**STATE OF ARKANSAS**

**BEFORE THE PUBLIC SERVICE COMMISSION**

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| **Energy Efficiency Notice of Inquiry** | **)** | **Docket No. 10-010-U** |
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# DIRECT TESTIMONY OF

# PAUL CHERNICK

**ON BEHALF OF**

**THE NATIONAL AUDUBON SOCIETY, INC.**

**AND**

**AUDUBON ARKANSAS**

Resource Insight, Inc.

**MARCH 23, 2010**

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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 Audubon 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: 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 avoided costs and cost-benefit determination for energy-efficiency programs.**

A: I have testified in several proceedings on the appropriate structure of cost-benefit tests for energy-efficiency and fuel-switching programs, and developed estimates of avoided costs for numerous utilities, as summarized in my qualifications.

I estimated statewide electric avoided costs for Vermont in 1997 and regional avoided generation costs for all of New England for a consortium of utilities in 1999, 2001, 2007, and 2009.[1] I also described appropriate cost-benefit tests for energy-efficiency and fuel-switching programs and the process of deriving avoided costs in a report to the Pennsylvania Energy Office in 1993.[2]

I developed gas avoided costs for Boston Gas (now part of KeySpan) in the late 1980s and early 1990s, for Washington Gas Light in the 1990s, in the New England consortium reports (above) in 1999 and 2001, in two 2006 reports for NYSERDA ("Natural Gas Energy Efficiency Resource Development Potential in Con Edison Service Area" and "Natural Gas Energy Efficiency Resource Development Potential in New York"), in New York's energy-efficiency rule-making, and for Peoples Gas Company and Philadelphia Gas Works.

**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. 09-0844.

## 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").

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[1]These are, respectively, "Avoided Energy Supply Costs for Demand-Side Management in Massachusetts" (1999), "Updated Avoided Energy Supply Costs for Demand-Side Screening in New England" (2001), "Avoided Energy Supply Costs in New England: 2007 Final Report" (2007), and "Avoided Energy Supply Costs in New England: 2009 Final Report" (2009), all for the Avoided-Energy-Supply-Component Study Group, c/o National Grid Company (Northborough, Massachusetts).

[2]That work was in "Qualifying the Benefits of Demand Management," the fifth volume of the five-volume *From Here to Efficiency: Securing Demand-Management Resources* published in 1992 and 1993 by the Pennsylvania Energy Office.

**Q: What is the purpose of your direct testimony?**

A: I have been asked to provide comments on behalf of Audubon in response to the following three issues raised by the Commission in its order of February 3 2020 (the Order) in this docket:

- Issue 4: full fuel-cycle efficiency
- Issue 5: independent administration
- Issue 6: commercial-and-industrial opt out

**Q: Please summarize your recommendations.**

A: Full fuel-cycle efficiency should not be the basis of determining the most beneficial end-use technology. Energy-investment decisions should be based on the total costs of each alternative. In many situations, a cubic foot of gas burned at the end use will provide more service to the customer than the same unit of gas burned at a combined-cycle plant and sent to the customer as electricity (with associated losses). As a result, switching clothes drying and space and water-heating from electricity to natural gas will often be cost-effective.

This is an empirical question. The Commission should ensure that programs encourage the efficient option (e.g., gas furnace, air-to-air heat pump, ground-source heat pump) with the lowest total cost for each situation (new construction, retrofit of baseboard electric, replacing a failing air-to-air heat pump; single-family and multi-family; with existing ductwork and without). The same is true for switching industrial end uses from natural gas to more-efficient electric uses. In each case, the utility that is reducing load and customer costs should be paying the bulk of incentives, while the utility that is building load should assist only to the extent that the additional load does not harm existing customers.

With respect to using an independent DSM administrator, I recommend that the Commission give the utilities a chance to demonstrate that they can run DSM programs efficiently and effectively, while establishing statewide program oversight. As described in more detail in Section IV, the Statewide Efficiency Monitor would set reporting and evaluation standards, ensure coordination among utility programs, identify programmatic best practices, and report regularly to the Commission. In addition to providing this vital information on a continuing basis, the establishment of the Monitor would let the utilities know that an statewide administration is a realistic alternative, if they are unwilling or unable to pursue state-of-the-art energy-efficiency programs.

Rather than opting out of energy efficiency, industrial customers should be encouraged to self-design DSM projects, identifying the most productive use of DSM funds in their facilities. Those self-designed projects should be subject to the same cost-effectiveness, measurement, and verification requirements applicable to other projects.

The design of programs that work for large customers should be referred to a collaborative process among the utilities, Audubon, the Attorney General, and consumer representatives. The Commission should strongly urge the utilities to fund the retention of a team of experts acceptable to all the parties; those costs, along with other prudent program-design costs, should be recoverable through DSM cost-recovery mechanisms.

## III. Issue 4: Full Fuel-Cycle Efficiency

**Q: How did the Commission frame the issue of full fuel-cycle efficiency?**

A: The Commission's February 3 Order (pp. 2–3) observed that CenterPoint Energy Arkansas Gas (CenterPoint) requested approval to provide customers with rebates to switch from electricity to natural gas for water and space heating, and perhaps for other services. The Commission's press release on the Order summarized the issue as "Whether fuel switching from electricity to gas for water and space heating under a concept called Full Fuel Cycle Measurement of Efficiency should be allowed under energy-efficiency programs."

**Q: How do you view fuel switching as an energy-efficiency measure?**

A: In general, energy-efficiency programs should be fuel-blind. If the total resource cost of providing an energy service (e.g., space heating) can be minimized by changing the fuel source, that efficiency measure should be implemented. The marginal costs of electricity and gas should be treated equally, along with all other costs: capital investments, O&M, water, and other costs that the Commission may choose to include in the benefit-cost test (in a later phase of this proceeding).

This balanced treatment of costs—using avoided or marginal costs for all fuels—is most important in the evaluation of fuel-switching measures, but it is also important in evaluating measures that conserve multiple fuels and in reflecting the incidental effects of energy-efficiency measures on non-targeted fuels. For example, duct sealing reduces energy use for both summer cooling and winter heating, while high-efficiency gas equipment may use more electricity than lower-efficiency systems and reducing electricity waste heat from lights and appliances will tend to increase gas heating loads.

**Q: Should gas utilities thus include in their energy-efficiency programs incentives for the conversion of electric end-uses to gas, as CenterPoint proposed?**

A: No. Reducing the costs of energy services for electric customers is the responsibility of the electric utilities, while reducing the costs of energy services for natural-gas customers is the responsibility of the gas utilities. Fuel-switching from electricity to gas should be included as eligible measures within the electric-utility DSM programs, while fuel-switching from gas to electricity should be included as eligible measures within the gas-utility DSM programs.

Fuel-switching measures should only be included in DSM programs where they are cost-effective.

**Q: Why would there be cost-effective options for both electric-to-gas and gas-to-electric fuel switching?**

A: The least-cost option will vary with the energy service that the consumer desires. Natural gas tends to have a substantial cost advantage over electricity, where the electricity would be used to produce heat though resistance, as in baseload space heating and conventional water heating. In many cases, the incremental cost of electricity is determined by the cost of gas burned in a central power plant (at close to 50% efficiency in a new combined-cycle plant, 30% in a steam boiler or a new combustion turbine, and even lower efficiencies in old peakers), plus the losses in the transmission and distribution system. Under some circumstances, the cost advantage for gas may be offset by increased efficiency of the electric end use, especially with high-efficiency heat pumps.

On the other hand, electricity can accomplish many tasks more efficiently than natural gas. For example, in industrial processes that must remove water from solutions or mixtures, the total cost of using electricity to freeze the water for removal may be less than the cost of using natural gas to boil off the water.

The economics of fuel choice are also affected by the time pattern of the end use. Winter uses, such as space heating, are off the electric system peak and on the gas system peak. The cost of gas at the city gate or burner tip will be similar for the two fuels. However, the natural-gas utility may have relatively high avoidable local T&D costs, while the winter avoidable capacity costs for the electric utility (generation, transmission and distribution) may be low, depending on the penetration of space heating. Cooling loads, on the other hand, fall heavily on the electric system distribution peaks but occur at a low-load time for the gas system.

**Q: Is the concept of full fuel-cycle efficiency, as CenterPoint has used that term, relevant to whether fuel-switching should be included as an energy-efficiency measure?**

A: Not really. Fuel-cycle efficiency analysis will often identify options for cost-effective fuel switching. However, the real question is economic: what is the lowest-cost solution to providing the energy service, given the marginal or avoided costs for the two fuels delivered to the end use, the cost and efficiencies of the end use equipment, and the additional values that the Commission may choose to include in the cost-benefit analysis.

**Q: What should be the roles of the various utilities in fuel-switching?**

A: Electric utilities should include electric-to-gas fuel-switching in their DSM portfolios and offer incentives to facilitate those measures, on the same basis as other measures.[3] Similarly, natural-gas utilities should include gas-to-electric fuel-switching in their DSM portfolios and offer incentives to facilitate those measures, on the same basis as other measures.

Utilities should not mix together their energy-efficiency programs and marketing or growth-related programs. It would be far too easy for the marketing programs to subvert the energy-efficiency programs, which have much greater

[3]In general, measure incentives should be set to encourage customers to select the least-cost alternative, while remaining supportive of customers who prefer some intermediate efficiency option.

potential benefit for consumers.[4] To the extent that the utility can prudently promote or subsidize some growth-related effort, it should be allowed to do so, but separately from the energy-efficiency programs. For example, a gas utility may be able to demonstrate that the costs of serving gas-cooling or -dehumidification loads is less than its rates, due to the highly off-peak nature of that end use. In that case, the gas utility could offer incentives (or a lower rate) for gas cooling, supplementing (and reducing the need for) the electric-utility incentives.

**Q: What priority should the Commission assign to fuel switching in the development of DSM programs?**

A: In most situations, development of high-quality energy-efficiency programs within a fuel source should be prioritized before fuel switching. The utilities should aggressively pursue the unambiguous benefits from avoiding lost opportunities in new construction, renovation, and routine equipment replacement; retrofitting boilers, lighting, motors, HVAC and pumps; and tightening building shells, sealing ducts, and insulating water heaters, pipes, ducts and building envelopes. Fuel-switching components of DSM programs can be developed while the utilities are capturing those efficiency savings.

## IV. Issue 5: Independent Administration

**Q: How did the Commission frame the issue of independent administration?**

A: The Commission's February 3 Order (p. 6) asks whether a third-party administrator should be given the responsibility to "establish goals and targets for spending and energy and demand savings." Its press release describes this issue

[4] Energy-efficiency programs may also be helpful in supporting economic-development efforts, offering new customers lower electric bills through higher efficiency.

as concerning "possible benefits and costs of creating and transferring individual utility EE program development and implementation to an independent administrator at a future date."

**Q: What jurisdictions currently utilize a statewide independent DSM administrator?**

A: The independent administrator model has been successfully implemented in Vermont, Maine, New Jersey and Oregon.

**Q: Are there advantages to use of an independent administrator?**

A: Yes. As the Commission noted, an independent administrator "would presumably be indifferent to the impact of the programs on utility revenues or any lost contributions to fixed costs, because the IA's focus would be primarily on helping customers reduce energy consumption and lower their utility bills" (Order, p. 6).

An independent administrator serving the entire state (or most of it) could offer the same programs over a large area, allowing contractors, engineers, architects, plumbers, retailers, distributors, and (for multi-site chains) customers to work with a single set of efficiency standards, applications, rebate levels, and forms, and otherwise avoid dealing with multiple inconsistent programs. Electric cooperatives and municipal utilities could opt into the programs run by an independent administrator without the complications of branding the programs for each utility, or the frictions that may exist from years of competition with the investor-owned utilities.

Independent administration would also allow for integration of electric and natural-gas programs (as well as measures affecting other fuels and water), including incentives for efficient fuel choices. And the independent administrator could provide the DSM-program-design-and- implementation skills that the Arkansas utilities have not yet developed, without requiring each of them to develop that capability separately.

**Q: Are there advantages to utility administration?**

A: Yes. The utilities often have extensive knowledge of customer operations and energy consumption, existing relationships with large customers through account representatives, and significant marketing, communication, administrative, financial, and data-management capabilities. All those resources are useful in supporting and marketing energy-efficiency programs.

**Q: Should the Commission establish an independent administrator at this time?**

A: No. If the utilities are willing to effectively pursue state-of-the-art DSM programs, there are potential administrative benefits to allowing them to be the administrators. However, the Commission should establish a Statewide Efficiency Monitor with the following responsibilities:

- setting monitoring, verification and evaluation (MV&E) standards for utility programs;
- reviewing MV&E reports;
- review investor-owned and cooperative programs on a continuing basis, to identifying (a) opportunities for improved coordination among utility programs, (b) programmatic best practices, and (c) opportunities to adopt better designs from other utilities in the state or elsewhere;
- reporting regularly to the Commission on utility performance.

The Statewide Efficiency Monitor should be a contractor with experience in the leading energy-efficiency programs nationally, selected by the Commission and funded through the utility energy-efficiency-cost-recovery mechanism. The Monitor should consult with an advisory board of non-utility parties with demonstrated interests in implementation of successful energy-efficiency programs, including Audubon, the Attorney General, the Energy Office, and the University of Arkansas.

**Q: How should the utilities proceed with program design and implementation?**

A: The utilities will find that it is easiest to demonstrate the prudence of their programs if they work with one another and non-utility parties (Audubon, the Attorney General, the Energy Office, and representatives of various customer groups) to select and supervise a team of consultants who can bring to Arkansas the lessons learned around the country about DSM program design and implementation. The resulting collaborative effort should achieve many of the goals of an independent administrator (consistency, integration and excellence), while leaving the utilities responsible for running their programs and eligible for lost-revenue recovery and incentives.

**Q: Under what circumstances should the Commission consider the designation of an independent administrator?**

A: If one or more utilities are not willing or able to implement effective and aggressive DSM under the incentive structure approved by the Commission, to ramp up their programs, or to coordinate and integrate their efficiency programs, an independent administrator may be the preferred solution for the under-performing utilities.

The Commission has set forth a deadline of December 31, 2012 for utilities to meet appropriate criteria for comprehensiveness that will be defined by the end of 2010 (Order in Docket No. 07-084, et al., February 3, 2010, p. 10; Order in Docket No. 08-1444, February 3, 2010). If any utility fails to meet substantively the comprehensiveness criteria by the end of 2012, the Commission should reduce the utility role in DSM to funding, billing and data collection, and select a third-party DSM administrator.

In addition to the December 2012 deadline, the Commission may also want to assess utility progress in 2010 and 2011, focusing on such indicators of intent as participation in a collaborative planning process, development of staffing and internal resources, coordination with other utilities, and acceptance of the Commission's provisions for lost revenues and shareholder incentives.

## V. Issue 6: Commercial-and-Industrial Opt Out

**Q: How did the Commission frame the issue of commercial and industrial opt-out?**

A: The Order (p. 7) introduces the issue as "the opportunity for large commercial and industrial ('C&I') customers to opt out of paying into publicly-funded EE programs and to 'self-direct' those funds into energy savings." The Order (p. 8) also requested "additional information on how to achieve optimal energy savings within the commercial and industria1 sector while benefiting society and ratepayers as a whole, including an assessment of EE projects and status in the large C&I sector." In addition, the Commission' press release describing the Order summarized the issue as "Whether commercial and industrial customers should be allowed to opt out of paying for energy efficiency programs if such customers have made substantial energy efficiency investments on their own."

**Q: Is this category of customers a significant portion of Arkansas retail energy use?**

A: Yes. Depending on the definition of "large," this category might represent a third of Arkansas retail electrical sales and about a quarter of retail natural-gas sales.

**Q: Do these large customers have significant opportunities for cost-effective energy-efficiency investments?**

A: Yes. A 2009 survey of energy efficiency potential studies for various Southern states, the South as a region, and nationally reported average achievable potential savings indicated substation achievable potential, as summarized in Table 1.[5] The various underlying studied estimated potential savings over periods of five to twenty years; the authors of the study annualized those values.

**Table 1: Estimated Annual Energy-Savings Potential as Percent of Sales**

| Class | Electricity | Natural Gas |
|---|---|---|
| Commercial | 1.47% | 0.95% |
| Industrial | 1.56% | 0.82% |

Substantial and highly cost-effective energy-savings opportunities exist, even where rates are high and utilities have been running DSM programs for many years. In Arkansas, with no history of utility DSM and low industrial electric rates, the savings potential is probably even greater.

**Q: Did the Commission clarify what it means by "opt out"?**

A: The Commission specifically cited the testimony in Docket No. 007-081-TF of CenterPoint Arkansas Gas Company witness, Dr. Dennis Goins, "who argued that the customers who opt out will achieve energy savings that are equal to or better than what they would have achieved had they remained paying participants in the publicly-funded programs" (Order, p. 7). I assume that the Commission intended that Dr. Goins testimony would define the justification for opt-out and the range of opt-out alternatives under discussion.

**Q: What are Dr. Goins's arguments in support of opt-out?**

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[5] Chandler, Sharon and Marilyn Brown. 2009. "Meta-Review of Efficiency Potential Studies and Their Implications for the South" Georgia Tech School of Public Policy Working Paper #51. Atlanta: Georgia Institute of Technology.

A: Dr. Goins's arguments are as follows:

1. There are large industrial "customers that finance their own energy efficiency investments or have no end uses compatible with [utility]-sponsored programs" (Direct, p. 8).

2. Direct, p. 9:

> A mandatory requirement to pay for … EE programs ensures that some [large industrial] customers will pay for programs that directly compete with customer-supplied EE investment capital. The customer—not [the utility]—knows best which EE investments to make and should be allowed to choose how available EE capital is spent.

3. Direct, pp. 9–10:

> Choices firms face in deciding how to deploy available operating and investment capital most effectively are not merely limited to decisions about which investment is most energy-efficient. In the real world, investments that reduce energy consumption compete with non-energy investments that may produce greater social benefits. For example, using available capital to expand production capacity and hire and train additional workers may produce social benefits that far outweigh incremental social benefits from reducing energy consumption. Utilities that ignore these foregone incremental non-energy benefits in their EE program evaluations simply overstate the cost-effectiveness of their programs.

4. "Businesses—not the regulated utility—are better-suited to improve energy efficiency in their particular sector and make decisions on the most cost-effective ways to deploy available business investment capital" (Direct, p. 10).

5. "Payments under mandatory program participation … can adversely affect the competitive position of an LCS customer relative to a competitor that is not forced to pay" for energy-efficiency programs (Direct, p. 10).

**Q: Are these arguments correct?**

A: No. On point (1), it is highly unlikely that any large industrial customers have exhausted the opportunities for cost-effective energy-efficiency investment.

While it is possible that some utility might design its DSM programs so ineptly that it would not offer services that match industrial efficiency opportunities, the Commission has indicated that it will require comprehensive programs, which would certainly include support for customized projects for the vast majority of Arkansas industrial customers.

On point (2), Dr. Goins misinterprets the operation of industrial DSM programs. Contrary to his assertion, utility DSM programs add to the capital available for energy-efficiency investment, rather than competing for a fixed investment pool.

In point (3), Dr. Goins presents a very strong argument in favor of utility-sponsored industrial energy-efficiency programs. Industrial firms tend to be preoccupied with capacity expansion, operational cycles and other measures to match output to market needs; cost-effective energy efficiency is apt to be sidelined by the primary focus on production.[6] There is thus an opportunity for the utility to intervene to facilitate efficiency. Again, Dr. Goins asserts that the utility DSM programs would divert a limited capital budget from other purposes. In fact, the utility would actually be providing investment resources that the firm would not normally make available for efficiency investment, due to its distraction by the considerations Dr. Goins cites.

In point (4), Dr. Goins asserts that industrial firms make better cost-effectiveness decisions about energy-efficiency investments than utility pro-

[6]The authors of "Unlocking Energy Efficiency in the U.S. Economy" agree with this characterization. "Energy typically represents a relatively small fraction of operating costs…, leading to low levels of awareness and attention from senior management at industrial companies…. This issue is exacerbated by the lack of focus on energy efficiency by top management .…" Granade, Hannah, Jon Creyts, Anton Derkach, Philip Farese, Scott Nyquist, and Ken Ostrowski. 2009. "Unlocking Energy Efficiency in the US Economy." McKinsey & Co. p. 80.

grams would. This assertion is patently untrue, for several reasons, including the competing demands for capital, insufficient staff technical training and expertise, distraction of other priorities, incorrect price signals, and inefficient investment criteria. (I deal with price signals and investment criteria below.)

In point (5), Dr. Goins ignores the reduction in industrial customers' bills due to the energy-efficiency program. The net effect of the industrial DSM programs will reduce the costs and increase the competitiveness of Arkansas industry.

**Q: You mentioned that industrial customers do not receive the right price signals to invest in energy efficiency. Please elaborate.**

A: The retail rates paid by customers are very different than the costs avoided by the utility and ratepayers due to improved energy efficiency. For example, according to EAI Exhibit KWC-1 in Docket No. 09-084-U, EAI expects avoided energy costs to grow steadily from $46.67/MWh in 2010 to $123.19/MWh in 2026. See Table 2 below.[7]

[7] I have not reviewed the derivation of these estimates, and thus cannot vouch for the accuracy of the values. However, the values appear to be reasonable for the purpose of this discussion and illustrate a typical relationship between industrial rates and avoided costs.

**Table 2: EAI Projection of Avoided Energy Cost**

| | $/MWh |
|---|---|
| 2010 | $48.67 |
| 2011 | $46.90 |
| 2012 | $49.47 |
| 2013 | $51.41 |
| 2014 | $56.72 |
| 2015 | $63.32 |
| 2016 | $68.05 |
| 2017 | $72.64 |
| 2018 | $78.16 |
| 2019 | $83.15 |
| 2020 | $89.46 |
| 2021 | $96.51 |
| 2022 | $101.05 |
| 2023 | $108.42 |
| 2024 | $115.10 |
| 2025 | $121.04 |
| 2026 | $123.19 |

In contrast, EAI's current energy rate for its Large Power Service and Large General Service customers averages $15.62/MWh, plus the energy cost rate, which averages $13.50/MWh over the last 12 months for which the rate has been set (April 2009 to March 2010), for a total price of $29.12/MWh. Entergy is proposing in its current rate case to increase the tariff energy rate to $21.50/MWh, for a total price of $35/MWh.

Entergy's 2010 estimate of avoided energy cost is 67% greater than the current total energy rate and 39% greater than the proposed large-customer energy rate. Large customers can not be expected to make efficient decisions regarding energy-efficiency investments when faced with price signals so far below avoided costs. Given the large discrepancy between energy prices and avoided costs, large-customer investments in energy efficiency are likely to be less than the economically optimal level.

In addition, Entergy's estimate of avoided energy costs rises much faster than inflation; unless the customer projects that retail electric rates will rise at the same rate, the customer will underestimate the benefit of long-term efficiency investments even more than the benefit of savings in 2010. Levelized at Entergy's 7.19% discount rate ( EAI Exhibit KWC-1 in Docket No. 09-084-U), Entergy's estimate of avoided energy costs over 15 years is about $70/MWh, 140% more than the current rate and twice the proposed total energy rate.

**Q: How do the demand charges for large electric customers affect their price signals?**

A: The problem with demand charges is that they are charged on each customer's "15 minutes of greatest use during the month."[8] That customer-specific peak is not necessarily the same as the contribution to the system peaks that drive the need for generation capacity. Demand charges encourage customers to move load off their own billing peak hour, even if that results in higher load at system peak hours. Greater efficiency only reduces demand charges if the efficiency improvement coincides with the customer's billing peak. Hence, demand charges provide incentives to implement load controls that shift load around, they do not provide efficient incentives to use less energy or contribute less to system peaks.

**Q: You mentioned that industrial customers use inefficient investment criteria. Please elaborate.**

A: While cost minimization requires the comparison of the present values of costs and benefits over the lifetime of the decisions, industrial firms generally use simple payback tests or "hurdle rates" that compare costs and benefits over only

[8]This language is from EAI's tariffs, but is typical for most electric utilities.

a couple years. The research cited below confirms that large customers typically require rapid paybacks as a condition of energy-efficiency investments.

> Many firms arbitrarily select a specific payback period as a method of investment appraisal. For example, in 1995 U.S. DOE's Industrial Assessment Center surveyed 104 business managers of small and medium-sized facilities. Eighty-six percent of respondents stated that a payback period of 24 months or less is attractive for energy-efficiency recommendations. Fifty-five percent of respondents replied that they would prefer a payback period of 12 months of less. In contrast, some larger companies or companies with significant corporate backing often accept 3-year paybacks, as they are generally more comfortable with higher levels of risk.[9]

> On average, companies want a payback on their energy efficiency investments in less than 3½ years and they appear to be standing firm on this, as relatively few believe their company's tolerance for payback has increased over the past five years.[10]

> Industrial sites generally receive very tight operational budgets, and plant managers are encouraged to maximize production while keeping near-term quarterly costs low. Furthermore, management tends to focus on quarterly targets, potentially at the expense of projects that pay back over longer periods. Forty-three percent of energy managers indicate that they use a payback period of less than 3 years for energy efficiency projects, while under difficult economic conditions anecdotal evidence suggests that many companies require a payback period of 18 months or less on all investments.[11]

Empirical analysis of corporate behavior confirms the above survey results:

[9]Elliott, R. Neal, Anna Shipley, and Vanessa McKinney. 2008. "Trends in Industrial Investment Decision Making" ACEEE IE081. Washington: American Council for an Energy Efficient Economy. p. 4.

[10]Johnson Controls. 2008. "Final Report: North America—March 28th, 2008." Unpublished report of 2008 survey of business executives. Milwaukee: Johnson Controls. p. 7.

[11]Granade, Hannah, Jon Creyts, Anton Derkach, Philip Farese, Scott Nyquist, and Ken Ostrowski. 2009. "Unlocking Energy Efficiency in the U.S. Economy." McKinsey & Co. p. 81.

> Over 98% of firms have estimated payback thresholds less than 5 years, and about 79% have payback thresholds less than 2 years. The mean payback threshold is 1.4 years, and the median is 1.2 years. These payback cutoffs correspond to implicit discount rates of about 70 and 80% for a 10-year project, respectively ....[12]

**Q: How important are these short payback requirements in affecting customer evaluation of energy-efficiency investments?**

A: These short payback requirements greatly understate the value of energy efficiency. For example, using EAI's avoided cost assumptions listed above, a 15-year measure implemented in 2010 would have present-value benefits equal to more than $700 per annual MWh saved. At EAI's proposed large-customer energy rate of about $35/MWh, a three-year payback requirement would value the same efficiency measure at only $105/MWh and an eighteen-month payback requirement would accept the measure only if it cost less than $53/MWh. A measure that cost $116 per annual MWh saved would have a 6:1 benefit-cost ratio using EAI's avoided costs, but would fail even the three-year payback test from the customer's perspective. These results are summarized in Table 3.

**Table 3: Differences between Utility TRC and Industrial-Customer Payback Tests**

| Evaluation Criterion | Cost | Benefit | Net Benefit | Pass Test? |
|---|---|---|---|---|
| Avoided costs over 15 years | $116 | $706 | $590 | Yes |
| Three-year Payback | $116 | $105 | ($11) | No |
| 18-month Payback | $116 | $53 | ($64) | No |

**Q: What forms of opt-out does Dr. Goins describe in his testimony?**

A: He offers (p. 11) the following three options, which appear to be effectively equivalent:

[12] Anderson, Soren, and Richard Newell. 2003. "Information Programs for Technology Adoption: The Case of Energy-Efficiency Audits" article in press. Elsevier; p. 18. Later published in *Resource and Energy Economics* 26(1): 27–50.

- "Exempt a customer from program participation and cost responsibility with no specific requirements."
- "Exempt any customer that certifies the customer has undertaken or plans to undertake EE investments or actions that produce energy savings and/or demand reductions at least equal to those produced under available utility programs."
- "Allow a customer to target funds that would normally have been paid through EE surcharges into self-directed EE investments."

In his surrebuttal, Dr. Goins clarified a couple points about his preferred approach, as follows:

- "The opt out must apply to the entire EE portfolio, not just a single program" (Exhibit DWG-SR-1).[13]
- The customer need only "Certify in writing that it has identified EE measures with stated, quantifiable goals, and has implemented or plans to implement one or more such measures at its expense" (Exhibit DWG-SR-1).

In Dr. Goins's proposal, the customer would not even be required to state its goals, let alone meet any specific goals. Dr. Goins's requirements could be met by a large industrial firm replacing a single incandescent lamp with a compact fluorescent. His proposed opt-out would leave unrealized large potential customer and system benefits from improved energy efficiency at large customer facilities

[13]It is hard to understand why any industrial customer would want to be prohibited from participating in programs for which it is eligible.

**Q: Should the Commission allow industrial customers to opt out of DSM programs?**

A: No. However, the Commission should allow large customers to design their own efficiency-investment projects within the utility programs.

The Commission should require that each utility include a comprehensive program for custom efficiency projects for large customers.[14] In contrast to prescriptive programs, which list specific eligible measures and provide fixed incentives per unit installed, custom programs provide incentives to buy down the cost of efficiency programs to the investment level generally acceptable to the customer class. All comprehensive utility portfolios must include custom programs for industrial process use and many complex commercial projects.[15] While those programs should include utility-financed technical assistance to identify efficiency options for large customers, they should also provide the option for customers to identify and design their own custom projects. Those customer-designed projects should be subject to the same screening and incentive rules as any other projects in the custom program.

**Q: What are the advantages of your approach over the self-directed investments described by Dr. Goins?**

A: Dr. Goins proposes that the customer be limited to an incentive equal to the "funds that would normally have been paid through EE surcharges," while the utility program would be able to provide funding without that constraint. Dr.

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[14]Such custom programs for large customers permit a much greater flexibility in incentivizing efficiency upgrades in the more-complex energy systems typical in large facilities. These programs are in contrast to the more-rigid prescriptive programs that have fixed incentives and a limited number of eligible measures. Custom programs are widely implemented by utility DSM programs.

[15]Examples of custom commercial projects would include reconfiguration of a building's HVAC system or major refrigeration systems, or adding shading to the building shell.

Goins proposes that the customer be left to decide which projects are cost-effective, using retail rates and whatever cost-effectiveness rules the firm employs, rather than the avoided costs faced by the utility. Dr. Goins would allow the utility to self-certify efficiency investments (or plans for investments), without requiring that the efficiency investments be made. In short, Dr. Goins's approach would leave the current inefficiency of large customers unchanged.

In contrast to Dr. Goins's approach, allowing large customers to propose their own efficiency projects within utility custom programs would provide adequate funding, apply appropriate cost-benefit criteria, fund real and effective measures, allow for utility-quality monitoring and evaluation, and combine the technical expertise of the customer's in-house staff and consultants with that of the program staff (which is likely to comprise primarily consultants in the early years of the programs).

**Q: Does this conclude your testimony?**

A: Yes.