
# The Outsourcing Option: Are There Some Gas Utility Functions That Others Can Do Better?

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**February 2009**

**09–03**

# Acknowledgments

This document expands on a paper written in June 2008 for the Colorado Public Utilities Commission by analyzing in more detail the major issues addressed in that paper. The author wishes to thank the Colorado Public Utilities Commission for funding that project.

The author also wishes to thank Terry Buckner, Office of the Attorney General, State of Tennessee; Leonard Crook, ICF International; Janis Fischer and other staff, Missouri Public Service Commission; Bob Harding, Minnesota Public Utilities Commission; and Jane Steinhauer, Indiana Utility Regulatory Commission, for their comments on an earlier draft of this paper. Special thanks go to Robert Marritz for his editing; and to NRRI's Executive Director, Scott Hempling, for his assistance in organizing this project and reviewing an earlier draft of this paper. Any errors in the document remain the responsibility of the author.

This paper can be accessed electronically at
http://www.nrri.org/pubs/gas/NRRI_gas_outsourcing_options_feb09-03.pdf

# Executive Summary

In fulfilling their obligation to serve the public, utilities carry out numerous activities that require many skills and areas of expertise. As in any business, some of these activities are performed in-house and some are outsourced. The utility regulator's responsibility is to establish performance expectations and ensure compliance. Utilities should do what they do best; what they cannot do best, they should outsource or contract to others. Regulators must assess whether the utility's decision about what activities to keep internal and what activities to outsource achieve this standard.

The premise of this paper is that regulators should periodically ask the question "Are there some utility functions that others would perform better?" and then create regulatory policies that induce the utilities to answer this question in a manner consistent with the public interest. Regulators therefore should assess outsourcing and then encourage or discourage it based on whether it enables the utility to carry out its functions more effectively. To carry out this assessment, regulators need to understand what outsourcing is, along with its positive and negative aspects.

Outsourcing occurs when a firm buys a product or service from an outside supplier. Sometimes a firm has previously performed an activity internally, but for business reasons decided to contract it out to another entity. U.S. firms, large and small, have outsourced a growing share of their business since the 1980s, frequently to foreign entities.

Regulated utilities have become part of this phenomenon. Over the past two decades, they have increasingly contracted once-internal functions to outside firms. One form of outsourcing in the natural gas industry involves what is called "asset (or capacity) management," in which the gas utility contracts with an outside firm to manage the utility's unused capacity. The specific gas-utility functions addressed in this paper are gas procurement and management of pipeline and storage capacity.

The major issues examined in this paper include: (1) the rationale for outsourcing; (2) downsides to outsourcing that could harm a utility's customers; (3) the utility's use of affiliates to carry out utility functions; (4) fees paid to a utility by an outside firm; (5) the sharing of outsourcing benefits among the utility, its customers, and the outside firm; (6) the selection of the outside firm; and (6) the commission's role in reviewing, evaluating, and approving outsourcing arrangements.

Appendix A identifies several questions that state commissions should ask themselves, utilities, and other stakeholders about outsourcing. This paper addresses most of these questions at various levels of detail.

**Recommendations**

1. A commission should consider both the potential benefits and costs of outsourcing. It should evaluate these benefits and costs relative to the gas utility itself performing the activities under existing regulations or alternative

regulations. Alternative regulations could include explicit incentives or performance standards that address, at least partially, the inefficiencies underlying the rationale for outsourcing. The benefits of outsourcing are utility-specific, depending upon factors such as a utility's size. Small utilities may find larger benefits from outsourcing in providing the expertise needed to exploit market conditions.

2. A commission should scrutinize any proposed utility-affiliate relationship. It should condition any such relationship on the enactment of standards-of-conduct rules and other actions protecting the utility's customers against self-dealing abuses.

3. A commission should ensure that a utility's customers receive adequate benefits from the efficiency gains or profits derived from an outsourcing arrangement. A commission should seriously consider an arrangement that determines beforehand the sharing of the benefits between the outside firm, the utility, and its customers.

4. Selection of an outside firm should include a competitive bidding process where a utility affiliate is involved. Such a process should not offer the utility opportunities to strategically exploit its information and intelligence to unduly favor an affiliate.

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# The Outsourcing Option: Are There Some Gas Utility Functions That Others Can Do Better?

The premise of this paper is that regulators should periodically ask the question "Are there some utility functions that others would perform better?" and then create regulatory policies that induce the utilities to answer this question in a manner consistent with the public interest. Regulators should assess outsourcing, and then encourage or discourage it, based on whether it enables the utility to carry out its functions effectively.

This paper refers to this assignment of services interchangeably as an outsourcing or contracting arrangement. In its most basic form, outsourcing represents any contracting arrangement where a firm has an outside entity perform a function that the firm had previously performed internally with its own resources. Advances in computer and communications technologies have lowered market transaction costs, making outsourcing more economically appealing.[1]

This paper addresses the following issues: (1) the rationale for outsourcing; (2) the risks of outsourcing; (3) a utility's outsourcing to an affiliate; (4) fees paid to a utility by an outside firm; (5) the sharing of benefits among the utility, its customers, and the outside firm; (6) the selection of the outside firm; and (7) the role of a commission in reviewing, evaluating, and approving outsourcing arrangements. These are the most important of the various issues a state commission should review when it is required to assess outsourcing proposals for asset management and gas procurement. This paper will provide an objective analysis of these topics, focusing on asset (or capacity) management and gas procurement.[2]

## I. Why commissions should investigate whether others can perform utility functions better: The case of capacity management and gas procurement

A major activity of local gas distribution companies is to acquire gas and deliver it to the city gate (i.e., the point of interconnection between the interstate pipeline system and the local distribution system). The combined costs associated with gas commodity and pipeline transportation presently represent, on average for the U.S., about three-quarters of the retail cost of residential gas service. The vast majority of gas utilities profit only from local gas delivery; they do not profit from the buying and selling of the gas commodity and pipeline transportation.

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[1] These technology advances particularly have increased outsourcing for functions like customer service, telemarketing, and financial services.

[2] This paper requires that the reader have a basic knowledge of the natural gas industry. To acquire or review that basic knowledge, see the NRRI document *The Natural Gas Industry at a Glance*, available at http://nrri.org/matrix/gas/natural_gas_industry_at_a_glance.pdf.

Prior to FERC Order 636 (1992)[3], retail gas utilities procured much of their city-gate supplies from the interstate pipelines under long-term contracts for gas commodity, transportation, and off-system storage services. Order 636 gave retail gas utilities opportunities to procure all of their gas supplies separately from transportation service, i.e., to purchase the gas from sources other than the transportation pipeline.

Also since FERC Order 636, holders of firm pipeline capacity are able to resell their unused capacity to other parties in what is called a capacity release market. The holders post the available capacity, in most instances, on an Electronic Bulletin Board (EBB) operated by interstate pipelines. Major sellers of unused pipeline capacity are local gas utilities, who purchase sufficient capacity to meet peak demands. Consequently, capacity is available for sale during non-peak periods. These utilities charge their customers for the full cost of all contracted capacity, and then credit their customers with revenues earned from selling released capacity. The more that a utility receives higher revenues from the resale of pipeline capacity, or from off-system sales and stored-gas sales, the more it offsets its revenue requirements on which retail rates are based.

Gas procurement and management of idle capacity have important effects on retail prices. The costs and revenues associated with these activities usually flow to customers through the utility's purchased gas adjustment clause. Most such clauses recover costs on a dollar-for-dollar basis and pass all the revenues offsets on to customers. Utilities therefore have no direct incentives (apart from the threat of an adjudicated cost allowance) to purchase best-cost gas and transportation services, and to manage their contractual capacity in the most economical way. This lack of strong incentives provides a basic reason for considering outside entities to perform these functions. These entities may have stronger incentives, more control of upstream delivery capacity, and a higher level of expertise than regulated utilities to perform these functions efficiently. Commissions should evaluate outsourcing arrangements on a utility-by-utility basis. Large utilities, for example, may have developed a high degree of expertise in gas procurement and asset management, while small utilities may not.

## II. Outsourcing as a business strategy

### A. Definition and basic features of outsourcing agreements

Outsourcing occurs when a firm contracts a previously internal business function to an outside supplier. The two entities typically enter into a contractual agreement that, among other things, defines the contracted services and the expected performance of the outside supplier. The utility client agrees to procure the services from the supplier under the terms of the contract. The contract describes each party's risks and responsibilities.

[3] The reader can access FERC Order 636 at http://www.ferc.gov/legal/maj-ord-reg.asp.

Business functions typically outsourced include call centers, information technology, accounting, and human resources. U.S. firms, large and small, have outsourced a growing amount of their business since the 1980s, frequently to foreign entities.

While outsourcing reduces the client firm's direct control over the outsourced operations, the firm must still oversee these activities. Leaving the outside firm with total discretion can lead to performance falling below the client firm's goals for the outsourcing arrangement. The contract between the two entities describes each party's risks and responsibilities.

Whether and to what extent outsourcing benefits the client firm depends on the details of an agreement. The agreement is often written as a performance contract that determines risk-sharing and rewards. Such a contract, for example, can penalize the outside firm for subpar performance and may also allow it to share in the efficiency gains or from surpassing pre-specified "benchmark" performance.[4] Many outsourcing arrangements involve "fee-for-service" compensation, which should correspond to the external firm's cost but also can depend on the relative bargaining power of the two entities.

Successful outsourcing often derives from the client firm measuring the value of outsourcing to itself. Measurement may involve benchmarking, where, for example, the client compares its actual costs with what its costs would have been in the absence of outsourcing.[5] Without benchmarking, for example, a commission would not know whether outsourcing resulted in cost savings and benefits to retail customers.

### B. Examples of outsourcing arrangements

Almost all public utilities in the U.S. outsource some of their business functions, notably information technology, maintenance, customer service support, and metering activities.[6] Many utilities, for example, contract out a portion of their construction and maintenance functions, including tree trimming and pipeline, distribution line, and substation construction. Others contract out their call centers and information technology services to outside parties.

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[4] Earlier forms of outsourcing arrangements priced an outside product or service based on a mark-up of the supplier's cost or on a fixed cost for providing the product or service. More recently, pricing has shifted to a "gains-sharing" structure in which both parties benefit from performance improvements. Asset-management outsourcing involving gas utilities and marketers, as discussed later, typically has such an incentive structure.

[5] The latter requires counterfactual evidence, that is, a prediction of the outcome in the absence of outsourcing.

[6] An early form of outsourcing by regulated utilities was for call center vendors, who established themselves as reliable, efficient, and low-cost suppliers of customer service.

### C. Rationales for outsourcing

Outsourcing may offer three kinds of benefits to a firm. First, the outside firm can pool the activities of a number of firms, realizing economies of scale that can result in cost savings to the client firm. Second, the outside firm may have a high level of expertise where a client firm does not. By specializing in a narrow area, it can achieve efficiencies that other firms with broader functions cannot. Third, especially for small firms, outsourcing can allow them to acquire the expertise that they could not afford to develop internally.

Although cost savings are the principal motivation to outsource, other dimensions of performance are relevant as well. A firm may outsource to improve the quality of its customer service, to more effectively collect monies from overdue bills, or to incorporate the latest technology in its information processing.

One argument in support of outsourcing is that a firm should focus on its "core competencies" and outsource or shed other activities. This thinking led to many firms shedding activities not considered "value-adding" and not directly contributing to profits.[7]

Experts view outsourcing as a management tool to achieve some specified goal. In the early years of outsourcing, the emphasis was on cost savings to the client firm, while the trend in recent years has shifted toward the added goal of service performance (e.g., customer service, information-technology service). A utility may not have the internal expertise and resources to use best-practice techniques, while an outside firm may. Firms of all sizes increasingly have adopted outsourcing as a core strategy because of the difficulties in acquiring skills in operational and administrative areas.

Outsourcing is a concept tied to "the law of comparative advantage." This economic principle says that a firm should concentrate on what it does best and contract out those functions (e.g., customer service, accounting, web management) that others can do at a lower opportunity cost. A variation of this concept argues that while the client firm may have capabilities comparable to an outside firm to perform those functions, it might still decide to outsource them because the opportunity cost to the client firm in undertaking those activities itself is higher.[8] A gas utility, for example, may have the same expertise as an unregulated energy marketer in

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[7] Some management experts, however, would not agree that divesting certain functions is a good corporate strategy, as some firms have found that losing control of them has damaged their relationship with customers.

[8] A firm, in other words, could be more efficient than outside firms in doing all functions, but the utility may still want to outsource those functions where it has the highest opportunity costs. By outsourcing, the firm could devote more of its internal resources to those functions that have the largest benefit to the firm's performance. The standard case for outsourcing, similar to the rationale for free trade, is that a firm (country) is better off when it concentrates on those functions (sectors) in which it has a comparative advantage (e.g., the lowest opportunity costs of production).

procuring natural gas in the wholesale market; but it would have to use scarce internal resources that might otherwise contribute more to the utility's profits when allocated to other company activities (e.g., sales promotion).[9]

A firm may also decide to outsource some of its internal functions to shift certain financial and operational risks and responsibilities to an outside entity that can manage the risks and perform the function more efficiently. These risks may be financial and operational in nature.

Outsourcing arrangements often represent long-term, mutually beneficial relationships between the client utility and the outside firm. Successful outsourcing requires that both parties perceive benefits from the arrangement. Such an outcome requires them to negotiate specific contractual provisions, including measurable performance criteria and financial incentives structured to benefit both parties.

### D. Downside to outsourcing

Outsourcing could also cause a firm to lose expertise in a crucial functional area. This atrophying effect could jeopardize its future performance. If a utility, for example, outsources all of its customer service activities, it could lose a special connection with its customers and therefore diminish its ability to understand customer problems as well as its relations with customers.

Any outsourcing arrangement poses a counterparty risk to the client firm. Counterparty risk is the risk associated with the financial stability of the firm providing outsourcing services. This risk can, for example, jeopardize the ability of the outside firm to purchase gas when needed, to enter into other transactions, or to compensate the utility for the right to market its unused pipeline and storage capacity. In some instances, a marketer performing outsourcing functions for a gas utility went bankrupt or left the business before the end of a contract, requiring the utility to find another provider.

For public utilities, outsourcing can cause harm to retail customers if: (1) incentives for performance by the outside firm do not induce the expected superior performance, (2) most of the efficiency or profit-sharing gains accrue to the outside firm or the utility's shareholders;[10] or (3) self-dealing abuses arise from a relationship between a utility and an outside firm that is also an affiliate. An outside firm, for example, could receive a fixed fee for its services, irrespective

[9] These lost contributions represent the opportunity cost from deploying its internal resources to gas procurement rather than alternative internal functions.

[10] Efficiency gains from asset management can reflect the increased value of a utility's assets because of a higher utilization rate. A proxy for this value is the net margins from additional sales attributed to the efforts of the asset manager. For gas procurement, efficiency gains coincide with lower purchased gas costs relative to some benchmark that, in theory, represents the purchased gas costs had the utility itself procured its gas supplies.

of its actual performance. Harm might also result if the utility neglects to monitor the outside firm's performance to ensure that it conforms to the outsourcing agreement.

Under self-dealing abuses, the parent company, which has the utility and an outside firm as affiliates, may be motivated to leverage its monopoly power in the price-regulated utility market to gain an advantage in the competitive market where its unregulated affiliate operates. The outcome could be that the utility and its customers are subsidizing the unregulated affiliate. Part IV of this paper identifies ways for commissions to address this problem.

Case law gives a commission the authority to impute to a utility the imprudent actions of the utility contractor.[11] Suppose that an outside firm raised the utility's costs by breaching its agreement with the utility. If the utility tried to pass those additional costs onto its customers without holding the outside firm responsible, the commission could charge the utility with imprudent behavior. The utility also may be held accountable for signing an agreement that incents the outside firm to act inconsistently with the utility's cost-minimizing obligations (e.g., using the utility's capacity to profit at the expense of the utility's customers).

A commission may lack the authority, staff resources, or technical ability to detect whether the outside firm has acted imprudently; or to determine whether the utility made a poor judgment in signing an agreement with an outside firm. When the outside firm and the utility are affiliates of the same parent company, a commission may find it especially difficult to secure the cooperation of the utility. Even when the two entities are independent of each other, a commission may lack the authority or ability to assess the performance of the outside firm in the same way that it does for jurisdictional utilities. The pertinent question here is: Does a commission have the authority to audit the books and operations of an unregulated firm, whether affiliated or unaffiliated?

The outside firm also may have an incentive to give more favorable terms to unregulated buyers. Compared to a utility affiliate, these buyers (e.g., large industrial users, merchant electric generators), are less able to pass through excessive costs to their customers, as they operate in more competitive markets. When the level of competition across markets is uneven, the parent company may have the propensity to shift costs and discriminate against its regulated utility. The tendency, in other words, would be to charge the utility affiliate more for the same services than unregulated buyers would pay.[12]

A primary motivation for outsourcing arrangements may stem from the utility earning little or no profits from the functions to be performed by an outside firm. Outsourcing would reallocate some of the gains from these activities to the utility's affiliate. The parent company of

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[11] S. Hempling, *The Fundamentals of Electricity Law*, 2006, SPOW-10-13.

[12] A worthwhile exercise would be to collect data and other pieces of information to test this hypothesis. Since much of this information would be proprietary, such a study would, however, probably not be feasible.

a gas utility, in other words, might see outsourcing as a way to evade regulation to earn higher profits. This evasion can easily conflict with promoting the interest of the utility's customers.

To prevent harm to retail customers from the problems inherent in outsourcing, as well as those arising out of abuses, this paper recommends that a state commission take a proactive role in overseeing outsourcing arrangements, especially when the outside firm is a utility affiliate. Part IV.D of this paper outlines the essential tasks of a commission for assuring that an outsourcing arrangement not only causes no harm to a utility's customers but actually benefits them, relative to the status quo and alternative arrangements for the utility functions involved.

### E. Generic features of outsourcing arrangements

The common features of gas utility outsourcing arrangements focused upon in this paper include:

1. The outside firm typically commits to provide gas supply or manage assets, or both, under a contractual pricing scheme. It also often takes control over the utility's firm transportation and storage assets.[13]

2. Both parties—the utility and the outside firm—may agree that the price for purchased gas be based on published indices, and the outside firm may pay a fixed fee for the right to market excess transportation and storage capacity. In some instances, the pricing formula includes benchmarking and a sharing rule, with a portion of the savings achieved by the outside firm flowing back to the utility and its customers.

3. The outside firm usually must comply with the utility's prescribed operational plan, or else face a penalty.

4. One common outsourcing model involves a utility arranging to receive full requirements supply from a single outside entity, which also manages the utility's physical non-distribution assets on a daily basis.

5. The outside firm is afforded the opportunity to optimize the assets not needed by the utility and generate revenues from marketing of the idle assets.

6. In a few instances, a service corporation provides asset-management services for affiliated gas utilities located in different states.

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[13] Some gas utilities in Massachusetts have asset-management agreements with outside parties in which the outside firm assumes management responsibility for gas supply and capacity contracts previously approved by the commission. *See, e.g.,* Massachusetts Department of Telecommunication and Energy, *Petition of the Berkshire Gas Company for Approval by the Department of Telecommunications and Energy of a Gas Portfolio Optimization Agreement and a Gas Sales and Purchase Agreement Executed Between the Berkshire Gas Company and BP Energy Company,* Order, D.T.E. 04-47, November 5, 2004.

The utility expects the outside firm to achieve lower gas cost by optimizing procurement through its larger portfolio, combining the utility's assets with other assets. The utility captures a portion of the expected benefits of such arrangements for customers through the outsourcing agreement. Because the regulated utility remains ultimately responsible for reliable gas supply and reasonable prices, it typically remains closely involved in procurement decision-making and frequently communicates with the outside firm.

# III. State experiences with outsourcing of capacity management and gas procurement

## A. Examples in selected states

Commissions in some states, notably Indiana, New Jersey, and Tennessee, approved changes to existing outsourcing arrangements by allocating more of the benefits to a utility and its customers. In some instances, the sharing ratio changed to distribute a higher percentage of the net margins[14] from the resale of unused pipeline capacity to the utility. In New Jersey, for example, Sequent Energy pays Elizabethtown Gas Company an annual fee for the right to act as its gas supplier and capacity-management agent.[15] The fee consists of a minimum fixed annual payment plus a share of the capacity-release credits, off-system sales margins, and storage arbitrage margins that Sequent Energy creates.[16] The Board of Public Utilities, in approving an extension of the agreement between the two parties, commented that:

> The Board has reviewed the … stipulation and … agreements for gas supply and capacity management services between Elizabethtown and Sequent. The stipulation will allow Elizabethtown and Sequent to extend their current capacity management and gas supply arrangement under terms that will provide for larger payments to Elizabethtown for its customers than under the terms of the previous arrangement. Elizabethtown's Basic Supply Service-Periodic clause will be credited with a minimum of one million dollars more annually under this arrangement than under the previous arrangement. In addition, the new

[14] Net margins, according to one definition, are the revenues net of expenses attributable to the service rendered by the asset manager.

[15] Sequent Energy and Elizabethtown are wholly owned subsidiaries of AGL Resources, a registered holding company.

[16] *See* New Jersey Board of Public Utilities, *In the Matter of the Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Concerning Its Proposed Capacity Management Plan*, Docket No. GM07100752, Order, March 19, 2008. The sharing ratio varies depending on the level of net margins. The asset manager keeps 100 percent of the first $5 million of net margins to cover its minimum fixed annual payment to the utility. The asset manager and the utility share the additional net margins. The utility's entire share gets credited to the utility's purchased gas adjustment mechanism.

> arrangement provides for a sharing of the capacity release credits, off-system sales margins and storage arbitrage margins … [and] that Elizabethtown will make a filing with the Board to competitively bid its asset management and gas supply arrangement on or before March 31, 2010.[17]

The Kentucky Public Service Commission has addressed four issues that have arisen from asset management arrangements:[18] (1) the request-for-proposals (RFP) process where there are a decreasing number of bidders over time, (2) the asset manager's adherence to the commission's affiliate transaction rules, (3) the creditworthiness and other requirements of an asset manager (the original asset managers for the two utilities filed for bankruptcy),[19] and (4) the effect of an asset-management relationship on hedging and performance-based regulation.

Sequent Energy and Atmos Energy Marketing act as asset managers for several affiliated gas utilities.[20] Gas utilities located in Georgia, Kentucky, New Jersey, Tennessee, and Virginia relied on at least one of these companies. Many of the utility-affiliate arrangements involve Sequent Energy paying the utility a fixed fee and both parties sharing in the net margins obtained from selling unused pipeline capacity to the market. The utility retains full operational control through mandatory compliance with a predetermined seasonal storage and operational plan. The agreement includes non-performance penalties and remedies.

A Georgia gas utility, Atlanta Gas Light, has a contract with an affiliate, Sequent Energy, to perform asset management. Since 2003, Sequent Energy has managed the utility's gas supply, transportation, and storage assets. The utility and the affiliate share in the margins from off-system sales and capacity release. In a past docket the commission denied extension of the relationship, requiring the utility to issue an RFP for asset-management services.[21] The

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[17] *Ibid.*, at 3-4.

[18] E-mail from Dawn McGee, Rate Analyst, Kentucky Public Service Commission, May 2, 2008. The Kentucky commission has approved asset management agreements for both Atmos Energy and Duke Energy. Each utility receives an "access" fee from the asset manager, which passes through the purchased gas cost clause as a credit. The commission views the major objective of asset management as making use of an underutilized asset such as pipeline and storage capacity under contract.

[19] Any outsourcing arrangement, as noted earlier, carries a counterparty risk in that the asset manager, for example, might face financial difficulties that prevent it from making required payments to the utility or from buying or selling gas when needed by the utility.

[20] The affiliated gas utilities and Sequent Energy are wholly owned subsidiaries of AGL Resources, a registered holding company. The affiliated gas utilities include Virginia Natural Gas, Atlanta Gas Light, Chattanooga Gas, and Elizabethtown Gas.

[21] *See* Georgia Public Service Commission, *Atlanta Gas Light Company's 2004-2007 Capacity Supply Plan*, Order Denying Extension of Asset Management Agreement, Docket No. 18437-U, July 19, 2007.

commission staff reviews the RFP prior to issuance. The commission also requires the utility to conduct an annual benchmark study that evaluates Sequent's performance relative to specified benchmarks. The commission staff reviews the results of the study and reports its findings to the commissioners.

In many instances, the utility chooses the asset manager through an RFP process that mitigates the possibility of self-dealing abuses.[22] Since the gas utility is ultimately responsible for reliable and reasonably priced gas supply, most often it remains closely involved in procurement and asset management decisions (even on a daily basis).

### B. Case studies

Five states in particular have conducted investigations on either existing outsourcing arrangements or the prospects for such arrangements. These states are Indiana, Minnesota, Tennessee, Virginia, and Washington.

#### 1. Indiana

In Indiana, the commission and non-utility stakeholders questioned whether an existing outsourcing arrangement could produce more benefits to utility customers and provide more transparent information. As in other states, the outsourcing arrangement in Indiana has evolved over the years to eliminate apparent problems and produce outcomes more in line with expectations.

In 2002 and 2006, the commission approved separate settlement agreements regarding gas supply services provided by ProLiance Energy to Indiana Gas Company, Southern Indiana Gas and Electric Company, and Citizens Gas & Coke Utility.[23] ProLiance Energy is a limited liability company that is owned jointly by affiliates of three Indiana gas utilities. It was created to provide "synergistic" benefits to the utilities by combining gas supply and planning,

[22] In choosing an outside firm, a utility considers a number of factors, including experience in managing pipeline and storage assets, conducting gas sales off-system and behind the gas utility's system to the utility's transportation customers, knowledge of the regional gas market, the fee offered to the utility for selling its unused assets, and the firm's financial strength.

[23] Indiana Utility Regulatory Commission, *Verified Joint Petition … for Approval of New Supply Agreements with ProLiance Energy, LLC*, Order, Cause No. 42973, April 25, 2006. The Commission initially approved, in Cause No. 40437, the contractual arrangements between the utilities and ProLiance Energy in September 1997. In 2002 the commission approved, in Cause Nos. 42233 and GCA50-S1, a settlement agreement resolving outstanding issues identified earlier in Cause No. 40437. In 2006, a second settlement agreement, in Cause No. 42973, addressed issues relating to the continuation of the utilities' agreement with ProLiance Energy.

enhancing bargaining power in the wholesale gas marketplace, and eliminating duplicative resources.

The agreements addressed five major issues first raised by parties during the early years of the outsourcing arrangement between ProLiance Energy and the Indiana gas utilities. These issues are: (1) transparency of information, (2) profit sharing, (3) capacity release access, (4) supply planning protocol, and (5) the adoption and clarity of affiliate guidelines.

The commission concluded that the terms in both the 2002 and 2006 settlements were in the "public interest based on demonstrated cost savings made possible via the joint administration of the utilities' supply portfolios." Under the agreements, according to the commission, ProLiance will continue to provide delivery services at a savings compared to what the utilities could achieve individually without the benefit of joint portfolio administration. The utilities' customers and ProLiance will share the benefit of those savings on a 50/50 basis.

The commission also approved the stipulation that the utilities will continue to have ownership of the supply planning process, including final decision-making authority for individual supply plans. The utilities are to collaborate, and may use ProLiance as a resource to optimize their supply resources and create synergies where possible. The utilities, however, may not delegate supply planning responsibility to ProLiance. Finally, the state's consumer counsel (or its auditor) has the right to monitor all aspects of the supply-planning process, including ProLiance Energy's role. Overall, the commission continued to find benefits from the joint administration of the utilities' supply portfolios.

The major provisions included in the settlement agreements approved by the commission called for:

1. competitive bids for future service prior to expiration of the supply agreements between ProLiance Energy and the utilities;

2. a capacity auction allowing the utilities to sell their underutilized pipeline capacity and to split the proceeds between their customers and themselves on an 85/15 percent basis, respectively;

3. a gas cost incentive mechanism (GCIM) that rewards and penalizes the utilities based on their performance in procuring gas for their customers;

4. increased allocation of benefits to the utilities' customers;

5. the utilities to continue to have responsibility for their own supply planning and for demonstrating the reasonableness of their gas costs as part of the gas cost adjustment (GCA) process;

6. large customers and marketers to have non-discriminatory access to a large portion of the utilities' available unused pipeline capacity entitlements;

7. half of the utilities' unused pipeline capacity entitlements to be offered by the utilities through a prearranged sales process that will solicit bids, with the other half retained by ProLiance Energy for marketing;

8. the utilities to adopt and clarify affiliate guidelines;

9. the utilities to pay customers $21 million, consisting of a one-time $7.5 million GCA refund by each utility, annual demand reductions, and a total of $2 million per year for three years designated for low-income assistance; and

10. a commission-administered enforcement process that includes financial penalties under certain conditions.

### 2. Minnesota

Minnesota was one of the early states to investigate the outsourcing of gas utilities' gas and transportation procurement functions.[24] The commission addressed two broad issues: (1) the benefits of outsourcing and (2) alternative regulatory policies with respect to outsourcing.

The commission initiated a proceeding by asking the parties four fundamental questions on outsourcing:

1. What are the potential benefits and costs of outsourcing the entire natural gas procurement function through competitive bidding?

2. Is outsourcing an efficient way to capture the benefits of competition for natural gas customers?

3. How would the benefits and costs of outsourcing compare to: (a) the current practice of using competitive bidding for individual supply, storage, and transportation contracts, and (b) retail choice for small customers?

4. Is the implementation of outsourcing feasible, given possible impediments in the following areas: (a) legal and regulatory, (b) corporate strategic business planning and culture, and (c) gas utility operations and reliability of service?

The Minnesota commission concluded that it probably cannot legally order a gas utility to outsource.[25] Commission staff argued, however, that the commission might have the authority

[24] *See* Minnesota Public Utilities Commission. *In the Matter of an Investigation into Outsourcing of Gas and Transportation Procurement Functions*, Staff Briefing Paper, Docket No. G-999/CI-99-688, January 11, 2000.

[25] *See* Minnesota Public Utilities Commission. *In the Matter of an Investigation into Outsourcing of Gas and Transportation Procurement Functions*, Order, Docket No. G-999/CI-99-688, February 14, 2000.

to require a utility to outsource its gas supply function if evidence of malfeasance or gross mismanagement by the utility exists.

The commission expressed its preference for reviewing a utility's proposal to outsource on a case-by-case basis. Parties commented that voluntary outsourcing is a viable, if not essential, alternative for small or troubled gas utilities performing on a subpar level because of their limited resources. Small utilities might lack adequate internal staff expertise and resources to perform their own gas procurement and asset management function; they also might have difficulties in satisfying the credit requirements of gas suppliers and pipelines.

Some parties pointed out that outsourced gas supply would be more expensive than the cost of gas under the current regulatory structure because the outside supplier would assume risks, for which it must be compensated, and would include a profit in the bid price. In contrast, a gas utility receives no profit, nor is it compensated for the risks it takes in supplying natural gas.[26]

The Minnesota commission's final decision agreed with the position of most parties that outsourcing could be a useful alternative for small gas utilities or utilities facing serious management problems. For other utilities, parties were unclear as to whether outsourcing offered cost advantages over traditional prudence review or over other regulatory approaches such as performance-based gas incentive plans. In conclusion, the commission considered outsourcing as a business strategy deserving careful consideration. It expressed the position that outsourcing can provide a benchmark for reasonable gas costs and a preferred long-term strategy as well.

### 3. Tennessee

In Tennessee, the three largest gas utilities have agreements for asset-management services.[27] At the time of this writing, the state's regulatory agency is in litigation in which a

[26] Some readers might question how an outside firm can provide a gas utility with lower-priced gas supplies when it buys gas from the same suppliers as the utility. Some critics of outsourcing argue that the price would likely be higher because of the profits going to a new middleman, the outside firm.

[27] *See* Tennessee Regulatory Authority, *Review of Nashville Gas Company's Incentive Plan Account Relating to Asset Management Fees*, Order Approving Settlement, Docket No. 05-00165, December 14, 2007; Atmos Energy Corporation, *Request of Atmos Corporation for Approval of Contract(s) Regarding Gas Commodity Requirements and Management of Transportation Storage Contracts*, Preliminary Filing of Requests for Proposal, Docket No. 08-00024, February 7, 2008; Tennessee Regulatory Authority, *Request of Chattanooga Gas Company for Approval of Asset Management Agreement*, Order Setting Issues for Resolution, Discovery and Procedural Schedule, Docket No. 08-00012, February 12, 2008; and Office of the Attorney General, State of Tennessee, *Request of Chattanooga Gas Company for Approval of Asset Management Agreement*, Customer Advocate's Brief, Docket No. 08-00012, February 20, 2008.

major issue is whether the present profit-sharing arrangement between a local gas utility and its asset manager is appropriate and fair to utility customers.

In addition to profit sharing, other concerns raised by customer groups were: (1) the length of the multi-year agreement; (2) safeguards against oversubscription of storage and capacity assets in relation to jurisdictional requirements; (3) efficacy of affiliate guidelines; (4) the asset manager's profits; (5) the adequacy of the asset management fee in relation to the economic value of the assets; and (6) the process for selecting an asset manager.[28] All the gas utilities presently use an RFP process to select an asset manager, which was not always the case.[29]

In December 2007, the commission ordered the adoption of new RFP procedures for soliciting an asset manager.[30] These procedures include: (1) describing the "content" requirements of the bid proposals and including methods for the evaluation of the bid proposals, and (2) specifying criteria for the selection of the winning bid, including at a minimum (a) the total value of the bid proposal, (b) the qualifications and the experience of the proposer, (c) the financial strength and stability of the proposer, and (d) the capability to perform the RFP tasks. The utility should select the bid with "the best combination of attributes based on the evaluation criteria." The new procedures contain the important provision that present asset managers, if they want to continue serving the utility after contract expiration, must submit a bid like other parties and must be evaluated using the same criteria.

In an ongoing docket (at the time of this writing), testimony by the state's Office of the Attorney General (AG)[31] addressed a number of concerns regarding the present asset management arrangement between Chattanooga Gas Company and an affiliate, Sequent. These concerns are representative of those raised by commissions and stakeholders in other jurisdictions as well.

One major concern was whether the utility's customers were receiving "just and reasonable" compensation under the agreement. The agreement calls for Sequent to use Chattanooga's excess pipeline and storage capacity and share the net margins with the utility and

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[28] Office of the Attorney General, State of Tennessee, *Docket to Evaluate Chattanooga Gas Company's Gas Purchases and Related Sharing Incentives*, Consumer Advocate's Identification of Issues, Claims and Remedies, Docket No. 07-00224, March 12, 2008.

[29] The Tennessee Regulatory Authority requires an RFP process and its review and approval of an asset management contract.

[30] Tennessee Regulatory Authority, *Review of Nashville Gas Company's Incentive Plan Account Relating to Asset Management Fees*, Order Approving Settlement, Docket No. 05-001165, December 14, 2007.

[31] Office of the Attorney General, State of Tennessee, Direct Testimony of Terry Buckner, before the Tennessee Regulatory Authority, Docket No. 07-00224, May 30, 2008.

its customers. In the present agreement, Sequent pays the utility 50 percent of the net margins in addition to guaranteeing a minimum management fee.[32]

The AG witness noted that many asset management arrangements around the country provide the utility with a minimum management fee plus a share of the net margins in excess of the minimum fee. Suppose, as an illustration, that the minimum fee is $2 million, the actual net margins were $5 million, and the sharing parameter was 0.5 (i.e., 50 percent of the "excess" net margins goes to the utility). In this example, the utility receives the sum of $2 million (from the minimum fee) and $1.5 million (50 percent of the "excess" net margins or $3 million). The asset manager recovers his $2 million paid as the minimum fee plus earns $1.5 million. As a share of the actual net margins, the utility receives 70 percent and the asset manager 30 percent.

The AG witness recommended that the share of the net margins (above the minimum fee) allocated to the utility be increased from 50 percent to 85 percent. The witness, in addition, recommended that 90 percent of the utility's share be credited to customers, an increase from the present 50 percent. These combined changes would increase significantly the share of "excess" net margins going to the utility's customers—from 25 percent (50% of 50%) to 76.5 percent (85% of 90%). The witness justified this large increase as being reasonable and fair to customers since they pay 100 percent of the capacity used by the asset manager to create the net margins.[33] The witness recognized that with a higher share going to the utility, the asset manager would bid a smaller amount for the minimum management fee.[34]

The witness also criticized the utility's RFP process for its vague criteria in selecting the winning bid. He recommended that the utility keep records showing its compliance with RFP procedures. He emphasized that a fair and transparent RFP procedure should mitigate the problem of a utility favoring an affiliate. Finally, he supported auditing the management of the utility's assets every three years.

#### 4. Virginia

In Virginia, the commission staff issued a report on asset management. The report was the product of a commission-initiated investigation and an audit of the existing asset-management agreement between Virginia Natural Gas (VNG) and its affiliate, Sequent Energy.[35]

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[32] As long as Sequent is the asset manager, all of the 50 percent goes to Chattanooga's customers. Otherwise, with another asset manager, Chattanooga's customers receive only half of this percentage, or 25 percent.

[33] Customers pay for that capacity through the purchased gas adjustment mechanism.

[34] The minimum fee represents an access-like charge for the right to sell a utility's idle pipeline and storage capacity. The lower the net margins that an asset manager expects to receive from sales, the less it values the right to make those sales.

[35] *See* Virginia State Corporation Commission, *Investigation of Gas Supply Asset Assignment and Agency Agreement Between Virginia Natural Gas, Inc., and Sequent Energy*

The commission's motive for the investigation and audit was to determine whether the agreement remains in the public interest. In its initial approval of the agreement, the commission noted that:

> [A]n essential task of the energy manager is to find, create, and take advantage of physical and financial market opportunities by managing VNG's assets in combination with other assets in order to meet the requirements of VNG's customers more efficiently. By allowing VNG to obtain natural gas procurement and asset management services from a consolidated and centralized source, the Agreement was designed to allow VNG to take advantage of economies of scale and other business efficiencies that would minimize the price of natural gas and create value for VNG and its customers.[36]

Sequent Energy acts as an agent in managing the supply, transportation, and storage contracts presently held by the utility. This arrangement, as expressed by the Virginia Corporation Commission, has allowed the utility to benefit from the economies of scale and other business efficiencies realized by Sequent. These efficiencies can lead to lower purchased gas costs for the utility and increased value of its pipeline and storage assets, with retail customers benefiting from revenue crediting.

The report discusses several aspects of an asset-management arrangement. The most important ones include:[37]

1. *Legal rights to a utility's assets:* Commission staff recommended an agency relationship;[38] assignment, it said, could limit the utility's legal rights to its own supply, transportation, and storage contracts during the term of the agreement.

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*Management, L.P., f/k/a AGL Energy Services, Inc.*, Staff Report and Joint Motion to Approve Affiliate Agreements and Close Investigation, Case No. PUE-2004-00111, October 14, 2005; and Virginia State Corporation Commission, *Investigation of Gas Supply Asset Assignment and Agency Agreement Between Virginia Natural Gas, Inc., and Sequent Energy Management, L.P., f/k/a AGL Energy Services, Inc.*, Order Approving Affiliate Agreements and Closing Investigation, Case No. PUE-2004-00111, October 31, 2005.

[36] Virginia State Corporation Commission, *Investigation of Gas Supply Asset Assignment and Agency Agreement Between Virginia Natural Gas, Inc., and Sequent Energy Management, L.P., f/k/a AGL Energy Services, Inc.*, Order Approving Affiliate Agreements and Closing Investigation, Case No. PUE-2004-00111, October 31, 2005, 1.

[37] See also Patrick W. Carr, "Asset Management Agreements and the Gas Utility Industry," presentation at the NASUCA Annual Meeting, November 13, 2006.

[38] In an agency relationship, according to the staff study, the assets would remain in the gas utility's name.

Assignment of capacity rights to the asset manager could jeopardize the utility customers' interest while increasing the potential profits of the asset manager.

2. *Gas supply pricing:* Staff favored a "virtual dispatch" approach for weighting gas quantities actually taken at each receipt point; the approach should correspond to the least-cost gas costs for a utility procuring its own gas; otherwise, the benchmark may be set too high, with the utility paying too much for gas.[39]

3. *Use of a utility's capacity or assets:* Commission staff emphasized the need to place top priority on meeting the needs of retail customers. An outside firm's use of utility assets, in other words, should be limited to that portion not needed by the utility. Staff warned that optimization by the asset manager may cause more frequent interruptions of non-firm utility load.

4. *Agreement duration:* The typical duration of asset management agreements is two to five years. Shorter durations give the utility more flexibility; staff recommended that contracts should include standard "out" clauses to cover circumstances such as bankruptcy or failure to perform.

5. *Asset-manager compensation:* A fixed fee provides revenue certainty to the utility but it may provide the asset manager with a weak incentive to maximize value. Staff warned that while margin or profit-sharing arrangements provide strong incentives, they require much care in design to ensure that the utility receives its fair share. (See Part IV.C of this paper for an analysis of this issue.)

6. *Affiliated relationship:* Affiliated relationships require special scrutiny because of the possibility for self-dealing abuses. (See Part IV.B of this paper for an analysis of this issue.)

7. *Utility oversight of the agreement:* The commission staff recommended that the utility take an active role in monitoring the asset manager's performance and operating practices affecting the utility.[40] (See Part IV.D of this paper for an analysis of this issue.)

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[39] Under the staff proposal, the utility's payment to the asset manager is based on index prices, with the quantities established by the utility's "virtual dispatch." Staff recommended that VNG creates virtual dispatch plans on a continuing basis, as though VNG was actually dispatching the gas. (The then-current practice was that the price for gas delivered to VNG on any given day is based on the weighted average cost of what VNG is allowed to take and transport, i.e., its entitlements under its existing transportation contracts. Sequent can profit by beating the weighted average entitlement price. Staff argued that this practice, while benefiting Sequent, also increases VNG's cost of gas.)

[40] The report recommended that the utility establish a management/operational group responsible for oversight of the asset manager's performance and operating practices,

8. *Reporting requirements to the commission:* Information reported to the commission, at the minimum, should include the price of gas supplies to the utility, the calculation of the margins from the sale of unused assets, the utility's share of the margin, and the utility's internal controls.

### 5. Washington

In Washington, the commission rejected continuation of an outsourcing arrangement between Avista Utilities and its marketing arm, Avista Energy.[41] The commission raised particular concerns about affiliated arrangements:

> The danger in an affiliated interest arrangement is that the pressure for profit creates a risk to ratepayers that management may shift the costs and burdens of company operations so that beneficial aspects flow to the affiliate (while benefiting the same stockholders) and burdensome aspects flow to the regulated company (and ultimately to ratepayers). In other words, any affiliated transaction poses a risk to ratepayers. Risks of manipulation, intentional or not, are inherent in any arrangement of this sort and are difficult to discover.[42]

The utility argued that its dealings with Avista Energy have benefited customers because of the affiliate's greater presence in the market for commodity, transportation, and storage services. The utility also argued that Avista Energy assumes some of the risks and costs associated with gas procurement that would otherwise be borne by the utility (e.g., nomination errors, counter party risk, some operation flow order risk, and entitlement risk). The utility added that its outsourcing agreement is able to optimize unused pipeline capacity through capacity releases and off-system sales to third parties. Finally, it argued that Avista Energy can do a better job than the utility because it has a different risk profile than the utility and it is an active participant in the market.[43]

A dissent by one of the commissioners concurred with the utility's view:

> By an order of magnitude or more, Avista Energy has more trades, more trading partners, more opportunities for offsetting trades, more flexibility and choices among capacity release, off-system sales and basin optimization, more ability to maintain a broad and deep trading staff, etc. The majority discount these features, observing that because Avista Utilities management already makes the final trading decisions, it can be successful in taking over the whole gas-procurement

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[41] *See* Washington Utilities and Transportation Commission, *Complaint v. Avista Corporation d/b/a Avista Utilities*, Sixth Supplemental Order Rejecting Benchmark Mechanism Tariff, Docket No. UG-021584, February 13, 2004.

[42] *Ibid.*, at 3.

[43] *See* Avista Corporation, Direct Testimony of Michael D'Arienzo, before the Washington Utilities and Transportation Commission, Docket No. UG-021584, April 18, 2003.

> function. This observation misses the point: now, Avista Utilities is permitted to take advantage of Avista Energy's operations; if Avista Utilities takes back the gas-procurement function, it will not be able to make the same decisions, because it will not be able to benefit from (or even be privy to) the range of choices provided through Avista Energy's scale, flexibility, and expertise.[44]

The commission, however, concluded that the affiliate, Avista Energy, benefited from the outsourcing relationship; it could not, however, find benefits for the utility and its customers.[45] The commission concluded that the utility is able to achieve the same results in gas procurement as its affiliate; no need, therefore, exists to continue the arrangement with its affiliate. Commission staff argued that the arrangement creates perverse incentives: it induces Avista Energy to favor capacity release and off-system sales over basin optimization because the agreement guarantees that Avista Utilities earns $3 million in revenues from capacity release and off-system sales. This perverse behavior could cause higher rates to customers. The commission also found that the utility failed to demonstrate adequate safeguards against the possibility of self-dealing abuses.

### C. FERC Order 712: Facilitating outsourcing arrangements

On June 19, 2008, FERC enacted rules (Order 712) that facilitated asset management arrangements (AMAs). FERC recognized the benefits in improving the efficiency of capacity markets and transactions tailored to customer needs:[46]

> AMAs provide significant benefits to many participants in the natural gas and electric marketplaces and to the secondary marketplace itself. They maximize the utilization and value of capacity by creating a mechanism for capacity holders to use third party experts to both (1) manage their gas supply arrangements and (2)

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[44] *See* Washington Utilities and Transportation Commission, *Complaint v. Avista Corporation d/b/a Avista Utilities*, Sixth Supplemental Order Rejecting Benchmark Mechanism Tariff, Docket No. UG-021584, February 13, 2004, 50.

[45] The commission reasoned that the agreement appeared to create rewards to Avista Energy for merely tracking market trends, exposing it to little risk and calling for a limited need for Avista Utilities to draw on the affiliate's market experience. The commission also opposed continuation of the agreement because it could not audit its performance: parties did not provide the commission with information on either the market value of services provided by Avista Energy or Avista Energy's cost of providing service to Avista Utilities.

[46] Federal Energy Regulatory Commission, *Promotion of a More Efficient Capacity Release Market*, Final Rule, Docket No. RM08-1-000, June 19, 2008. Asset management, as defined by FERC, is a contractual arrangement where one party agrees to manage the gas supply and delivery arrangements, including transportation and storage assets, for a gas utility. It might involve, for example, a gas utility releasing its surplus pipeline or storage capacity to an outside entity which will perform the functions that the releasing utility could do for itself.

> use that capacity to make gas sales or re-releases of the capacity to others when the capacity is not needed to serve the releasing shipper. AMAs result in ultimate savings for end-use customers by providing for lower gas supply costs and more efficient use of the pipeline grid.[47]

In its order, FERC eased certain restrictions on short-term pipeline capacity release transactions. This action helps to facilitate asset management transactions by exempting: (1) capacity releases made as part of an asset management arrangement from the existing prohibition on tying[48], and (2) asset management arrangements from bidding requirements in existing FERC regulations.[49] These requirements included the posting of capacity-release transactions for competitive bidding, unless the transactions are at the maximum rate or are for thirty-one days or less. The FERC reasoned that:

> Based on the industry-wide support for AMAs [asset management arrangement] as shown in the comments, the Commission finds that AMAs are in the public interest because they are beneficial to numerous market participants and to the market in general. Thus, the Commission is modifying the prohibition on tying, the Part 284.8 regulations concerning bidding, and making additional policy changes requested by the commenters discussed below in order to eliminate obstacles to the utilization and implementation of AMAs.[50]

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[47] *Ibid.*, at 22. FERC noted that other than gas utilities, other large natural gas users, such as electric generators and industrial customers, have benefited from asset management arrangements. These users rely on asset managers to avoid having to spend time and money on acquiring the internal expertise necessary to manage their gas supply and transportation arrangements. The American Gas Association (AGA), in comments before FERC, expressed the view that asset management arrangements provide benefits by increasing the load-responsive use of gas supply, increasing liquidity in the capacity markets, and more efficiently utilizing capacity. (*See* American Gas Association, *Comments of the American Gas Association*, FERC Docket No. RM08-1-000, January 25, 2008.)

[48] FERC acknowledged the common feature of asset management arrangements requiring the releasing shipper (e.g., the gas utility) to release both its capacity and gas supply in a single package. This capacity normally includes the sum of the capacity needed by the releasing shipper and the unneeded capacity that the asset manager can resell in the wholesale market.

[49] The predominance of comments supported FERC eliminating the requirement for competitive bidding in the context of an asset management arrangement.

[50] Commenters argued that the bidding requirements prevent the timely closing of asset management transactions involving the bundling of pipeline capacity and gas supply or the bundling of capacity on multiple pipelines. FERC, in effect, reasoned that the benefits of facilitating asset management arrangements exceed any costs from relaxing the regulations.

FERC's action should increase interest by marketers and others to provide asset management services. The pre-Order 712 restrictions stifled profit opportunities that likely would have drawn additional firms to provide such services.

# IV. Major areas of consideration for state commissions

A review of outsourcing activities by gas utilities in the form of asset management and gas procurement points to several issues.[51] These issues relate to the calculation of the benefits and the costs, the distribution of the benefits from an asset management arrangement, the affiliate relation between the utility and the outside firm, the length of the utility-outside firm arrangement, and the process for selecting an outside firm. Other less apparent issues include transparency of information and the rights of the outside firm to sell excess capacity relative to the rights of a utility's retail customers.

## A. The fundamental regulatory question: Do the benefits of outsourcing exceed the costs?

### 1. Economic gains

Outsourcing raises a fundamental question for state commissions: whether the benefits outweigh the costs. The gas utility purchases pipeline and off-system storage capacity in line with the demand characteristics (e.g., load shape) of its customers. This capacity is often underutilized. An outside firm offers the opportunity to market that capacity and produce revenues beyond the revenues the utility might receive through capacity release and its other actions.

The outside firm might have more scale, flexibility, and expertise in natural gas markets than the local gas utility. Under a typical asset management arrangement, the utility perceives the outside firm to have greater skill and expertise both in purchasing low-cost gas supplies and in maximizing the value of pipeline capacity not needed to meet the utility's gas supply needs. The asset manager also may have superior access to different markets and more flexibility to maximize the value of assets, in addition to realizing scale economies. The asset manager, in addition, can achieve more economical results from procuring gas for several entities with a diverse and a more "even" demand profile.[52] These conditions can lead to efficiency gains.

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(Federal Energy Regulatory Commission, *Promotion of a More Efficient Capacity Release Market*, Final Rule, Docket No. RM08-1-000, June 19, 2008, 81.)

[51] Part III of this paper highlighted these issues for several outsourcing arrangements.

[52] The outside firm, for example, can purchase gas for a group of entities that collectively have a higher load factor and a more attractive load shape than an individual utility's "peaky" load shape.

Gas utilities have argued that outsourcing can: (1) provide reliable, least-cost supply and transportation service to their customers; (2) optimize the competitive value of their supply, transportation, and underground-storage assets;[53] and (3) optimize their combined resource portfolios to reduce the unit cost for sales customers. Asset management allows a gas utility to increase the utilization of its facilities and lower gas costs.[54] By generating additional revenues from capacity release, off-system sales, and market sales of stored gas, an outside firm can increase the amount of revenues credited to retail customers from carrying out these functions. The above arguments particularly hold for small utilities that may not have the size or expertise to maximize their efficiencies from procuring gas or managing their physical assets.[55] Small utilities, in addition, may have a credit problem that limits their ability and flexibility to make economical purchases.[56]

The increased revenues or value from the management of a utility's assets by an outside firm can derive from different sources. The outside firm may better exploit market conditions to gain a higher price. It may more aggressively market the unused assets, leading to a higher utilization rate and more sales. It may bundle a utility's excess capacity with gas supplies and other components more proficiently to optimize the value of the capacity.[57] This rebundling can produce economies of scope by combining different "components" into one package.[58] These

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[53] An asset manager, for example, might have more flexibility than a utility to customize service bundling arrangements to meet the varying needs of wholesale buyers. These arrangements might include combining gas supply with transportation service in a way that increases value to buyers than if these components were sold separately.

[54] The potential benefits of asset management in selling a utility's unused capacity are negatively correlated with the utilization rates of its pipeline and storage capacity: the more unused capacity a utility has, the more excess capacity is available for sale by the asset manager. The benefits also depend upon the ability of the asset manager to earn value from the unused capacity—that is, to receive as high a price as possible.

[55] Some evidence exists, however, that small utilities lack appeal for asset managers because of the relatively small amount of unused capacity and storage capacity available for resale.

[56] An asset manager may overcome the credit problem by using its own lines of credit.

[57] Gas utilities tend to resell their excess pipeline and storage capacity as stand-alone services; asset managers more commonly package the excess capacity with commodity gas to sell on the market. (Richard Lelash, "Gas Supply Procurement Review," presentation to the NASUCA Gas Committee, January 13, 2009.) In using the gas utility's capacity for bundled sales to third parties, the asset manager must comply with FERC buy/sell rules.

[58] Economies of scope can lead to cost savings from one entity bundling gas supply, storage, and transportation into one package relative to the total costs of different entities providing these components separately.

economies can result in lower costs to the customer relative to buying the components separately; or in higher value to customers relative to the aggregate value of the individual components.[59] Rebundling also would lower transaction costs for buyers. Lower transaction costs mean that buyers and sellers incur fewer costs, in addition to price, in consummating trades. High transaction costs preclude trading that would otherwise be economical and beneficial to market participants. Consumers, because of transaction costs, may prefer a bundled product over one where they would have to purchase separate components and "assemble" them themselves.[60]

Outsourcing of gas procurement and asset management can help to focus a utility's attention on its core competencies such as managing and operating its distribution system. If a gas utility were to increase its profits at the margin, it would have an incentive to devote more internal resources to those activities that a have a direct bearing on profits. Most gas utilities make little or no profits from the buying and reselling of gas. They also receive few or little profits from reselling their surplus pipeline capacity and from off-system sales, as retail customers receive most or all of the benefits (e.g., from revenue crediting).

### 2. The cost of contracting relative to vertical integration

One possible cost of contracting with an outside firm is the utility's loss of control over some functions that were managed internally. Starting with Ronald Coase, economists have examined the significance of transaction costs[61] in influencing the institutional arrangement (e.g., vertical integration, market trades) for the exchange of goods and services.[62] The transaction-cost literature has shown that governance structures will evolve to minimize transaction costs.[63]

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[59] Assuming that the value of bundling to buyers is no greater than the value of its components, mixed bundling (i.e., the offering of both a rebundled package and separate components) is a distinct strategy only if package is sold at discount relative to its components.

[60] In the natural gas sector, for example, residential and small commercial customers may incur high transaction costs (per unit of gas consumed) to acquire unbundled services from multiple suppliers that more than offset the benefits from purchasing some of these components in a competitive market. (These transaction costs might consist of search cost and the time spent in deciding what supplier to choose.) These customers would, therefore, find it economical to purchase bundled service from one supplier, even if that supplier does not operate in a competitive market.

[61] Transaction costs are costs, other than price, that firms incur in transacting business. These costs include the cost of negotiating, writing and enforcing contracts.

[62] *See* Ronald Coase, "The Problem of Social Cost," *Journal of Law and Economics* 3 (October 1960): 1-44.

[63] *See*, for example, Oliver E. Williamson, *Markets and Hierarchies: Analysis and Antitrust Implications* (New York: The Free Press, 1975). Low transaction costs mean that

In the instance of contracts for outsourced services, transaction costs originate from (1) information acquisition, (2) initial negotiation, (3) monitoring, (4) enforcement, (5) contract renewal issues, and (6) deviation of evolving market conditions from contract terms and conditions. When these costs are high relative to the transaction costs of vertical integration (i.e., no outsourcing), outsourcing arrangements become less economically attractive.

A vertical structure—where, for example, a utility performs all of the business functions internally—tends to prevail when the purchase of control rights are infeasible or too costly to include in a bilateral contract. Some of these rights include the elimination of opportunistic behavior by an entity with market leverage. Internal allocation mechanisms can help to mitigate these kinds of transactions costs, but they lead to other costs. The costs of internal organization could derive from the relatively inferior adaptive behavior of bureaucratic hierarchies (e.g., the organizational structure of a large utility) to rapidly changing outside opportunities and circumstances over the longer term. Problems also exist with the difficulty of designing a corporate-wide compensation mechanism that gives managers and employees appropriate incentives to control costs and maintain high performance in other areas. No governance structure is free from at least some transaction costs. The decision about whether or not to vertically integrate or outsource certain functions then becomes a tradeoff between the costs of alternative governance arrangements.

What this argument implies for outsourcing is that unless a gas utility feels it can manage a contract for asset management with an outside firm to its satisfaction, it would tend to perform the function itself. Vertical disintegration of gas utilities could increase transaction costs and eliminate scope economies from one firm undertaking different but interrelated functions.[64] By outsourcing gas procurement, a utility might incur high contracting costs and lose the economies from efficiently synchronizing gas purchases with utilization of its contracted pipeline capacity.

The contact between a utility and an outside firm for gas procurement and asset management services might entail several complexities that would make such a contract infeasible or highly costly to negotiate and enforce. These complexities can stem from having to determine the sharing of the revenues from sales of excess capacity or rebundled services, actual control of the utility's assets by the outside firm, the benchmark for determining reasonable prices for procured gas, the division of responsibility between the utility and the outside firm, and the role of the utility in monitoring the performance of the outside firm.

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buyers and sellers incur minimal costs, in addition to price, in consummating trades. High transaction costs preclude trading that would otherwise be economical and beneficial to buyers and sellers.

[64] Scope economies, in this context, refer to the situation in which the cost of the gas utility performing the functions of gas procurement and asset management internally is lower than the cost of having the utility performing one of these functions and an outside firm performing the other function.

### 3. Stronger regulatory incentives to deal with one problem addressed by outsourcing

In most states, utilities lack strong incentives to perform these activities at high levels of efficiency. Economic theory says regulated utilities may not have strong incentives to pursue a least-cost strategy because of their monopoly position in retail markets and the cost-plus nature of traditional regulation; regulated utilities do, however, try to prevent excessive costs that become publicly transparent because of the risk of cost disallowance, which would lower their earnings. But even when trying to avoid a cost disallowance from grossly subpar performance, the utility does not have strong economic incentives to perform exceptionally well.[65] The lack of strong incentives partially derives from purchased gas adjustment (PGA) mechanisms that permit pass-through of cost changes with little likelihood of effective prudence review. A utility may be lax in finding the best deals for gas supplies or managing its unused pipeline capacity most efficiently. An effective incentive mechanism,[66] as argued in an NRRI report,[67] can motivate a utility to improve its performance by:

1. Applying more resources to the function (employing more highly qualified staff, acquiring superior market intelligence, and so forth);

2. Taking greater advantage of the considerable buying power that gas utilities and their agents have in the marketplace, by virtue of the large, stable, firm loads they represent, to negotiate lower prices or better terms;

3. Managing the substantial flexibility within asset portfolios to maximum advantage;

4. Harvesting the full value of the transportation and storage assets held for the procurement function when they are not needed to meet customers' needs, generating revenues that offset gas costs; and

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[65] A state commission may want to consider alternatives to incentive-based regulation or outsourcing in response to evidence showing less-than-acceptable performance by the utility in gas procurement or asset management. These alternatives include: (1) disallowance of imprudent costs, (2) performance standards for the utility functions involved, and (3) a management audit recommending new internal processes and other utility actions. In addition, the state commission should identify reasons for the utility's subpar performance.

[66] Under an effective incentive mechanism, purchased gas cost pass-through to customers should decline when the new incentives lead to a reduction in the actual cost of purchased gas, relative to costs without the incentives, that exceeds the "incentive payment" earned by the utility under the mechanism. An improper benchmark, or other factors, could produce negative outcomes to drive up the costs to a utility's customers. *See* Ken Costello and James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI Report 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

[67] *Ibid.*, at 2.

5. Taking calculated risks that, lacking incentives, gas utilities might be unwilling to take.

These outcomes correspond to the potential benefits from outsourcing. The questions for a commission are: (1) whether it (along with stakeholders) can design an effective incentive mechanism that would assure improved utility performance; and (2) even if it can, whether it might be more effective to implement an incentive mechanism to improve utility performance or, alternatively, to outsource gas procurement and asset management.[68] An incentive mechanism may fall short of achieving the same benefits that outsourcing might: an outsourcing firm may control upstream pipeline and storage capacity, for example, allowing it to make transactions using the utility's underutilized assets that a gas utility could not make on its own.

### B. "Outsourcing" to an affiliate

An affiliate relationship raises another fundamental question: whether this association constitutes genuine outsourcing or is just a device by which to make captive customers bear the risks while shareholders receive the rewards. Assume that both the utility and the outside entity are under the control of the same parent company. Their resources are then internal to a single corporation. Why could not the parent company allocate the expertise and skills of the other entity to the utility? Would not this allocation eliminate the middleman in carrying out the designated functions? Could not the costs to the utility's customers be held down as a result? One can legitimately ask: what is the real reason for an affiliate to provide services that the utility itself provides using the same resources of the parent company? The reason may simply be that the parent company expects to earn higher profits by allowing its unregulated affiliate to profit from providing services that the regulated utility had previously provided itself at less or no profit. This additional profit could come at the expense of the utility's customers. A benign explanation is that the unregulated affiliate is providing similar services to other utilities under the control of the same parent company. Economies of scale might, therefore, exist that would make this arrangement economically tenable and beneficial to all the utilities' customers.

Part III.A offers several examples in which the utility's asset manager is an affiliate. Unless a state commission has in place properly structured and strictly enforced[69] standards-of-conduct, competitive bidding, and affiliate pricing rules, the danger always exists that outcomes may lie contrary to the interests of the utility's customers. Self-dealing abuses can result in the unregulated affiliate benefiting at the expense of the utility's customers. An affiliate

[68] A third choice might be to implement a regulatory incentive mechanism and allow the utility to decide whether it wants to perform the functions internally or contract out to a third party. A utility might judge that an outside firm is better able to achieve and surpass "benchmark" performance in gas procurement and capacity management than it would be on its own.

[69] Strict enforcement requires utility cooperation in providing commission staff and other parties detail information on transactions, so that they can determine whether any self-dealing abuse has occurred.

relationship, for example, can provide an asset manager with an incentive to give better deals and procure lower-cost gas to entities other than the regulated utility.

The intent of standards of conduct is to prevent a utility from exploiting its monopoly status to the detriment of consumers—for example, by subsidizing an unregulated affiliate, or by erecting artificial entry barriers favoring an affiliate and stifling the development of competition from other asset managers. This exploitation results in anticompetitive practices.[70] Standards of conduct generally attempt to avoid two activities, each of which could adversely affect the utility's retail customers. The first involves inflating the price of regulated service through cost-shifting, cross-subsidization, and other practices. The second would, by giving discriminatory or preferential treatment to an affiliate, reduce the entry of other suppliers. A utility's customers would consequently pay higher prices for unregulated goods and services. In the instance of outsourcing, standards of conduct could help to prevent a utility from giving preferential treatment to an affiliate, which, from the perspective of the utility's customers, may not be the best choice of firm for providing the specified services.

Cost shifting, affiliate abuses, and cross-subsidies, all symptoms of bad behavior, occur for essentially two reasons.[71] First, regulators have less-than-perfect information about whether abusive or anticompetitive behavior exists. A utility, consequently, would have the ability to report costs that are improperly allocated to certain (e.g., "captive") customers. The second reason for bad behavior is that a utility's prices are primarily dependent upon its reported costs. When a utility reports higher costs, assuming approval by regulators, its prices would go up.[72]

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[70] Anticompetitive practices consist of behavior that violates normal market practices by making a firm better and consumers worse off. One example would be preferential treatment by a utility of its affiliate in gaining access to an essential facility. By erecting a barrier to nonaffiliates, competition diminishes, in the process allowing the affiliate to exercise market power. The outcome would be higher prices for consumers and higher profits for the affiliate.

[71] A parent company may find it profitable to shift some of the costs of its unregulated affiliate to the regulated utility. Cost-shifting is not always anticompetitive; it is, however, economically inefficient and unfair to a utility's customers, since it charges them for costs that they did not cause. It has the effect of raising the prices of regulated services (assuming that the commission allows the pass-through of those costs into rates). Yet it could have no effect on the unregulated market—it may simply be a way for the parent company to increase its profits by cost-accounting manipulation, rather than predation or other strategies giving an affiliate an advantage over its competitors. *See*, e.g., Jaison R. Abel, *An Economic Analysis of Marketing Affiliates in a Deregulated Electric Power Industry* (Columbus, OH: The National Regulatory Research Institute, 1998).

[72] This outcome assumes that prices are subject to rate-of-return regulation. Price caps, or some other kind of incentive-based regulation, can help to break the close linkage between prices and an individual utility's costs. Some analysts would argue that abuses stem largely from rate-of-return regulation, rather than monopoly power *per se*.

With an affiliate acting as the outside firm, the parent company may benefit from the local utility oversubscribing pipeline and storage capacity. This oversubscription results in an excess of pipeline or storage reserve capacity. By purchasing additional capacity, the utility would be financially responsible for more idle capacity that the outside firm can sell at a profit. The problem for the utility's customers is that the utility would try to recover from them the costs of the additional capacity.[73] There would thus be a mismatch of risk and reward: Absent close regulatory scrutiny, the utility's customers would bear backstop financial responsibility for the surplus capacity, while the affiliate (and the parent company's shareholders) would receive the benefits of extra revenues.

Efficient competition requires that prospective outside firms, whether affiliated or unaffiliated with the local utility, have equal opportunity to compete for the utility's business. "Equal opportunity" has different connotations among the different interest groups, as well as among economists themselves. What is considered fair by some may be viewed as unfair by others: A utility may interpret standards-of-conduct rules as overly restrictive, placing its affiliate at a disadvantage; non-affiliates, on the other hand, may regard these rules as necessary to avoid what they perceive as inherent favoritism toward the utility's affiliate. The debate over how to create equal opportunity for all prospective firms centers on the parties' perception of barriers to entry.[74] All parties have an incentive to seek a "home field advantage," whereas the job of regulators is to eliminate any tilt that favors one category of providers.

### C. Distribution of profits and efficiency gains

Outsourcing offers the potential for achieving certain regulatory objectives: It can produce efficiency gains and cost savings that otherwise would go unexploited. Most gas utilities throughout the country lack strong incentives to purchase gas at the lowest cost and to optimize the utilization and the value of their pipeline capacity. If an agreement with an outside firm is able to provide that firm with such incentives, the potential exists for better performance that ultimately could benefit customers. The key word is "if" because of the challenges in designing incentives that align the outside firm's interests with the utility's interests. State commissions themselves know well the difficulties in structuring regulatory incentives that, at the same time, are beneficial to both customers and the utility.

The issue of incentives revolves around the sharing of the profits and efficiency gains that result from outsourcing. The agreement between the utility and the outside firm should specify the distribution of the gains between the two entities. Regulators, in turn, would determine the share of the utility gains allocated to shareholders and customers. These two sharing issues have

[73] These costs would include pipeline demand charges that a gas utility normally would try to recover through its purchased gas adjustment (PGA) mechanism.

[74] The perception that opportunity is not equal may discourage prospective unaffiliated outside firms from bidding to provide services to a utility. These firms may conclude that they are wasting their time and resources on bidding if they believe that the utility would favor an affiliate.

come up in a number of states, including Georgia, Indiana, New Jersey, Tennessee, and Virginia. In Georgia, for example, the commission approved a stipulation that increased the percentage of net margin that Sequent Energy, the asset manager for Atlanta Gas Light, allocates to the Universal Service Fund from 50 percent to 60 percent.[75] In Indiana, the commission and other parties felt that changes in the outsourcing agreements between ProLiance Energy and gas utilities preserve the benefits of "joint portfolio administration" while allocating a higher share of the benefits to the utilities' customers.

No easy answer exists as to how to strike a proper balance between (1) providing adequate incentives to utility management and asset managers and (2) allocating an adequate share of the gains to customers. Most regulators probably would consider a dollar allocated to a utility's customers to be more valuable than a dollar allocated to the utility itself. (This observation draws largely on the actual sharing arrangements approved by state regulators across the country for the various incentive mechanisms in place for both natural gas and electric utilities.) This presumption has definite implications for the design of a sharing arrangement. Most regulators, for example, would not accept the outcome of a sharing arrangement where benefits to the utility are comparable to the benefits to its customers.

A higher share of the gains from capacity release or the sale of other unused assets allocated to customers appears compatible with customer interests; but an excessive share to customers could reduce the incentive of the asset manager to negotiate hard to market idle utility capacity; or, in the instance of utilities, to negotiate hard with the asset manager. Would the economic gains to customers improve with a 100-percent share of the gains going to customers, assuming that feeble negotiations by the utility with the outside firm would be the result? Or would an 80-percent share of the gains going to customers result in more robust negotiations? A regulator should ask what sharing arrangement would, realistically, maximize benefits to customers. To assign all the gains to customers makes the dubious assumption that the utility's behavior would not change with a severely diminished share of the gains.

Appendix B uses simple arithmetic and economic analysis to illustrate the incentive and the benefit-distribution effects from three distinct sharing arrangements. These arrangements specify the allocation of net margins from the resale of unused pipeline and storage capacity between the asset manager and the utility.[76] One salient outcome is that paying an asset manager

[75] The Universal Service Fund is used by Atlanta Gas Light to recover bad debt arising from service to low-income residential consumers.

[76] State commissions have applied similar arrangements to the distribution, between a utility and its customers, of net margins from off-system and interruptible sales and, for electric utilities, from wholesale power sales. Some commissions estimate the revenues from these sales and deduct them from test-year revenue requirements. Under such an arrangement, the utility is at risk for sales up to the estimated revenues; in some instances the utility retains all the revenues above the estimate, while in others the utility shares those revenues with its customers based on some predetermined sharing ratio. In other states, the utility shares all the revenues with its customers; this sharing arrangement avoids the need to estimate test-year revenues and sales.

an upfront lump sum payment, with the asset manager retaining all of the actual margins, risks the utility and its customers receiving an inadequate return from the resale of unused pipeline and storage capacity. Specifying up front a fixed share of the actual net margins going to the asset manager and the utility could avoid the problem of the asset manager receiving an excessive share. The tradeoff is that the asset manager would have a weaker incentive to resell the unused capacity relative to an arrangement that allows it to keep all of the net margins after initially paying the utility a fee for the right to resell the capacity.

### D. The tasks of a proactive commission

State commissions need to determine what role they should play in reviewing, evaluating, and approving an outsourcing arrangement. A threshold question is whether they have the authority to compel such an arrangement if it would be in the public interest. A subordinate question is whether they have the authority to review outsourcing agreements or monitor their performance. If neither authority exists, the commission's only recourse in protecting the public interest may be to prohibit all outsourcing.

Assuming that a commission has the authority—directly or indirectly—to order or encourage outsourcing, there remains a wide range of possible commission conduct. At one extreme, a commission may choose not to involve itself until the utility requests recovery of costs related to an outsourcing arrangement. The commission, in this instance, would have no say in the RFP process or in the terms and conditions of an outsourcing agreement, and no guidance on whether the utility should outsource and if so, how. The utility, in other words, would make all outsourcing decisions without any regulatory oversight. The commission would leave all questions as to the prudence of a utility's outsourcing arrangement until a later time, when the utility requests cost recovery. It is questionable whether such a hands-off approach would serve the interests of any of the parties well.

At the other extreme, a commission might involve itself with outsourcing from the very first step—from examining the merits of outsourcing, to developing a process for selecting an outside firm, to determining how the utility should conduct outsourcing, to enacting rules that set the parameters. Under this policy, the commission would make early commitments to a utility's outsourcing activities, which could include giving its approval to the arrangement and guaranteeing recovery of all costs.

It is possible that a commission could over-regulate a utility's activities.[77] First, the utility knows best how to assess its needs and purchase services. Second, increased commission involvement tends to increase utility administrative costs, disrupt its decision-making process

[77] Some readers may associate "over-regulation" with regulatory micromanagement of a utility. Micromanagement here refers to the regulator getting involved with the day-to-day activities of a utility or telling the utility how to carry out a specific task. Opponents of regulatory micromanagement have argued that, even if regulators are well-intentioned, they likely would cause inefficiencies, largely because of information asymmetry, if they prejudged and steered utility decision-making.

through interventions and delays, and impose additional costs on all stakeholders and on the commission itself. The utility's customers would ultimately bear some of these costs.

An intermediate policy, which this paper endorses, would involve a commission overseeing the whole outsourcing process without intervening in the utility's actions and committing to the arrangement. Under this policy, a commission would examine:

1. Whether outsourcing may be the best alternative from the perspective of a utility's customers. Would the utility have lower purchased gas costs and higher revenue credits from sale of idle pipeline and storage capacity?

2. The process for selecting an outside firm. Is the process transparent and objective, with explicit criteria for evaluating different bids?

3. Whether an agreement between a utility and an outside firm is in the utility's interest (especially for an agreement with an affiliate). Does the agreement assign too great a share of the costs savings and the revenue credits to the outside firm?, and

4. How the outside firm has performed relative to the goals of the utility, regulatory policies and rules, and the pre-outsourcing performance of the utility. A commission can either monitor the performance of the outside firm itself or require the utility to do so and report its findings to the commission. The questions addressed include: (a) how did the outside firm perform relative to benchmarks and expectations; and (b) did the firm perform in line with the contractual agreement, as well as regulatory policies and rules?

An intermediate policy involves six tasks: (1) development of guidelines/principles for outsourcing (e.g., guidelines for issuing an RFP);[78] (2) review and evaluation of outsourcing proposals (e.g., with regard to the likely benefits to the utility's customers); (3) approval, acknowledgment, acceptance, or rejection of outsourcing proposals (e.g., the commitment of a commission to a plan); (4) oversight and monitoring of in-place outsourcing arrangements (e.g., how well the outcomes of outsourcing coincided with expectations and the pre-outsourcing performance of the utility); (5) a decision on prospective outsourcing arrangements; and (6) a decision on cost recovery. A commission should determine whether legal constraints would prevent it from executing one of more of these tasks.

A commission also should require a utility to closely oversee any outsourcing arrangement. Without such oversight, an outside firm may not adhere to the terms and conditions of its agreement with the utility. Non-compliance may hurt the utility customers'

[78] Some readers may argue for the development of rules rather than guidelines, with the reasoning that rules are necessary for any enforcement to be effective.

interests.[79] The utility's oversight should include the submittal of periodic reports to the commission.[80] Reports should answer the questions: (1) how did the outside firm perform relative to utility and commission expectations, and (2) did the outside firm perform in line with the agreement signed between it and the utility?[81]

An outsourcing agreement in the form of a performance contract needs to specify the services to be provided, the parameters for providing them, and the measurement of service performance. The performance contract specifies risk-sharing and rewards. It can, for example, penalize the outside firm for subpar performance and allow it to share in the gains from surpassing a specified benchmark. The regulator might want to review and understand the contract to make sure that the performance measures are compatible with customers' interests.

Commission involvement can effectively deter self-dealing abuses. The commission must act as an objective third party on behalf of the utility's customers to monitor any abuses or collusive behavior on the part of the utility and its affiliate.

### E. Process for selecting an outside firm

As expressed in FERC Order 712,

> In many instances the asset manager is chosen through a request-for-proposal (RFP) process. The RFP describes the details and terms and conditions of the proposed deal and seeks bids from service providers willing to provide the requested services. The methodology for choosing a winning bidder under an RFP often reflects many different factors, including price, creditworthiness, experience, reliability, and flexibility, and it is clear that price is not always the determining factor. Some RFP procedures are state mandated, and thus, in those situations, the LDC must get approval from the state for the final agreement.[82]

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[79] Non-compliance may, however, benefit the parent company of the utility and the outside firm from, for example, affiliate abuses reflected in transfer pricing, cost-shifting, or cross-subsidization.

[80] In conjunction with utility reporting, an outsourcing agreement may include allowing the commission staff to access records to evaluate the performance of the outside firm.

[81] In Georgia, the commission requires Atlanta Gas Light to submit an annual benchmark study evaluating the performance of its asset manager, Sequent, relative to the provisions of the agreement between the two parties.

[82] Federal Energy Regulatory Commission, *Promotion of a More Efficient Capacity Release Market*, Final Rule, Docket No. RM08-1-000, June 19, 2008, 77.

Competitive bidding allows the utility fewer opportunities to strategically exploit its information and intelligence to unduly favor an affiliate for outsourced services.[83] The effectiveness of competitive bidding to mitigate these problems also depends on the design and operation of the bidding process. It is important that the RFP process attract a number of firms to bid; otherwise, over time one firm would tend to dominate.

A typical competitive bidding process for selecting an outside firm to perform a function for a utility contains three steps: (1) preparation and issuance of the request for proposals (RFP), (2) the evaluation and selection of bids, and (3) post-bidding contracting and negotiation.[84] The RFP and the selection process should include specific criteria for evaluating proposals by prospective outside firms in addition to the expected scope of work.[85] The commission may want to review these criteria for their relationship to promoting the utility customers' interests. Where a utility's affiliate is a potential bidder, a commission may especially want to pay close attention to the selection process. A competitive RFP process would help assure an arm's-length transaction, especially if a commission assigns an outside referee or independent evaluator to review and assess the bids.

A contentious aspect of bidding processes is the weights assigned to non-price criteria. Examples of bidding and selection criteria for outsourcing services include: (1) the bid amounts (e.g., commodity discount, lump-sum annual payment, or a combination), (2) the ratio for sharing-of-benefits, (3) management experience and expertise of the bidder,[86] (4) performance guarantees (e.g., minimum fee paid to the utility for the right to sell excess pipeline capacity,[87] or no impairment of the reliability of the utility's system or service to its customers), and (5) contract lengths.

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[83] An alternative to competitive bidding is the utility bilaterally negotiating with an outside firm, selected by the utility external to a formal bidding process.

[84] Contract issues can include performance security bonds, cost-escalation clauses, and force majeure provisions (e.g., "regulatory out" provision).

[85] Because of the potential for substantial economic damage, confidentiality of bid information is imperative. The same import of confidentiality also applies to the service agreement signed between the utility and the outside firm.

[86] The bidder, for example, should: (1) have the ability to package gas supplies and delivery services so as to maximize value to the utility; (2) have a high level of knowledge of wholesale gas markets; and (3) leverage its position to negotiate favorable contracts with gas suppliers and other wholesale gas providers.

[87] The bidder may commit to pay the utility $3 million per year for having the right to profit from selling the utility's unused pipeline to outside parties such as other gas utilities, industrial users, and electric generators. One condition may be that the bidder's right is secondary to the utility's rights to assure its firm sales customers of highly reliable service and the lowest attainable cost for gas service.

A bidding procedure can involve a scoring system to rank bidders on individual criteria. The final selection of bids may depend upon rankings of individual criteria and the overall score. The utility may apply a quantitative weighting scheme to rank the importance of each criterion; alternatively, criteria may be evaluated and prioritized on a completely qualitative basis. Some of the criteria, such as experience and creditworthiness, could be judged by whether or not they satisfy some threshold.

One decision rule is simply to add up the scores for each bidder, weighted by the significance attached to each criterion, and rank the bidders based on the weighted scores. We can express this so-called additive linear (i.e., decision) rule as:

$$V_j = \sum w_i s_{ij,}$$

where $w_i$ represents the weight assigned to the ith criterion and $s_{ij}$ is the score ascribed to the jth bidder for the ith weight. The aggregate score for each bidder ($V_j$) equals the bid for each criterion (for example, the score given to a bidder for creditworthiness), summed across all criteria. The score is, therefore, a weighted average score metric, where the weights represent the relative importance of each criterion.[88]

A certain degree of subjectivity and arbitrariness is inevitable in setting, prioritizing, and weighting the criteria, and in the final evaluation of bids. These characteristics of the selection process may offer self-dealing opportunities to the utility: The commission and non-utility stakeholders, because of asymmetric information, may find it difficult to refute the utility in its selection.

### F. Length of outsourcing arrangements and the process for renewal

Two opposing forces come into play that affect the optimal duration of an agreement between an outside firm and a utility. The first, favoring longer-term agreements, relates to the cost of negotiating transactional terms on a period-by-period basis (for example, annually or every two years), which, other things held constant, would drive up transaction costs over time. Changing the outside firm frequently also hinders a long-term relationship from developing between the two parties, which could jeopardize cooperation for maximum performance. Finally, longer-term agreements avoid any transitional problems in switching outside firms. These problems might include lost market opportunities.

The second force, causing longer-term agreements to be less attractive, relates to the risk of losing the ability to adapt to changing market and other conditions. This rigidity could be highly costly to a utility in an uncertain and dynamic market environment. The utility also faces risk in a long-term arrangement that the outside firm may not perform as expected, or that the

[88] The additive linear rule is appropriate only if the scores assigned to one criterion do not affect the scores assigned to other criteria (e.g., the score assigned to creditworthiness is independent of the score assigned to managerial experience ); that is, the criteria are mutually exclusive.

outside firm may be receiving high profits from the arrangements with little gains to the utility. This outcome can occur when the utility negotiated a bad deal with an outside firm, which, under a long-term deal, has consequences over a number of years.

Once an agreement expires, the utility has the choice of renewing the agreement with the present outside firm, conducting a formal process for selecting a future firm, or terminating any outsourcing arrangement and performing the specified functions internally. The utility, if it desires to continue outsourcing, should report to the commission the benefits of the just-expired arrangement. If it can justify outsourcing, the utility should then conduct a formal process for selecting a future outside firm. Especially if the outside firm is an affiliate of the utility, the commission should reject an automatic renewal. One possible exception to this rule could occur when the utility provides solid evidence that its customers would benefit from a continued relationship with the affiliate, relative to the benefits of the utility conducting a formal process to accept bids from other potential outside firms.

## V. Major recommendations

This paper makes four major recommendations. First, a commission should consider both the potential benefits and costs of outsourcing. It should evaluate these benefits and costs relative to the gas utility itself performing the activities under existing regulations or alternative regulations. Alternative regulations, which may not achieve the full benefits of outsourcing, could include explicit incentives or performance standards that partially address the inefficiencies underlying the rationale for outsourcing. The benefits of outsourcing are utility-specific, depending upon factors such as a utility's size. Small utilities may find more significant benefits from outsourcing in providing the expertise needed to exploit market conditions. The measurable benefits of outsourcing may simply be: (1) the additional revenues received from sale of the utility's underutilized pipeline and storage capacity, and (2) the reduction in purchased gas cost.

Second, a commission should scrutinize any proposed utility-affiliate relationship. It should condition any such relationship on the enactment of standards-of-conduct rules and their strict enforcement, in addition to other actions needed to protect the utility's customers against self-dealing abuses. A commission also may require a utility to provide evidence that it has complied with the commission rules.

Third, a commission should assure that a utility's customers receive adequate benefits from the efficiency gains or profits derived from an outsourcing arrangement. A commission should seriously consider an arrangement that determines beforehand the sharing of the benefits between the outside firm, the utility, and its customers.[89]

[89] This recommendation may involve the utility having discussions with commission staff and non-utility stakeholders to gain support for a new tariff that incorporates such a sharing/incentive arrangement. Alternatively, parties could discuss a sharing/incentive arrangement in a rulemaking proceeding.

Fourth, the selection of an outside firm should include a competitive bidding process where a utility affiliate is involved. Such a process should not allow the utility opportunities to strategically exploit its information and intelligence to unduly favor an affiliate. A commission should require a utility to quantify, to the extent feasible, the different evaluation criteria. Less quantification of the criteria translates into greater opportunities for mischief, especially when a utility's affiliate is a bidder.

## Appendix A: Questions Commissions Should Ask about Outsourcing

***Desirability of outsourcing***

1. What are the legitimate objectives of outsourcing?
2. What factors would make outsourcing beneficial or detrimental to a utility's customers?
3. What alternatives to outsourcing could improve a utility's performance? What are the benefits and costs of these alternatives relative to outsourcing?

***Conditions affecting commission decisions on outsourcing***

1. Is there any evidence to support a utility's subpar performance in functions considered for outsourcing?
2. If such evidence exists, what factors account for the subpar performance?
3. What skills and expertise does an outside firm have that a utility does not?
4. Under what conditions, if any, should a commission require a utility to outsource some of its functions?
5. If a commission lacks legal authority to mandate outsourcing, what alternatives does it have to induce a utility to outsource when deemed appropriate?

***Issues faced by commissions and their decisions***

1. What metric(s) should a commission use in measuring and assessing a utility's performance in functions considered for outsourcing? What have been the experiences of outsourcing arrangements across states? What problems have arisen? What issues were raised? How did commissions respond to those problems and issues?
2. To what extent should a commission review, evaluate, and approve provisions in outsourcing contracts?
3. How have commissions decided on major issues, including: (a) utility "outsourcing" to an affiliate; (b) sharing of efficiency gains and profits between the outside firm, the utility, and its customers; (c) the role of the commission in approving, overseeing, and evaluating an outsourcing arrangement; (d) the process for selecting a vendor to perform outsourced services and functions; and (e) the length of an outsourcing agreement and the process for renewal?

## Appendix B: Illustration of Three Sharing Arrangements

The sharing of net margins from the resale of unused pipeline and storage capacity between the asset manager and the utility can occur under one of three rules. The compensation or amount of net margins accruing to the utility (C), generically, equals

$$C = A + s \cdot NM^a$$

where A is the guaranteed compensation to the utility (e.g., the upfront management fee paid by the outside firm to the utility for the right to resell excess pipeline and storage capacity),[90] s is the share of the actual net margins ($NM^a$)[91] allocated to the utility (or, as shown later for what is called the hybrid sharing rule, the actual net margins net of the upfront management fee).[92]

Under *arrangement 1*, where C equals A (i.e., s equals zero), the amount received by the utility is independent of the actual sale of excess capacity (i.e., the utility receives a lump sum payment from the asset manager); in negotiating A, both the asset manager and the utility would have to predict for themselves the expected net margins from sales. Under this arrangement, the utility knows with certainty the amount of compensation it receives.[93] The asset manager incurs risk, since actual net margins may be less than A;[94] the utility would expect a higher A value when s equals zero than when s is greater than zero (i.e., when the utility receives no compensation from net margins, it expects a higher A). The share of the actual net margins

[90] The guaranteed compensation (A) can closely relate to the fee that the utility pays the asset manager for services related to the sale of the utility's excess pipeline and storage capacity. The compensation also should relate to the economic value of the excess capacity that the utility transfers to the asset manager.

[91] $NM^a$ can equal the total margins generated by the asset manager.

[92] This appendix assumes that the sharing ratio (s) is constant. In practice, the sharing ratio can vary, depending on the level of actual net margins. One example of a variable sharing ratio is as follows: a sharing ratio of 0.7 when net margins are between $3-$5 million, and a sharing ratio of 0.6 at net margins above $5 million. The logic for a higher share of net margins going to the asset manager at a higher level of net margins is that the asset manager would have to make more effort and incur higher costs in achieving more marginal sales of idle capacity.

[93] The advantage of an asset management fee is that the guaranteed payment is not affected by factors such as weather. An unusually cold winter, for example, would leave less unused pipeline capacity available for off-system sales. The credit to the utility and its customers, consequently, would be less.

[94] The asset manager would be expected to hedge on the low side in negotiating a guaranteed upfront payment to the utility.

distributed to the utility is unknown, since the share depends upon the relationship between actual net margins and A.

Under *arrangement 2*, the pure sharing arrangement, A equals zero (i.e., the utility receives zero upfront guaranteed compensation from the asset manager). The utility and the asset manager, with certainty, receives s and (1 – s) of the actual net margins, respectively. This rule is analogous to the sharing arrangement in some states for off-system and capacity-release sales, where base rates do not account for the revenues from those sales but the utility and customers receive a pre-specified percentage of actual sales.[95]

*Arrangement 3* is a hybrid sharing arrangement where the utility receives a minimum fixed compensation (i.e., A > 0) plus a share of the actual net margins (i.e., s > 0) above the minimum fixed compensation.[96] Under this rule, the utility receives a total compensation of $NM_u = A + s(NM^a - A)$. Suppose that the asset manager pays the utility an upfront compensation of $4 million, the actual net margins are $6 million, and the sharing ratio is 0.6. In this example, the utility receives a total compensation of $5.2 million [$4 million + 0.6 ($6 million - $4 million)].

Mathematically, the share of the actual net margins allocated to the utility ($S_u$) equals

$$S_u = s + A(1 - s)/NM^a,$$

where (as above) s is the share of the actual net margins allocated to the utility, excluding the fixed compensation A; $NM^e$ is the expected net margins; and $NM^a$ is the actual net margins. Suppose that the asset manager and the utility agree on a management fee of $3 million, which we assume equals $NM^e$. Assume also that s equals 0.5 and actual net margins are $10 million ($NM^a$). In this example, the utility receives $6.5 million from the sum of the management fee ($3 million) plus 50 percent of the actual net margins above $3 million ($3.5 million).[97] The asset manager receives $3.5 million from actual net margins. The utility's share of the net margins is 0.65 (.5 +$3 million/$10 million). The residual share, 0.35, goes to the asset manager.

The following points identify the major outcomes for the three sharing arrangements:

1. The higher the value of s, the less incentive the asset manager has to increase net margins (since it keeps only 1 – s of the net margins). A high sharing ratio (e.g., 0.9) may diminish the effort of an asset manager to market additional excess capacity to

[95] 80 percent of the margins from off-system sales, for example, might get credited to firm sales customers, with the remaining 20 percent retained by the utility.

[96] If the sharing applied to all net margins (i.e., s > 0), the asset manager would be at greater risk of not recovering sufficient net margins to recover its guaranteed payment to the utility. It is assumed here that this risk would be found unacceptable to most asset managers when the value of s is high (e.g., 0.8-0.9).

[97] The sum flowing to the utility equals $A + s(NM^a - A)$, or $A(1 - s) + s(NM^a)$.

the extent that its share of the net margins falls below its transaction costs in making additional sales. As a general proposition, when the asset manager receives a smaller share of the net margins from incremental sales, it has less incentive to pursue those sales.

2. A tradeoff exists between providing a strong incentive for the asset manager to market a utility's excess capacity and ensuring an adequate distribution of the gains from transactions to the utility and its customers. Any incentive mechanism would need to balance these two objectives, implicitly setting a value for s that reflects the relative weights assigned by a regulator to creating "high-powered" incentives and the assurance of adequate benefits to the utility and its customers. In the extreme case where the utility receives no compensation for additional transactions (i.e., *arrangement 1* above, where the utility receives only a lump-sum upfront fee), the asset manager has maximum incentive to market the utility's capacity (since it keeps 100 percent of the actual net margins). The outcome, however, may be deficient compensation to the utility relative to the profits made by the asset manager. Assume that the asset manager pays the utility an upfront fee of $2 million for the right to market the utility's excess pipeline capacity. If the asset manager goes out and makes a net margin of $10 million from marketing this capacity, the asset manager's share of the net margins is 80 percent ([$10 million - $2 million]/$10 million). The utility then receives only 20 percent of the net margins. Some commissions might consider this share as meager relative to what: (1) the asset manager receives, and (2) the utility's customers should receive, since they pay for all the utility's pipeline capacity under contract, including the excess capacity that the asset manager sells for the utility.

3. Under a pure constant-sharing mechanism (*arrangement 2* above), the same percentage of net margins is received by the asset manager and the utility under all levels of net margins; the percentage is determined by negotiation between the AM and the utility, with possible commission oversight; under this mechanism, the asset manager and the utility share the risk of a low net margin. When the expected level of net margins is highly uncertain, the pure sharing arrangement has the attractiveness of guaranteeing a utility what is ostensibly a fair share of the total net margins.[98] Under a mechanism where the utility receives only a lump-sum payment (*arrangement 1*), it becomes important to set that payment in line with expected net margins. In our previous example, the asset manager ends up receiving 80 percent of the total net margins. This share presumably would violate fairness standards; namely, the utility, and especially its customers, should receive most of the net margins, since customers pay for the cost of the excess capacity that the asset manager uses to make the sales.

[98] "Fair share" is a highly subjective term, but one not devoid of objective significance. It may mean, for example, that most of the benefits from selling excess capacity should accrue to the utility's customers, since they are responsible for the costs of this capacity.

4. Under a pure lump-sum payment (i.e., fixed fee) scheme, the utility can accept the bid offering the highest guaranteed payment (assuming other things held constant or the other bidding criteria have far low priority). The expectation is that the highest bidder will perceive the most value from marketing unused pipeline capacity. Assume two bidders expect to market $5 million and $7 million of unused capacity, respectively. The second bidder would be expected to bid more for the right to market the capacity—he may offer up to $7 million, while the first bidder would not offer anything more than $5 million. The utility would accept the offer of the second bidder—the economical choice, because the second bidder presumably is able to extract higher value from the unused capacity.[99] A major problem with a fixed-fee payment is that, if not determined from competitive bidding, it could result in the asset manager retaining an excessively high percentage of the actual net margins.

[99] The second bidder might have a more favorable customer mix, more expertise, better organization, and complementary assets, each of which could cause it to value the utility's capacity at a higher value.