BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR A DETERMINATION THAT ADDITIONAL ELECTRIC GENERATING CAPACITY WILL BE USED AND USEFUL	)	CAUSE NO. PUD 200500516
APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR A DETERMINATION THAT ADDITIONAL BASELOAD ELECTRIC GENERATING CAPACITY WILL BE USED AND USEFUL	)	CAUSE NO. PUD 200600030
IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION GRANTING PRE-APPROVAL TO CONSTRUCT RED ROCK GENERATING FACILITY AND AUTHORIZING A RECOVERY RIDER	)	CAUSE NO. PUD 200700012 (CONSOLIDATED)

Rebuttal Testimony

of

Ken Seiden

on behalf of

Oklahoma Gas and Electric Company

June 18, 2007

Q. **Please state your name, by whom you are employed, and your business address.**

A. My name is Ken Seiden. I am employed by Quantec, LLC. My address is 720 SW Washington, Suite 400, Portland, Oregon, 97205.

Q. **What position do you hold with Quantec, LLC?**

A. I hold the position of Executive Vice President.

Q. **Please describe your education and business experience.**

A. I received a Ph.D. in economics from the University of Oregon in 1986. Prior to my present position with Quantec, I was employed as President of Essential Economics, Inc., and held several positions at Barakat and Chamberlin. Earlier in my career, I was a Market Economist at Pacific Bell, and an Industry Economist at the Bonneville Power Administration.

Q. **Are you familiar with demand forecasting and demand-side management (DSM) issues in the electric utility industry?**

A. Yes. I began developing and applying econometric and end-use forecasting methodologies in the early 1980's, and began forecasting DSM impacts in the late 1980's. I was the co-author of several Electric Power Research Institute (EPRI) guidebooks focusing on forecasting both technical and achievable DSM potential, estimating customer responsiveness to rates, and incorporating uncertainty into demand forecasting and DSM planning. Throughout my 25-year career, I have performed and directed a wide array of demand forecasting and DSM analysis assignments across the United States. In addition to the EPRI guidebooks, I have had several articles published, have spoken at numerous national industry conferences, and developed and taught many workshops on forecasting and DSM. A biography describing my professional experience is provided in Exhibit KS-1.

Q. **Are you familiar with OG&E's energy and peak demand forecasts?**

A. Yes. I began working with OG&E on load forecasting issues in 1997, and have been responsible for developing the Company's long-term energy and peak demand forecasts over this past decade.

Q. **What is the purpose of your rebuttal testimony in this proceeding?**

A. The purpose of my rebuttal testimony is to address the responsive testimony of intervenors concerning the relationship between real prices and the Company's load forecast, and the amount of cost-effective DSM resources available to OG&E. My testimony will show that the impact of price changes on OG&E's capacity requirements is much smaller than estimated by AG Witness Mr. Athas. My testimony will also show that the DSM levels suggested by Mr. Athas may be theoretically achievable, but at a minimum will require a rapid and significant investment in DSM program capabilities, infrastructure, and customer incentives. The costs of achieving a 101 MW of DSM/energy efficiency impact in the next five years could easily exceed $100 million with a continuing and significant funding obligation after 2012. In my opinion, it is premature to assume a large impact on demand requirements from new DSM/energy efficiency programs before the Commission has had an opportunity to thoroughly review the new programs and determine whether major expenditures are justified.

Q. **Do you agree with the forecast reductions proposed by Mr. Athas due to a price elasticity adjustment?**

A. No. On page 4, lines 19-23 Mr. Athas makes an initial claim that the reduction in the forecast from price effects would be 1,500 GWH and 400 MW in the year 2012. However, in the last table of Exhibit JGA-5 Mr. Athas indicates that there would be a 62 MW reduction in the retail peak demand forecast beginning in 2012. Information provided by Mr. Athas in response to OG&E Data Request 2-11 confirms that the 400 MW reduction in 2012 was listed in error and according to his calculations the price elasticity effects would instead yield a 62 MW reduction in 2012.

Q. **Do you agree with this 62 MW level of price elasticity adjustment?**

A. No. Based on the overall electric price increases addressed by Mr. Motley, the reduction due to price elasticity is less than 35 MW in 2012, which is immaterial as compared to the overall load forecast.

Q. **Do you agree with AG Witness Athas' claim that OG&E has not considered the potential for DSM resources other than capacity reducing Demand Response options (page 17, lines 1-9)?**

A. No. Moreover, it appears that OG&E supplied Mr. Athas with information that contradicts this claim on at least five occasions.[1] Also, it is important to recognize that DSM experts describe both energy efficiency and demand response programs as subsets of a broad definition of DSM. Mr. Athas cites a 2005 study by AEG titled "OGE Demand Response Study" as proof that OG&E failed to evaluate Energy Efficiency options. Witness Athas makes the incorrect assumption that the "OGE Demand Response Study" contained information solely related to demand response programs. In fact, the AEG study (Exhibit JGA-2, 88-90) included the consideration of an extensive range of energy efficiency programs: residential and commercial lighting, building envelope retrofits, residential air conditioning and setback thermostats, residential new construction, residential appliances, commercial HVAC and control systems, motors, office equipment, and audits. OG&E has implemented some of these programs, rejected some of these programs and has some under consideration.

Q. **Has OG&E incorporated the impacts from DSM programs in its energy sales and peak demand forecasts?**

A. In part. The peak demand forecast adds back the reductions in loads due to interruptible rates and self-generation from customers given real-time price (RTP) signals. This allows OG&E to directly consider these impacts as dispatchable capacity resources in its IRP modeling. However, neither the energy nor the peak demand

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[1] Cause No. PUD 200700012; Oklahoma Corporation Commission's 3rd Set of Data Request to OG&E (OCC 3.1.f); Oklahoma Corporation Commission's 4th Set of Data Request to OG&E (OCC 4-11); Oklahoma Corporation Commission's 5th Set of Data Request to OG&E (OCC 5-11 and OCC 5-13a); Attorney General of Oklahoma's 2nd Set of Data Requests to OG&E (AG 2-1 [OG&E IRP (Pages III-6 through III-11 entitled "Existing DSM"])

impacts from OG&E's energy efficiency programs have been directly addressed in the demand forecasts.

OG&E recently began assimilating the data necessary to gauge the impacts from its energy efficiency programs. As shown in Exhibit KS-2, cumulative energy efficiency impacts increased from about 1,000 MWh in 2001 to over 5,700 MWh in 2005, the last year of historical sales data contained in OG&E's 2006 load forecast. The econometric models used to forecast sales are implicitly accounting for these impacts because they are embedded in the historical energy sales series.

Q. **What is the magnitude of energy efficiency program impacts embedded in the load forecast?**

A. As shown in Exhibit KS-2, the increase in energy efficiency impacts from 1,000 MWh in 2001 to over 5,700 MWh in 2005 means that OG&E's energy efficiency impacts were growing at a compound annual growth rate of 54%. The load forecast assumes OG&E will be able to maintain this growth rate by implementing and funding additional energy efficiency programs. Consequently, the forecast estimates an increase from the 2005 level to 118,000 MWh in 2012. Using a 0.5162 coincident peak load factor, this yields a retail peak demand reduction estimate of 26 MW in 2012. I have estimated that OG&E will need to spend an additional $23 million by 2012 to achieve this level of increase.

Q. **Mr. Athas uses the states of Connecticut and Vermont as "benchmarks" (pages 18-19) of what OG&E can accomplish with more aggressive energy efficiency programs. Is it appropriate to compare these states to Oklahoma?**

A. No. A number of factors need to be considered in benchmarking investor-owned utility energy efficiency resource acquisition in Oklahoma to other parts of the country. Some of the more important factors include avoided costs, climate, forecast of new construction, seasonal peaking conditions, and most importantly, the financial treatment of energy efficiency resources.

Q. **Mr. Athas suggests that OG&E can obtain 125 MW and 815 GWh of energy efficiency resources in the next 5 years (pg 20, lines 14-15). Do you agree that this is an achievable level?**

A. Mr. Athas' projection is extremely unlikely without appropriate cost recovery mechanisms. Assuming appropriate cost recovery treatment, 101 MW may be achievable if OG&E embarks on a rapid, significant investment in DSM program capabilities, infrastructure, and customer incentives. This 101 MW is inclusive of the 26 MW embedded in the load forecast, so the net additional amount is approximately 75 MW. I estimate that these combined efforts would require the expenditure of more than $100 million between 2008 and 2012 and will require a continuing expenditure of at least $25 million per year after 2012. To achieve an additional 75 MW, OG&E will be required to implement even more programs and incur significant new funding in addition to the $23 million I believe is necessary to achieve the 26 MW.

Exhibit KS-3 provides a simple scaling of the results from a recent study of DSM potential Quantec conducted for Aquila in the state of Missouri--a much closer benchmark to OG&E with respect to electric end-uses and climate. The results of the study suggest that OG&E could potentially achieve savings of 450 GWh and 101 MW from a very aggressive investment in energy efficiency resources.

Q. **How are DSM energy efficiency program costs generally recovered?**

A. There are four general ways to recover expenditures on energy efficiency resources:

1. No special treatment of DSM: Many states, including Oklahoma, do not have any special provisions for the treatment of energy efficiency resources. Energy efficiency is treated as another line item expense to be recovered through traditional test year, cost-of-service based rate making.

2. Deferral and amortization of DSM: States using this approach effectively allow all expenses associated with DSM to be treated as an asset. The expenses are deferred between rate cases, then recovered along with carrying costs over the amortization period through general rates or a tariff rider.

3. DSM tariff rider: States using this approach authorize contemporaneous collection of DSM expenses through a tariff rider. A balancing account is used to track and adjust for differences between annual expenses and annual rate recovery.

4. DSM System Benefit Charge (SBC): States relying on third-party administration of DSM use an SBC to fund the programs. Generally, the SBC is based on electric consumption and the utility serves as collection agent for the third party.

Q. **How does DSM cost recovery treatment impact the acquisition of energy efficiency resources?**

A. There is a clear difference in the amount of energy efficiency resources acquired between states that do not have legislative or regulatory provisions providing special treatment of DSM, and those that use one or more of the DSM cost recovery mechanisms listed above. As shown in Exhibit KS-4, investor-owned utilities in states having special regulatory or legislative treatment of energy efficiency resources spend between 0.4% and 3.1% of annual revenues on energy efficiency programs, with the average amount equal to 1.6% of annual revenues. Conversely, in states where there are no special provisions for recovering DSM expenditures, energy efficiency spending ranges from 0.0% to 0.4% of annual revenue, with the mean at 0.04% of annual revenue.

Q. **In your opinion, do DSM investments require alternative cost recovery mechanisms?**

A. Yes. Traditional cost-of-service ratemaking is in my opinion impractical. DSM investments incurred prior to the rate case are simply not recovered through rates, and are therefore paid by shareholders. If there are increasing expenditures on energy efficiency after a rate case, expenses above and beyond the historical test year are also borne by shareholders. Unlike a generating resource, DSM is acquired through a series of relatively small increments. Therefore, the magnitude of the investments are not likely to warrant a general rate case filing by the utility due to the expense associated with such a filing. Consequently, uncompensated investments are borne by shareholders for many years.

Q. **What else are states currently doing to promote energy efficiency?**

A. A variety of organizations have recognized that energy efficiency can play an important role in utility resource planning, and that a policy framework that better aligns utility incentives with energy efficiency activities is important to encourage such activities. These views, and a current summary of the status of utility incentives have been recently summarized in an October 2006 paper by the ACEEE titled "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives." Exhibit KS-5 is a table from that report that illustrates the cost recovery and performance mechanisms currently in use. I have updated that table to reflect recent changes in Idaho and Vermont.

Q. **Will you please summarize your conclusions?**

A. Mr. Athas' calculation of a reduction in the 2012 load forecast due to price elasticity and DSM impacts of 187 MW is incorrect. Mr. Athas' calculations do not recognize that the load forecast already includes embedded energy efficiency reductions of 26 MW. I estimate an immaterial price elasticity effect of less than 35 MW, not the 62 MW ultimately calculated by Mr. Athas. In addition, theoretically another 75 MW may be achievable in 2012 through more aggressive DSM energy efficiency resource programs, with a preliminary cost that could approach $100 million, and will require significant ongoing expenditures.

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

A. Yes.

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Experience

Quantec, LLC
Executive Vice President (2007 to present)
Vice President (1999 to 2006)

Specializes in competitive assessment, program evaluation, pricing, forecasting, market segmentation, and business planning. Dr. Seiden was the original architect of Quantec's End Use Forecaster and DICE models, and leads the firm's energy forecasting and DSM planning practices.

Essential Economics, Inc.
President (1996 to 1998)

Specialized in applications of economics, statistics, and strategic planning services for infrastructure utilities. Areas of expertise include corporate strategy and business planning, sales forecasting, competitive pricing strategies, market simulation software development, discrete choice analysis, market transformation analysis, conservation program planning, evaluation, and benefit/cost studies.

Barakat & Chamberlin, Inc.
Project Director (1994 to 1996)
Senior Associate (1992 to 1994)
Associate (1989 to 1992)

Managed projects and performed analyses for a consulting firm specializing in regulated industries and the transition from a regulated environment to a competitive environment.

Pacific Bell
Market Economist (1987 to 1989)

Assessed impacts of telecommunications deregulation on sales, market share and profits using non-linear regression techniques. Combined diffusion of innovations and discrete choice methods to forecast demand for new products and services including virtual private networks and the integrated services digital network (ISDN); completed forecasts supporting business cases and sales targets; and coordinated joint research with Bell Communications Research.

Wholesale Rate Division, Bonneville Power Administration
Industry Economist (1984 to 1986)

Evaluated the impacts of alternative wholesale pricing strategies on sales and public utility behavior using advanced systems of equations statistical methods. Assisted with the development of risk-mitigating rate designs and testimony preparation.

Department of Economics, University of the Pacific
Visiting Assistant Professor (1986 to 1987)

Department of Economics, University of Oregon
Instructor and Researcher (1981 to 1986)

Education

Ph.D. Economics, University of Oregon, 1986.

M.S. Economics, University of Oregon, 1984.

B.A. Economics, University of Connecticut, 1981.

Publications

"The Crystal Ball: Forecasting for Demand Trading," *Public Utilities Fortnightly*, pp. 30-33. March 2002, with William Smith.

"Day-Ahead/Hour-Ahead Forecasting for Demand Trading: A Guidebook." EPRI Technical Report. With W. Smith, B. Kalweit, A. Faruqui, E. Alpay, L. Miller, and S. Schick, December 2001.

"Economic Analysis of Electric Ground Support Equipment." EPRI Technical Report. With L. Sandell, July 2001.

"Anticipating Competitor Responses in Retail Electricity Price Design" in *Pricing in Competitive Electricity Markets*, edited by Ahmad Faruqui and Kelly Eakin, Kluwer Academic Publishers, 2000. With A. Faruqui, pp. 85-101.

"Business Case for Fast Charging of Industrial Lift Truck Fleets, a Life Cycle Cost Model." EPRI Technical Report. With M. Sami Khawaja, Scott Dimetrosky, and John Shinn, September 2000.

Anticipating Competitor Response in Retail Electricity Price Design EPRI TR-112087, April 1999.

"Strategic Rate Making in the Context of Dynamic Ramsey Pricing," *Applied Economics*, vol. 26, no. 4, pp 363-374. With K. Jensen and R. Harman. April 1994.

"Efficient Block Rate Structures: Rethinking Conventional Wisdom," *The Electricity Journal*, pp. 54-59. With J. Chamberlin. December 1993/January 1994.

"Econometric and End-Use Models: Is it Either/Or Or Both?" *Proceedings of the Ninth Annual Forecasting Symposium*. Sponsored by the Electric Power Research Institute. With A. Faruqui and C. Melendy. San Diego, CA, September, 1993.

Practical Applications of Forecasting Under Uncertainty. EPRI CU-2912. With A. Faruqui and C. Sabo. Palo Alto: Electric Power Research Institute, October 1992.

"The Potential for Energy Efficiency in Electric End-Use Technologies." *Transactions of the IEEE Meeting*. With G. Wikler, A. Faruqui, and C. Gellings. Seattle, WA, July 1992.

"Potential Energy Savings from Efficient Electric Technologies." *Energy Policy,* pp. 217-230. With C. Gellings and A. Faruqui. April 1991.

Customer Response to Rate Options. EPRI CU-7131. Electric Power Research Institute. With A. Faruqui et al. Palo Alto, January 1991.

Impact of Demand-Side Management on Future Customer Electricity Demand: An Update. EPRI CU-6953. With A. Faruqui et al. September 1990.

Estimating Efficiency Savings Embedded in Electric Utility Forecasts. EPRI CU-6925. With A. Faruqui. August 1990.

Uncertainty in Forecasting. EPRI CU-6855. With A. Faruqui et al. May 1990.

Efficient Energy Use: Estimates of Maximum Energy Savings. EPRI CU-6746. With A. Faruqui et al. March 1990.

"The Behavior of Publicly Owned Utilities in Wholesale Electricity Markets: The Case of the Pacific Northwest." *Energy Economics*, pp. 241-250. With L. L. Peters. 1987.

Invited Presentations

Doing More with Less: Producing Multi-Dimensional Electricity Sales Forecasts in Record Time. For the F2006 Business Forecasting Conference. With Ken Grant, OG&E Electric Services. June 2006

Quantitative Frontiers: Load Research and Forecasting. For the *AEIC's Load Research Committee. November 2005.*

"Selling Energy Efficiency Through its Economic Benefits," presented at the Iowa Association of Energy Efficiency Annual Conference, October 2003, Des Moines, IA.

Conference Papers

Using Hourly Load and Weather Data for Long-Term Peak Demand Forecasting. For 2005 AEIC Annual Load Research Conference . With Collin Elliot and Matei Perussi. July 2005.

Incorporating Load Research in Long-Term Peak Demand Forecasting. 2002 AEIC Annual Load Research Conference. With Shon Kraley. July 2002

Weather and Risk in Peak Forecasting: An Update. With Ebru Alpay Lauren Miller, Buz Poole, OG&E Electric Services. For EPRI's 13th Forecasting Symposium. November 2001.

"Freerider and Freedriver Effects from a High-Efficiency Gas Furnace Program, " presented at the 1999 International Energy Program Evaluation Conference. With H. Platis. August 1999, Denver CO.

"The Persistence of Savings from a Comprehensive, Low-Income Energy-Efficiency Program," presented at the 1999 International Energy Program Evaluation Conference. With E. Titus and J. Peters.

August 1999, Denver CO.

"Making Forecasts and Weather Normalization Work Together," presented at the Electric Power Research Institute's 12th Forecasting Symposium, Forecasting in a Restructured Market, April 1999, Denver, CO.

"DSM Planning Under Uncertainty." Co-author of paper presented to American Economic Association/Transportation and Public Utilities Group annual meeting. With A. Faruqui. Anaheim, CA, January 1993.

"Approaches to Dealing with Uncertainty in Forecasting." Co-author of paper presented at EPRI's 8th Electric Utility Forecasting Symposium. With A. Faruqui and P. Cleary. Baltimore, MD, October 1991.

"Cost-Effectiveness Analysis Under Uncertainty." Canadian Electrical Association Demand-Side Management Conference, with A. Faruqui et al., Toronto, Canada, October 1990.

"Impact of Utility Demand-Side Management Programs on U.S. Electricity Demand: 1990-2010." ACEEE 1990 Summer Study, with A. Faruqui and S. D. Braithwait, Asilomar Conference Center, Monterey, CA, August 1990.

"Second-Stage Effects of Demand-Side Management Programs." the Advanced Workshop in Regulation and Public Utility Economics, Third Annual Western Conference. With A. Faruqui, San Diego, CA, July 1990.

"Forecasting the Demand for New Products: A Synthesis of Diffusion of Innovations and Discrete Choice Approaches." Rutgers University Advanced Workshop in Public Utility Economics and Regulation, Second Annual Western Conference, Monterey, CA, July 1989.

Exhibit KS-2
Historical and Projected Energy Efficiency Program Impacts

Cumulative Energy Efficiency Program Impacts (MWh)							Load Factor 0.5162	CAGR 54%
Year	Residential Geothermal	Energy Star Homes	Commercial Geothermal	Multifamily Geothermal	Air Source Heat Pumps	Total Cumulative EE Impacts	Growth in Cumulative EE MWH Impacts	Cumulative EE MW Impacts
2001	272.0	157.9	584.0	0.0		1,014		0.2
2002	447.2	561.5	900.0	80.0		1,989	96.2%	0.4
2003	604.0	1155.3	940.0	80.0		2,779	39.8%	0.6
2004	662.4	1811.9	992.0	89.6		3,556	27.9%	0.8
2005	751.6	2558.2	1361.2	89.6	959.2	5,720	60.9%	1.3
2006						8,815	54.1%	1.9
2007						13,586	54.1%	3.0
2008						20,938	54.1%	4.6
2009						32,269	54.1%	7.1
2010						49,732	54.1%	11.0
2011						76,645	54.1%	17.0
2012						118,123	54.1%	26.1

Athas Estimates for Reduction in Energy/Demand in 2012	815,000	125
% of Athas EE embedded in OG&E forecast	14.5%	20.9%

Exhibit KS-3
Preliminary Estimate of Achievable Energy Efficiency (EE) Potential at OG&E Assuming Removal of Financial Disincentives

Year	2006 OG&E Energy Retail Forecast (MWh)	Cumulative EE savings %	OG&E EE Savings (MWh)	OG&E Peak Demand MW savings	Annual Expenditures on Energy Efficiency
2008	26,159,043	0.1%	32,490	7.2	$5,200,000
2009	26,716,490	0.4%	101,531	22.5	$15,200,000
2010	27,241,809	0.8%	220,323	48.7	$25,800,000
2011	27,747,974	1.2%	337,442	74.6	$25,800,000
2012	28,220,380	1.6%	454,965	100.6	$25,800,000

Exhibit KS-4
DSM Spending as Percent of Annual Revenues, and DSM Incremental Annual Savings Percent, by Cost Recovery Mechanism

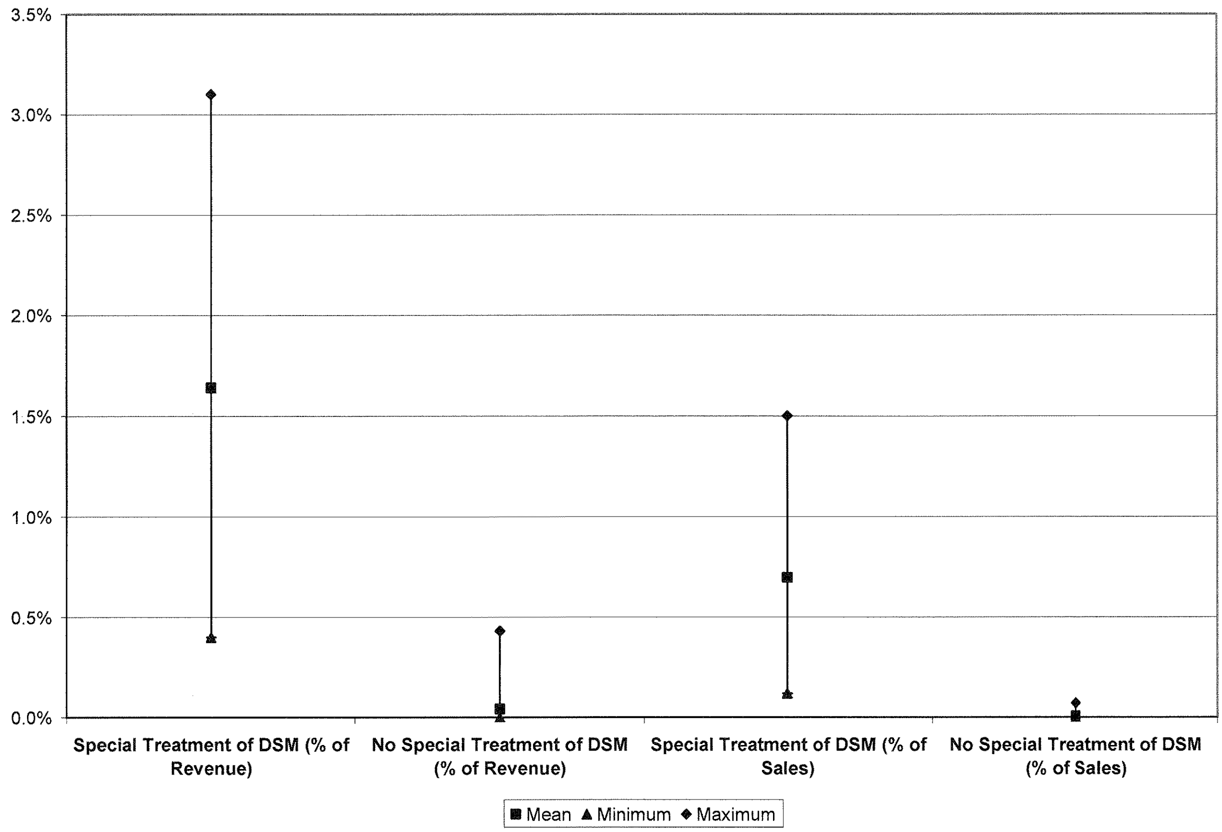

Exhibit KS-5

Table 1. Regulatory Mechanisms for Cost Recovery, Performance Incentives, and Decoupling

State	Cost Recovery	Direct Lost Revenues Recovery	Performance Incentives	Decoupling
Arizona	Yes- Electric rate cases	No	Yes – Capped at 10% of Arizona Public Service's electric energy efficiency program budget. APS's electric EE Plan no yet finalized	No
California	Yes- Electric and natural gas "system benefits" or "public goods" charge plus additional funding through rates	No	Under Development	Yes, Natural gas and Electric
Colorado	Yes- Electric rate cases	No	No	No
Connecticut	Yes- Electric system benefit charge (SBC)	No – Electric distribution companies are only allowed recovery of lost revenues if their earnings are below their allowed rate of return for six months. In addition, in certain regions in Connecticut, the DPUC has introduced a type of lost-revenue recovery mechanism for new CL&M electric load response and distributed generation initiatives.	Yes	No- Electric Partial – Natural gas In CT DPUC Docket 05-05-09, the DPUC rejected enacting any changes to existing rate-making approaches for electric and natural gas utilities. (Electric has no decoupling but two natural gas local distribution companies have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers-a "conservation adjustment mechanism".)
Florida	Yes- Electric rate or tariff rider/surcharge	No	No	No
Idaho	Yes- Electric rate or tariff rider/surcharge	No	No	Yes - Electric

State	Cost Recovery	Direct Lost Revenues Recovery	Performance Incentives	Decoupling

Illinois	Yes- small scale electric energy efficiency programs Supported by an assessment on electric utilities	No	N/A- The electric and natural gas energy efficiency programs are administered by the Department of Commerce and Economic Opportunity (DCEO), a state agency.	No
Iowa	Yes	No	No	No
Maine	Yes- Public benefits assessment	No	N/A- Efficiency Maine, a division of the Maine Public Utilities Commission, administers the electric energy efficiency programs.	No
Massachusetts	Yes- Electric SBC	No	Yes – 5% (of electric EE expenditures) shareholder incentive for meeting goals	No
Minnesota	Yes- Electric and natural gas cases (based on legislative mandate)	No	Yes- Electric and natural gas	No
Montana	Yes- Electric SBC Yes- Natural gas general rate cases	No	No	No
Nevada	Yes- Electric rate cases	No	Yes- Electric	No
New Jersey	Yes- Electric SBC	No	N/A (NJ is moving to state administration)	No
New Hampshire	Yes- Electric SBC	No	Yes – Electric	No
New Mexico	Not applicable yet; just enacted law that requires utility; DSM cost recovery to be via rate cases.	No	No	No- However a new statute (dealing with both electrical and natural gas) calls for removal of disincentives nothing proposed or in place.
New York	Yes- Electric SBC	No	NA- Electric (NYSERDA administers the electric energy efficiency programs)	Investigating – open docket
State	**Cost Recovery**	**Direct Lost Revenues Recovery**	**Performance Incentives**	**Decoupling**
Ohio	Yes- Electric rate rider	No	N/A – Electric (The Ohio Department of Development administers the electric energy efficiency programs.)	No- Electric Issue is being examined for natural gas utilities.

Oregon	Yes- Electric and natural gas SBC	No	N/A – Electric (The Energy Trust of Oregon administers the electric and natural gas energy efficiency programs.) No- Natural gas	No- Electric. Yes- mechanisms in place for the two biggest natural gas utilities.
Rhode Island	Yes- Electric SBC	No	Yes	No
Texas	Yes	No	No	No
Utah	Yes- Electric rate or tariff rider/surcharge	No	No	No
Vermont	Yes- Electric SBC	No	Yes (non-utility) – Electric (A nonprofit, EVT, administers the programs. EVT can obtain an incentive for the program performance.)	Yes - Electric
Washington	Yes- Electric rate or tariff rider/surcharge	No	No	Investigating – Electric
Wisconsin	Yes-Electric SBC, plus additional funding through rates is possible, if utilities request and PSCW approves.	No	Generally N/A – Electric (Currently the state of WI, Dept. of Administration administers the majority of the programs but utilities have the option to administer.) Once exception, Alliant Energy is allowed to earn its rate-of-return on one C/I "shared savings" energy efficiency program.	No – Electric (A proposal was submitted in one current rate case.)