any party, may make a finding and enter a temporary order granting approval or partial approval of a gas cost recovery plan in a gas supply and cost recovery review, after first having given notice to the parties to the review, and after having afforded to the parties to the review a reasonable opportunity for a full and complete hearing. A temporary order made pursuant to this subsection shall be considered a final order for purposes of judicial review.

(9) If the commission has made a final or temporary order in a gas supply and cost review, the utility may each month incorporate in its rates for the

period covered by the order any amounts up to the gas cost recovery factors permitted in that order. If the commission has not made a final or temporary order within 3 months of the submission of a complete gas cost recovery plan, or by the beginning of the period covered in the plan, whichever comes later, or if a temporary order has expired without being extended or replaced, then pending an order which determines the gas cost recovery factors, a gas utility may each month adjust its rates to incorporate all or a part of the gas cost recovery factors requested in its plan. Any amounts collected under the gas cost recovery factors before the commission makes its final order shall be subject to prompt refund with interest to the extent that the total amounts collected exceed the total amounts determined in the commission's final order to be reasonable and prudent for the same period of time.

(10) Not less than 3 months before the beginning of the third quarter of the 12-month period, the utility may file a revised gas cost recovery plan which shall cover the remainder of the 12-month period. Upon receipt of the revised gas cost recovery plan, the commission shall reopen the gas supply and cost review. In addition, the commission may reopen the gas supply and cost review on its own motion or on the showing of good cause by any party if at least 6 months have elapsed since the utility submitted its complete filing and if there are at least 60 days remaining in the 12-month period under consideration. A reopened gas supply and cost review shall be conducted as a contested case pursuant to chapter 4 of Act No. 306 of the Public Acts of 1969, and in accordance with subsections (3), (6), (8), and (9).

(11) Not more than 45 days following the last day of each billing month in which a gas cost recovery factor has been applied to customers' bills, the gas utility shall file with the commission a detailed statement for that month of the revenues recorded pursuant to the gas cost recovery factor and the allowance for cost of gas included in the base rates established in the latest commission order for the gas utility, and the cost of gas sold. The detailed statement shall be in the manner and form prescribed by the commission. The commission shall establish procedures for insuring that the detailed statement is promptly verified and corrected if necessary.

(12) Not less than once a year, and not later than 3 months after the end of the 12-month period covered by a gas utility's gas cost recovery plan, the commission shall commence a proceeding, to be known as a gas cost reconciliation, as a contested case pursuant to chapter 4 of Act No. 306 of the Public Acts of 1969. Reasonable discovery shall be permitted before and during the reconciliation proceeding in order to assist parties and interested persons in obtaining evidence concerning reconciliation issues including, but not limited to, the reasonableness and prudence of expenditures and the amounts collected pursuant to the clause. At the gas cost reconciliation the commission shall reconcile the revenues recorded pursuant to the gas cost recovery factor and the allowance for cost of gas included in the base rates established in the latest commission order for the gas utility with the amounts actually expensed and included in the cost of gas sold by the gas utility. The commission shall consider any issue regarding the reasonableness and prudence of expenses for

which customers were charged if the issue could not have been considered adequately at a previously conducted gas supply and cost review.

(13) In its order in a gas cost reconciliation, the commission shall require a gas utility to refund to customers or credit to customers' bills any net amount determined to have been recovered over the period covered in excess of the amounts determined to have been actually expensed by the utility for gas sold, and to have been incurred through reasonable and prudent actions not precluded by the commission order in the gas supply and cost review. Such refunds or credits shall be apportioned among the customers of the utility utilizing procedures that the commission determines to be reasonable. The commission may adopt different procedures with respect to customers served under the various rate schedules of the utility and may, in appropriate circumstances, order refunds or credits in proportion to the excess amounts actually collected from each such customer during the period covered.

(14) In its order in a gas cost reconciliation, the commission shall authorize a gas utility to recover from customers any net amount by which the amount determined to have been recovered over the period covered was less than the amount determined to have been actually expensed by the utility for gas sold, and to have been incurred through reasonable and prudent actions not precluded by the commission order in the gas supply and cost review. For excess costs incurred through actions contrary to the commission's gas supply and cost review order, the commission shall authorize a utility to recover costs incurred for gas sold in the 12-month period in excess of the amount recovered over the period only if the utility demonstrates by clear and convincing evidence that the excess expenses were beyond the ability of the utility to control through reasonable and prudent actions. For excess costs incurred through actions consistent with commission's gas supply and cost review order, the commission shall authorize a utility to recover costs incurred for gas sold in the 12-month period in excess of the amount recovered over the period only if the utility demonstrates that the excess expenses were reasonable and prudent. Such amounts in excess of the amounts actually recovered by the utility for gas sold shall be apportioned among and charged to the customers of the utility utilizing procedures that the commission determines to be reasonable. The commission may adopt different procedures with respect to customers served under the various rate schedules of the utility and may, in appropriate circumstances, order charges to be made in proportion to the amounts which would have been paid by such customers if the amounts in excess of the amounts actually recovered by the utility for gas sold had been included in the gas cost recovery factors with respect to such customers during the period covered. Charges for such excess amounts shall be spread over a period that the commission determines to be appropriate.

(15) If the commission orders refunds or credits pursuant to subsection (13), or additional charges to customers pursuant to subsection (14), in its final order in a gas cost reconciliation, the refunds, credits, or additional charges shall include interest and shall be apportioned among the utility's customer classes in proportion to their respective usage during the reconcilia-

tion period. In determining the interest included in a refund, credit, or additional charge pursuant to this subsection, the commission shall consider, to the extent material and practicable, the time at which the excess recoveries or insufficient recoveries, or both, occurred. The commission shall determine a rate of interest for excess recoveries, refunds, and credits equal to the greater of the average short-term borrowing rate available to the gas utility during the appropriate period, or the authorized rate of return on the common stock of the gas utility during that same period. The commission shall determine a rate of interest for insufficient recoveries and additional charges equal to the average short-term borrowing rate available to the gas utility during the appropriate period.

(16) To avoid undue hardship or unduly burdensome or excessive cost, the commission may exempt a gas utility with fewer than 200,000 customers in the state of Michigan from 1 or more of the procedural provisions of this section or may modify the filing requirements of this section.

(17) Notwithstanding any other provision of this act, the commission may, upon application by a gas utility, set gas cost recovery factors, in a manner otherwise consistent with this act, in an order resulting from a general rate case. Within 120 days following the effective date of this section, for the purpose of setting gas cost recovery factors, the commission shall permit a gas utility to reopen a general rate case in which a final order was issued within 120 days before or after the effective date of this section or to amend an application or reopen the evidentiary record in a pending general rate case. If the commission sets gas cost recovery factors in an order resulting from a general rate case:

(a) The gas cost recovery factors shall cover a future period of 48 months or the number of months which elapse until the commission orders new gas cost recovery factors in a general rate case, whichever is the shorter period.

(b) Annual reconciliation proceedings shall be conducted pursuant to subsection (12) and if an annual reconciliation proceeding shows a recoverable amount pursuant to subsection (14), the commission shall authorize the gas utility to defer the amount and to accumulate interest on the amount pursuant to subsection (15), and in the next order resulting from a general rate case authorize the utility to recover the amount and interest from its customers in the manner provided in subsection (14).

(c) The gas cost recovery factors shall not be subject to revision pursuant to subsection (10).

P.A.1939, No. 3, § 6h, added by P.A.1982, No. 304, § 1, Imd. Eff. Oct. 13, 1982.

[1] Section 460.1.

Library References

Gas ⚬=14.1(1) et seq.
WESTLAW Topic No. 190.
C.J.S. Gas § 31 et seq.

SURVEY METHOD AND SUMMARY OF RESULTS

The survey encompassed 49 state regulatory commissions and responses were received from 44 of these state commissions. We have not received a response from the following five commissions: Alaska, New Hampshire, Oklahoma, Pennsylvania, and Rhode Island. Information on Missouri was also included.

The survey was faxed to state commissions on March 30, 1993 in the morning with a request to respond by fax on April 1. Follow-up phone calls were initiated on April 2, and continued throughout the month of April.

The surveys were addressed to the member of the NARUC Staff Subcommittee on Gas (if the state Commission had a representative) or to the individual who responded to the request for information for the 1991 NRRI report "Current PGA & FAC Practices".

On May 18, 1993, a draft summary of the information collected was sent to the participants for verification of their individual state responses. A final summary document has been produced with the clarifications suggested by them.

GAS COST RECOVERY SURVEY OF STATE COMMISSIONS

1. How does your Commission deal with gas costs? (i.e. PGA clauses, rate cases, etc.)

2. Has this changed since the November 1991 NRRI study entitled Current PGA and FAC Practices?

3. Has FERC Order 636 prompted any reexamination of these practices?

4. If yes,

    - Has your Commission started any proceedings? If so, please describe

        - Has your Commission opened a specific docket for this? Is there testimony?

        - If so, please send a copy of the order creating the docket and copies of any testimony.

        - Have there been any orders issued? Please send a copy.

    - What is the current status of these proceedings?

5. If your Commission utilizes PGAs, is the underlying authority for the PGA:

    - A statutory one? (please provide a copy of the specific citation)

    - Application of PSC rules and regulations? (please provide a copy of these)

    - One that evolved from individual case proceedings? (please provide PUR cite, if applicable)

6. Are the company PGA clauses

    - generic? (please provide an example of a recently approved tariff, based on restructuring.)

- differing and company specific? (please provide an example of a recently approved tariff, based on restructuring.)

7. Responsibility, workload & staffing for monitoring of gas costs

- Who has responsibility for PGA/ACA activities?

  - Division or Department responsibility

  - Position titles & size of staff (please note the number of staff in each position title and indicate whether these responsibilities are full time)

  - How many gas companies does your Commission regulate?

  - How many pipelines directly service your state (LDCs)?

8. Effectiveness, reliance on FERC

- How much has your staff relied upon FERC in the past?

- How effective do you feel your staff has been in dealing with prudency issues? Please give specific examples to illustrate.

State ______________________________

Name of Person Completing Survey ______________________________

Title ______________________________

Phone # ______________________________

Date ______________________________

MECHANISMS USED FOR GAS COST RECOVERY

1. How does your Commission deal with gas costs? (i.e. PGA clauses, rate cases, etc.)

States not using PGA clauses:

NRRI 1991 DATA
No PGAs: Michigan
Vermont
California (for non-core market only)

1993 SURVEY DATA
No PGAs: Michigan
Vermont
California (for non-core market only)

Variations:

Arkansas	PGA & rate cases are used.
Colorado	PGA & rate cases are used.
Connecticut	PGA & rate cases are used.
Maine	Summer/winter Cost of Gas Adjustment (CGA) & rate cases are used.
Massachusetts	Gas costs are embedded on base rates at the time of a rate case. The difference between these estimates and actual costs are collected through a CGA factor which is revised every 6 months.
Michigan	The Commission uses a contested case proceeding (Gas Cost Recovery Proceedings) which includes a future plan and an after the fact reconciliation.
Mississippi	PGA & rate cases are used.
Missouri	An actual cost adjustment audit (ACA) is performed annually to true up costs.
Montana	Gas tracking procedures were begun after November, 1991.
New Jersey	The Commission utilizes a Levelized (Annual) Gas Adjustment Clause. Gas costs for the next 12 months are estimated. These costs are in effect for 12 months and any necessary adjustments must be filed for in October of each year.

North Carolina	The Commission uses annual hearings to compare and true-up costs. Fixed costs are allocated by cost of service analysis in the context of a general rate case to arrive at unit costs by rate class.
Oregon	PGA & rate cases are used.
South Carolina	The Commission uses annual hearings to true up costs.
Tennessee	PGA & rate cases are used.
Wisconsin	The company must file an annual purchase plan and also file for significant variances.
Wyoming	PGAs or rate cases are used.

<u>PGAs & Rate cases</u>

Arkansas
Colorado
Connecticut
Maine
Mississippi
Oregon
Tennessee
Wyoming

FREQUENCY OF PGA ADJUSTMENTS

2. Has this changed since the November 1991 NRRI study entitled Current PGA and FAC Practices?

State:	Survey Info Per 1991 NRRI Data:	MoPSC Survey 1993:
Alabama	Annually or more often, if required	Annually or more often, if required
Alaska	Quarterly	Quarterly
Arizona	Monthly	Monthly
Arkansas	Monthly	Monthly
California	No PGA, Annual review	*Biannual
Colorado	Annually	Annually
Connecticut	Monthly	Monthly
Delaware	Semiannually, annually	Semiannually, annually
District of Columbia	Monthly	Monthly
Florida	Semiannually	Semiannually
Georgia	When needed	When needed
Idaho	At least once a year	At least once a year
Illinois	Monthly & annually	Monthly & annually
Indiana	Quarterly or semiannually	Quarterly or semiannually
Iowa	Change in gas costs	Change in gas costs
Kansas	Annually	Annually
Kentucky	Quarterly or semiannually	Quarterly or semiannually
Louisiana	Monthly	Monthly
Maine	Semiannually	Semiannually
Maryland	Monthly	Monthly
Massachusetts	Semiannually	Semiannually
Michigan	Not in 1991 data	N/A
Minnesota	Quarterly	*Monthly
Mississippi	Not in 1991 data	N/A

Missouri	When a threshold specified in individual Company tariffs is reached	When a threshold specified in individual Company tariffs is reached
Montana	Semiannually and annually	N/A
Nevada	Annually	Annually
New Hampshire	Semiannually	N/R
New Jersey	Annually	Annually
New Mexico	Monthly	Monthly
New York	Monthly	Monthly
North Carolina	Semiannually	*As required with annual true up
North Dakota	Not required to file	Not required to file
Ohio	Quarterly	Quarterly
Oregon	Annually	Annually
Pennsylvania	When purchased gas costs change by 1 percent or more	N/R
Rhode Island	Annually	N/R
South Carolina	Monthly/Semiannually	Filings range from monthly to semi annually, hearings annually
South Dakota	Not required to make periodic filings	Not required to make periodic filings
Tennessee	When rates change	When rates change
Texas	Monthly	Monthly
Utah	Semiannually/Annually	Semiannually/Annually
Vermont	Not in 1991 Data	N/A
Virginia	Quarterly	Quarterly
Washington	Not required to make periodic filings	Not required to make periodic filings
West Virginia	Annually	Annually
Wisconsin	Each PGA period (usually 12 months), not required to make periodic filings	Each PGA period (usually 12 months), not required to make periodic filings
Wyoming	Quarterly to annually	Quarterly to annually

* - denotes a change from 1991 data
N/A - not provided in response
N/R - no response

DISTRIBUTION OF FREQUENCIES

1993 DATA

Annually	Semiannually	Quarterly	Monthly	As Needed	Not Required to File
Alabama	California	Alaska	Arizona	Georgia	North Dakota
Colorado	Delaware	Indiana	Arkansas	Iowa	South Dakota
Delaware	Florida	Kentucky	Connecticut	Missouri	Washington
Idaho	Indiana	Minnesota	District of Columbia	Pennsylvania	
Illinois	Kentucky	Ohio	Illinois	Tennessee	N=3
Kansas	Maine	Virginia	Louisiana	North Carolina	
Montana	Massachusetts	Wyoming	Maryland		
Nevada	Montana		Minnesota	N=6	
New Jersey	New Hampshire	N=7	New Mexico		
Oregon	South Carolina		New York		
Rhode Island	Utah		Texas		
Utah					
West Virginia	N=11		N=10		
Wisconsin					
N=14					

*A state may appear in more than one column as some apply a different frequency to large or small companies.

REEXAMINATION OF PRACTICES DUE TO FERC ORDER 636

3. Has FERC Order 636 prompted any reexamination of these practices?
4. If yes,
   - Has your Commission started any proceedings? If so, please describe
     - Has your Commission opened a specific docket for this? Is there testimony?
     - If so, please send a copy of the order creating the docket and copies of any testimony.
     - Have there been any orders issued? Please send a copy.
   - What is the current status of these proceedings?

<u>No</u>	<u>Will in near future</u>	<u>Yes</u>
Alabama	Arizona	Arkansas
California	Illinois	Colorado
Connecticut	Maine	Georgia
Delaware	Massachusetts	Iowa
District of Columbia	Virginia	Kentucky
Florida		Maryland
Idaho	N=5	Minnesota
Kansas		Missouri
Louisiana		Montana
Michigan		New Jersey
Mississippi		New Mexico
Nevada		New York
North Dakota		North Carolina
Oregon		South Dakota
South Carolina		Ohio
Tennessee		West Virginia
Texas		Wisconsin
Utah		
Vermont		N=17
Wyoming		
N=20		

	<u>Status</u>
Arkansas	The Staff recently examined this during the last rate case for the largest LDC. There was an order issued but this was not provided.
California	The Staff started a 636 type of restructuring on the PG&E Canadian gas supply before Order 636 came out.

Georgia	Docket No. 4248-U was established. There was no proposed schedule as of 3/30/93.
Iowa	Written comments and order are to be sent in NOI 92-1. Follow up meeting is to be held later this year.
Kentucky	The Commission issued a generic docket Administrative Case No. 346 January 29, 1993. Copy of order was sent.
Maine	The Commission just opened a Gas Integrated Resource Planning Investigation. There is no testimony yet.
Maryland	The Commission did issue a generic order 5 years ago for their 3 large gas companies to present annual gas supply plans to Commission Staff for review.
Minnesota	Staff is starting to collect and review information now.
Missouri	The Commission initiated a Gas Purchasing/Cost Recovery Project Team in January 1993 to determine if the manner of regulating natural gas utilities needs to be modified. Present regulation is being examined to note whether it reflects the changes which have occurred with regard to more open markets in the natural gas industry, augmented by the issuance of FERC's Order No. 636.
Montana	Informal discussions have taken place with some of the utilities.
Nevada	As they become more familiar with 636, changes may be required. The Commission opened Docket 92-110-1 to monitor FERC activity with respect to Order 636.
New Jersey	The Gas Policy Group has been meeting with utilities, producer representatives, industrial customers and marketers to discuss the implications of Order 636. Written comments have been received.
New Mexico	Case No. 2472 is a rulemaking for gas transportation. There is no testimony yet.
North Carolina	Revisions occurred before Order 636; however, Order 436 & 500 contributed to this. The NCUC adopted Rule 1-17(k) pursuant to legislation enacted by the General Assembly to address the current environment of open access.
Ohio	Since April, 1992, the PUCO has conducted monthly industry roundtables to bring all parties together to discuss the impact Order 636 may have on the operation of the current PGA. No docket has been opened. They anticipate opening a rulemaking procedure to incorporate minor changes to the PGA rules. No timeline has been set for this proceeding yet.
South Dakota	The Staff is waiting on a Company proposal that is to be filed.

Vermont	They have held a strong legal tradition of not allowing automatic electric fuel cost increases and feels this also applies to gas. We received the order on a Vermont Gas case.
West Virginia	In September 1992, the Consumer Advocate Division (CAD) petitioned the Commission to initiate a general investigatory proceeding to monitor gas utilities' restructuring of services under contracts with interstate pipelines. In February 1993, the CAD petitioned the Commission to require gas utilities to file additional information regarding the possible impact of Order 636. This information was to be filed April 1, 1993. The Commission held informal prehearing conferences in April, 1993 with each of the 4 large gas utilities to discuss the information they have compiled and receive their comments. We have copies of the CAD petition and the Commission Order.
Wisconsin	About a year ago, the Commission initiated a task force to examine this. The task force includes representatives from the companies and the staff. Commission Staff felt they were stretching the legality of the PGA. A report should be done within a month with recommendations.

BASIS FOR THE AUTHORITY FOR PGAS

5. If your Commission utilizes PGAs, is the underlying authority for the PGA:
   - A statutory one? (please provide a copy of the specific citation)
   - Application of PSC rules and regulations? (please provide a copy of these)
   - One that evolved from individual case proceedings? (please provide PUR cite, if applicable)

Statutory	PSC Rules and Regulations	Individual Case Proceedings
Arkansas	Alabama	Alabama
Connecticut	Colorado	Arizona
Delaware	Connecticut	Colorado
Illinois	Georgia	District of Columbia
Maine	Illinois	Florida
Maryland	Iowa	Idaho
Nevada	Kansas	Kentucky
New York	Louisiana	Missouri
North Carolina	Maine	Montana
Ohio	Massachusetts	New Jersey
Oregon	Minnesota	North Dakota
South Carolina	Mississippi	Oregon
South Dakota	Nevada	Utah
Utah	New Mexico	
Wisconsin	New York	N=13
	North Carolina	
N=15	Ohio	
	Tennessee	
	Texas	
	Virginia	
	West Virginia	
	Wisconsin	
	Wyoming	
	N=23	

*Some states responded that the authority for the PGAs was in more than one category.

Documents

Alabama	Received a tariff for the Purchased Gas Adjustment Rider for Alabama Gas Corp.
Arkansas	Received copy of statutory authority cite.
Colorado	Received an order on gas cost adjustment and tariffs for Public Service Co. of Colorado.
Delaware	Received copy of PGA statutory authority.
Florida	Received copy of order.
Georgia	Received tariffs for Atlanta Gas Light Co. and United Cities Gas.
Illinois	Received copy of Illinois Admin. Code Part 525 Uniform Purchased Gas Adjustment Clause.
Iowa	Received order initiating notice of inquiry on responses to FERC pipeline restructuring NOI-92-1 and Statute 476.6 on adjustments.
Kansas	Received copy of Commission generic order.
Louisiana	Received Commission generic order on Cost of Gas Adjustment Clause.
Maine	Received copies of statute on cost of gas adjustment and Commission rules
Maryland	Statute 540 cited but was not provided.
Massachusetts	Received rules on cost of gas adjustment clause.
Mississippi	Received Commission rules on Purchased Gas Adjustment Provision.
Nevada	Received statute.
New Jersey	Received order on energy cost adjustments.
New Mexico	Application of Rule 640 was cited but was not provided.
North Carolina	Received General Statute 62-133.4.
Ohio	Received copy of statute and Commission rules.
Oregon	Received Statute ORS 757.210 & 757.259 and generic proceeding order 89-1046, issued Aug. 4, 1989.
South Carolina	Received copy of statute.

South Dakota	Received copy of statute.
Texas	Received copy of Commission rule.
Utah	Received code section and current tariff provisions example.
West Virginia	Received rule 30-C.
Wisconsin	Received copy of PGA order and report done in 1980.

PGA CLAUSES

6. Are the company PGA clauses
   - generic? (please provide an example of a recently approved tariff, based on restructuring.)
   - differing and company specific? (please provide an example of a recently approved tariff, based on restructuring.)

Generic	Company-specific
Colorado	Alabama
Connecticut	Arizona
District of Columbia	Arkansas
Florida	Delaware
Georgia	Idaho
Illinois	Kansas
Iowa	Kentucky
Louisiana	Massachusetts
Maine	Missouri
Maryland	Montana
Minnesota	Nevada
New York	New Jersey
North Carolina	New Mexico
Ohio	North Dakota
Tennessee	Oregon
Virginia	South Carolina
	South Dakota
N=16	Texas
	Utah
	West Virginia
	Wisconsin
	Wyoming
	N=22

Arkansas	Received copy of Arkansas Louisiana Gas Supply rate filing.
Delaware	Received copy of gas cost adjustment clause tariff for Delmarva Power & Light.
Florida	Received order and tariff on true-up.
Georgia	Received tariffs for Atlanta Gas Light Co. & United Cities Gas.

Illinois	Received copy of ICC PGA rules.
Kansas	Received tariff for Arkansas Louisiana Gas Co.
Louisiana	Received copy of Trans Louisiana Gas Company tariff.
New Jersey	Received example of order and tariffs.
North Carolina	Received copy of Rule NCUC Rule R1-17(k).
North Dakota	Received copy of Northern States Power Co. tariff on PGA.
Oregon	Received copy of Northwest Natural Gas tariff and Washington Water Power tariff.

RESPONSIBILITY FOR MONITORING GAS COSTS

7. Responsibility, workload & staffing for monitoring of gas costs
   - Who has responsibility for PGA/ACA activities?
     - Division or Department responsibility
     - Position titles & size of staff (please note the number of staff in each position title and indicate whether these responsibilities are full time)
     - How many gas companies does your Commission regulate?
     - How many pipelines directly service your state (LDCs)?

Primarily falls under the Energy Division (12) or the Accounting Division (10) followed by a Rates/Regulation Division (9).

Most use a multi-disciplinary team approach of accounting and engineering/rates expertise.

The majority of the Staffs have PGA work as a part-time function and have a number of other responsibilities.

<u>Those that do have some devoted positions:</u>

Alabama	1 full time auditor
Arkansas	1 full time supervisor 2 full time auditors
Florida	1 full time analyst
South Carolina	1 full time chief - gas department 1 full time rate analyst
West Virginia	7 full time analysts, 1 engineer and 1 staff attorney

PRUDENCE ISSUES

8. How effective do you feel your staff has been in dealing with prudency issues? Please give specific examples to illustrate.

Prudence has not been an issue	Limited effectiveness	Very Effective
Colorado	Idaho	Alabama
Delaware	Kansas	Arizona
District of Columbia	Kentucky	Connecticut
Florida	Maryland	Georgia
Massachusetts	Missouri	Iowa
Michigan	New York	New Jersey
Minnesota	South Carolina	North Carolina
Mississippi		South Dakota
New Mexico	N=7	Tennessee
North Dakota		Texas
Virginia		Utah
Wisconsin		Vermont
		West Virginia
N=12		N=13

Features:

Iowa - Conducts an annual review of purchasing practices.

Maryland - Staff believes they have been effective in the supply planning area.

New Jersey - Staff cited a recent New Jersey Natural Gas Company fuel clause proceeding.

North Carolina - The Staff has just dealt with its first two prudence reviews.

Tennessee - The Staff utilizes an outside consulting firm to issue an opinion on prudence.

Texas - The Staff has recently completed several cases where costs were looked at in detail.

Vermont - Affiliate relations have become a concern.

West Virginia - Rule 43 requires gas utilities to prove that dependable lower priced gas is not readily available.

GAS PURCHASING/COST RECOVERY PROJECT TEAM WORKSHOP PARTICIPANTS

June 27, 1994
Room 510, Truman State Office Bldg., Jefferson City, MO

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Pendergast, Mike	Laclede Gas Company
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Langston, Michael	Missouri Gas Energy
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Franklin, Beth	Missouri Pipeline Company
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Kovach, Richard J.	Union Electric Company
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Janzen, Howard	Williams Natural Gas Company
Mucci, Ron	Williams Natural Gas Company
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