STATE OF ARKANSAS

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Consideration of Innovative	**)**	
Approaches to Ratebase Rate-of-Return	**)**	
Ratemaking Including, But Not Limited To,	**)**	**Docket No. 08-137-U**
Annual Earnings Reviews, Formula Rates, and	**)**	
Incentive Rates for Jurisdictional Electric and	**)**	
Natural-Gas Public Utilities	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE NATIONAL AUDUBON SOCIETY, INC.

AND

AUDUBON ARKANSAS

Resource Insight, Inc.

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 230 times on utility issues before various regulatory, legislative, and judicial bodies, including the utility regulators of twenty-eight states, five Canadian provinces, New Orleans, the District of Columbia, and two U.S. Federal agencies.

Q: Have you testified previously before this Commission?

A: Yes. I testified on lost-revenue recovery and shareholder incentives in Energy Arkansas's current rate proceeding, Docket No. 09-084-U, and on fuel switching, program administration and oversight, and programs for large customers in the Energy Efficiency Notice of Inquiry proceeding, Docket No. 10-010-U.

Q: Please summarize your experience in the planning and promotion of energy-efficiency programs.

A: I have testified on demand-side management (DSM) potential, economics and program design in approximately 54 proceedings since 1980. In the 1990s, I participated in several collaborative efforts among utilities, consumer advocates, and other parties, including those for Potomac Electric Power, Baltimore G&E, Delmarva Power, Potomac Edison, Washington Gas Light, Central Vermont Public Service, Vermont Gas, and New York State E&G. More recently, I have participated in collaboratives related to Con Edison's gas and electricity efficiency programs and New York statewide program rules and objectives.

Q: Please summarize your experience regarding recovery of utility energy-efficiency program costs and associated revenue losses.

A: I first proposed a combined revenue-stabilization and conservation-funding mechanism in testimony on alternatives to the Seabrook nuclear power plant before the New Hampshire Public Utilities Commission in Docket No. DE1-312 in October 1982. My qualifications list a number of subsequent engagements related to ratemaking for energy-efficiency, including recovery of direct costs and lost revenue.

I have supported broader revenue stabilization than proposed by the utilities in some cases (e.g., in Ontario), and proposed modifications to utility decoupling proposals in other situations (e.g., for Con Edison's electric sales, Vectren's Indiana gas territories). I have also worked on issues of cost recovery in collaborative efforts among utilities, consumer advocates, and other parties, including Con Edison's gas revenue-per-customer decoupling collaborative. Most recently, I developed and testified in support of the proposals of Philadelphia Gas Works for recovery of DSM costs and lost revenues.

Q: Please summarize your experience regarding estimation of avoided costs.

A: I have testified on avoided electric and gas costs in numerous proceedings, as listed in Exhibit PLC-1. I have developed avoided costs for non-utility generation since the early 1980s, and for DSM since the late 1980s. I was lead author for the avoided-cost section of a comprehensive report on DSM program design and valuation on behalf of the Pennsylvania Energy Office. With others, I estimated avoided gas costs statewide for the New York State Energy Research and Development Administration. While much of my work has been on behalf of non-utility parties, I have developed avoided gas costs on behalf of Boston Gas Company, Peoples Gas and North Shore Gas in Illinois, and Philadelphia

Gas Works; avoided electric costs on behalf of the Hull (MA) Municipal Light Plant, New York State Electric and Gas, Orange and Rockland Utilities, Niagara Mohawk; and (with others) both electric and gas avoided costs for a consortium of New England utilities and programs administrators.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the National Audubon Society, Inc., and Audubon Arkansas (collectively, "Audubon").

Q: What is the purpose of your direct testimony?

A: I have been asked to respond to the Commission's request in Order No. 7 in this docket for input on three issues: lost contributions to fixed costs, avoided costs, and shareholder incentives for program performance (Order No. 7, p. 7).

Q: Please summarize your testimony.

A: In facilitating the transition of the utilities to operating comprehensive energy-efficiency programs, two changes to ratemaking may be critical: recovery of lost margins (or decoupling revenue from sales), and shareholder incentives for DSM achievements. Given the vast potential benefit to ratepayers of improved energy efficiency, the Commission should adjust ratemaking procedures to be consistent with major DSM undertakings.

Protecting the utilities from revenue losses due to their own DSM programs requires either a lost-margin recovery mechanism designed to recover the best estimate of actual lost margin or a decoupling mechanism that adjusts utility revenues up or down to meet a predetermined revenue target, regardless of sales levels. Lost-margin recovery is conceptually simple, but requires the use of both of the following estimates:

- The best available estimate of the reduction in billing determinants—based on comprehensive tracking, monitoring, verification and evaluation efforts —rather than the deemed savings used for program planning.
- The most-accurate feasible estimate of the lost revenues, rather than assuming a single lost-contribution rate for all measures implemented at any time in the year for all customers on all rate schedules within a customer class.

Administration of a decoupling mechanism is simpler than administration of a lost-margin mechanism, but decoupling mechanisms must be designed with great care. Once the principle of lost-margin recovery has been established, the Commission would have many opportunities (whether it welcomes them or not) to consider and reconsider numerous details in the estimation of lost margins. In contrast, once the decoupling revenue target has been set, the Commission's review of decoupling filings would generally be limited to little more than review of the utility's arithmetic.

Either recovery of lost revenues or decoupling would hold the utility harmless for the effects of their programs. No additional incentive is required to make the shareholders whole. However, properly designed incentives may be justified to attract management attention and resources to the DSM effort, as well as to overcome traditional patterns in utility practice. Those incentives should be based on the following principles:

- Initially, incentives may be computed entirely or principally as a share of the net total resource cost, or societal benefit, of the program.
- Over time, the incentive structure should become more sophisticated, to encourage a diverse and comprehensive portfolio approach to DSM, including market transformation.

- Incentives should be computed from the best available estimate of savings and measure lives at the time the programs are implemented, while leaving the utility responsible (and hence liable) for keeping those data up to date.
- No incentives should be granted for mediocre performance. Indeed, penalties should be assessed for inadequate performance.
- The incentive structure for each utility should be tied to the definition of comprehensiveness and the determination of specific performance goals and targets in Docket No. 08-144-U, with incentives starting only once the utility has achieved a significant portion (probably around 75%) of the goal for each year set by the Commission.
- Incentives should not exceed 10% of direct program expenditures, and should generally be much less.

Monitoring, verification, and evaluation of savings are essential to both lost-revenue recovery and incentive computations, as well as to program design and refinement. To maximize the quality and credibility of the savings estimates, the monitoring, verification, and evaluation functions should be administered by non-utility contractors selected by the Commission and advised by the non-utility parties.

Avoided costs for both gas and electric utilities comprise wholesale-level costs and retail adders, the categories of which vary between electric and gas utilities. Within each industry, the wholesale costs should be essentially the same for all Arkansas utilities, and those costs should be estimated statewide in a public process. Retail adders (e.g., losses and avoided T&D costs) will vary by utility.

III. Recovery of Lost Revenues

Q: What is the purpose of computing the lost contributions to fixed costs resulting from utility energy-efficiency programs?

A: The principal purpose of energy-efficiency programs is to reduce costs to customers, including costs that flow through utility bills. For electric utilities, those costs include fuel, variable O&M, net purchased power, and new generation, transmission, and distribution investments. For gas utilities, the avoided costs include purchased gas, transportation and storage contracts, and local storage, transmission, and distribution investments.

When load is reduced, or grows more slowly, the utility's revenues are less than they would have been otherwise, and so are the utility's costs. In the short term, an electric utility saves on fuel, variable O&M, and net purchased power (either by purchasing less or selling more energy and capacity); a gas utility saves on purchased gas and some transportation and storage costs.[1] These short-term savings are generally less than the reduction in revenues, leaving the utility with lower earnings until rates are reset in the next general rate proceeding.

Under these conditions, every kWh that a customer does not use due to an energy-efficiency program reduces the utility's earnings. As a result, the utility has a financial incentive to delay implementation of DSM, especially measures that have particularly large effects on revenue.

Q: What approaches are generally used for recovery of lost revenues?

A: The three principal approaches are as follows:

[1]Most of these costs (fuel, purchased power, purchased gas) are reconciled through fuel adjustments and gas-supply rates, so the reductions in utility costs and revenues are equal.

- *Projection of DSM-program effects* in estimating sales and setting rates in general rate proceedings. These are the full-year effects of measures installed prior to the rate year (both preceding the rate filing and during the rate proceeding), plus partial-year effects of measures installed during the rate year. This approach is most effective if rate proceedings are filed every year, and may have difficulties dealing with situations in which projections of installations turn out to be dramatically wrong.
- *After-the-fact computation of lost revenues,* from the count of measures installed, the estimated savings per measure, and the lost revenues per kWh or ccf.[2] The establishment of a lost-revenue mechanism is conceptually simple, but dependent on many details of tracking the number of installations and estimating their effect on sales and revenues. Lost-revenue mechanisms were more-widely employed in the 1990s, but have been replaced with decoupling (below) in several jurisdictions.
- *Decoupling of revenues from sales,* by setting a revenue target, reconciling actual revenues to that target, and returning the difference to the customers or utility (depending on whether the utility over- or under-collects the revenue target). Decoupling, or rate stabilization, does not usually distinguish among the causes of these revenue deviations. Unlike lost-revenue mechanisms, decoupling mechanisms are generally straightforward to operate, but great care must be taken in the details of mechanism design.

Q: How do computations of lost revenues typically work?

A: The basic approach in computing lost revenues comprises the following steps, for each measure covered by an energy-efficiency program:

[2] Entergy has proposed this approach in its current rate case, Docket No. 09-084-U.

1. Count the number of measures installed under the program. An effective and accurate tracking system is essential for this determination.
2. Estimate the annual sales effects of each measure. This step requires that the tracking mechanism must report more than the number of installations; the sales reduction will depend on the size and efficiency of the installed equipment, hours of operation (which depends on business type and location of the measure), and other data.
3. Estimate the percentage of the savings that would have occurred without the program, and that thus do not reflect any program-related revenue loss.[3] This step is dependent on high-quality evaluation.
4. Estimate the extent of spillover from the program to non-participants.[4] Again, this is a function of evaluation.
5. From the tracking mechanism, determine the types of customers participating in the program, differentiated by rate schedule and by any other factors that affect lost revenues per kWh or ccf saved.
6. Compute when the savings from each measure would start, given both the installation schedule (from the tracking system) and any seasonality of the

[3]The participants who would have invested in efficiency without the program are often called "free riders." That terminology incorrectly suggests that they are somehow getting a better deal than other participants.

[4]Examples of spillover would include installations that occur because engineers, architects and contractors come to habitually specify efficient equipment, or because efficient equipment becomes the standard equipment stocked in warehouses and stores and is hence easier to find and less expensive than inefficient equipment.

affected load (e.g., space-heating efficiency measures installed in May do not save much energy until the following November).[5]

7. Determine the lost contribution to fixed charges, per kWh or ccf, for each group of customers. This computation requires determination of the customer's bill reduction per kWh or ccf saved, net of any short-run savings to the utility and net of any costs that will be reallocated through reconciliation mechanisms. [6]
8. Compute the resulting lost contribution to fixed cost as the product of the energy savings and the lost contribution per kWh or ccf, by class.

Q: What problems arise if the lost revenues are poorly estimated?

A: Erroneous estimate of lost margins produce problems with fairness, incentives, and gaming. The fairness problem arises because the utility may get much more (or less) back in lost revenues than it actually loses, and customers pay much less (or more) for fixed costs than without the DSM program.

The problem of incentives is even more serious than that of fairness. If the utility realizes that it will be overpaid for some installations, and underpaid for other installations, it will have an incentive to encourage participation by customers in the first group and discourage participation by customers in the second. If lost-revenue recovery for a particular measure is apt to be less than the actual lost revenues, the utility would have an incentive to discourage

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[5]Seasonal rates and seasonal differences in the coincidence of measure load with customer billing demands may cause lost contribution per unit of sales to vary with the date of installation and the date on which rates are reset in the next rate case.

[6]For example, demand charges may or may not be reduced by reduced sales, especially if the tariff includes contract demands and/or demand ratchets. In classes with block rates, lost revenues should reflect the percentage of participants with marginal usage in each block. Effective rates may also vary among measures, due to differences in time-of-use and seasonal patterns.

implementation of that measure, perhaps by imposing additional administrative burdens or reducing rebates.

The gaming problem is very similar to the incentive problem, but with a more active utility role. If the utility anticipates that it will be overpaid for some installations, and underpaid for other installations, it will have an incentive to steer the programs to the most-profitable installations. For example, the utility might promote a program heavily to customers with small installations, small savings, and/or lower lost revenue per unit of savings, but claim higher lost margins based on average savings and average revenues for some broader group of potential participants.

Q: How would a revenue-stabilization mechanism operate?

A: A revenue-stabilization or decoupling mechanism would compare actual revenues to a target revenue level, and adjust rates to flow the difference to the utility or its customers.[7]

Q: Would a revenue-stabilization mechanism have any advantages compared to a lost-revenue mechanism?

A: Yes, at least three. First, a revenue-stabilization mechanism would eliminate any weather-related over- and under-collections, stabilizing bills for customers and revenues for the utility. After a particularly hot summer or cold winter, when electric bills have strained customers' budgets, customers would receive rate reductions offsetting the non-fuel part of the increased cost. After particularly mild weather, when customer bills and utility earnings would tend to be lower than normal, customers would give up some of those benefits and Entergy earnings would rise toward normal.

[7] Revenue decoupling is a simpler variant of the return-on-equity adjustment proposed by Entergy in its current rate case, Docket No. 09-084-U.

Second, the projection of sales in a rate proceeding would no longer be of great import. Were the forecast overstated, the revenue-stabilization charge would increase; if understated, the charge would decrease and perhaps even become negative. Reducing the weight of the sales forecast in rate proceedings should reduce the cost and burden for the utility, the Commission Staff, the Attorney General, and other parties.

Third, lost-revenue adjustments also generally cannot account for savings resulting from the utility's role in encouraging or supporting efforts by other parties, where measuring the savings or allocating a specific share of savings to the utility would be difficult. Examples would include providing information and other indirect support for energy-efficiency investments, as well as the effects of market-transformation efforts, governmental codes and standards, and other programs. A revenue-stabilization mechanism does not differentiate among the possible reasons for differences between target and actual revenues, and hence would protect utility revenues from the effect of all sorts of efficiency programs, regardless of who administers those programs.

Q: Would a revenue-decoupling mechanism have any disadvantage compared to a lost-revenue mechanism?

A: The major potential disadvantage of a revenue-decoupling mechanism is that, unless otherwise specified, it trues up revenues for all variations in sales, including economic cycles. Thus, in an economic downturn, a revenue-decoupling mechanism would protect the utility shareholders from economic conditions, when almost everyone else—households, businesses, state and local governments—is suffering.[8] This would often be viewed as unfair. Hence, some

[8]Entergy's proposed true-up for return on equity would have a similar effect.

modification of decoupling in the event of serious economic disruption is probably justified.

Q: Would the deemed savings filed by the utilities in Docket No. 07-152-TF be appropriate for estimating the sales reductions in Step 2 of lost-revenue determination?

A: Not in all cases. The deemed savings are tools for screening and planning, and may be reasonable sources of forecasts for lost revenues. Some of the deemed-savings estimates are structured in a manner suitable for estimating actual savings, after the fact, and reconciling lost revenues, but in many cases the deemed-savings estimates will not be the best estimate of savings after the fact.

Deemed-savings estimates are often stated per application (per house, per commercial customer, per appliance replaced). They are based on guesses borrowed from other jurisdiction (with different energy prices, building codes, climates, and DSM incentives) regarding the size of the equipment installed, the size of the load (e.g., the house, room, or building receiving the measure), the pre-DSM efficiency and the post-DSM efficiency, annual hours of use, and other factors. Consider the following examples:

- Some deemed savings assume that existing equipment would have continued in place, and compute savings compared to that inefficient equipment. But programs may offer incentives that are inadequate to cause customers to replace existing equipment, ensuring that the savings are limited to situations in which some new unit would be installed, so the actual lost revenues are more like the difference from standard new equipment to efficient new equipment.
- A control measure, such as a programmable thermostat, may control a small or large amount of lighting or equipment, serving a small room or an

entire building, and the space may be used continuously (allowing little control) or rarely (allowing frequent setbacks).

The standard for estimating savings for lost-revenue recovery should be the best information available at the time the utility files for cost recovery. That information may be the same as the deemed savings, especially for those measures for which the deemed savings are computed based on the characteristics of installations. But the lost-revenue recovery should also reflect data available from the installation-tracking process and any other new information. The resulting recovery may be more or less than would been computed from the deemed savings. This important point is that the lost-revenue recovery should recover actual lost contribution to fixed costs.

Q: Is it more important that savings estimates be accurate for program design or for lost-revenue recovery?

A: Accuracy is much more important in lost-revenue recovery. In many cases, changing the assumed savings of a measure by a considerable margin would make no difference in program design. A measure with a benefit-cost ratio of 3.0 will remain cost-effective even were the estimate of its savings found to be overstated by 100%. For lost-revenue recovery, that same error of estimating savings at twice their actual value would result in a public utility recovering twice its lost revenues, potentially millions of dollars across a DSM portfolio.

Q: What actions are necessary to ensure availability of the information needed to estimate actual lost contribution to fixed costs?

A: In order for the lost-revenue mechanism to be effective, the tracking mechanism must record all the information necessary to estimate the incremental savings attributable to the DSM programs, such as equipment size, existing equipment status, building size, and hours of use, and the information necessary to determine participation by rate schedule. In addition, monitoring, verification, and evaluation efforts must be sufficient to test and correct a range of other assumptions about the effectiveness of various measures and their interactions. Most of these efforts are important for other purposes—load forecasting, cost-effectiveness determination, improved program design—so the incremental costs of monitoring, verification, and evaluation to support lost-revenue recovery should not be substantial.[9]

For each rate schedule, lost revenues should be estimated for each type of measure. At a minimum, that computation should include at least heating, cooling and baseload measures. Depending on the rate schedule (and the DSM measures applicable to the customers on that schedule), it may be appropriate to further distinguish among measures (e.g., economizers, outdoor lighting) or subsets of customers on the rate schedule (e.g., customers with their usage entirely in the first block).

IV. Avoided Costs

Q: How should avoided costs be computed for DSM program screening?

A: Since both the electric and gas industries operate in a largely competitive wholesale market, the most straightforward approach to projecting wholesale avoided costs is to use projections of market prices.[10] These costs must be adjusted to reflect the shape of retail load, and to include other delivery costs.

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[9]Due to the utility's strong self-interest in the monitoring, verification, and evaluation process, that process should be directed by collaboration among such parties as the utility, the Attorney General, Audubon, and other consumer interests. (Whether the Commission's General Staff should be a participant or observer in this process is a policy issue for the Commission.)

[10]The utilities should not be procuring or retaining resources with avoidable costs greater than market prices. A utility may believe some resource is cost-effective, even though it is priced above

Q: Should avoided costs vary significantly among utilities in Arkansas?

A: Not for the wholesale components of cost. All the electric utilities (IOU, cooperative, or municipal) face essentially the same cost for acquiring more energy (either producing it at marginal costs or purchasing it from other generators), the same market prices for the sale of energy freed up by DSM, and the same market options for purchasing and selling capacity. While the various gas companies take gas from different pipelines, wholesale prices do not appear to differ significantly among Arkansas city gates.

As a result, the wholesale avoided costs should be estimated in a statewide process. It would make no sense to design various utilities' DSM programs based on inconsistent estimates of Henry Hub gas prices. The Commission should thus institute a statewide process for setting wholesale avoided costs. The analysis can be performed by an independent third party (as is New York, where wholesale avoided costs are estimated by the Commission Staff) or by a contractor selected and supervised by the utilities and non-utility parties (as in the case for all six of the New England states).

The estimation of both the wholesale avoided costs and the retail adders should be entirely public and thoroughly documented.

Q: Please describe the derivation of avoided electric generation costs.

A: Avoided generation energy costs can be estimated starting with brokers' quotes (or supplier offers) for forward energy or with the results of market-oriented production-cost models. Since forward quotes for energy delivered in the Entergy system (the best proxy for all of Arkansas) appear to be available only a couple years into the future, they provide only a starting point for avoided costs,

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market, due to the security of supply or other factors. If the Commission agrees, the factors causing that extra value should also be added to the costs avoided by energy efficiency.

and a check on production cost models. Those models will need to reflect demand and supply conditions in the SPP, the Entergy system, and at least parts of SERC (e.g., the TVA and Southern Company), MISO and the Midwestern parts of PJM.

Modeling of energy costs should include the costs of tradable emissions permits, including reasonable projections of the price of carbon emissions. Production-costing models should reflect the increases in variable O&M, increases in heat rate, and reductions in capacity resulting from pending and future environmental retrofits for existing generation.

Forward contract prices are stated for flat blocks of power, such as 50 MWh per hour for all hours in a month, or for all on-peak hours. Actual retail energy usage (and average DSM savings) has a very different time pattern. In particular, when loads are high (due to hot summer or cold winter temperatures), prices tend to be high, so the value of the average kWh used or saved is more than that of the average kWh in the flat wholesale power blocks. The additional value of the load-shaped energy can be estimated by comparing the load-weighted to hour-weighted average prices from market values (if available), system lambda data, or production-cost modeling results.

For DSM-screening purposes, avoided energy costs are usually differentiated by seasonal periods (typically summer to recognize the higher loads, winter to recognize higher fuel costs, and spring/fall) and time of use. The savings from each measure or program are then characterized by season and time of use.

In addition to wholesale energy, DSM avoids some capacity costs. In the long term, the capacity cost is generally derived from the real-levelized capital and operating cost of new peaking capacity.[11] In the shorter term, the value of reduced capacity requirements can be determined from recent wholesale peaking capacity transactions or from the costs of keeping older peaking units (combustion turbines or old gas boiler plants) on line. In any case, the avoided cost of per kW-year of capacity must be increased by the required reserve margin to determine the avoided capacity cost per kilowatt of demand reduction.

Q: What costs must be added to wholesale electric generation prices to develop full avoided electric costs?

A: There are two categories of costs below the wholesale level. First, marginal losses must be added to the generation costs. Since line losses increase with the square of the current flowing through the line, marginal line losses tend to be twice the average variable losses, and the losses (marginal or average) tend to be higher in high-load hours than in low-load hours, and highest at the system peak. Marginal line losses for various time periods can be modeled with fairly complicated models, or simply scaled from the annual average losses.[12] Regardless of where the customer's load is metered, almost all energy is consumed at distribution voltage, so avoided costs should reflect losses to the distribution level, which need not vary among classes.

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[11]The utility may be planning to add more-expensive intermediate capacity (e.g., a gas combined-cycle unit) or baseload capacity (e.g., a coal plant), but the additional cost of that capacity should be covered by its energy savings compared to a peaker. If the additional capital cost is not entirely offset by energy savings, the more-expensive generation will not usually be justified.

[12]Reported losses (e.g., in the FERC Form 1, p. 401a, line 27) are generally computed by comparing sales to generation energy for the year. Sales in 2009 include energy generated in December 2008 but not metered and billed until January 2009, and some energy generated in December 2009 is not recorded as sales until January 2010. Hence, the reported losses should be averaged over several years.

Second, reducing loads will tend to reduce the need for new transmission-and-distribution capacity. Avoided T&D investment per kilowatt are usually estimated by taking the additions in each year (net of retirements, grossed up to reflect inflation from the installation date of the average dollar of retired equipment), inflating several years' data to a common year, and dividing by load growth in that period. That capital cost is then annualized with a real carrying charge (reflecting return, depreciation, and taxes) and adding O&M.

Q: Please describe the derivation of avoided gas commodity costs.

A: Wholesale forward monthly contracts for gas at Henry Hub are actively traded about five years out; those prices provide a market-based projection of the wholesale price of gas. Further out, escalation in gas prices should be based on forecasts, such as the Energy Information Administration's Annual Energy Outlook. The Henry Hub price should be increased by a small adder, reflecting the difference in prices from the Hub to Arkansas city gates.

Most gas-DSM-program administrators screen measures and programs using avoided costs computed by end use (typically baseload, space heating and water heating), rather than time period. Annual baseload avoided costs are simply the average prices across the months, weighted by the number of days in the month. Annual space-heating avoided costs are greater than baseload because more of the energy is used in the high-price winter months, and because sales within each month are higher on days with higher loads, when market prices are also likely to be higher. The market price for each month should be adjusted upward by the historical ratio of the daily prices weighted by heating load (or heating degree-days, as a proxy for heating load), and the resulting prices should be averaged across months, weighted by normal monthly heating load (or degree-days).

Water heating loads are intermediate in shape between baseload and space heating; while customers use hot water in every month, usage of hot water and standby and distribution losses rise in cold weather. Avoided costs for water heating can be estimated as are those for space heating (if data are available on water-heating usage patterns), or as a weighted average of baseload and space heating avoided costs.

Q: What costs must be added to wholesale gas prices to develop full avoided gas costs?

A: In addition to meeting normal loads, gas utilities must have sufficient reserve capacity to meet loads on the design day, and in design-basis cold spells. That reserve may be in the form of pipeline capacity, underground storage capacity, compressed or liquefied gas storage, or propane storage and injection capacity. Avoided cost for each weather-sensitive load shape should include the cost of reserve capacity for the difference between design and normal loads, divided by the normal annual gas usage.

Losses in the gas delivery system do not appear to be significantly related to throughput, and thus are not usually avoidable by energy-efficiency programs. Some systems have costs, such as energy for compression, that do vary with load; those should be included in avoided costs.

Finally, avoided load transmission and distribution costs should be estimated for gas utilities as they are for electric utilities.

V. Shareholder Shared-Savings Incentive

A. The Purpose of Shareholder Incentives for Demand-Side Management

Q: Are shareholder incentives required to make shareholders whole for the effects of DSM?

A: No. Lost-revenue recovery or decoupling would make shareholders whole for the revenue reduction from DSM. Utilities sometimes argue (as EAI has in Docket No. 09-084-U) that shareholders are harmed by the loss of the opportunity to invest in supply that is no longer needed due to energy efficiency.

This is an entirely specious argument. If the Commission sets a utility's allowed return on equity at the cost of equity, shareholders should be indifferent between investing more in that particular utility and putting their money in other investments of equivalent risk. Shareholders are harmed by reduction in the utility's capital requirement only if the allowed exceeds the cost of capital, in which case the Commission should reduce the allowed return.

The utilities would earn exactly the same return on an *investment* in energy efficiency as they do for traditional investments in generation, transmission, storage or distribution. However, utilities usually invest very little in energy efficiency; almost all of the costs are expensed and recovered quite quickly. Hence, there is no asymmetry in the treatment of DSM and supply under traditional ratemaking. Utilities do not earn a return on any expenses: fuel, purchased power, labor, purchased services or DSM.

Q: Is there a justification for shareholder incentives?

A: Yes. While not justified to maintain a return to shareholders, incentives may be necessary to promote real and sometimes difficult shifts in organizational culture and practice. For instance, utilities may resist aggressive utility investment in DSM due to inertia, distraction by more-traditional organizational priorities, lack of positive experience with aggressive DSM, inadequate expertise, and even a perception that it energy efficiency may conflict with legitimate corporate goals. Senior utility management is more familiar with supply planning than with demand planning, and supply advocates tend to be more powerful within the organization than are the demand-side advocates. Many senior managers came up through the traditional supply functions of the utility—power-plant construction and operation, power and gas purchasing, transmission and distribution planning—and related financial operations, and may be more interested in those activities than building a center of excellence in DSM. Staff members who have spent their entire lives encouraging the use of energy may have difficulty adapting to a policy of discouraging its use. In particular, utilities are used to evaluating their performance and competitiveness by tracking rates in cents per kWh or ccf; employees with that perspective may have a hard time believing that DSM (even with favorable recovery of costs and lost revenues) will not harm their company.[13]

In addition, utility management may prefer higher sales, since a larger and faster-growing company is more exciting to manage. The growing company will present more opportunities for hiring and promoting staff, making dramatic decisions about expansion projects, and being feted by investment banks and equipment suppliers. For particular groups within utility management, such as power-plant and transmission planners, the reduction in the need for and importance of their services may be threatening.

[13]Some utility managers may also believe that DSM harms shareholders, and hence their own prospects. This is yet another barrier to DSM implementation.

It is this combination of inertia and the very real self-interest of utility management that creates the need for some incentive to overcome internal resistance to energy efficiency. Even if the lost-revenue mechanism or decoupling would create a level playing field in objective financial terms, an explicit incentive might be necessary to balance the inertia of history and managerial psychology.

B. Incentive Structure

Q: How might a shareholder incentive be structured?

A: One relatively simple approach to shifting corporate culture towards implementation of energy-efficiency resources that has been used in many jurisdictions has been to offer utilities a share of the savings of the net benefits resulting from their energy-efficiency programs. Arkansas can build on that experience.

The net benefits should include all the cost categories used in program screening, including Commission-approved avoided costs, utility program and measure costs, and participant costs.

Incentive computations should use the best information available at the time the utility is implementing the program.[14] The purpose of the incentive is to encourage the utility to strive to do more of the things that are identified as contributing to the objectives set out by the Commission. For the incentive to be effective, and not frustrate or confuse utility management, the utility must have a clear idea of the incentives related to various levels of activity. If a particular measure appears to have net benefits of $500 per installation at the time that the utility is committing to the installations, the utility should be able to count on

[14] These may not be the best estimates at the time of cost recovery, which would be used in computing lost revenues.

that value in estimating the incentive it will earn. Changing the assumptions after the fact is likely to give inconsistent signals and undermine the relationship between achievements and rewards.

Management should implement the DSM plan on the basis of the best available information from time to time during the plan implementation period. As soon as new information becomes available, the incentives for future commitments should be based on the improved information, and the utility (working with other interested parties) should determine whether any modifications to the program are appropriate.

Nor should the utility be allowed to insulate itself from new information. There must be mechanisms—a vigorous consultative process with an independent evaluation function would be perfect—for stakeholders to provide the utility with evidence that an assumption is wrong. The utility should retain the responsibility for determining how to review the evidence and whether to change its assumptions. If the utility does not respond appropriately to the evidence (seriously reviewing it and revising assumptions as appropriate), it should be at risk for disallowance of incentives that depend on the unexamined assumptions. In addition, the utility should be at risk for expenditures that appeared to be cost-effective with the utility's inputs, but not with ex-post-facto estimates that correspond to the ignored suggestions.

Q: Should the incentive be a fixed fraction of program net benefits?

A: No. Incentives should reward exemplary performance. Incentives should thus start once the utility has achieved a substantial amount of savings or benefits. That threshold should be based on what other utilities have achieved, taking into account the ramp-up required to get to full DSM implementation. In various states, these thresholds have been set at 70% to 100% of savings targets.

The threshold should be set in conjunction with the definition of "comprehensive" programs and savings goals and targets to be set in the Sustainable Energy Resources Docket No. 08-144-U. Once the annual targets are set, the Commission should set the incentive threshold. The more aggressive the goals and targets, the lower the thresholds can be as a percentage of those targets.

Q: Should the incentive mechanism provide for penalties, as well?

A: Yes. The utilities should also be exposed to penalties for performance below a minimal standard, which may be lower than the threshold for earning incentives. Again, the appropriate penalty threshold and penalty rate should be set to be consistent with the goals and targets.

Q: Once the utility's performance reaches the threshold, what should happen with the incentive?

A: The utilities should be eligible for incentives in proportion to the estimated performance minus the threshold. In other words, if the incentive rate is 10%, the estimated benefits are $10 million and the threshold is $8 million, the incentive should be ($10–$8) × 0.1 = $0.2 million.

Q: How should incentives relate to program spending?

A: Most incentive schemes provide for maximum incentives that are less 10% of program costs, such as the following examples:

- Arizona: 10%
- Colorado: 20% for lost-revenue compensation plus incentive[15]
- Connecticut: 8% (at 130% of goal)
- Massachusetts: 5%

[15]Lost-revenue recovery would probably consume most of this cap, leaving little room for incentives.

- New Hampshire: 8%–12%
- Vermont: 2.6%

Considering that Connecticut, Vermont, and Massachusetts are some of the leading jurisdictions in energy efficiency, there does not appear to be any need for incentives to exceed 10% of program spending, and much less is probably adequate.

Q: Should the incentive mechanism be driven entirely by net benefits?

A: Not beyond a transition period. Net total-resource-cost (TRC) benefits are an important measure of the success of a DSM program. Unfortunately, exclusive focus on maximizing TRC benefits, especially in the short term, can result in the utility concentrating almost excessively on a small subset of programs and measures that are easy to implement and produce high TRC benefits, primarily lighting retrofits for large commercial customers and sometimes residential screw-in compact fluorescents.[16] To prevent excessive concentration of effort in these narrow market segments, various jurisdictions have moved beyond shared savings to base incentive mechanisms at least partly on such factors as the following:

- Achievement of minimum savings levels in various customer classes, such as residential and non-residential.
- Savings achieved in hard-to-reach market segments, such as low-income residential and small general-service customers.[17]

[16] These measures are valuable, but relatively short-lived; the programs are also time-limited, as Federal efficiency standards phase out standard incandescent lamps and the linear fluorescents now standard in commercial installations.

[17] It may also be appropriate to include an incentive for efficiency improvements for industrial customers, who often require more complicated customized solutions, compared to comparable-sized commercial customers.

- Energy- and peak-reduction goals.
- Geographical equity in program implementation.
- Weighted average measure life.
- Achievements in new construction, training, and other market-transformation activities.

These factors can be accommodated as separate incentives, or as thresholds or modifiers to a shared-savings mechanism. Development of complex incentive mechanisms is best accomplished through a collaborative process among the concerned parties, rather than in litigation.

Q: Does this conclude your testimony?

A: Yes.