Survey Responses of State Utility Commissions on Long-Term Gas Contracting and Hedging

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We are disseminating this report to all state utility commissions in the hope that they will find it useful. At a minimum, the report should help them compare their regulatory policies and practices in long-term gas contracting, hedging, and related topics with those in other states.

Executive Summary

Shale gas has been one of the few bright spots in the U.S. economy over the past four years. It has transformed the country's energy landscape. The current consensus is that shale gas will help to assure sufficient U.S. gas supplies over the next several decades at a reasonable cost.

The impetus behind this study is the increased attention of natural-gas market players to the prospects for long-term gas contracting, which arises in no small way from the shale-gas revolution. This interest hinges on the U.S. gas market having ample supplies over the next several decades, producing more stable and predictable prices than those we have seen over much of the past ten years. With these conditions, both gas producers and natural-gas utilities have already conveyed an interest in long-term commercial arrangements.

This survey report contains the responses of 35 state utility commissions, reflecting their policies and practices as they relate to long-term gas contracting, hedging, and related matters. The survey results show that the vast majority of utility commissions give utilities little guidance. A number of them said that they would entertain long-term contracts if the utility can demonstrate that they are in the public interest or fit optimally in its gas portfolio strategy.

The survey responses show that few commissions have an explicit policy on long-term gas contracting. Commissions typically evaluate a proposed long-term contract on a case-by-case basis. Most commissions, in other words, adopt a neutral policy on long-term contracts by neither outright restricting nor encouraging them.

Some industry observers contend that unless state commissions become more proactive in promoting long-term contracting, utilities will continue to rely heavily on financial hedging and other mechanisms to reduce price and supply risks. There is an obvious lack of interest so far on the part of gas utilities in proposing long-term physical gas contracts before their commissions. One possible reason is that utilities see few economic gains relative to the risks. That is, utilities consider long-term contracts to carry an unfavorable reward-risk imbalance. As reflected in the survey responses, utilities generally receive no profits from long-term contracts but risk cost disallowances from an after-the fact review. Hindsight review is more likely when the market price of natural gas falls below the contract price and the long-term contract contains rigid terms and conditions. One implication is that state commissions will be more accepting of long-term contracts when they contain flexible terms and conditions, including renegotiation rights for the utility.

Three states, Colorado, Oklahoma and Oregon, have departed from the norm by taking proactive roles in encouraging long-term gas contracting (*see* Appendix A). Their efforts can offer guidance to other states who want to consider long-term contracting as a potential low-cost hedge benefiting utility customers over time. One key element of a long-term contracting policy is the certainty for cost recovery by a utility. The commitment of a commission is vital in inducing utilities to take a "second look" at long-term contracts.

Table of Contents

I. Scope of Study 1

II. Reasons for Recent Interest in Long-Term Gas Contracting 2

A. The shale-gas revolution 3

B. Implications for long-term contracting 3

III. Survey Methodology 4

IV. Summary of Survey Responses 5

Appendix A: Examples of Three States Taking a Proactive Stance on Long-Term Contracting 9

Appendix B: Survey Questions 13

Appendix C: State-by-State Survey Responses 14

Survey Responses of State Utility Commissions on Long-Term Gas Contracting and Hedging

I. Scope of Study

The National Regulatory Research Institute (NRRI) undertook this study with financial support from America's Natural Gas Alliance (ANGA). This study compiled state-level information on how state utility commissions view long-term natural-gas contracts for ratemaking and other regulatory actions. It also highlighted the major findings from the information collected.

Specifically, the study asked commissions about their current policies on long-term gas and coal contracts and the recovery of their costs from ratepayers. Gas contracts, sometimes referred to as *bilateral physical contracts*, represent an agreement between two parties for the sale and purchase of natural gas with specific terms and conditions.

"Long-term" can have different meanings. In this report, it refers to a multi-year period; one definition is that "long-term" has a minimum duration of three years. A long-term contract might call for a fixed amount of supply (thereby guaranteeing reliability) but with variable-price terms (e.g., linked to the first-of-the-month futures price adjusted for basis).[1] Some long-term contracts may fix the price over, say, the next five years. Although long-term contracting exists for both upstream gas-storage service and pipeline transportation, this report focuses only on commodity gas.

The study, in addition, inquired about state-commission policies on gas hedging and the treatment of its costs for ratemaking. Gas utilities have actively hedged gas prices since the beginning of this century. In this report, "hedging" refers to an economic activity in which a utility protects an existing or anticipated physical market exposure from unexpected or adverse price fluctuations. Hedges come in both physical and financial forms: Gas utilities can use storage or bilateral physical contracts (e.g., long-term gas contracts) with fixed prices as hedges; they can also purchase financial hedges, such as futures contracts, options, and swaps.

This study confines itself to collecting information on existing state-commission policies and practices. The information contained in this report provides a national perspective on long-term gas contracting and hedging. This report will allow individual commissions, for example, to compare their policies and practices with those in other states. These states might include those that have been most proactive in encouraging long-term gas contracting. They include Colorado, Oklahoma, and Oregon (*see* Appendix A). There may be other states as well, but the survey responses indicate that, so far, few states have actively involved themselves in long-term

[1] In this example, the parties make a long-term commitment to supply but not to price; the parties do commit, however, to a price based on some agreed-upon formula.

gas contracting. Few states also have articulated an explicit policy or position on long-term gas contracting. The survey responses generally reflect a state position of neutrality on long-term contracting that is devoid of specific guidelines or "safe harbor" rules.

Finally, some readers will use this report to identify possible problems—flawed regulatory policies, for instance—that are obstacles to the advancement of specific objectives. One relevant objective for this study is a balanced portfolio of gas supplies that combines different commercial transactions, including long-term and short-term contracts. Many gas and electric utilities apply a portfolio approach[2] to gas procurement, which involves purchasing gas under different durations and other terms and conditions.[3] Some readers may interpret the survey responses as showing that long-term contracts currently play a less-than-optimal role in a gas or electric utility's portfolio.

II. Reasons for Recent Interest in Long-Term Gas Contracting

One feature of the U.S. natural-gas market is the predominance of short-term transactions for commodity gas, as well as for pipeline contracts, compared to 25 years ago and most other countries.[4] In most countries that consume natural gas, for example, long-term contracts are a basic element of supply security. In the U.S., as gas utilities have downsized the bundled-sales-service side of their business, they have invariably lowered their demand for long-term commitment. Overall, competitive pressures have made long-term commercial arrangements more expensive for gas utilities and other gas buyers. A major reason for the restructuring of the U.S. natural-gas industry was the high social costs from rigid multi-year contractual arrangements as the industry transitioned to a more liberalized structure.

[2] Utilities might buy some gas in the spot market (days or months ahead) and some under contract for longer periods (e.g., six months or two years ahead). The utility might overlay these purchases, especially for spot gas, with financial derivatives to hedge the price.

[3] A gas portfolio would account for the price of natural gas, security of supply, flexibility of gas supply (e.g., ability to adjust supply when conditions change), and gas deliverability. Some industry observers refer to a portfolio as the "best cost" approach to gas procurement. "Best cost" can refer to, for example, a portfolio that achieves the lowest cost for highly reliable service, with moderate price volatility. As an example, in its natural-gas integrated resource plan, Avista Utilities stated that the goal of its natural-gas procurement is "to provide reliable supply at stable and competitive prices in navigating a variety of market conditions." *See* http://www.avistautilities.com/inside/resources/irp/electric/Documents/2009%20Natural%20Gas%20IRP-FINAL.pdf.

[4] *See*, for example, Ken Costello, "Going 'Long' with Natural Gas?" *The Electricity Journal*, 24(5) (June 2011): 42-49.

Events since around 2008 have dramatically changed the market environment, enough to warrant a reconsideration of long-term contracting in the natural-gas sector. The new environment has initiated interest on the part of gas producers—and, to a lesser extent, buyers—in long-term arrangements.

A. The shale-gas revolution

Shale gas has been one of the few bright spots in the U.S. economy over the past four years.[5] It has transformed the country's energy landscape. The current consensus is that shale gas will help to assure sufficient U.S. gas supplies over the next several decades at a reasonable cost, assuming gas prices do not fall too low and environmental opposition to hydraulic fracturing does not intensify.[6]

B. Implications for long-term contracting

The impetus behind this study is the increased attention of natural-gas market players to the prospects for long-term gas contracting, which in no small way arises from the shale-gas revolution.[7] This interest hinges on the U.S. gas market having ample supplies over the next several decades, producing more stable and predictable prices than those we have seen over much of the past ten years. With these conditions, both gas producers and natural-gas utilities have already conveyed an interest in long-term commercial arrangements. Gas producers may view long-term contracting as a way to stabilize their cash flow and revenues. They may also see less risk from a bearish outlook in which market prices are less likely to soar far above a contracted price.[8] During most of the time since 2000, we have seen high price volatility resulting from moderate or even small changes in market conditions. With additional supply

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[5] As expressed by the U.S. Energy Information Administration:

> The combination of horizontal drilling and hydraulic fracturing technologies has made it possible to produce shale gas economically, leading to an average annual growth rate of 48 percent over the period of 2006-2010. (*Annual Energy Outlook 2011* at http://www.eia.gov/forecasts/aeo/chapter_executive_summary.cfm#domestic.)

[6] *See*, for example, U.S. Department of Energy and National Energy Technology Laboratory, *Modern Gas Shale Development in the United States: A Primer*, April 2009. Hydraulic fracturing involves the injection of a mix of water, sand, and chemicals into the earth at a pressure great enough to crack the rock.

[7] A feature of the pre-1980 U.S. natural gas industry was long-term contracts (e.g., over 20 years in duration) at fixed prices, for both producer-pipeline transactions and pipeline-gas utility transactions.

[8] In a volatile market, producers sacrifice potential profits from rising market prices. If, for example, the contract price is $5 and the market price rises to $7, the producer forgoes $2 that it could have otherwise earned in the absence of a contract.

from shale gas, most analysts expect the market price to fluctuate less, especially to upward extremes.

Trading parties might also find it easier to specify contractual terms with fewer contingencies—natural-gas prices would be less likely to soar to extremely high levels, for instance. Thus, renegotiations would occur less often, thereby reducing the transaction costs associated with long-term contracting.[9]

Another factor supporting long-term contracts is the reluctance of some gas buyers to commit to investments that require the purchase of natural gas over a multi-year period unless offered price and supply stability. One such investment are combined cycle gas turbines (CCGTs), whose economics hinge on the price paid for natural gas over the next 20 or so years. Even though natural-gas prices have become more stable over the past two years, a common perception is that they are inherently volatile. Many gas buyers are therefore reluctant to commit on a long-term basis to a fuel source whose future prices could lie substantially above current levels.[10] "Long-term" here refers to a time horizon that extends beyond what most analysts predict to be a sustained period of low natural-gas prices.

It is unknown to what extent long-term gas contracting will proliferate in the years ahead. The answer depends in part on the risk-reward relationship that gas and electric utilities face. State utility commissions will play a crucial role in determining this relationship. Preapproval and other forms of regulatory commitment are important factors. As of now, as reflected in the survey responses, most state commissions are reluctant to preapprove long-term contracts or have not yet had to address it. One reason may be that state commissions sense a tension between regulatory commitment and a potential perverse-incentive problem: If the regulator both approves a contract and guarantees cost recovery, a "moral hazard" might result in which the utility would lack a strong incentive to appropriately and sufficiently monitor the contract in the best interests of its customers. On the other side, too little commitment can lead to regulatory opportunism and uncertainty of cost recovery. This trade-off poses a difficult challenge for commissions.

III. Survey Methodology

NRRI sent out 12 survey questions to the state utility commissions (*see* Appendix B). ANGA and NRRI collaborated in drafting the questions. NRRI canvassed all the state utility commissions (with the exception of Hawaii) and the District of Columbia Public Service

[9] Transaction costs are those costs (excluding the price) that firms and consumers incurred in consummating a trade. They include the costs of trading parties to find each other and then to negotiate, draft, monitor, and enforce contracts. Empirical and theoretical studies have shown the importance of transaction costs in determining the most efficient institutional arrangement for trading.

[10] This risk aversion exhibited by gas buyers means that they would be willing to pay a higher price to have more price stability over time.

Commission. NRRI divided the study into two phases: In *Phase I*, it sent out survey questions on March 23 to selected states and reported on the responses. The selected states were Arkansas, Colorado, Florida, Georgia, Kansas, Louisiana, Missouri, North Carolina, South Carolina, and Texas. In *Phase II*, NRRI expanded the survey by sending out questions on April 11 to all the remaining states (except Hawaii) and the District of Columbia. In both phases, NRRI re-sent the questions to those commissions that did not reply by the original deadline.

NRRI received responses from *34 states and the District of Columbia*. In almost all instances, the commissions answered the 12 questions. This report provides readers with a compendium of state regulatory policies and practices on long-term gas contracting, hedging, and related topics.

IV. Summary of Survey Responses

The 35 responses received from utility commissions reflect different regulatory policies and practices as they relate to long-term gas contracting and hedging. Appendix C includes all the responses to the 12 questions. NRRI grouped the tables by topic. The rationale is that states will likely find it more valuable to compare their individual policies and practices with those of other states.

The responses show a commonality that some readers might interpret as having implications for future state commission actions directed at achieving certain goals. As one example, if the intent is to have gas utilities consider long-term contracts, some analysts might argue that commissions should preapprove those contracts when they find them appropriate.[11] Contracting can produce uneconomic results, however; namely, a price above the prevailing spot-market price or excess gas supplies because of an unexpected downturn in demand. Politics and public pressure may compel commissions to have utility shareholders share this burden rather than have customers bear all of it. Thus, commissions might be reluctant to preapprove a contract that passes all risks to customers.

Another factor that can affect a utility's willingness to sign a long-term contract is regulatory guidelines. Guidelines can act as "safe harbor" rules or guiding principles that reduce uncertainty for the utility and mitigate hindsight reviews. By increasing the certainty of cost recovery, a utility might be more willing to sign a long-term contract.

The survey results show that the vast majority of utility commissions give utilities little guidance. A number of them said that they would entertain long-term contracts if the utility could demonstrate that they are in the public interest or fit optimally in its gas portfolio strategy.

A summary of the responses received from the state utility commissions follows:

[11] One argument for preapproval is that it creates a more symmetric risk-reward relationship from the utility's perspective. Because, as the survey responses show, utilities do not explicitly profit from long-term contracts, minimizing the risk of cost recovery becomes critical.

1. *Few commissions have an explicit policy on long-term gas contracting.* Commissions typically evaluate a proposed long-term contract on a case-by-case basis. Most commissions, in other words, take a neutral policy toward long-term contracts by neither restricting nor encouraging them outright. Some industry observers contend that unless state commissions become more proactive in promoting long-term contracting, utilities will continue to rely heavily on financial hedging and other mechanisms to reduce price and supply risks. There is an obvious lack of interest so far on the part of gas utilities to propose long-term physical gas contracts before their commissions.

2. *Three states, Colorado, Oklahoma and Oregon, have departed from the norm by taking proactive roles in encouraging long-term gas contracting*. Their efforts can offer guidance to other states that want to consider long-term contracting as a potential low-cost hedge benefiting utility customers over time. One key element of a long-term contracting policy is the certainty for cost recovery by a utility. The commitment of a commission is vital in inducing utilities to take a "second look" at long-term contracts.

3. *A number of commissions indicated that long-term contracting could be part of a diversified portfolio that mitigates risk.* Many recognize that diversification gives a utility more flexibility and protection from unknown future events.

4. *One possible reason for why gas and electric utilities rely little on long-term gas contracts is that they see little economic gain relative to the risks.* That is, utilities consider long-term contracts to carry an unfavorable reward-risk imbalance. As reflected in the survey responses, utilities generally receive no profits from long-term contracts but risk cost disallowances from an after-the fact review. Hindsight review is more likely when the market price of natural gas falls below the contract price and the long-term contract contains rigid terms and conditions. One implication is that state commission would be more accepting of long-term contracts when they contain flexible terms and conditions, including renegotiation rights for the utility.

5. *Cost recovery for long-term contracts generally depends on their prudence.* Few commissions preapprove long-term contracts, and almost all rely on retrospective reviews to determine their reasonableness. Regulatory commitments under preapproval are controversial as a general matter because they can assign to customers virtually all the risks of a costly activity, such as long-term contracting, with rigid provisions and an uncertain outcome. The challenge for regulators is to strike an appropriate balance between credibility to utility investors and fairness to customers. In the extreme, a commitment to utility investors that the utility will recover all of its costs for a long-term contract would be credible from the perspective of investors, but it would likely be unfair from the perspective of utility customers.

6. *Most utilities do not rely on competitive bidding for procuring gas supplies.* When used, the utility typically chooses the winner. Commissions generally take a hands-

off approach toward picking winners and identifying criteria for evaluating bids. One exception occurs when a utility affiliate is a potential supplier. Many commissions indicated, however, that they retain the right to disallow those costs that reflect an imprudent utility.

7. *For cost recovery and ratemaking, long-term contracts usually receive the same treatment as shorter-term transactions.* Most commissions allow utilities to recover the costs associated with long-term contracts through a purchased gas adjustment (PGA) mechanism on a dollar-for-dollar basis, subject to a prudence review. In other words, gas utilities do not profit from long-term contracts, and they risk cost disallowance from an after-the-fact review.

8. *Most commissions do not have special reporting requirements for long-term gas contracts.* Many commissions, however, require utilities to file information on contracts so that they can conduct a prudence review.

9. *Most commissions allow utilities to hedge and evaluate their hedging practices after the fact through prudence reviews.* Most commissions do not evaluate and preapprove a utility's hedging plan beforehand.[12] Commissions generally allow a utility to recover hedging costs through its PGA, subject to a prudence review.

10. *A commission rarely would prescribe specific parameters for a utility's hedging strategy.* A number of commissions provide general guidance by indicating the importance of price stability or the avoidance of high price volatility as an objective of a gas-procurement strategy.[13] A few commissions also specify: (a) minimum and maximum hedging amounts and (b) the hedging instruments that utilities should use. Some commissions indicated that utilities have hedged less because of recent developments in the production of shale gas.

11. *Most gas utilities hedge with financial instruments and storage.* Much more rarely do they hedge with long-term physical gas contracts.[14] Commissions and gas utilities,

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[12] Two possible reasons for this tendency are: (1) Preapproval can have the negative effect of inducing the utility to adhere too strictly to the letter of a hedging plan as a means to avoid later cost disallowances while avoiding prudent actions (e.g., a proposed departure from the plan to take advantage of a market shift) that would benefit customers; and (2) utility management is in a better position than a commission to design a hedging plan.

[13] Regulatory guidance can include criteria for acceptable long-term contracts, commission procedures for reviewing and evaluating long-term contracts, articulation of the role that long-term contracting can play in a utility's gas-portfolio plan, and the conditions under which the regulator would tend to favor long-term contracting and allow recovery of the costs associated with a contract. Guidelines have the effect of reducing regulatory risk for a utility from signing a long-term contract.

[14] Most state commissions and utilities place importance on mitigating price volatility and price risk. Utilities can use different approaches to achieve this goal: (a) staggering of contracts, (b) financial

for whatever reason, may have an unwarranted bias against long-term physical contracts.[15] Education is crucial for decision makers to understand better the complementary role that long-term contracts can play in a utility's portfolio.

12. *Hardly any commission has credit requirements for long-term gas contracts.* Some commissions indicated, however, that the creditworthiness of a supplier is a factor in determining the prudence or reasonableness of a contract.

13. *Time horizons for gas hedges generally are one to four years.* The time horizon most often reported was one year. Some commissions reported a shortening of the time horizon for gas hedges over the past few years.

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hedging, (c) storage, (d) portfolio diversification and management, and (e) long-term physical contracts with a fixed price or specified price range.

[15] Many analysts find little difference, for hedging purposes, between long-term physical contracts and financial derivatives.

Appendix A: Examples of Three States Taking a Proactive Stance on Long-Term Contracting

Colorado

Section 40-3.2-206(4) of the Colorado Revised Statutes allows a utility to enter into a long-term gas-supply agreement and file it with the Public Utilities Commission for review and approval.[16] The section requires future Commissions to honor the contracts approved previously. The concern was that these Commissions would disallow cost recovery if the contract price were higher than the prevailing market price. The Commission approved one contract under this legislation in Docket No. 10M-245E.

Specifically, Section 40-3.2-206(4) states that:

> A long-term gas supply agreement is an agreement with a term of not less than three years or more than twenty years. All long-term gas supply agreements may be filed with the Commission for review and approval. The Commission shall determine whether the utility acted prudently by entering into the specific agreement, whether the proposed agreement appears to be beneficial to consumers, and whether the agreement is in the public interest. If an agreement is approved, the utility is entitled to recover through rates the costs it incurs under the approved agreement, and any approved amendments to the agreement, notwithstanding any change in the market price of natural gas during the term of the agreement. The Commission shall not reverse its approval of the long-term gas agreement even if the agreement price is higher than a future market price of natural gas.

In Docket 10M-245E, the Commission found a proposed contract between Public Service Company of Colorado and Anadarko to be beneficial to customers and in the public interest.[17] The utility issued an RFP for long-term gas contract, and Anadarko submitted the winning bid. The contract calls for ten years' gas supply at "a fixed price offer with an annual adjustment or

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[16] The Statutes implement the requirements of HB 10-1365 ("Clean Air-Clean Jobs Act").

[17] Colorado Public Utilities Commission, *In the Matter Of Commission Consideration of Public Service Company of Colorado's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act,"* Final Order Addressing Emission Reduction Plan, Docket No. 10M-245E, December 9. 2010. The utility calculated that the contract could reduce its discounted revenue requirements by $100 million over ten years. The utility also estimated that the average price of gas under the ten-year contract would be $5.48 per dekatherm.

escalation."[18] The Commission felt that even though the contract does not guarantee supply to the utility, the utility would have sufficient security and credit support from Anadarko's parent companies.

The Commission also decided that the utility should be protected from exposure to liability from non-performance of the contract, so long as the utility "does not cause the contract breach and any replacement costs are prudently incurred."

The Commission concluded in its order that:

> We find additional long-term gas contracts could provide value to the Company and its customers … Therefore, we direct Public Service to investigate additional long-term natural-gas supply contracts. However, we recognize that the decision to enter into additional long-term contracts is within the Company's management discretion.

Oklahoma

The Corporation Commission approved a Notice of Inquiry (NOI) on June 15, 2011 to "examine existing and pending federal regulations and legislation that could impact regulated utilities and their customers in the State of Oklahoma.[19] Furthermore the Commission will examine and consider the potential impact of such regulations on the natural-gas commodity market in Oklahoma." The NOI suggested that long-term gas contracts could be an important part of an environmental compliance plan.[20] One of the questions in the NOI was:

> If regulated utilities were to seek approval of long-term natural-gas supply contracts, what are the appropriate factors for the Commission to consider in determining whether such approval should be granted by the Commission?[21]

The Commission felt that the existing process precluded utilities from availing themselves of market opportunities because of the long time needed for decisions.[22] The rules were also vague on prudence determinations.

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[18] Even though Commission staff raised the concern that the contract was not a strict fixed-price contract, it concluded that the contract would provide more price stability than traditional index-based contracts.

[19] Cause No. PUD 201100077 at http://www.occeweb.com/pu/EPA/NOI/DRAFT%20NOI_06-15-11.pdf.

[20] The stimulant for the NOI was the new EPA emission mandates, which includes mercury and air-toxicity standards and cross-state air pollution rules.

[21] Ibid., 4.

The Commission conducted an open hearing process that allowed interested parties to file comments. It ultimately enacted new rules that apply only to electric utilities. The Commission felt that the rules would protect utility customers and allow utilities the flexibility to take advantage of long-term contracting.

Under the new rules, a utility will come before the Commission to gain approval of its RFP process. If the Commission approves the process and the utility complies with it, a winning long-term gas contract longer than five years will receive automatic preapproval and prudence determination.[23] The Commissions will rely on independent evaluators to review proposed requests for proposals (RFPs).

Essentially, the new rules will reduce uncertainty for utilities and provide a process for preapproval of long-term gas contracts. Its intent is also to prevent a utility from entering into a long-term contract that would harm customer interests.

Oregon

The Public Utility Commission has guidelines for gas procurement that recognize the potential value of long-term contracts:

> The utility's portfolio should include contracts of varying duration … To the extent reasonable and feasible, the utility's portfolio should include contracts that allow the utility to vary its gas take and pricing requirements on a seasonal or monthly basis. Physical arrangements may also cover annual and multi-year periods.[24]

The Commission's approval of a long-term gas-supply plan does not assure utility recovery of all costs associated with the plan. The Commission will consider, however, a utility's actions consistent with an approved plan. The Commission staff makes recommendations to the commissioners. The Commission waits to determine prudence until a utility makes a filing to recover contract costs in rates.

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[22] The following discussion comes from the presentation of Brandy Wreath, titled "Oklahoma's Collaborative Efforts to Address the Need for Long-Term Natural Gas Contracts," before the NARUC Committee on Gas, conference call, May 25, 2012.

[23] For contracts of less than five years in duration, the utility will assume the risk subject to an annual prudence review.

[24] Oregon Public Utility Commission, *Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's Three Local Distribution Companies*, Docket No. UM 1286, Order No. 10-197, May 27, 2010, Natural Gas Portfolio Development Guidelines, 2 at http://apps.puc.state.or.us/orders/2010ords/10-197.pdf

The Oregon commission places much emphasis on a technical working-group and public-meetings process to provide input from a wide variety of interest groups and individuals. Gas plans require: (1) the evaluation of all resources on a consistent and comparable basis, (2) the consideration of uncertainty, (3) specification of the primary goal as least cost to the utility and its customers consistent with the long-run public interest, and (4) consistency with the energy policy of the state of Oregon. A utility must file an action plan that describes its actions over the next two years to carry out its long-term plan.

In another relevant matter, in 2011 the Commission approved a joint venture between Northwest Natural Gas Company ("NW Natural") and Encana Oil & Gas (USA) to develop gas reserves in Wyoming.[25] The arrangement involves NW Natural providing partial funding for drilling. As compensation, the utility would have a working interest in the working wells.

The Commission found the 30-year arrangement prudent and in the interest of NW Natural's customers. The Commission ruled that the meaning of prudence narrows to the utility's decision to enter into the arrangement and not to how it manages the contracts underlying the arrangement.

The Commission found the arrangement favorable to customers by:

1. *Reducing the utility's gas costs over time by an estimated $52 million in present-value terms*: The utility estimated that the average price of gas under the arrangement would be $5.15 per dekatherm, which is less than the projected market price from various sources.

2. *Mitigating price volatility as a hedge*: The arrangement will allow the utility to procure a portion of its gas supplies at stable prices; one benefit is that it will protect customers from sharp price increases, especially those that last for an extended period.

3. *Providing the utility with a reliable long-term supply of gas.*

4. *Allocating fairly the benefits and risks between utility shareholders and customers for any residual risks*.

[25] The main source for the following discussion is Oregon Public Utility Commission, *In the Matters of Northwest Natural Gas Company Applications for Deferred Accounting Order Regarding Purchase of Natural Gas Reserves and Proposed Purchase of Natural Gas Reserves*, Docket Nos. UM 1520 and UG 204, Order No. 11-176, May 25, 2011 at http://apps.puc.state.or.us/orders/2011ords/11-176.pdf.

Appendix B: Survey Questions

1. What position has your commission taken on long-term natural-gas (for both electric and gas utilities) and coal contracts: (a) as a policy matter, (b) for a prudence review, and (c) for the RFP process?

2. What are your commission's rules for competitive bidding of (a) natural gas and (b) coal? For example, what information do bidders have to provide as part of their submittal? What are the criteria for evaluating bids?

3. How does your commission treat, for ratemaking and procurement purposes, (a) long-term natural-gas and coal contracts and (2) less-than-one-year transactions? For example, are long-term contracts considered a physical hedge? Is the value of long-term contracts rate based?

4. What factors does your commission consider for determining winning bids (e.g., price, supply certainty, contract length, renegotiation and other non-price contractual provisions)?

5. What parties are responsible for determining winning bids for natural gas and coal (e.g., independent contractor, utility, PUC)?

6. What reporting requirements does your commission have for (a) natural gas and (b) coal contracts?

7. Does your commission have any hedging requirements for gas and electric utilities? For example, do utilities have to hedge a minimum portion of their fuel needs?

8. What data does your commission use in determining approval of coal contracts?

9. What credit requirements does your commission have for (a) natural-gas and (b) coal contracts?

10. How does your commission treat, for ratemaking purposes, hedging costs for natural gas and coal (e.g., rate of return, penalties, automatic pass-through)? For example, hedging costs can include the premiums paid for financial options.

11. How much physical hedging (e.g., long-term bilateral contracts) and financial hedging (e.g., futures contracts, swaps) for natural gas and coal do the electric and gas utilities in your state undertake?

12. What typically are the different time horizons for natural gas and coal hedges (e.g., one year, two years, ten years)?

Appendix C: State-by-State Survey Responses

State	1. What position has your Commission taken on long-term natural gas (for both electric and gas utilities) and coal contracts: (a) as a policy matter, (b) for a prudence review, and (c) for the request for proposal (RFP) process?
Alabama	*Natural Gas Utilities*: (a) no official policy, (b) every contract is subject to Commission review, (c) not applicable *Electric Utilities*: By its order in Docket No. 18148 issued May 29, 1981, the Alabama Public Service Commission established Rate ECR (Energy Cost Recovery) as the mechanism for Alabama Power Company to recover prudently incurred fuel costs. Rate ECR and the effective Energy Cost Recovery factor provide for the recovery of: (1) the cost of fossil fuel and emission allowances, (2) gains, losses and costs associated with Alabama Power's utilization of futures, options and over the counter derivatives (including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps) for the purpose of hedging its energy and fuel costs, and (3) other fuel related costs such as nuclear fuel and purchased power.
Arizona	For natural gas utilities, the Commission has formally recognized price stability as one of the policy goals for natural gas procurement. Specifically, Order 61225 states that "LDCs should pursue longer term, fixed price supply options as a viable option when they choose which gas supplies to include in their supply portfolios." When the Commission Staff conducts a prudence review during a rate case, the utility's adherence to this Commission policy statement is reviewed. The Commission does not have generic rules for natural gas LDCs regarding their RFP process. Specific details of a given LDC's RFP process may be addressed during rate proceedings. The Commission has not taken a position on long-term natural gas or coal contracts for electric utilities as a policy matter. Commission Staff generally reviews the prudence of natural gas and coal procurement in individual electric utility rate cases. The Commission has not taken a position on natural gas or coal contracts for electric utilities in regard to an RFP process.
Arkansas	*Natural Gas Utilities*: The Commission has not stated a specific position or policy on long-term natural gas contracts. Natural gas utilities purchasing decision are expected to conform to the Commission Natural Gas Procurement Plan Rules (Procurement Rules). *Electric Utilities*: The Commission has not stated a general position or policy regarding long-term natural gas and coal contracts as a policy matter, for prudence review, or for the RFP process.
California	The CPUC has not taken a position on long-term natural-gas supply contracts. Natural gas utilities' procurement costs are subject to gas cost incentive mechanisms. The natural gas utilities are able to enter into long-term contracts, but generally they have entered into monthly contracts. Electric utility procurement planning in general is considered in Long-term Procurement Plan proceedings. Electric utilities' natural gas procurement activities, including long-term contracts, are subject to review by Procurement Review Groups. Contracts 5 years or longer must be approved in advance by the CPUC. Electric utilities in California are able to enter into long-term contracts but rarely have done so.

Colorado	As a part of legislation on coal-to-gas generation emissions reductions last year, the Colorado Legislature enacted legislation endorsing long-term gas contracting and providing certainty by requiring future Commissions to honor such contracts. The Commission approved one contract under this legislation in Docket No. 10M-245E, and has generally encouraged long-term gas contracting. The Commission has not addressed coal contracting terms. Utilities generally request preapproval of long-term gas contracts. Therefore, cost recovery has not been an issue in subsequent prudence reviews. The Commission has not provided any guidance or requirements for coal or gas commodity procurement processes. All fuel costs including costs determined from long term natural gas and coal contracts are subject to prudence review in a subsequent Fuel Cost Recovery proceeding.
Connecticut	The PURA does not regulate natural gas for electric utilities. The PURA has a policy on hedging of gas commodity contracts that does not financially benefit the LDCs: Any losses from hedging are attributed to the LDCs and not the ratepayer; therefore, the LDCs do not hedge gas supply with financial instruments. Any large customer can ask the LDC to hedge that customer's supply, but that customer is responsible for all costs of that gas supply.
Delaware	The regulated companies contracts are monitored through strategic supply and demand plans filed annually. Specific contracts are not specifically approved by the Commission. Delaware does not have a prudence standard. The annual RFP for Delmarva Power & Light Company's electric standard offer service contracts are three years for residential and small commercial and one year for medium and large commercial.
District of Columbia	Not applicable. Commission has not taken a position at this time.
Florida	The Florida Commission established a Fuel Adjustment Clause in the 1970s, which was further defined in 1980 to use projected cost and a true-up mechanism. The Fuel Clause is defined in Commission Orders, not in statutes or rules. An annual fuel hearing is held each November to review fuel expenses and set fuel factors for the coming projected year. The Commission does not specifically determine the prudent cost of each fuel expense each year. Instead, the Commission can review specific expenses for prudent cost determination and can go back for ten years or more to review expenses. The idea is that the utility gets timely cost recovery and the Commission can go back for a number of years for prudent cost reviews. The Commission does not have a particular policy on long-term gas supply contracts, and, generally, does not make specific prudent cost determinations for each long-term gas supply contract. The Commission reviews the utility's fuel procurement process and fuel supply contracts. Florida electric utilities and gas distribution utilities have long-term gas supply contracts that are typically indexed to market prices. For such contracts, Commission-staff auditors verify that the market prices paid are appropriate. The Purchased Gas Adjustment (PGA) clause works in a similar manner for investor-owned gas-distribution utilities that still have a merchant function.

Georgia	All fuel costs, including costs determined from long-term natural-gas and coal contracts, are subject to prudence review in a subsequent Fuel Cost Recovery proceeding.
Indiana	Per Indiana Code, gas utilities may apply for a change in its gas cost charge in quarterly proceedings. Indiana Code § 8-1-2-42(g)(3)(A) specifically states that the Commission may approve the requested gas charge only if "the gas utility has made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the lowest gas cost reasonably possible." Indiana utilizes a statutory quarterly fuel summary proceeding (electric utility "FAC") process (Indiana Code 8-1-2-42(d)) which includes a requirement for it to make a finding that "the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible." Accordingly, the review of contracts and their prudence generally occurs within FAC and GCA proceedings. The process includes a statutory cost audit as well as a decision/process review that is conducted by Indiana sanctioned ratepayer advocate and other interested parties. The Commission makes use of sub-dockets (topic specific investigations that allow for an extended review) to review complex utility decisions as needed. The Commission has consistently recognized the value of appropriately priced long-term coal contracts as a sound instrument to ensure a reliable fuel supply. Coal transportation contracts are viewed similarly. The limited use of natural gas as a baseload fuel for Indiana electric utilities has not to date resulted in a need to form a precedent for long-term natural gas supply contracts, although the Commission recognizes the value of the firm natural gas transportation contracts for specific units.
Iowa	The Utilities Board looks at long-term natural gas and coal contracts on a case-by-case basis depending on whether an issue is raised about a specific contract. The Utilities Board does not have an RFP process that it oversees for these contracts.
Kansas	The natural gas utilities have to file a monthly natural gas purchasing report that covers all old and new contracts. The utilities also have to come in once a year to review the previous year's natural gas purchases and to present their plan for the next year. If a contract goes through an RFP process or is close to the market index, the contract is then approved. If the contract is significantly above the market index, then we ask for an explanation. Most of the time the higher price is because the natural gas comes from a gathering station and the utility has to pay for the process of the natural gas. All of the natural gas utilities that we regulate have a monthly Purchase Gas Adjustment (PGA) and an annual true-up, Annual Energy Cost Adjustment (ACA) where our auditors review a sample of the contracts for prudence.
Maine	For Local Distribution Companies (LDCs), the MPUC reviews purchasing processes on case-by-case bases, e.g., through the review of Integrated Resource Plans and cost-of-gas cases, but does not have a standard policy. The Maine PUC does not regulate generation and, therefore, is not involved in decisions by electric generators on long-term fuel contracts.

Maryland	*Note*: Electric generation is deregulated for most electric service in Maryland. Consequently, no fuel procurement for that generation is regulated. Only two regulated municipal utilities have generation, none of it is coal and most of it is oil. No long-term procurements have been ordered for those municipal electric utilities. A small amount of longer term contracting has been found prudent. General clarification on "long-term" gas contracts: Maryland LDCs have no gas commodity contracts beyond the upcoming storage fill or heating seasons. All responses to this survey assume "long-term" is limited to roughly no longer than six months. Our largest LDC must contract between 10 and 20% of flowing supply prior to the heating season. The second largest was required to contract roughly 15% of its summer storage injections prior to the injection season, but no winter hedging was ordered for that utility. Contracting beyond "bid-week" purchases has traditionally been limited in policy and practice.
Michigan	Currently the regulated utilities of Michigan are proposing contracts for natural gas that extend no longer than 2 years ahead of consumption. The Commission will most likely find this shorter-term approach to hedging reasonable. The last of our major utilities transitioned from a long-term (4 years out) hedging strategy to a more short-term hedging strategy (2 years out, less volumes purchased at lower trigger prices) with the 2012-2013 plan. This move was welcomed by Commission Staff and other intervening parties as well, although in the past longer term hedging was also approved by the Commission. A wide variety of hedging strategies will be considered by the Commission as long as overall the hedging plan appears reasonable and prudent. When reviewing hedging for prudence, Staff looks at all the available information the utility had at the time it secured its hedge. This includes the then-current market price of gas, the futures prices at the time, and any forecasts that may indicate where future prices will be headed. We also look at the 5 year forecast to ensure that the utility is not over hedging volumes for future years. It is the utility's responsibility to negotiate and enter into fuel contracts that are in the best interest of its customers. Traditionally, the length of coal contracts has been a function of the market, i.e., longer contracts in the past (10+ years) with a recent trend toward contracts of no more than a few years. The Commission has not taken a position on the length of coal contracts, but evaluates all electric supply fuel contracts, including coal contracts, individually with the duration of the contract being only one factor considered in evaluating the reasonableness and prudence of a utility's fuel supply plan.
Minnesota	The Commission has not taken a position on long-term versus medium- or short-term natural gas or coal contracts. The cost of fuel purchased under all contracts, regardless of term, is reviewed annually.
Mississippi	In general, contracts are reviewed on a case-by-case basis either as part of the annual statutorily required fuel audits or a specific docketed filing before the Commission. To date, no long-term natural gas contracts have been proposed. The Public Utilities Rules of Practice and Procedure outline general standards for fuel procurement and use. These standards require utilities to procure fuel at the lowest and best prices available from reliable suppliers. The Public Utilities Staff is charged with reviewing the procurements to assess the utilities' effectiveness in achieving these standards. Accordingly, the Staff performs such steps as it deems necessary in the circumstances to make a determination. While RFP's are not currently required for every contract, a well-designed RFP process is preferred.
Missouri	With regard to long-term natural gas and coal contracts, as a policy matter, the Commission has not specifically addressed this topic.

Missouri – *continued*	With regard to long-term and less-than-one-year natural gas contracts for natural gas utilities, recovery generally takes place in the context of the purchased gas adjustment clause and actual cost adjustment process where there is an annual prudence review process. With regard to coal contracts for the electric utilities, prudence review and recovery generally takes place in permanent rates. For three of our four electric utilities, 95% of the difference between the actual cost and the cost in the permanent rates is recovered through a fuel adjustment clause. Prudence reviews of fuel costs for these utilities occur at least every 18 months.
Montana	The Commission regulates the recovery of coal procurement costs for the thermal generation assets of its primary jurisdictional utilities, NorthWestern Energy (NWE) and Montana-Dakota Utilities (MDU) in the context of rate case proceedings. It has not stated a position on the hedging of coal procurement costs. The Commission does not have administrative rules that govern gas cost hedging, but generally encourages the pursuit of price stability as an important component of a reasonable and prudent portfolio. In general, Montana utilities have discretion in the purchase of commodities subject to Commission prudence reviews.
Nevada	The Nevada Commission does not have a specific policy on long-term contracts. It addresses the issues on a utility-by-utility basis depending upon that utility's unique circumstances. The Commission, however, has implemented regulations that require electric and natural gas utilities to finalize their respective plans for meeting their energy requirements. The gas utilities are required to file annually an informational report only, which includes a plan for supply of natural gas. The plan sets forth the criteria used to both determine the level and mix of natural gas and to select sources of natural gas. Plus, the plan sets forth the strategies for minimizing retail price volatility and maximizing reliability of supply. Sierra Pacific Power Company files its plan with the electric department's energy supply plan, with an identical procurement plan, which was approved by the Commission. Southwest Gas Corporation files its informational plan with its annual rate adjustment application. Its procurement plan includes a volatility mitigation plan that consisted of meeting 30% of its forecasted annual volumes with fixed price contracts and fixed-for-floating financial derivatives. Electric utilities are required pursuant to regulation to file with their tri-annual integrated resource plan an energy supply plan that establishes parameters for fuel and power procurement for the subsequent three calendar year period. The energy supply-plan objective is to balance minimizing cost of supply, minimizing retail rate volatility, and maximizing reliability of supply. The energy supply plan consists of a purchased power procurement plan, a fuel procurement plan, and a risk mitigation strategy. Annually, the electric utility is required to file for approval of an updated plan for the remaining period of the initial three-year term. If the Commission approves the energy supply plan, or portions thereof, a presumption of prudence exists. The electric utility is required, however, to monitor market conditions and change the plan accordingly, even without Commission action, or be subject to a disallowance.
New Hampshire	*Natural Gas Utilities*: They are required to file Integrated Resource Plans every three years in which long-term supply planning is reviewed (5-year horizon). Long-term contracts (greater than one year) are primarily for pipeline capacity but utilities have some long-term contracts for peaking supplies with indexed pricing.
New York	*Note for Electric Utilities*: The major electric utilities in New York have largely divested their generation assets in an effort to provide competitive supply offerings to customers. Therefore, many of the questions related to utility oversight responsibilities with regard to fuel purchasing do not apply. The independent generators are responsible procuring their fuel. These generators sell electricity into the New York wholesale energy market

New York – *continued*	and receive the competitive market-clearing price. The Commission does, however, have certain policies and guidelines, which the utilities are required to follow, that are intended to reduce price volatility associated with energy market price fluctuations for smaller customers, generally, residential and small commercial and industrial customers. *Natural Gas Utilities*: (a) The Commission imposes no restrictions on long term natural gas contracts (1-5 years); fixed-price contracts are restricted to hedge policy of nominal 1-year duration and winter season only hedge preferred; b) Same as (a) above; (c) RFP process for all contracts is the same with minimum 3 or more competitive bids preferred. *Electric Utilities*: (a) The Commission imposes no restrictions. Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts. Some utilities that have power purchase agreements with gas-fired generators have purchased gas futures and options contracts for their hedged customer classes for up to 3 years; (b) Same as (a) above; (c) Same as (a) above.
North Carolina	The Commission has no formal position on long-term contracting. *Natural Gas Utilities*: Pricing is obviously a significant contracting issue. LDCs primarily have contracts that are indexed to first of the month pricing that lock in prices one month ahead for base sales volumes (volumes they expect to sell regardless of weather) and they generally meet swings in volumes with gas priced at the spot market for any demand not covered by swing contracts. Two other contract issues are security of supply and volumetric swing capability. The Commission has approved the payment of reservation fees under gas commodity contracts. Reservation fees can provide for both supply security (payment of the fee guarantees volumes will be available barring force majeure) and swing capability. *Electric Utilities*: All fuel costs are subject to a prudence review in annual fuel-charge adjustment proceedings for electric utilities. In practice, the electric utilities subject to the Commission's jurisdiction have issued RFPs and entered long-term contracts to purchase varying portions of their forecasted needs for coal. The Commission has no standing requirements with respect to the long-term contracts or an RFP process to purchase such fuels.
Ohio[26]	The Commission does not have an established position on the appropriate term of natural gas contracts. The appropriateness of long-term vs. short-term contract lengths is obviously dependent on conditions in the natural gas market at any point in time. Such decisions would be evaluated within the context of a prudence review, which judges those decisions based on market conditions at the time such decisions were made.
Oklahoma	Oklahoma utilities have relied on long-term contracts for decades. The Commission has rules that dictate the process that utilities should follow if a utility is seeking a pre-determination of prudence. These rules were just updated for 2012. Prudence is either determined in advance by complying with the Commissions rules or at the time of review if the rules were not followed. This is done on an annual basis as part of the annual fuel audit and prudence review. We support the use of long-term contracts as part of an overall portfolio. We do expect the utility to address the need for the fuel supply as well as attempts to protect against price volatility if the contract is index based.

[26] All the responses of the Ohio Public Utilities Commission pertain only to natural-gas utilities.

Oklahoma – *continued*	We use independent evaluators to participate in the RFP process for fuel procurement. The new rules allow a utility to have the RFP preapproved if they are seeking a pre-determination of prudence.
Oregon	For gas utilities, the Commission has issued guidelines that the regulated LDCs are expected to follow when developing their gas supply portfolios. See http://apps.puc.state.or.us/orders/2011ords/11-196.pdf (Docket UM 1286, Order No. 11-196). For electric utilities, the Commission does not have a prescriptive policy. Prudence is determined when a utility makes a filing that proposes to put the contract costs into rates. There are not prescriptive guidelines on such contracts in Oregon's RFP process. See also the Order which governs the bidding process for supply resources—gas turbines, wind farms, contracts for such, etc at http://apps.puc.state.or.us/orders/2006ords/06-446.pdf (Order No. 06-446).
South Carolina	The Commission has taken no position on long-term natural gas and coal contracts. The PSCSC reviews utilities' fuel purchases and purchasing practices annually and rules on prudence. The PSCSC must approve contracts for firm gas supply or transportation.
South Dakota	The Commission has not taken a formal position on long-term contracts for either LDC gas supply or electric fuel. It has allowed companies to contract long term but has not promoted or discouraged the practice.
Texas (PUCT[27])	The Commission does not prescribe the length of term of natural gas or coal contracts. The prudence of new fuel contracts is reviewed in the fuel reconciliation process every one to three years pursuant to P.U.C. SUBST. R. §25.236.
Utah	As a policy matter, the Commission has not developed a formal policy for long-term natural gas and coal contracts. If a contract were brought before the Commission, it would be evaluated on a case-by-case basis. For a prudence review, the Commission approves PacifiCorp's net power cost amount for recovery in rates; the net power cost amount reflects the costs for coal obtained through some executed long-term coal contracts. With regard to Questar Gas Company (QGC), the Commission has approved the Wexpro Stipulation and Agreement. The prudence of market purchases can be evaluated during gas pass-through proceedings. For the RFP process, the Commission is not involved in RFP decisions for long-term gas and coal contracts. Prudence of these contracts is determined through rate proceedings.
Virginia	The Commission has not taken a position on long-term natural gas or coal contracts for utilities. All purchased gas costs and electric fuel expenses, however, are subject to audit and prudence reviews.

[27] The PUCT does not regulate gas utilities so its responses pertain only to electric utilities under its jurisdiction.

Washington	Long-term natural gas contracts have always been allowed in the PGA as a pass-through to ratepayers. The costs are included in the weighted-average-cost-of-gas (WACOG).
Wisconsin	The Commission typically prefers a portfolio approach taken by the energy utilities for fuel procurement. The portfolio approach would have a varying mix of contract lengths including plans for spot market purchases. Currently, though, none of our utilities has contracts for coal greater than six years and for natural gas greater than three years. The reasonableness of recovering costs from long-term contracts would be reviewed annually for both gas and electric utilities as part of required gas supply and electric fuel cost plan filings.
Wyoming	Utilities are required to provide safe, adequate and reliable service at the most reasonable rates. As a policy matter, the Commission expects utilities to identify their source of supply based on the unique operating opportunities and constraints within their service territories. All utility decisions may be reviewed for prudence either beforehand or after the fact. The Commission does not participate in utilities' RFP processes.

State	2. What are your Commission’s rules for competitive bidding of (a) natural gas and (b) coal? For example, what information do bidders have to provide as part of their submittal? What are the criteria for evaluating bids?
Alabama	*Natural Gas Utilities*: Not applicable, as the Commission does not have rules on competitive bidding. *Electric Utilities*: While the Commission has not established any formal competitive bidding rules for coal or natural gas for Alabama Power, it has established general guidelines for the RFP process associated with purchased power. The competitive bidding practices of the Company, concerning coal and natural gas, would be subject to review by the Commission in the course of establishing the Energy Cost Recovery factor as describe in the response to *Question 1* above.
Arizona	The ACC does not have specific rules on competitive bidding for natural gas supplies for natural gas LDCs. Details of each utility’s competitive bidding process may be considered during a general rate proceeding. The ACC does not have specific rules on competitive bidding for natural gas or coal supplies for electric utilities. Details of an electric utility's fuel procurement process may be considered during a general rate proceeding.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules do not explicitly require competitive bidding of natural gas purchases. It is standard practice, however, for natural gas utilities to acquire the majority of their natural gas supply using a RFP process or electronic bidding platform. Since the RFP process has been in place for a number of years, bidders are known to the natural gas utilities. Bids are not sent to parties who are not qualified to perform financially. Bids are examined to make sure the seller can actually deliver the service being requested. Bids must confirm to the terms of the RFP. *Electric Utilities*: The Commission does not have specific rules on competitive bidding for natural gas or coal. The Commission does not have specific criteria for evaluating bids for natural gas or coal.
California	The CPUC has not specified rules for competitive bidding for natural gas procurement.
Colorado	We do not have any rules for competitive bidding of the gas or coal commodity. In practice the utility files an application for approval of a long-term gas contract. Under the application process the utility must meet its burden of proof to show that the contract is in the public interest. This has generally included a comparison of the different contracts offered by suppliers, comparison of contract and projected market pricing, hedging value, and the creditworthiness of the supplier.
Connecticut	The PURA uses the purchased gas adjustment clause (PGA) proceeding for a prudence review of all gas supply purchase semiannually.

Delaware	Not applicable
District of Columbia	A working group is used to monitor the gas utility's procurement practices. DC is a deregulated market and does not have formal rules on the procurement of fuel. Commission has a market monitor for the electric utility's procurement of power for customers that do not select an alternative power supplier.
Florida	The Commission does not determine which supplier is awarded a contract. The RFP process is done by the utility. The Commission reviews and audits these RFPs and bid evaluations to make sure the contract awarded is based on an appropriate bid evaluation. Price, supplier creditworthiness, supplier reliability and performance, coal quality specifications, and transportation issues are some of the appropriate criteria for evaluating bids. For example, with coal contracts, the utility should explain the elimination of any low bid. This decision might be based on creditworthiness and/or performance and reliability concerns or the inability to consistently deliver coal of a particular quality.
Georgia	The Commission does not have competitive bidding requirements for natural gas or coal. The utilities do rely, however, on competitive bidding practices for coal supplies. The utility determines the winning bids. The winning bids are subject to a prudence review in a subsequent Fuel Cost Recovery proceeding.
Indiana	The competitive bidding process is generally reviewed as needed and no formal policy for electric utility coal purchasing has been established. There is no formal bidding process for natural gas for gas utilities. Notwithstanding, there are specific requirements to show that competitive pricing occurs when there are transactions between affiliates for both gas and electric utilities.
Iowa	Not applicable.
Kansas	Initially, the Commission only looks at the prices and not at the process for competitive bidding. If the prices seem high, however, we have encouraged utilities to expand their bidding pool to the extent feasible.
Maine	See response to *Question 1*.
Maryland	LDCs must demonstrate that procurements were competitive and followed all requirements for dealings with utility affiliates.
Michigan	The Commission requests that if competitive bidding is used, the utility lists all bidders for natural gas contracts, the date of the bid, the price that was offered, the delivery date for the gas and any locked in basis, but the Commission does not have any specific rules for competitive bidding. The main criterion used for

Michigan – *continued*	evaluating bids is the final price, which includes commodity, transportation, and basis. Most utilities provide the bidding party's name, but some do not and just refer to the suppliers as Supplier A, B, C, etc. For coal contracts, similar information is requested, such as the tonnage, price, region, type of coal, contact start and end dates, penalties, contract flexibility, or other special contract provisions. The Commission has broad review authority through Public Act 304. The applicable parts of the act that cover coal contracts specify that the Commission shall "Disallow additional costs resulting from unreasonably or imprudently renegotiated fuel contracts." It is within the Commission's discretion to determine if the length of the contract is reasonable within the context of the contract's provisions.
Minnesota	The Commission does not have rules on competitive bidding for natural gas or coal contracts unless the contract is with an affiliate. Each utility administers its own bidding and evaluation process for fuel procurement. If the counterparty to the contract is an affiliate, then the utility must obtain Commission approval for the affiliate agreement, and include in its petition a summary of the request for proposals and a summary of each proposal (or bid) received or an explanation as to why competitive bidding was not used in the procurement process.
Mississippi	Though the Commission does not have formal rules on competitive bidding, the Public Utilities Rules of Practice and Procedure outline general standards for fuel procurement and use. (See response to *Question 1*.)
Missouri	With regard to competitive bidding for natural gas utilities, the Commission's affiliate rule encourages competitive bidding where an affiliate is involved. There are no specific Commission criteria for evaluating bids. With regard to electric utilities competitive bidding for coal, there are no specific Commission criteria for evaluating bids.
Montana	Utilities construct their own requests for proposals; the Commission's rules do not specify information to be provided by bidders. Review of the competitive procurement process is evaluated in cost recovery dockets.
Nevada	The Nevada Commission does not have competitive bidding regulations.
New Hampshire	*Natural Gas Utilities*: Competitive bidding is not required by Commission rule but long-term supply contracts are competitively bid in compliance with the IRP; and the bidding process and results are reviewed through peak and off-peak cost of gas filings.
New York	*Natural Gas Utilities*: In general, the RFP process for all contracts is the same with the minimum of 3 or more competitive bids preferred; required information includes length of contract, pricing terms (monthly or daily and fixed price or what index), volume flexibility in daily delivery quantity (can determine not only adder cost but whether contract is base loaded or swing volume), reservation charge if any, receipt point, delivery point, etc. The evaluation criterion is least-cost reliable offer to meet portfolio needs.

New York – *continued*	*Electric Utilities*: Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts.
North Carolina	*Natural Gas Utilities*: The Commission does not establish rules for competitive bidding for gas LDCs. The LDCs use, however, an RFP to obtain bids. The Public Staff reviews the RFPs, and both the bids that are accepted and the bids that were ultimately rejected in addition to the reasons for each decision. *Electric Utilities*: There are no Commission-established rules on competitive bidding for natural gas or coal. As noted above, however, such fuel costs are subject to prudence reviews.
Ohio	Three of the four largest natural gas companies now use an auction format to purchase gas. For those that use an RFP process, the Commission does have any rules that govern this process.
Oklahoma	All fuel sources are held to the same standard under the rules. The Commission has had more requests for waivers with coal as there are fewer suppliers to bid in response to an RFP. The bid evaluation for each RFP will vary and is determined as part of the RFP approval process. The basics would include creditworthiness, supply surety, pricing, delivery options, and price volatility mitigation if applicable.
Oregon	For electric and gas utilities, the Commission does not have a prescriptive policy. Utilities follow their own procedure in terms of information required from bidders and how that information is evaluated. Then, when a utility makes a filing, which would put the contract costs into rates, parties to the proceeding can challenge the prudence of such costs.
South Carolina	The Commission has no rules for competitive bidding of natural gas and coal. The PSCSC reviews utilities' purchases and purchasing practices annually and rules on prudence.
South Dakota	Bidding is not required in South Dakota.
Texas (PUCT)	The Commission does not have any rules on a formal competitive bidding RFP process. See response to *Question 3*, below.
Utah	The Commission does not have rules on competitive bidding of natural gas and coal. The Commission relies on the procurement requirements of the utilities and prudence is determined in a rate proceeding.
Virginia	The Commission has no rules for competitive bidding of purchased gas costs or coal.

Washington	The Commission has no rules on competitive bidding for fuel.
Wisconsin	The Commission requires the utilities to have available for review all of the documents associated with the bidding process, including the analysis used to select the winning bids. The Commission does not prescribe any aspect of the utilities' bidding process.
Wyoming	The Commission does not oversee the bidding process or evaluate submitted bids.

State	3. How does your Commission treat, for ratemaking and procurement purposes, (a) long-term natural gas and coal contracts and (b) less-than-one-year transactions? For example, are long-term contracts considered a physical hedge? Is the value of long-term contracts rate based?
Alabama	*Natural Gas Utilities*: Long-term and short-term contracts are treated the same for ratemaking purposes. The costs are recovered through the PGA as they are incurred. *Electric Utilities*: Alabama Power's fuel costs are recovered through Rate ECR when incurred. The value of long-term contracts is not included in rate base.
Arizona	For natural gas utilities, the costs related to both long-term contracts and less-than-one-year transactions are passed through the purchased gas adjustor mechanism in the same manner. For electric utilities, the costs for fuel from both long-term contracts and less-than-one-year transactions are recovered in the same manner. Fuel costs are recovered as expenses through base rates, not rate based. Between rate cases, the amount of costs that differs from the level set at the time of the last rate case is recovered or refunded through an adjustment mechanism.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules do not distinguish between long-term and short-term natural gas contacts. The Commission's Procurement Rules state that the portfolio should consist of an appropriate combination of different types of gas purchase contracts and or financial hedging instruments designed to yield an appropriate balance of reliability, reduced volatility and reasonable price. The cost of long-term contacts for natural gas are not included as part of base rates. Natural gas utilities in Arkansas recover gas costs from customers through a Purchased Gas Adjustment Clause (PGA) mechanism, which appears as a line item on customer bills. There is no mark-up or profit added to the cost of gas. The utilities only recover from customers the actual cost of the natural gas commodity and the cost of transporting that gas from gas producing regions over interstate pipelines to the natural gas utilities. The costs recovered through the PGA mechanism are subject to Commission review and approval to ensure that the utilities purchase prudently the gas in conformity with the requirements of Arkansas law and the Commission's Rules. *Electric Utilities*: Electric utilities in Arkansas recover the cost of natural gas and coal used as fuel to generate electricity through an Energy Cost Recovery rider (ECR) or a Fuel Adjustment Clause. The costs recovered through those mechanisms are subject to Commission review and approval to ensure that the utilities purchase prudently natural gas and coal used as fuel to generate electricity. The value of any contracts for natural gas and coal used as fuel to generate electricity is not rate-based.
California	Natural gas utility procurement costs incurred under long-term or short-term contracts are subject to gas cost incentive mechanisms. Costs are booked to purchased gas accounts. The value of a long-term contract is not rate-based.

Colorado Commission rules require gas utilities to submit a hedging plan, and the state's largest electric utility also submits a fuel gas hedging plan. Utilities include long-term gas contracts as part of their hedging plans, and they recover these costs through Gas Cost Adjustment (GCA) and Electric Cost Adjustment (ECA) pass-through mechanisms.

The Commission has not addressed coal contracting terms.

All gas and coal costs are recovered through the GCA and ECA.

Connecticut The PURA is not involved with these issues because of the current hedging rules.

Delaware Physical and financial hedges are treated similarly. Contracts are not entered into rate base; all gas procurement costs, including hedging, are a direct pass through included in the annual fuel adjustment rate filings.

Short-term contracts—those less than one year—would be considered spot market purchases.

District of Columbia Not applicable as DC is a deregulated market so procurement of fuel is generally not a matter of concern. A long-term contract, however, could be considered as a physical hedge.

Florida The Commission allows utilities to recover the costs associated with long-term fuel supply contracts and spot contracts through the fuel clause and PGA clause. While a long-term fixed price contract for coal can be considered a physical hedge, the Florida Commission's review of a utility's hedging involves natural gas, fuel oil (including fuel oil for coal transportation), and purchased power. Long-term fixed-price gas contracts, which are not common, are considered a physical hedge. The Commission does not give rate-based treatment to long-term contracts. See also the response to *Question 1*.

Georgia All prudently incurred fuel costs are recovered under a Fuel Cost Recovery tariff independent of whether the fuel was procured under long-term or short-term contracts.

Indiana For coal contracts, the Commission has avoided hindsight review of coal contracts that were previously recognized as satisfying the above-mentioned FAC prudence test. The timely review of contracts generally occurs when the costs for such contracts are subject to FAC review. Additional review is established for affiliate transactions.

The Commission also avoids hindsight review of natural gas contracts that were previously recognized as satisfying the GCA prudence test. The timely review of contracts occurs when the costs for such contracts are subject to GCA review. Once long-term contracts are reviewed and found to be reasonable in the quarterly proceedings and reviewed for prudence in accordance with Indiana Code 8-1-2-42(g)(2), there is no review thereafter. As mentioned before, however, additional review is established for natural gas utility-affiliate transactions.

Iowa Natural gas contracts, both long-term and less-than-one-year, for system customers are part of the Utilities Board purchased gas adjustment procedures and the costs are a direct pass through to customers.

Kansas All recovery is through the ECAs and PGAs.

Maine LDCs recover all gas supply costs through cost of gas rates, which customers pay through rates that are separate from delivery/base rates. There is a working capital component in these rates to reflect the time value of money, but all costs are treated as expenses and are not included rate base.

Maryland Because hedging has been ordered at levels specified by the Commission, no disallowances for hedging have occurred. All transactions are less than one year; and no contracts are rate-based.

Michigan All natural gas contracts—long-term and less than one year—are treated as a cost of gas, even if they include a premium. The cost of the hedge is included in the GCR during the year that the gas will be consumed. The utility cannot collect the cost of a hedge contract until the year the gas is consumed. The Commission considers storage a physical hedge and futures contracts more of a financial hedge.

All coal contracts regardless of the length are considered power supply costs and are recovered through the utility's power supply cost recovery clause and not through a rate case proceeding. The Commission has no guidelines or requirements for coal purchasing, but in general a contract over one year could be considered a hedge.

Minnesota Generally, no distinction is made for ratemaking or procurement purposes between contracts that are more than one year in length and those that are less than one year in length. The cost of the fuel procured under the contract is recovered through monthly automatic rate adjustments for fuel costs at approximately the same time the fuel is used (by the utility) or consumed (by the ratepayer).

Mississippi The costs for both long-term and less-than-one-year transactions are passed through the statutorily required fuel adjustment clauses for each company and audited quarterly or annually. The value of long-term contracts is not included as an investment in rate base.

Missouri For long-term and less-than-one-year natural gas contracts for natural gas utilities, recovery generally takes place in the context of the purchased gas adjustment clause and actual cost adjustment process where Commission Staff conducts an annual prudence review. Long-term and less-than-one-year natural gas contracts could be a physical hedge if they are fixed price. The value of long-term contracts is generally not recognized as part of rate-base unless they are part of inventory, which mostly composes of shorter-term gas supplies.

For long-term and less-than-one-year coal contracts for electric utilities, recovery generally takes place in the base rates and, where applicable, recovery of changes takes place in the fuel adjustment clause. Long-term and less-than-one-year coal contracts could be a physical hedge if they are fixed price. The value of long-term contracts is generally not recognized as part of rate base unless they are part of inventory.

Montana The Commission reviews all purchases in contested proceedings. The Commission does not define hedges in terms of specific contract lengths. The coal and natural gas markets are not static, and the Commission is aware that contract intervals, spot market values, and hedging opportunities may vary substantially over time.

Nevada The Commission allows electric utilities to recover all reasonably and prudently incurred fuel and purchased power costs via the fuel adjustment clause mechanism with no distinction between long-term and short-term contracts.

New Hampshire *Natural Gas Utilities*: Long-term contracts use indexed pricing (not considered a financial or physical hedge); cost recovery occurs through the cost of gas mechanism.

New York *Natural Gas Utilities*: Fixed price contracts and storage gas are the physical hedges. All gas costs get recovered through an automatic pass-through mechanism.

Electric Utilities: Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts.

North Carolina *Natural Gas Utilities*: LDCs' gas purchasing practices are subject to an Annual Review of Gas Costs pursuant to N.C.G.S. 62-133.4(c).

Electric Utilities: Whether purchased through long-term contracts or spot (less-than-one-year) transactions, the reasonable and prudent costs of natural gas or coal burned during a test year are recoverable as fuel costs in the annual Fuel Charge Adjustment proceedings.

Ohio All gas procurement costs are recovered either through the GCR mechanism or, for those utilities that use auctions, through the auction-based Standard Choice Offer mechanism. No gas costs are recovered through base rates. Whether something is considered a physical hedge or not has no ratemaking implications.

Oklahoma Fuel contracts are collected through fuel adjustment riders whether they are long or short term. Oklahoma statute does not allow a utility to profit on fuel purchases so the utility earns no return.

Oregon For gas utilities, LDCs are required to meet with Commission Staff quarterly to provide an update on the status of their procurement plan including hedges and storage injections/withdrawals. Annually, LDCs file their purchased gas adjustments (PGAs) to true up actual gas costs with what was projected the previous year. At that time, Staff and parties can question prudence of the LDCs gas purchases.

For electric utilities, see the responses to *Questions 1 and 2* above. Less-than-one-year transactions are treated similarly for ratemaking purposes. Long-term contracts are treated as part of a utility's overall resource portfolio. The value of long-term contracts is not rate-based.

South Carolina Long-term contracts have been referred to as being physical hedges. When a commodity such as coal is actually received it is placed into the inventory of the utility unless used immediately. Inventory is a rate base item. Items used or taken out of inventory are expensed when used. When expensed it would become part of fuel cost and passed along to the ratepayer as determined in fuel proceedings. The values of long term contracts are not a rate-based.

South Dakota

Long-term and short-term transactions in addition to hedging costs are all allowed PGA items. There is no ratemaking distinction between them in terms of cost recovery. Long-term contracts have not been rate-based. Storage inventories are rate-based with some companies.

Texas (PUCT)

The Commission treats any contract of one year or more as long-term and less than one year as short term or spot. The only fuel allowed rate-base treatment is storage inventory. Fuel revenues and expenses are reconciled at 12 to 36 month intervals subject to the electric utility showing that its eligible fuel expenses during the reconciliation period were reasonable and necessary to provide reliable electric service to retail customers.

Utah

For Questar Gas, the Wexpro gas is provided under a cost-of-service formula which includes rate base and return on equity components. The costs for Wexpro gas, as well as all market purchases, are included in regular pass-through filings.

For PacifiCorp, the Commission approves net power costs in a general rate case, which are then included in rates. The value of long-term contracts is not rate-based; coal stock on hand, however, is included in rate base.

Virginia

The Commission allows the delivered costs associated with both long-term natural gas and coal contracts and less-than-one-year transactions to be recovered through the gas utilities purchased gas adjustment ("PGA") clauses and the electric utilities fuel factor rate. A long-term natural gas or coal contract would generally be considered a physical hedge.

Washington

Both long-term (greater than one year) and less-than-one-year natural gas contracts in the PGA are not rate-based. These contracts (in the PGA) are treated as commodity costs.

Wisconsin

When the contracts have an established price, the contracts would provide a hedge to fuel costs, or at least, would reduce the utility's exposure to market price variability for the associated contract volumes. The recovery of fuel costs would be based on contract terms and not prevailing market prices.

Wyoming

The costs reflected in both long-term and short-term fuel contracts are contained within the net power costs (separate from rate base). As the Commission doesn't have mandated hedging requirements, the value of long-term contracts as a hedging asset is not treated as a rate base asset; the inclusion of hedging costs (within net power costs) depends on individual prudence reviews.

State	4. What factors does your Commission consider for determining winning bids (e.g., price, supply certainty, contract length, renegotiation and other non-price contractual provisions)?
Alabama	*Natural Gas Utilities*: Not applicable, as the Commission approves contracts but does not determine the “winning” parties. *Electric Utilities*: With Commission oversight, Alabama Power (or Southern Company Services, as agent for Alabama Power), conducts the RFP process and evaluation of the competitive bids. The primary factors considered in the evaluation process include: price, supply certainty, contract length, contract flexibility and contract risk.
Arizona	The Commission does not determine winning bids for natural gas supply contracts for natural gas utilities. The Commission does not determine winning bids for natural gas or coal supply contracts for electric utilities.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules state that a natural gas utility's portfolio should consist of a combination of different types of gas purchase contracts and/or financial hedging instruments designed to yield an appropriate balance of reliability, reduced volatility and reasonable price. *Electric Utilities*: The Commission has not specified a specific list of factors to consider in evaluating bids for natural gas or coal used as fuel to generate electricity.
California	Natural gas utilities do not generally seek CPUC approval for their procurement contracts. Procurement costs are subject to gas cost incentive mechanisms. The CPUC and Procurement Review Groups might consider a variety of factors in reviewing long-term contracts entered into by electric utilities. Least cost would generally be a primary consideration. The CPUC must approve contracts with terms 5 years or longer.
Colorado	See response to *Question 2*.
Connecticut	The PURA uses the PGA proceeding to review all gas supply cost and transactions.
Delaware	The utility is the responsible party for determining winning bids.
District of Columbia	The Commission has a market monitor for the electric utility’s procurement of power for customers that do not have an alternative power supplier. A working group monitors the gas utility’s procurement practices.

Florida The Commission does not determine winning bids; it does review the utility's management process and decisions, however. Commission staff conducts annual audits, reviews testimony, and submits discovery questions to ensure each utility has a responsible approach to determining winning bids. See also the response to *Question 2*.

Georgia The Commission does not determine the winning bids—the utility does. The winning bids, however, are subject to a prudence review in a subsequent Fuel Cost Recovery proceeding.

Indiana The Commission does not generically evaluate the bidding process. Occasionally, intervening parties in the FAC and GCA proceedings have raised specific issues; they were addressed on a case specific basis.

Iowa Not applicable.

Kansas This is left up to the utilities unless the prices significantly exceed the market indexes.

Maine LDCs recover all gas supply costs through cost of gas rates, which customers pay through rates that are separate from delivery/base rates. There is a working capital component in these rates to reflect the time value of money; but all costs are treated as expenses and are not included rate base.

Maryland RFPs specify all non-price terms (including whether a supplier has been unreliable in the past), so decisions are based entirely on price.

Michigan The most important factor the Commission considers would be price and delivery date. The Commission trusts that the utilities would not get into contracts with an unreliable supplier. The Commission doesn’t typically see any non-price provisions in the contracts.

For coal contracts, the Commission evaluates each contract as a total package; it does not focus, therefore, on any single provision to determine reasonableness and prudence. It is the utility’s obligation to justify its selection of a particular contract and prove that it was the best option.

Minnesota The Commission typically does not evaluate bids.

Mississippi The Commission does not review this information outside a fuel audit unless it is a specific docketed filing before the Commission. If specific contract requirements are not outlined in the docket, then multiple factors may be reviewed, including but not limited to price, reliability, and experience, along with comparisons to other current and prior similar contracts, to determine a standard of reasonableness.

Missouri For natural gas contracts for gas utilities both price and non-price factors are reviewed as part of the PGA/ACA process.

For natural gas contracts for electric utilities both price and non-price factors are reviewed as part of the rate cases. For three of the four electric utilities, 95% of the difference between the actual cost and the cost in the permanent

Missouri – *continued*	rates is recovered through a fuel adjustment clause. Prudence reviews of fuel costs for these utilities occur at least every 18 months.
Montana	The Commission does not determine winning bids. The Commission may, however, review the winning bids and the selection process during a cost recovery proceeding. Generally, the Commission encourages utilities to consider the following attributes when evaluating bids: price, stability, flexibility, reliability, risk, diversity and contract length.
Nevada	The Nevada Commission does not have competitive bidding regulations.
New Hampshire	*Natural Gas Utilities*: In its review of an RFP and the bids, the Commission considers all of the above in addition to demand charges.
New York	*Natural Gas Utilities*: Least price reliable supply parameter; portfolio of contract terms and lengths *Electric Utilities*: Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts.
North Carolina	See response to *Question 2*.
Ohio	The Commission does not determine winning bids. That is a utility function which the Commission reviews through the Management Performance audit process.
Oklahoma	The Commission does not select winning bidders; it determines the reasonableness of the bidders selected by the utility. The Commission does consider, however, all of the above factors when conducting this analysis. Additionally, it considers the need for price volatility mitigation.
Oregon	For gas utilities, the Commission does not have a prescriptive policy. Utilities follow their own procedure in terms of information required from bidders and how they evaluate that information. Then, when a utility makes a filing that would put the contract costs into rates, parties to the proceeding can challenge the prudence of such costs. For electric utilities, see responses to *Questions 1, 2, and 3* above. The competitive bidding guidelines referenced in the response to *Question 1* pertain to new generating and contractual power supply resources, but not to fuel supplies.
South Carolina	The Commission is not involved in the utilities' bid evaluation processes.
South Dakota	There are no bidding requirements in South Dakota.

Texas (PUCT)	The Commission is not involved in any competitive bidding RFP process.
Utah	Not applicable
Virginia	The Commission does not determine winning bids.
Washington	Not applicable. The Commission evaluates ongoing purchases in the context of general market conditions.
Wisconsin	The Commission requires the utilities to have available for review all of the documents associated with the bidding process, including the analysis used to select the winning bids. The Commission does not prescribe any aspect of the utilities' bidding process.
Wyoming	The Commission does not oversee the bidding process or evaluate submitted bids.

State	5. What parties are responsible for determining winning bids for natural gas and coal (e.g., independent contractor, utility, PUC)?
Alabama	*Natural Gas Utilities*: Utilities determine who they enter into agreements with. The agreements are then submitted to the Commission for review and approval/disapproval. *Electric Utilities*: See response to *Question 4*.
Arizona	For natural gas LDC procurement bids, the utility determines the winning bids. These are subject to a prudence review by the Commission. Electric utilities are responsible for obtaining their natural gas and coal supplies. Competitive bidding is not required for fuel supplies. Procurement is subject, however, to a prudence review by the Commission.
Arkansas	*Natural Gas Utilities*: The utilities are responsible for determining winning bids for natural gas purchase contracts. *Electric Utilities*: The utilities are responsible for determining winning bids for contracts for natural gas or coal used as fuel to generate electricity.
California	Utilities generally determine the winning bid.
Colorado	See response to *Question 2*.
Connecticut	The LDCs are responsible for all gas supply purchases; the PURA uses the PGA proceedings to review their purchases.
Delaware	Utilities are the responsible party for determining winning bids.
District of Columbia	Not applicable.
Florida	Utilities determine winning bids and the Commission reviews their decisions.
Georgia	Utilities

Indiana	Utilities are responsible for managing its fuel supply portfolio. Natural gas utilities have the responsibility to manage their natural gas supply portfolio as well. The Commission has indicated that Indiana's natural gas utilities should make reasonable efforts to mitigate gas price volatility in their supply portfolio. One option is a hedge program that mitigates gas price volatility and considers market conditions and the price of natural gas on a current and forward-looking basis.
Iowa	Not applicable.
Kansas	Utilities
Maine	The utilities make the final decisions.
Maryland	In most instances, the utility chooses the winner. Some supply is determined by an asset manager and in those instances the performance of the asset manager is evaluated for prudence.
Michigan	For both gas and electric, the utility determines the winning bidder for the contract. The Commission has the responsibility of determining if the utility's decision to enter into the contract was reasonable and prudent based on the information the utility had when it made the decision to enter into the contract.
Minnesota	Utilities
Mississippi	In general, contracts are selected by the utility according to the specific order (via established relationship or the RFP) then presented to the Commission for approval either as part of a fuel audit or in a specific docketed filing.
Missouri	*Natural gas utilities* determine the winning bids subject to an annual prudence review as part of the PGA/ACA process. *Electric utilities* also determine the winning bids subject to a prudence review as part of a rate case and, if applicable, the fuel adjustment clause process.
Montana	The utilities are responsible for choosing the winning bids for natural gas and coal procurement.
Nevada	The utilities are responsible for determining the winning bids in a competitive solicitation.
New Hampshire	*Natural Gas Utilities*: The utility makes the decision; cost recovery depends on the outcome of a prudence review.

New York	*Natural Gas Utilities*: Utilities with PUC staff review *Electric Utilities*: Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts.
Ohio	Utilities
Oklahoma	Utilities
Oregon	For gas utilities, see response to *Question 4*. For electric utilities, see response to *Question 2*. Note that for new generating and contractual power supply resources, the competitive bidding guidelines mentioned in the response to *Question 1* govern a structure under which the utility evaluates the bids and determines the winning resource options. An independent evaluator monitors the process in some detail, however, and submits a report to the Commission.
North Carolina	*Natural Gas Utilities*: The LDCs determine winning bids. The LDCs file testimony with the Commission in an Annual Review of Gas Costs. The Public Staff audits the LDCs' purchasing practices. *Electric Utilities*: The electric utilities are responsible for determining winning bids.
South Carolina	Utilities are responsible for bid evaluation and awarding of contracts. Determination of prudence is reviewed in annual fuel cost proceedings.
South Dakota	Utilities
Texas (PUCT)	The Commission is not involved in any competitive bidding RFP process
Utah	Utilities
Virginia	Utilities have management responsibility for this procurement activity and the obligation to demonstrate the reasonableness of the resulting cost for which recovery is proposed.
Washington	Not applicable

Wisconsin Each utility is responsible for selecting its natural gas and coal supply sources.

Wyoming The utilities determine winning bids.

State	6. What reporting requirements does your Commission have for (a) natural gas and (b) coal contracts?
Alabama	*Natural Gas Utilities*: A redacted copy of contract omitting competitively sensitive information is officially filed with the Commission and available to the public. A full and complete copy of the contract is submitted to the staff for full review but is not available to the public. *Electric Utilities*: The Commission requires that Alabama Power maintain sufficient records to be readily available upon request for review by the Commission staff.
Arizona	Natural gas utilities in Arizona file monthly PGA reports with the Commission documenting the monthly accounting of the PGA bank balance as well as providing various details of the natural gas purchases during that month. Electric utilities in Arizona file monthly adjustor reports with the Commission that include total fuel and purchased power costs, as well as other information. Details of fuel purchases are usually considered to be confidential and are provided to Commission staff in either a separate monthly report to Staff or upon request.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules do not have explicit requirements for reporting natural gas contracts. The contracts of natural gas utilities, however, are reviewed in the context of the overall review of a utility's Procurement Plan. *Electric Utilities*: The Commission does not have any specific reporting requirements for contracts to purchase natural gas or coal used as fuel to generate electricity.
California	None
Colorado	None
Connecticut	The semiannual PGA.
Delaware	The utilities file annual supply plans, which include supply portfolios. The utilities include a portfolio of the firm transportation and storage services in their annual fuel adjustment cases. The utilities also submit quarterly hedging reports, within 30 days following the close of the quarter, detailing the quantities hedged, type of hedge, the prices of the hedges, and a comparison to market (NYMEX) prices.
District of Columbia	Not applicable. The gas utility files annually, however, on its gas procurement related practices.

Florida

The Commission requires that each utility submit 423 Forms (list coal suppliers, contracted amounts, location of mines, transportation prices and methods, etc.) and monthly A Schedules.

Georgia

Both natural gas and coal contracts must be identified by the utility in its filing to adjust fuel rates in a Fuel Cost Recovery proceeding.

Indiana

The electric utility is responsible for managing its fuel supply portfolio. The natural gas utility also has the responsibility to manage its natural gas supply portfolio. The Commission has indicated that Indiana's natural gas utilities should make reasonable efforts to mitigate gas price volatility in their supply portfolio. This includes a hedge program to mitigate gas price volatility and consider market conditions and the price of natural gas on a current and forward-looking basis.

Iowa

Board rules require that natural gas utilities provide copies of transportation contracts with customers. Contracts between the utility and interstate pipeline companies and producers for system gas are required to be provided to the Board within 30 days of any change.

The Board does not have specific rules requiring contracts to be filed. The Board, however, does have a process called an ARC proceeding that allows the Board to periodically bring in the utility for a prudence review of coal, freight and purchased power contracts.

Kansas

A sampling is evaluated during the ACA process.

Maine

While there are no specific filing requirements, LDCs report on their processes and procedures in IRP cases and periodic cost of gas cases. In addition, the Commission may request detailed information on the contracts during other regulatory reviews.

Maryland

Contract details are provided in the annual prudence review cases.

Michigan

The Commission requires that the supplier is reliable supplier in that the utility has possibly done business with in the past and is on the utility's list of approved suppliers. The price, date the contract was secured, and delivery date for the commodity are required reporting information.

Public Act 304 contains the following requirements for a power supply cost recovery plan:

"The plan shall describe all major contracts and power supply arrangements entered into by the utility for providing power supply during the specified 12-month period. The description of the major contracts and arrangements shall include the price of fuel, the duration of the contract or arrangement, and an explanation or description of any other term or provision as required by the Commission."

The utility must provide support for its decision that will allow the Commission to also conclude the utility acted reasonably.

Minnesota All natural gas and electric utilities file annual reports describing their fuel procurement policies and actions taken to minimize costs. The reporting for natural gas contracts varies depending on the type of contract and the utility. The electric utilities provide a list of their coal contracts in their annual reports.

Mississippi The Commission does not have any standard reporting requirements for such contracts outside of the annual fuel audit/procurement review. Some specific orders, however, require submission of the contracts for approval on renewal and may require an RFP process for selection.

Missouri For LDCs' natural gas contracts, the Commission reviews the contracts in the context of annual prudence reviews as part of the PGA/ACA process.

For electric utilities' natural gas and coal contracts, the Commission Staff reviews the contracts in the context of a rate case and, if applicable, in prudence reviews as part of the fuel adjustment clause process.

Montana The Commission does not have specific reporting requirements for natural gas or coal contracts. The Commission may review contracts for prudence in the appropriate cost recovery proceedings.

Nevada Refer to the regulations referenced in response to *Question 1*.

New Hampshire *Natural Gas Utilities*: Contracts are filed with Staff.

New York *Natural Gas Utilities*: All master contracts for natural gas must be filed with the Secretary to the Commission within 30 days of the signatory date. Amendments to the master contract must follow the same rule. Each utility is required to submit a quarterly summary of all transportation and supply contracts, including the length of contract and purchase terms.

Electric Utilities: Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts.

North Carolina *Natural Gas Utilities*: The Public Staff reviews the LDCs' gas supply contracts each year. As part of the Annual Review of Gas Costs, the Commission receives a numbered list of suppliers (with names redacted) that shows amounts paid and volumes delivered by month.

Electric Utilities: The Commission has no standing reporting requirements for such contracts *per se*, but the electric utilities must file: (1) a monthly fuel report per Commission Rule R8-52 and (2) an application for a Fuel Charge Adjustment on an annual basis, including the information specified in Commission Rule R8-55. In addition, electric utilities may furnish any details of such contracts in response to discovery requests submitted by parties to annual fuel charge adjustment proceedings.

Ohio The Commission does not have reporting requirements *per se*. It reviews contracts retrospectively as part of the Management Performance audit.

Oklahoma	All contracts must be made available to the Commission for review upon request. Utilities also submit monthly reports showing purchases, storage injections, withdrawals, transmission, etc. Utilities also notify the Commission in advance of conducting an RFP, even if they do not request a predetermination of prudence.
Oregon	For natural gas utilities, see response to *Question 4*. For electric utilities, see response to *Question 2*.
South Carolina	The Commission has no specific contract reporting provisions for coal or natural gas. Regulated utilities file monthly fuel cost reports and are subject to annual fuel cost proceedings for electric utilities and purchased gas proceedings for natural gas utilities. The South Carolina Office of Regulatory Staff audits the fuel costs and presents its findings during the fuel cost hearings.
South Dakota	The Commission has no formal reporting requirements. Information is available upon request.
Texas (PUCT)	In fuel reconciliation proceedings mentioned in *Question 1*, for both natural gas and coal, summaries of all fuel supply contracts, fuel related transportation agreements, purchased power contracts and any other fuel-related contracts shall be provided. The summaries shall include the contract number or other designation, supplier, negotiation date or date signed, origin date of supply or service, term, and specific service provided under the contract. Work papers of the summaries shall include the pricing mechanism, the purchase obligation, the maximum takes available, the economic out provision, delivery points, transportation provision, and quality or measurement. The work papers shall include a copy of each contract that had an effect on costs incurred during any portion of the reconciliation.
Utah	None
Virginia	Natural gas utilities are required to file annual hedging activities reports, which include all costs associated with financial hedging activities. Electric utilities file monthly fuel monitoring system reports detailing coal and natural gas purchases.
Washington	Natural gas contracts for gas utilities are reported in their PGA.
Wisconsin	Each year, the large investor-owned Wisconsin electric utilities are required to file electric fuel cost plans for the next calendar year. In addition, all of the Wisconsin gas utilities are required to file, by July 1st, gas-supply plans for the coming gas year.
Wyoming	See Commission Rule § 218, which applies to commodities purchased for resale (i.e. natural gas purchases made by a natural gas utility). *Section 218. Filing Contracts*: Every utility shall file with the Commission one copy of all special contracts which govern the sale by the utility of public utility service or the purchase by the utility of a utility commodity

Wyoming – *continued*

for resale. If the utility has numerous sale or purchase contracts which are in all essentials similar, the utility may request to file a selected one or a few in lieu of filing all such contracts.

State	7. Does your Commission have any hedging requirements for gas and electric utilities? For example, do utilities have to hedge a minimum portion of their fuel needs?
Alabama	*Natural Gas Utilities*: The Commission has no specific hedging requirements. *Electric Utilities*: The Commission has approved a hedge program for Alabama Power that prescribes certain parameters for the maximum hedge positions and the use of options and swap instruments. The approved hedge program does not require a minimum level of hedge positions for Alabama Power.
Arizona	The Commission does not have any formal minimum amount that must be hedged for natural gas utilities, but, as noted in response to *Question 1*, the Commission has formally recognized price stability as one of the goals of the procurement process for natural gas utilities. The Commission does not have any minimum amount that must be hedged for electric utilities. Electric utilities often hedge for natural gas, but not for coal.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules states that a gas utility's portfolio should consist of an appropriated combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield the optimum balance of reliability, reduced volatility and reasonable price. *Electric Utilities*: The Commission does not have any specific hedging requirements associated with the purchase of natural gas or coal used as fuel to generate electricity.
California	Natural gas utilities may hedge. One natural gas utility is required to hedge a portion of its winter gas supply needs. Electric utilities must hedge enough to keep the risk of electric rate increases within certain tolerance levels.
Colorado	The Commission has no specific requirements, but gas utilities must submit a hedging plan. The largest electric utility also submits an electric fuel gas hedging plan.
Connecticut	Same as the response to *Question 1*.
Delaware	*Delmarva Power & Light Company*: 50% non-discretionary hedging program in which 50% of projected city gate requirements and storage are to be hedged on a pro rata basis (1/12th each month) over 12-months preceding the month in which the physical gas is to be delivered. *Chesapeake Utilities Corporation*: Maintain the current eligible portfolio as 70% of the total gas supply requirement to meet its forecasted weather normalized firm sales reduced by the storage gas volumes forecasted to meet such firm requirements, plus projected storage injections. Approximately 6% of the eligible portfolio will be hedged each month, for a total of 70% of the eligible requirements. Fixed hedging is limited to physical

Delaware – *continued*

hedges only and occurs on the second Wednesday of the month.

District of Columbia

The volumes to be hedged are computed from the minimum daily load anticipated to provide service to firm customers in each month of the winter period. Reporting requirements are in place. The Commission approves the gas utility's plan for use of certain financial instruments or physical hedges.

Florida

The Commission has hedging requirements for fuel oil and natural gas. The requirements can be found in the Commission Orders *No. PSC-02-1484-FOF-EI and No. PSC-08-0316-PAA-EI.* The utilities are required to a file Risk Management Plan with the Commission for the projected year detailing all of their hedging policies and including their percent of volumes to be hedged.

Georgia

Electric utilities have a policy for using financial instruments to hedge natural gas prices. This policy was approved by the Commission.

Indiana

For natural gas utilities, there is no standard in place. The Commission has indicated through GCA orders that gas utilities should make reasonable efforts to mitigate gas price volatility. This includes a procurement program that works to mitigate gas price volatility and considers market conditions and the price of natural gas on a current and forward-looking basis.

For electric utilities, there is no standard in place as well. The Commission has reviewed and approved power and gas hedging policies for individual utilities.

Iowa

Board rules at 199 IAC 19.10(7)"a" requires a natural gas utility to provide specific listed information about any hedging instrument entered into by the utility. Storage costs, which are sometimes considered hedges, are filed as part of the PGA. The Board does not have specific requirements in its rules, but mandates each utility to have a specific hedging plan, to follow the plan, and to report to the Board at least once a year about the plan.

Kansas

Each of the natural gas utilities has a hedging program. Because each utility is unique in some way, the natural gas utilities have different programs. In the past two years the Commission has strongly encouraged the utilities to only use calls and to reduce the hedging budget. With natural gas at the price it is at now and with little indication it will increase significantly in the future, the Commission has concluded that the need for hedging has been reduced.

Maine

The Commission has approved specific hedging programs on a case-by-case basis. There are not any general Commission policies of how much of the supply portfolio should be hedged or for what terms.

Maryland

See *Question 1*.

Michigan

The Commission does not have any minimum hedging requirements, although all Michigan regulated utilities currently have in their plans a target hedge volume such as 20% of total requirements or something similar in nature. The Commission has always approved plans with this type of hedging strategy, but does not mandate it. In the past when prices were higher and less stable, the Commission set some time-dependent hedging targets that the utilities met. The utilities never opposed these targets so it's difficult to say whether or not they were mandates.

Michigan – *continued*

For coal, the Commission does not have any hedging requirements. Some utilities have indicated that they buy a portion of their coal several years in advance to layer in various contracts for coal supply in a given year, and the Commission has not found this to be unreasonable.

Minnesota

The Commission does not require hedging. Several of the larger natural gas and electric utilities, however, have requested and received variances to Commission rules governing the automatic adjustment of rates for recovering fuel costs that allow them to include the cost of hedging in their automatic rate adjustments. When granted, these variances typically: (1) limit the amount of hedging that may be done and (2) do not require the utility to engage in required amounts of hedging.

Mississippi

The Commission does not require utilities to hedge any minimum portion. They are, however, limited to a maximum dependent on the specific order (see response to *Question 11* for specifics).

Missouri

For natural gas utilities, the Commission instituted a hedging rule. There is no specific minimum hedge percentage specified in the rule.

The Commission does not have hedging requirements for electric utilities.

Montana

The Commission does not require regulated utilities to hedge portions of natural gas or other commodities.

Nevada

As noted in the response to *Question 1*, both the electric utility energy supply plan and the natural gas utility information resource plan filing require consideration of strategies for minimizing retail price volatility (which includes hedging strategies) and maximizing reliability of supply. Currently, only Southwest Gas Corporation's volatility mitigation plan, which was accepted by the Commission, includes financial hedging instruments.

New Hampshire

Natural Gas Utilities: The Commission has approved hedging policies that lock in price for 70% of winter requirements (combination of physical and financial hedges) and 50% of May and October requirements.

New York

Natural Gas Utilities: Currently, hedges and storage volumes combined should not exceed 60% of normal winter demand requirement. Utilities exceeding this level bear a heavy burden of proof that their actions were prudent. Utility actions are reviewed annually (at a minimum) and discussed in both post-winter and pre-winter planning reviews. Staff guidance is discussed based on perceived market volatility.

Electric Utilities: The electric utilities are required to enter into physical and/or financial electric supply contracts (hedges) in an effort to reduce supply price volatility for their residential, small commercial and industrial customers that choose to purchase electric supply from the utility rather than from an independent energy service company. The Commission has no requirements dictating the precise levels to which the utilities must hedge (with the exception that hedged energy cannot be 0% or 100%).

North Carolina	*Natural Gas Utilities*: The NCUC does not require hedging, but has made hedging available as a tool for managing gas prices (Docket No. G-100, Sub 84). An LDC's decision to hedge or not hedge is subject to review in an Annual Review of Gas Costs. The Commission has allowed the pass-through of hedging costs as gas costs and has assured the LDCs that it will judge the prudence of their hedging decisions based on the facts that were known or should have been known at the time that the hedges were entered into. There is no minimum portfolio as each LDC is responsible for hedging to meet the needs of its particular customer base. *Electric Utilities*: The Commission has not established hedging requirements for electric utilities.
Ohio	For natural gas, no.
Oklahoma	Although the Commission has no requirement, it does require the hedging strategy to be disclosed in the IRP.
Oregon	For gas utilities, see response to *Question 3*. For electric utilities, the Commission does not have prescriptive hedging requirements. Natural gas hedges were a heavily contested part of two recent electric company power cost proceedings, UE 227 and UE 228.
South Carolina	Utilities who hedge have their own individual programs which are presented to the Commission for review and approval. In general, hedging volume has declined in recent years. One natural gas company has suspended its hedging program. The other has a zero minimum hedging requirement.
South Dakota	The Commission does not have a hedging requirement.
Texas (PUCT)	The Commission does not have a hedging requirement for electric utilities.
Utah	The Commission has no requirement to hedge; on both the gas and the electric side, however, interested parties have discussed hedging strategies with the utilities. The prudence of the Companies strategies is the subject of rate proceedings.
Virginia	The Commission does not have a hedging requirement for natural gas and electric utilities.
Washington	The Commission does not have a hedging requirement for gas contracts with regard to the PGA.

Wisconsin

No, the Commission does not require any gas or electric utility to hedge its fuel costs.

Wyoming

The Commission does not require utilities to hedge any of their fuel needs. *Section 249(g)(i). Electric, Gas, and Water Public Utility Commodity Purchase Pass-On Procedure*: Utilities must demonstrate that their efforts to serve customers result in the most reasonable rate available consistent with safe, adequate and reliable service. A public utility may file integrated resource plans or commodity acquisition plans for Commission review and such plans, after acknowledgment by the Commission, shall comply with this requirement.

State	8. What data does your Commission use in determining approval of coal contracts?
Alabama	*Natural Gas Utilities*: Not applicable *Electric Utilities*: See responses to *Questions 1 and 4*.
Arizona	The Commission does not approve coal contracts but may review the prudence of the contracts in rate cases.
Arkansas	The Commission has not specified any data to use in the consideration of any contracts for the purchase of coal used as fuel to generate electricity.
California	Not applicable
Colorado	The Commission has not approved coal contracts
Connecticut	Not applicable, as the generation of electricity is deregulated in Connecticut.
Delaware	Not applicable
District of Columbia	Not applicable
Florida	For coal, the Commission reviews the RFPs, bid evaluations, transportation costs, etc. See also the response to *Question 2*.
Georgia	The utility approves coal contracts. The contracts are subject to a prudence reviews in subsequent Fuel Cost Recovery proceeding.
Indiana	See above
Iowa	Not applicable

Kansas Coal contracts are reviewed like natural gas contracts in the ACA process.

Maine Not applicable

Maryland Electric generation is deregulated for most electric service in Maryland. Consequently, all fuel procurement for that generation is not regulated. Only two regulated municipal utilities have generation, none of it is coal and most of it is oil. No long-term procurements have been ordered for those municipal electric utilities. A small amount of longer term contracting has been found prudent.

Michigan As referenced above, Public Act 304 contains the following requirements for a power supply cost power supply cost recovery plan:

"The plan shall describe all major contracts and power supply arrangements entered into by the utility for providing power supply during the specified 12-month period. The description of the major contracts and arrangements shall include the price of fuel, the duration of the contract or arrangement, and an explanation or description of any other term or provision as required by the Commission."

The coal contracts are evaluated on the basis of a utility's unique needs and the provisions in the contract. The utility must justify its decision on the basis of other available options, market conditions, supply and transportation issues, etc. so that Commission can conclude that the contract is reasonable. The Commission's review is done on a utility-by-utility basis, i.e. utility contracts are not directly measured against each other because of their diverse requirements and contract provisions.

Minnesota Individual coal contracts do not require Commission approval unless the counter-party is an affiliate. The companies report annually on their fuel procurement policies and cost minimization strategies. These annual reports are usually accepted by the Commission.

Mississippi The Commission does not require any specific or standard data when determining approval of coal contracts. Contracts are reviewed for reasonableness during the annual fuel audit/procurement reviews for each utility or by specific docketed filing requirements.

Missouri The Commission does not approve coal contracts.

Montana The Commission evaluates coal contracts in rate case proceedings, using cost data and other information provided by the applicant.

Nevada The Commission does not approve coal supply contracts. It does determine, however, if the cost associated with the contracts are reasonable and prudently incurred, thus recoverable. The reasonableness and prudence finding depends on the information contained in the annual fuel adjustment clause (deferred energy accounting adjustment) application (e.g., compliance with the energy supply plan).

New Hampshire	Not applicable
New York	*Natural Gas Utilities*: Not applicable *Electric Utilities*: Not applicable
North Carolina	The Commission does not approve coal contracts.
Ohio	Not applicable
Oklahoma	Same factors as in *Question 4* as well as any additional items identified in the RFP.
Oregon	For electric utilities, see response to *Question 2*.
South Carolina	The Commission does not approve coal contracts. Utilities' coal purchases and purchasing practices, as well as transportation costs, are reviewed annually and the Commission then rules on prudence. The South Carolina Office of Regulatory Staff audits the fuel costs, including coal costs, and presents its findings during the fuel cost hearings.
South Dakota	The Commission requires no approval.
Texas (PUCT)	In a fuel reconciliation proceeding, the Commission reviews the reasonableness and necessity of expenses incurred to provide reliable electric service to retail customers.
Utah	The Commission instead approves PacifiCorp's net power costs and their prudence during a rate proceeding.
Virginia	The Commission does not approve coal contracts.
Washington	The Commission does not approve coal contracts *per se*. Fuel costs are evaluated for prudence within the context of markets at the time of execution.
Wisconsin	The Commission requires the utilities to have available for review all of the documents associated with the bidding process, including the analysis used to select the winning bids.
Wyoming	The Commission does not approve coal contracts.

State	9. What credit requirements does your Commission have for (a) natural gas and (b) coal contracts?
Alabama	*Natural Gas Utilities*: No specific credit requirements *Electric Utilities*: Generally, any credit requirements, letters of credit, guarantees, liquidated damages, etc. is specified by Alabama Power (or Southern Company Services, as agent for Alabama Power) in the RFP process and in the actual bi-lateral contract. These requirements are subject to Commission oversight and staff review through the establishment of the Energy Cost Recovery factor.
Arizona	The Commission has not set credit requirements for natural gas contracts for natural gas LDCs. The Commission has not set credit requirements for natural gas or coal contracts for electric utilities.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules do not contain credit requirements for natural gas contracts. Natural gas utilities are expected to purchase only from credit worthy sellers. *Electric Utilities*: The Commission has not specified any credit requirements for contracts to purchase natural gas or coal used as fuel to generate electricity.
California	The Commission has not specified credit requirements for long-term natural gas contracts.
Colorado	See response to *Question 2*.
Connecticut	Natural gas utilities purchase their own supply with a PGA prudence review. The generation of electricity is deregulated in Connecticut.
Delaware	The Commission does not have credit requirements; the utilities, however, have commodity risk management polices they follow.
District of Columbia	Not applicable
Florida	For review of hedging activities, the Commission annually reviews each utility's counterparty credit risk standards found within the utility's Commission filed Risk Management Plan. Utilities can only enter hedging transactions, such as swaps and options, with creditworthy counterparties. For coal supply agreements, the Commission does not have specific credit requirements but this would be an issue in a

Florida – *continued* prudent cost review. See also the responses to *Questions 1 and 2*.

Georgia None. The utility is responsible for assessment of supplier credit quality. Utility fuel purchasing decisions are subject to prudence review in subsequent Fuel Cost Recovery proceeding.

Indiana For natural gas utilities, there is no credit standard in place.

Iowa Not applicable

Kansas None

Maine Not applicable

Maryland The Commission doesn't set credit requirements for LDC gas supply.

Michigan A utility having "creditworthy" suppliers would fall under the Commission's normal reasonableness and prudence review. The Commission itself has no credit requirements for the contracts.

Minnesota The Commission does not have creditworthiness standards or requirements. Utilities establish their own credit requirements with vendors.

Mississippi To date, the Commission does not have any standard rules in place limiting the credit requirement for natural gas and coal contracts.

Missouri *Natural gas utilities* develop the credit requirements.

Electric utilities (for both natural gas and coal contracts) develop the credit requirements.

Montana The Commission does not specify credit requirements for natural gas or coal contracts. Creditworthiness is evaluated in the context of overall utility prudence.

Nevada The Nevada Commission does not have any credit requirements for natural gas or coal contracts.

New Hampshire None

New York	*Natural Gas Utilities*: Not applicable *Electric Utilities*: Not applicable
North Carolina	None for either LDCs or electric utilities
Ohio	The Commission does not determine credit requirements.
Oklahoma	None
Oregon	For electric and gas utilities, see response to *Question 2*. Note that utilities do have their own credit requirements.
South Carolina	The Commission does not have credit requirements for natural gas or coal contracts.
South Dakota	None
Texas (PUCT)	The Commission does not have a credit requirement for electric utilities fuel contracts.
Utah	None, as credit requirements are determined by the utilities.
Virginia	The Commission does not have any credit requirements for natural gas or coal contracts.
Washington	None
Wisconsin	The Commission does not prescribe any aspect of the utilities' credit procedures but reviews the process set up for measuring credit risk, establishing credit limits, monitoring current exposure to the limits and managements oversight of the process.
Wyoming	None

State	10. How does your Commission treat, for ratemaking purposes, hedging costs for natural gas and coal (e.g., rate of return, penalties, automatic pass-through)? For example, hedging costs can include the premiums paid for financial options.
Alabama	*Natural Gas Utilities*: Hedging costs are recovered through the PGA. *Electric Utilities*: For Alabama Power, hedging gains and losses and the cost of options and swaps are considered a part of the Company's fuel cost and subject to recovery through Rate ECR.
Arizona	For natural gas utilities in Arizona, hedging costs are passed through the PGA mechanism subsequent to a subsequent prudence review. For electric utilities in Arizona, hedging costs are treated like fuel and purchased power costs; only the direct costs of contracts used for hedging fuel and purchased power costs, however, may be recovered through the adjustor mechanisms.
Arkansas	*Natural Gas Utilities*: The Commission's Procurement Rules allows for the recovery of hedging costs through the gas cost recovery clause. *Electric Utilities*: The Commission has not specified the ratemaking treatment for hedging costs associated with the purchase of natural gas or coal used as fuel to generate electricity.
California	A portion of the hedging costs incurred by natural gas utilities is subject to gas cost incentive mechanisms. Hedging costs incurred by electric utilities are typically pass-through costs
Colorado	Hedging costs for gas are included as a part of the GCA or ECA pass-through mechanisms. There is no coal hedging.
Connecticut	Same as the response to *Question 1*.
Delaware	The Commission allows direct pass through of the costs paid to third parties as part of a gas price hedging program approved by the Commission. These cost include payments to obtain an option, whether or not exercised, payments to obtain a price band or cap, swap transaction costs, and other similar costs, *less* revenues or payments received for the sale of an option, swap transaction revenues, or similar revenues or payments received.
District of Columbia	Hedging costs are recovered as part of the natural gas commodity cost.

Florida

See the response to *Question 7* for referenced Orders. The Commission allows the savings/costs of hedging to be passed through the fuel clause annually. The savings/costs are subject to a prudence determination before being allowed for recovery through the fuel clause. Commission staff verifies whether the price of swaps entered was comparable to market prices to determine prudence.

Georgia

The Commission allows automatic pass-through subject to a prudence review in subsequent Fuel Cost Recovery proceeding.

Indiana

In general, hedging costs for coal and natural gas are reviewed and, if found to be reasonable, they are included as a fuel cost or natural gas cost in the FAC and GCA proceedings and recovered on a 1:1 basis.

Iowa

For natural gas utilities, the costs related to hedging are passed through the PGA as a direct pass-through without a rate of return, penalties etc.

For electric utilities, these costs would also flow through the EAC. For MEC, recovery would come through a rate case proceeding.

Kansas

Only the natural gas utilities have customers pay for hedging programs. The utilities have a hedging budget that is collected during the April to October period and is a separate line item on the customer's bill.

Maine

Prudently incurred hedging costs are allowed to be flowed through the cost of gas factors.

Maryland

Hedging costs are allowed if found to be prudent.

Michigan

For natural gas the Commission classifies all hedging costs as part of the cost of gas after each contract has been deemed reasonable and prudent. We allow option premiums to pass through as long as the total dollar amount is limited and the hedges themselves which include a strike price and premium are reasonable. Only one or two of Michigan's utilities still purchases options with premiums, and the quantity they purchase is a very small with reasonable strike prices and negligible total premium amounts.

To our knowledge, utilities in Michigan do not enter into any financial hedges for coal contracts. Some utilities physically hedge by locking in a percent of their coal requirements in the years leading up to the year the coal is needed, such that about 75% of their coal may be secured by the year it is needed. This is only done up to about 3 years in advance. If a utility did ask for financial hedging costs to be passed through to customers, it would be evaluated through the normal power supply cost recovery process in Michigan as described above.

Minnesota

Hedging costs may be recovered as an automatic pass-through if the utility has obtained a variance to the Commission rules for automatic adjustment of rates for fuel costs.

Mississippi

Hedging costs are generally passed through special riders or the purchased gas adjustment: Mississippi Power Co via the Energy Cost Management clause (ECM) files annually, Entergy Mississippi via the Power Management Rider (PMR) files quarterly, and Atmos and CenterPoint Energy via the Purchased Gas

Mississippi – *continued*

Adjustment (PGA) file monthly. These are automatic pass-through clauses that are filed and reviewed by Staff. The hedging orders typically follow Financial Accounting Standards 133 regarding what is properly classified as a financial hedge.

Missouri

For natural gas utilities, hedging costs are typically treated as part of the purchased gas adjustment process, subject to an annual prudence review.

For electric utilities, hedging costs are typically normalized in the rate case process unless determined to be imprudently incurred. For electric utilities with a fuel adjustment clause, hedging is subject to a prudence review that takes place at least every 18 months.

Montana

Natural gas procurement costs, including any hedging costs, are typically recovered through cost tracker proceedings. Procurement costs are evaluated for prudence on the basis of information available at the time the costs were incurred. NWE must file a biennial natural gas procurement plan, and future cost evaluations may reference proposed strategies. The Commission strongly discourages the use of some financial derivatives such as call options. Procurement costs are generally passed through, but utilities are allowed equity return on stored gas. Coal procurement costs are recovered indirectly in rate case proceedings through inclusion in test year costs.

Nevada

The Commission considers hedging costs to be associated with the underlying commodity, thus the costs are recovered in the fuel adjustment clause.

New Hampshire

Natural Gas Utilities: automatic pass-through

New York

Natural Gas Utilities: Automatic pass-through as a real gas cost

Electric Utilities: Automatic pass-through of all of hedging costs through tariffed supply cost mechanisms applicable to the customers receiving the benefit of the hedges

North Carolina

Natural Gas Utilities: All prudently-incurred hedging costs including premiums are passed through as gas costs.

Electric Utilities: Reasonable and prudent hedging costs for natural gas and coal purchases are recovered as fuel costs.

Ohio

The costs associated with physical natural gas hedges are passed through the GCR mechanism. No natural gas utility has engaged in financial hedges.

Oklahoma

These costs are passed through the fuel adjustment clause in the settlement month.

Oregon

For both electric and gas utilities, the Commission does not have a prescriptive policy. When a utility applies to have these costs put into rates, parties to the proceeding can challenge these and other costs. Generally, the

Oregon – *continued* Commission considers bid-asked spreads and related costs associated with hedges to be prudent.

South Carolina Hedging costs are included in the cost of fuel (or gas). They are passed along to ratepayers via fuel cost and gas cost factors which are re-set annually for electric companies and periodically for gas companies.

South Dakota All such costs are flowed through the PGA.

Texas (PUCT) In a fuel reconciliation proceeding, the Commission will consider an electric utility's request for special circumstances to recover as eligible fuel expenses, fuel or fuel related expenses (such as hedging costs) that are otherwise excluded from eligibility. In determining whether special circumstances exist, the Commission shall consider—in addition to other factors developed in the record of the reconciliation proceeding—whether the fuel expense or transaction giving rise to the ineligible fuel expense resulted in, or is reasonably expected to result in, increased reliability of supply or lower fuel expenses than would otherwise be the case; and that such benefits received or expected to be received by ratepayers exceed the costs that ratepayers otherwise would have paid or otherwise would reasonably expect to pay.

Utah Hedging costs are evaluated for prudence during rate proceedings. Hedging costs associated with Questar are evaluated during gas pass-through proceedings. Hedging costs associated with PacifiCorp have historically been evaluated during general rate cases. The Commission recently approved an energy balancing account for PacifiCorp, however, and hedging costs will be evaluated in those proceedings as well. For both utilities, the Commission has approved rates which reflect the inclusion of hedging costs.

Virginia On a utility-by-utility basis, natural gas and electric utilities may apply for and receive Commission approval to recover hedging costs through their PGA clauses and fuel factor rates (automatic pass-through).

Washington In the PGA, hedging costs have always been allowed and are included in the commodity costs passed through to customers of gas utilities.

Wisconsin In order to have the ability to recover costs associated with hedging activity, a utility needs Commission approval of its risk management plan. Although to actually recover any hedging costs, the utility may need to demonstrate that the hedging activity complied with its approved risk management plan.

Wyoming Recovery of hedging costs may be requested in pass-on applications pursuant to Commission rules. Such costs are subject to a prudence review.

State	11. How much physical hedging (e.g., long-term bilateral contracts) and financial hedging (e.g., futures contracts, swaps) for natural gas and coal do the electric and gas utilities in your state undertake?
Alabama	*Natural Gas Utilities*: Physical hedging: up to 60% of normal usage depending on market conditions; financial hedging: none in recent years *Electric Utilities*: Under the Commission approved natural gas hedge program, Alabama Power is allowed to hedge up to 75% of its budgeted natural gas needs for a period not to exceed 42 months. The Commission has not approved a hedge program for coal. Alabama Power's fuel diversity, contract diversity, number of vendors, number of coal transportation options and number of coal markets, however, all serve to hedge against fuel volatility.
Arizona	The large natural gas LDCs in Arizona have generally hedged between 30-50% of their annual natural gas supplies, with most of that being physical hedging. The electric utilities don't usually hedge for coal. They use both physical and financial hedging for natural gas, but the amounts are usually confidential.
Arkansas	*Natural Gas Utilities*: The Commission Procurement Rules do not see forth specific requirements for hedging. Because of the current natural gas market, the use of financial hedges has been limited, while storage continues to be used as a physical hedge. *Electric Utilities*: Hedging information about the purchase of natural gas and coal as fuel to generate electricity is not readily available.
California	The amount of hedging varies a great deal between natural gas utilities. Electric utilities are required to hedge enough to keep the risk of electric rate increases within certain amounts.
Colorado	The largest gas utility and the largest electric utility (for fuel gas) hedge a significant portion of annual requirements through financial instruments. Small gas utilities have also purchased fixed-price supplies. Most hedging is for a maximum term of one year. The largest electric utility has a long-term fuel gas contract.
Connecticut	The natural gas utilities do not use long-term contracts for supply.

Delaware See response to *Question 7*.

District of Columbia The amount of hedging varies. Gas utilities are able to hedge entire portion of storage fill. A pilot program for winter hedging limits procurement of gas during heating season to 10% of sales. For the winter heating season, the gas utility determines the volumes to be hedged by computing the minimum daily load anticipated to provide service to firm customers in each month of the winter period.

Florida The overwhelming majority of the natural gas hedging transactions is financial transactions such as swaps and options. Commission staff has seen small amounts of physical hedging in the past via a long-term fixed price natural gas contract. Gas storage is also a physical hedge.

Georgia Although there are no restrictions on financial hedging for coal, utilities do not use these financial instruments for coal. Coal is either acquired based on long-term contracts ranging from 1-5 years, or coal is purchased on a spot market basis. The major investor-owned utility in Georgia has an internal policy on the amount of coal it wants to purchase under contract prior to the burn year. The policy is confidential; it does, however, establish acquisition percentages for a number of years prior to the burn year. Since the policy does not require 100% of the forecast burn to be acquired prior to the burn year, some amount of coal is acquired based on spot contracts during the burn year.

Natural gas prices are hedged with financial instruments and limited to 30% to 50% of budgeted gas burn for each month.

Indiana Long-term contracts as a source of a natural gas utilities' supply portfolio are fairly common. Natural gas utilities use financial hedges less than physical hedges. Financial hedges are found mostly in the supply portfolios of state's larger natural gas utilities.

Electric utilities extensively use mid- to long-term coal contracts, effectively attaining in excess of 90% of expected burn. Financial transactions distinct from the RTO markets are limited to a couple of utilities and then only a small fraction of their total need; one utility does use gas hedging, however, for the bulk of its expected burn. The RTO markets offer what some view as near-term hedging products.

Iowa Natural gas utilities purchase storage for approximately one-third of system requirements. Hedging of another portion of system requirements is around 30%. The specific amount of hedging done in a year depends on the plan followed by the utility.

The Board has no specific requirements on hedging for electric generation. Utilities do some hedging of gas contracts used for generation purposes, however. Iowa utilities have long used long-term contracting for coal procurement purposes. These contracts provide hedging against significant cost changes.

Kansas The basic rule of thumb is 1/3, physical hedge, 1/3 financial hedge (calls), and 1/3 purchased in the month ahead market.

Maine Maine's largest LDC hedges about 70% of its winter supply requirements and 40% of its summer/shoulder

Maine – *continued*

requirements. The other LDCs hedge based upon particular commodity needs and market conditions.

Maryland

See response to *Question 1*. The Commission considers storage to be a major physical hedge because roughly half of winter supply comes from storage.

Michigan

Currently, most of the natural gas utilities purchase approximately 20% of their annual requirements ahead of time. One of the major gas utilities still has a maximum of 60%, but to get to that percentage the utility has to have multiple price triggers below the first quartile. This utility calculates rolling historical quartiles to be used as a buying tool. Given the low price of gas, it is unlikely that the utility will achieve 60%.

For coal, electric utilities have indicated that long-term contracts in the traditional meaning of contracts with different pricing indices and provisions are no longer available. The major utilities are buying multiple year contracts several years in advance to layer in a portion of their coal for a given year. In general, the major utilities could have in the neighborhood of 75% of their coal supply for a given year fixed before the start of the year. About 25% would have been secured in the previous year, another 25% two year prior, and 25% three years prior to the year. Electric utilities still aim to purchase some amount of coal on the spot market to allow flexibility during the year.

Minnesota

For natural gas contracts, the amount of hedging varies from utility to utility. The amount of hedging may be as low as zero percent and as high as 50-65% of the company's supply portfolio.

This information is not readily available for coal contracts.

Mississippi

MPC is allowed to enter into fixed-price hedging arrangements up to 75% of the quantity of natural gas anticipated to be consumed to supply retail jurisdictional customers. (*Docket 2000-UN-943*)

EMI is allowed to enter into fixed-price financial hedging instruments up to 75% of the quantity of fuel anticipated to be consumed to supply its retail jurisdictional customers. (*Docket 2003-UN-737*)

Atmos Energy is allowed to enter into fixed-price financial hedging instruments up to 50% of its winter seasonal purchases for retail jurisdictional customers (*Docket 2006-UA-389*).

Centerpoint Energy is allowed to enter into fixed-price financial hedging up to 50% of its annual normalized flowing gas purchases for retail jurisdictional customers (*Docket 2001-UA-700*).

Missouri

For natural gas utilities, a combination of physical hedging (typically in storage) and financial hedging is used. The percentage of hedged supply varies by year and by utility. A general hedge percentage for natural gas utilities is typically in a range of 50% to 75% of normal winter requirements.

The percentage of hedged natural gas and coal supply for electric utilities varies from year to year and by utility to utility. For some of the electric utilities, due to the small amount of natural gas used, hedging of natural gas is very limited.

Montana

NWE, MDU, and EWM physically hedge significant volumes of heating season gas through storage. NWE hedges 10% or less of procured gas through swaps. NWE and MDU purchase coal through long-term fixed-price

Montana – *continued*

contracts with cost-plus escalators.

Nevada

Nevada Power Company's and Sierra Pacific Power Company's laddering natural gas procurement strategy effectively requires by the beginning of the fourth gas season ahead of the current gas season that100% of the forecasted natural gas volumes be secured. Southwest Gas Corporation target is 30% of the annual natural gas volumes be acquired by the beginning of the gas year.

New Hampshire

Natural Gas Utilities: Winter requirements: 50% physical hedged, 20% financial hedged; summer requirements: 25% financial hedged

New York

Natural Gas Utilities: There is no set amount. Staff provides guidance year-to-year based on perceived volatility in the market. Currently, hedges and storage volumes combined should not exceed 60% of normal winter demand requirement. Utilities exceeding this level bear a heavy burden of proof that the actions were prudent. These actions are reviewed annually (at a minimum) and discussed in both post winter and pre-winter planning reviews. Storage injections are not currently hedged but have been in the past.

Electric Utilities: There is no set amount. Staff provides guidance year-to-year based on market conditions. This year the statewide average fixed hedge level is about 60% for the hedged customer classes and consists primarily of electric swaps.

North Carolina

Natural Gas Utilities: Each LDC is responsible for determining the amount of hedging that meets the needs of its sales customers. No long-term bilateral fixed price contracts have been reported to the Commission. The amount of financial hedging varies by LDC and by current circumstances for each LDC. Of the two large LDCs in North Carolina, Piedmont Natural Gas now hedges 22.5% to 45% and PSNC Energy limits hedges to 25% of estimated firm sales volumes. One small LDC utilizes physical hedges as part of its gas supply portfolio but never hedges longer than a 12-month period.

Electric Utilities: The use of hedging varies between electric utilities and varies for individual electric utilities at different points in time. In general, the Commission staff believes that the vast majority of coal is purchased using physical hedging, but not financial hedging. Gas purchases use physical and financial hedging, but amounts cannot be reliably estimated at this time.

Ohio

The vast majority of gas sold in Ohio is sold by unregulated natural gas marketers. Other than storage very little hedging of natural gas takes place.

Oklahoma

Natural gas utilities have been using financial hedging regularly for years. These programs are preapproved and deemed prudent if they follow the approved plans.

Electric utilities rely on storage and flexible contracts for physical hedging. They have not used much financial hedging.

Oregon

For gas utilities, see response to *Question 1*.

For electric utilities, see response to *Question 7* about gas hedges. More detailed information is confidential.

Oregon –
continued

South Carolina

Currently, no regulated natural gas utilities hedge natural gas purchases.

One regulated electric utility targets financial hedges between 50% and 80% of its estimated natural gas consumption for the upcoming year. No regulated electric utility uses financial hedges for coal purchases. One utility generally enters into long-term (1-3 years) contracts for 75-80% of its coal requirements.

South Dakota

Information submitted to the Commission is confidential.

Texas (PUCT)

There is minimal physical or financial hedging because recovery of such fuel expenses would be subject to a showing of special circumstances.

Utah

Currently, Questar has approximately 60% of its gas effectively physically hedged through the Wexpro agreement. For that portion if its winter needs that cannot be met through Wexpro Gas, Questar procures approximately one-third of the estimated winter requirement through physical swap prices and one-third through prudently priced financial hedges.

PacifiCorp's hedging strategy is confidential.

Virginia

The amount of hedging varies by natural gas and electric utility. As noted above, natural gas utilities must receive prior Commission approval to recover hedging costs in their PGA clauses.

Washington

In the PGA, long-term bilateral contracts are often times offset by financial hedges. Gas utilities have generally hedged from between 30% to 75% of their portfolio. In other words, a significant portion of the gas portfolio consists of two- to three-year bilateral contracts.

Wisconsin

The risk management plans authorized by the Commission originally allowed the electric utilities to hedge up to 75% of their market price risk exposure but recent Commission decisions has dropped the limit to 65%

Wyoming

The utilities have designed their own natural gas hedging programs. Some do not hedge at all. (In some cases, utilities volumes are less than the minimum hedge volume; others prefer to allow the price to "float.") Some utility programs call for 30%-100% of projected volume requirements to be hedged.

State	12. What typically are the different time horizons for natural gas and coal hedges (e.g., one year, two years, ten years)?
Alabama	*Natural Gas Utilities:* Physical hedges tend to be within a one-year time frame; some financial hedges have time horizons of up to three years. *Electric Utilities*: See response to *Question 11*.
Arizona	Natural gas utilities hedge up to three years in advance, with contracts of up to one year. Electric utilities do not hedge for coal. The time horizon for natural gas hedges is usually confidential.
Arkansas	*Natural Gas Utilities*: Typically time horizons for natural gas hedges range from one to three years. *Electric Utilities*: Information on time horizons for hedges associated with the purchase of natural gas and coal as fuel to generate electricity is not readily available.
California	This information is confidential. The time horizon varies greatly from utility to utility and between electric and gas utilities.
Colorado	Gas hedging is typically on a one-year term. The Commission approved a long-term gas contract for our largest electric utility with a term of 10 years
Connecticut	Electric generation is deregulated.
Delaware	The typical time is 12 months; there are hedges, however, that were taken under prior programs for longer periods that are still "on the books" today.
District of Columbia	Generally, less than one year for the natural gas utility, but the utility is allowed to use a longer horizon than one-year.
Florida	The typical time frame that the Commission staff has seen for natural gas hedges is usually 12 to 18 months.
Georgia	As mentioned in a prior response, coal hedging with financial instruments is not used. Instead, coal is acquired over a period using a series of long-term contracts; the remaining coal that had not been purchased in advance is acquired as spot coal in the burn year. Natural gas prices are hedged with financial instruments evenly over time in the 24 months prior to the

Georgia – *continued*

month the gas is consumed. The utility may use financial instruments to hedge a limited amount of budgeted burn volume 25 to 48 months prior to the month the gas is consumed.

Indiana

The physical hedges for natural gas typically have a time horizon of 1 to 2 years and on occasion extend to 3 years. The time horizon for natural gas financial hedges is one year or less.

For electric utilities, financial gas hedges are markedly less than a year; financial power hedges are less than a year (although there are limited power purchases of longer term, 2-3 years generally, and the Commission has preapproved wind purchases with 20-year terms), and coal contracts are generally in the 2-3 year range.

Iowa

The hedging plans for each utility vary depending on the parameters adopted by a utility. The plans have included hedges for one year, two years, and on a very limited basis three years and beyond. The timing of hedging for both coal and gas depends on the philosophy of the utility. The IUB does not regulate this.

Kansas

The Commission allows the natural gas utilities to go out one year on their hedging programs.

Maine

Maine's largest LDC hedges approximately 18 months forward. See prior response.

Maryland

Maryland LDCs have no gas commodity contracts beyond the upcoming storage fill or heating seasons.

Michigan

For natural gas contracts, natural gas utilities purchase two years ahead of consumption maximum.

Electric utilities have indicated that they are currently buying coal no more than about 3-5 years in advance because that is all that is available in the market due to coal price volatility.

Minnesota

Most natural gas hedging contracts are no more than one-year in length.

This information is not readily available for coal contracts.

Mississippi

One to three years

Missouri

For natural gas utilities, it is very rare to see a gas supply contract exceed 12 months. Financial hedges sometimes do extend out to 2 years and beyond.

For electric utilities, physical coal contracts vary from one to five years.

Montana

From 2006 through 2009 NWE purchased fixed-for-float hedge contracts that typically came in one- or two-year blocks. NWE has proposed to rate base a gas production field with an expected 47-year life.

Nevada	See the response to *Question 11*.
New Hampshire	*Natural Gas Utilities*: 18 months horizon for financial hedges, storage injections during the off-peak period for physical hedges
New York	*Natural Gas Utilities*: Physical and financial hedges are nominally for one year only and only apply to winter delivered volumes. Annual volumes were hedged previously in periods of higher volatility but not currently. *Electric Utilities*: Generally, electric utilities do not own gas or coal-fired generation and have no gas or coal purchasing contracts. Some utilities that have power purchase agreements with gas-fired generators have purchased gas futures and options contracts for their hedged customer classes for up to 3 years.
North Carolina	*Natural Gas Utilities*: North Carolina utilities had been hedging two years out but recently have reduced that to one year. *Electric Utilities*: The typical time horizon for physical coal hedges is three years. Natural gas hedges vary and typical amounts cannot be reliably estimated at this time.
Ohio	See answer to *Question 11*.
Oklahoma	Mostly annual hedges have been used in the financial portion. The physical hedges range from annual to under 5 years for most natural gas utilities.
Oregon	For electric and natural gas utilities, gas hedges go out to approximately three to four years. See response to *Question 7*. Utilities generally do not have coal hedges.
South Carolina	No South Carolina regulated utility uses financial hedges for coal purchases. Natural gas hedging time horizons vary between 12 and 36 months. One utility generally enters into long-term (1-3 years) coal contracts for 75-80% of its coal requirements, with the remaining 20-25% purchased on the spot market.
South Dakota	This information is confidential.
Texas (PUCT)	The PUCT does not have a hedging requirement for electric utilities.
Virginia	The time horizon varies by natural gas and electric utility. Typical time horizons range from approximately six months to two years.

Washington

For gas utilities, the long-term contracts/hedges generally range between 1-3 years.

Wisconsin

Utilities typically begin to hedge a portion of their risk exposure about two years in advance. They are limited to monthly transactions that are no more than 20% of the total expected volumes subject to market price risk for any future month.

Wyoming

The majority of utilities that engage in hedging practices have a time horizon of a year or less for natural gas. Certain utilities' natural gas hedges extend to three and four years.

Coal is generally secured through long-term contracts (10+ years); shorter-term contracts (two to three years), however, are being seen recently.