SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH)

IURC CAUSE NO. 44927

DIRECT TESTIMONY
OF
RICHARD G. STEVIE
VICE PRESIDENT, INTEGRAL ANALYTICS,

ON

COST EFFECTIVENESS OF VECTREN SOUTH'S
2018-2020 DEMAND SIDE MANAGEMENT PLAN

SPONSORING PETITIONER'S EXHIBIT NO. 2,
ATTACHMENTS RGS-1 and RGS-2

VERIFIED DIRECT TESTIMONY OF RICHARD G. STEVIE

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is Richard G. Stevie. I am employed as Vice President, Forecasting, by Integral Analytics, Inc. ("IA"). My business address is 123 East Fourth Street, Suite 300, Cincinnati, Ohio 45202. I am submitting this testimony on behalf of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company").

Q. Please describe Integral Analytics.

A. IA is an analytical software and consulting firm focused on operational, planning, and market research solutions for the energy industry. IA excels at sophisticated and accurate analytical approaches to valuation. Its analytical, programming, and statistical methods offer clients precise, fast and affordable valuation. As part of its set of software tools, IA developed the DSMore model which is used for valuing the cost-effectiveness of energy efficiency and demand response programs across 30 States. IA develops accurate valuations by capturing all avoided costs and the covariance between prices and loads, and values these impacts across 40 years of actual hourly weather patterns, which ensures accuracy in quantifying avoided costs.

Q. Please briefly describe your educational background and business experience.

A. I received a Bachelor's degree in Economics from Thomas More College in May 1971. In June 1973, I was awarded a Master of Arts degree in Economics from the University of Cincinnati. In August 1977, I received a Ph.D. in Economics from the University of Cincinnati. In 2012, I was named a Research Fellow for the Economics Center at the University of Cincinnati.

Since joining IA in 2012, I have been involved in projects on cost-effectiveness analysis of energy efficiency and demand response programs, system load forecasting, spatial load forecasting for distribution planning, rate negotiation, bi data/smart grid analytics, and utility planning analytics. In addition, I h presented/written papers on estimating the value of electric service, regulatory stakeholder objectives, cost of energy efficiency, and energy efficiency cost recovery mechanisms.

Prior to joining IA, I was Chief Economist for Duke Energy. During my tenure with Duke Energy, I managed several key analytical functions including economic forecasts, projections of energy sales and peak load demands, customer research on energy usage, market research, product development analytics, evaluation of energy efficiency and demand response program cost-effectiveness, and measurement and verification of energy efficiency and demand response impacts. I have been involved in many regulatory proceedings and provided expert witness testimony on numerous utility economic issues in Ohio, Kentucky, Indiana, North Carolina, and South Carolina. The principle areas of testimony involved load forecasting, cost-effectiveness analysis of energy efficiency and demand response programs, measurement and verification plans for energy efficiency and demand response programs, market pricing for energy, regulatory recovery mechanisms for energy efficiency, weather normalization of energy sales, and assessment of economic conditions.

Before the merger with Duke Energy, I was General Manager of Market Analytics for Cinergy Corp. and prior to that Senior Economist with the Cincinnati Gas & Electric Company. In addition, I was a past Director of Economic Research for the Public Staff of the North Carolina Utilities Commission. While working at the Public Staff, I provided expert testimony on numerous issues including cost of capital, capital structure, operating ratio, and rate design.

For over twenty years, I chaired the Regional Economic Advisory Committee for the Greater Cincinnati Chamber of Commerce. As chair of the committee, I led the development and presentation of the Chamber's Annual Economic Outlook. In addition, I have appeared in numerous local forums to provide views on the economy.

Q. Are you a member of any professional organizations?

A. Yes, I am a member of the American Economic Association, the National Association of Business Economists, the International Association for Energy Economics, and the Association of Energy Services Professionals.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the results of the cost-effectiveness analysis of the Vectren South 2018 - 2020 Electric Energy Efficiency Plan ("2018 - 2020 Plan") which was developed under the direction of Vectren South. I also review and comment on the Vectren South long-term impact of the 2018-2020 Plan on the rates and bills of participants and non-participants. Finally, I discuss the process used to project the cost of Vectren South's energy efficiency portfolio for use in the development of the Company's Integrated Resource Plan ("IRP").

Q. Are you sponsoring any attachments?

A. Yes. I am sponsoring Petitioner's Exhibit No. 2, **Attachment RGS-1**, which is a Benefit/Cost Test Matrix and Petitioner's Exhibit No. 2, **Attachment RGS-2**, which is a copy of my research related to EE spending and impacts.

II. COST-EFFECTIVENESS MODELLING

Q. What are the cost effectiveness tests you performed?

A. As required by the Indiana Utility Regulatory Commission ("IURC" or "Commission"), the 2018 - 2020 Plan considers the Utility Cost Test ("UCT" also known as the Program Administrator Cost Test), the Total Resource Cost Test ("TRC Test"), the Ratepayer Impact Measure Test ("RIM"), and the Participant Test.

Q. How were these tests evaluated?

A. The tests were evaluated using the DSMore model.

Q. What is the DSMore model?

A. DSMore is a financial analysis tool designed to evaluate the costs, benefits, and risks of energy efficiency programs and measures. DSMore estimates the value of an energy efficiency measure at an hourly level across distributions of weather and/or energy costs or prices. By examining energy efficiency performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing energy efficiency measures versus traditional generation capacity additions, and further, to ensure that demand side resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: UCT, RIM Test, TRC Test, Participant Test, and Societal Test. For this proceeding, test results will be reported for the previously mentioned set of tests required by the IURC. DSMore can be utilized to provide the results of those tests for any type of energy efficiency program (demand response and/or energy saving).

Test results are also developed for a range of weather conditions, including normal weather, and under various cost and market price conditions. Because DSMore is designed to be able to analyze extreme conditions, one can obtain a distribution of cost-effectiveness outcomes or expectations. Avoided costs for energy efficiency tend to increase with increasing market prices and/or more extreme weather conditions due to the covariance between load and costs/prices. Understanding the manner in which energy efficiency cost effectiveness varies under these conditions allows a more precise valuation of energy efficiency programs and demand response programs.

Generally, the DSMore model requires the user to input specific information regarding the energy efficiency measure or program to be analyzed as well as the cost and rate information of the utility. These inputs enable one to then analyze the cost-effectiveness of the measure or program.

Q. What energy efficiency program or measure information is input into the model?

A. The information required on an energy efficiency program or measure includes, but is not limited to:

- Number of program participants, including free ridership or free drivers;
- Projected program costs, contractor costs and/or administration costs;
- Customer incentives, demand response credits or other incentives;
- Measure life, incremental customer costs and/or annual maintenance costs;
- Load impacts (kWh, kW and the hourly timing of reductions); and
- Hours of interruption, magnitude of load reductions or load floors.

Q. What utility information is input into the model?

A. The utility information required for the model includes, but is not limited to:

- Discount rate;
- Loss ratio, either for annual average losses or peak losses;
- Rate structure, or tariff appropriate for a given customer class;
- Avoided costs of energy, capacity, transmission & distribution; and
- Cost escalators.

Q. How are programs or measures modeled?

A. An analyst or program manager at Vectren South develops the inputs for the program or measure using information on expected program costs, load impacts, customer incentives necessary to drive customers' participation, free rider expectations, and expected number of participants. Past program experience and results of measurement and verification studies can also add reliability to the program or measure values. Once this information has been compiled, it is used in runs of the DSMore model to determine cost-effectiveness.

In DSMore, the load impacts of the program or measure may be analyzed as a percent of savings reduction from the current level of use, as proportional to the load shape for the customer, or as an hourly reduction in kWh and/or kW. These approaches apply to energy saving programs and measures. For demand response programs, the analyst must provide information on the amount of the expected load reduction and the possible timing of the reduction.

Q. What is the source of the data for the program or measure?

A. Program managers and analysts at Vectren South develop the inputs for each program or measure for the DSMore runs.

Q. What is the source for the utility inputs to the model?

A. Vectren South staff provided information on the required utility inputs with guidance from IA.

III. COST-EFFECTIVENESS TESTS

Q. Please describe how energy efficiency programs and measures are analyzed.

A. Evaluating cost-effectiveness of energy-efficiency programs involves estimating the net present value of the financial stream of costs versus benefits, *e.g.*, the cost to implement the measures is valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of each program's cost-effectiveness relative to the benefits of the projected load impacts. The principal tests for screening energy efficiency measures are the Participant Test, the UCT, the RIM Test, and the TRC Test. The following paragraphs provide a summary of the applicable tests.

- The Participant Test compares the benefits to the participant through bill savings plus incentives from the utility relative to the incremental costs to the participant for implementing the energy efficiency measure. The costs can include capital cost as well as increased annual operating cost, if applicable.
- The UCT compares utility benefits (avoided costs) to incurred utility costs to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of

electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program. The RIM Test compares the same benefits as the UCT (utility avoided costs) to the total costs to the utility including the utility costs to implement the programs and lost revenues.
- The TRC test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test; however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC. The TRC Test represents a combination of the Participant Test and the RIM or non-participants test.

Petitioner's Exhibit No. 2, Attachment RGS-1 provides a more detailed summary of the items included in the respective tests.

Q. Would you discuss information provided by each of the tests?

A. Yes. Each one of the tests provides an insight into the cost-effectiveness of the programs from the perspective of different stakeholders: participant (Participant Test), non-participants (RIM), the utility and ratepayers (UCT), and society as a whole (TRC). The use of multiple tests can ensure the development of a reasonable set of energy efficiency programs, indicate the likelihood that customers will participate, and also protect against cross-subsidization.

In general, programs must pass the Participant Test or the programs will not be successful in the market place, i.e., will not be adopted by potential participants.

The bill savings (see line 1 on Petitioner's Exhibit No. 2, Attachment RGS-1) that provide a benefit to the program participants represent lost revenues to the utility (see line 21 on Petitioner's Exhibit No. 2, Attachment RGS-1).

The UCT, in essence, provides the same type of information as the benefit cost analysis conducted by Integrated Resource Planning (IRP) models. The UCT evaluates the long-run implications for utility revenue requirements, just like in an IRP. For example, if a program passes the UCT, it means that long-run requirements for customers will be lower than if the utility did not implement the program.

The RIM Test is similar to the UCT except that the lost revenues, the bill savings from the Participant Test, now show up as a cost[1]. These lost revenues have to be spread for recovery across all the utility's customer sales to enable the utility to cover its costs. That is why the RIM Test is called the non-participants test. If a program fails the RIM Test, it indicates that rates would likely have to increase. What the RIM Test does not tell us is whether rates would increase more if the program were not implemented. That is why this test is viewed with a significant level of skepticism. While having a program pass the RIM Test is a positive outcome, the value of the test is limited. Generally, programs that target energy efficiency tend to fail the RIM Test.

Finally, there is the TRC Test. The TRC Test actually represents the sum of the components of the Participant Test and the non-participants or RIM Test. This is why it is viewed as a comprehensive test since impacts on participants and non-participants are considered. One point to note is that while the TRC Test does not explicitly include lost revenues, in combining the components of the two tests, the utility bill savings and the incentives paid to customers by the utility which are benefits in the Participant Test are offset by the lost revenues and customer incentives (costs in the RIM Test). These components cancel each other out and are not included in the calculation of the TRC Test. Typically, if a program

1 The RIM Test net of fuel removes lost revenues associated with fuel costs. However, revenues associated with fuel costs would still be counted as a benefit in the calculation of the Participant Test.

passes the UCT, it will pass the TRC Test unless the participant's cost to implement the energy efficiency measure is large relative to the program benefits.

Again, each test provides insights into a very complex issue. Understanding the implications when a program passes or fails a test helps in deciding whether or not to implement the program or judge its success.

Q. What were the results of the cost-effectiveness analysis?

A. The Company seeks, in part, approval to implement the following set of programs.

RESIDENTIAL CUSTOMER PROGRAMS

- Residential Lighting;
- Residential Prescriptive;
- Residential New Construction;
- Home Energy Assessment & Weatherization;
- Income Qualified Weatherization;
- Food Bank - LED Bulb Distribution;
- Energy Efficient Schools;
- Residential Behavioral Savings;
- Appliance Recycling;
- Smart Thermostat Program;
- Conservation Voltage Reduction Residential;
- Smart DLC - Wifi DR/DLC Changeout;
- Bring Your Own Thermostat.

COMMERCIAL & INDUSTRIAL PROGRAMS

- Commercial Prescriptive Rebate;
- Commercial Custom;
- Small Business Direct Install;
- Commercial New Construction;
- Building Tune-Up;
- Multi-Family Retrofit;

- Conservation Voltage Reduction Commercial.

Table RGS-1 below provides the cost-effectiveness test results for each program as well as the portfolio in total. For several programs, the Participant Test could not be calculated since there were no costs to participants for adopting the program. These are represented by "NA" on the table. All of the programs pass the TRC and UCT cost effectiveness Tests, but not the RIM Test. While there are programs that do not pass the RIM Test, this should not be interpreted to mean the programs fail cost-effectiveness. In these cases, one should look to the UCT test as passage of that test reveals whether or not one can expect the long-run revenue requirements for ratepayers would increase or decrease as a result of program implementation.

The table also provides two estimates of the projected cost per kWh saved. The first is on a levelized cost basis, while the second is on a cost per first year kWh basis.

Table RGS-1 – Vectren South 2018-2020 Electric Energy Efficiency Plan – Cost Effectiveness Results

Vectren South 2018-2020 Electric DSM Plan Cost Effectiveness Results									
Residential Programs	**TRC**	**UCT**	**RIM**	**Participant**	**TRC Net Benefits**	**UCT Net Benefits**	**RIM Net Fuel**	**Levelized Cost/kWh**	**First Year Cost/kWh**
Residential Lighting	4.20	6.19	0.86	5.18	$ 11,354,267	$ 12,498,117	1.41	$0.015	$0.116
Residential Prescriptive	1.28	2.68	0.99	1.04	$ 1,113,799	$ 3,153,088	1.39	$0.054	$0.356
Residential New Construction	1.25	2.02	0.79	1.39	$ 98,697	$ 248,511	1.09	$0.059	$0.466
Home Energy Assessment & Weatherization	1.19	1.19	0.48	NA	$ 277,622	$ 277,622	0.66	$0.063	$0.618
Income Qualified Weatherization	1.30	1.30	0.59	NA	$ 752,131	$ 752,131	0.78	$0.077	$0.861
Food Bank - LED Bulb Distribution	8.42	8.42	0.88	NA	$ 2,503,138	$ 2,503,138	1.48	$0.011	$0.125
Energy Efficient Schools	3.28	3.28	0.53	NA	$ 829,622	$ 829,622	0.86	$0.018	$0.157
Residential Behavioral Savings	1.54	1.54	0.50	NA	$ 440,606	$ 440,606	0.72	$0.045	$0.049
Appliance Recycling	1.19	1.02	0.36	NA	$ 83,146	$ 12,513	0.51	$0.051	$0.201
Smart Thermostat Program	7.58	4.49	4.49	NA	$ 1,072,628	$ 960,597	4.49	NA	NA
CVR Residential	1.59	1.59	0.66	NA	$ 580,613	$ 580,613	0.89	$0.065	$0.158
SmartDLC - Wifi DR/DLC Changeout	1.90	1.75	0.92	NA	$ 1,301,580	$ 1,181,234	1.18	$0.103	$1.110
BYOT (Bring Your Own Thermostat)	2.80	1.92	1.92	NA	$ 498,223	$ 370,438	1.92	NA	NA
Residential Programs Total	**2.25**	**2.73**	**0.79**	**4.06**	**$ 20,906,071**	**$ 23,808,228**	**1.16**	**$0.038**	**$0.213**
C&I Programs	**TRC**	**UCT**	**RIM**	**Participant**	**TRC Net Benefits**	**UCT Net Benefits**	**RIM Net Fuel**	**Levelized Cost/kWh**	**First Year Cost/kWh**
Commercial Prescriptive	1.63	3.68	0.51	2.70	$ 2,811,420	$ 5,291,462	0.84	$0.015	$0.146
Commercial Custom	2.05	3.27	0.52	3.59	$ 5,003,931	$ 6,772,616	0.85	$0.018	$0.207
Small Business Direct Install	5.34	2.38	0.53	24.51	$ 6,333,499	$ 4,520,941	0.82	$0.027	$0.296
Commercial New Construction	2.01	1.69	0.45	9.55	$ 652,266	$ 530,199	0.67	$0.033	$0.290
Building Tune-up	1.09	1.13	0.34	9.35	$ 46,816	$ 67,027	0.49	$0.040	$0.261
Multi-Family Retrofit	3.99	2.28	0.53	24.86	$ 167,808	$ 125,751	0.82	$0.028	$0.330
CVR Commercial	1.30	1.30	0.55	NA	$ 219,929	$ 219,929	0.75	$0.067	$0.133
C&I Programs Total	**2.21**	**2.69**	**0.51**	**4.57**	**$ 15,235,668**	**$ 17,527,926**	**0.81**	**$0.022**	**$0.217**
Portfolio Results	**TRC**	**UCT**	**RIM**	**Participant**	**TRC Net Benefits**	**UCT Net Benefits**	**RIM Net Fuel**	**Levelized Cost/kWh**	**First Year Cost/kWh**
Portfolio CVR	1.47	1.47	0.61	NA	$ 800,541	$ 800,541	0.83	$0.066	$0.151
Electric Portfolio Without Performance Incentive	2.05	2.44	0.63	4.31	$ 33,475,259	$ 38,669,674	0.94	$0.032	$0.241
Electric Portfolio including Performance Incentive	1.83	2.15	0.60	4.31	$ 29,763,559	$ 34,957,974	0.90	$0.036	$0.274
Note: Under the Participant Test, NA occurs when there are no participant incremental costs. In those cases, the Participant Test result is effectively infinite.									

Q. What does your analysis show concerning the long-term effect, or potential effect, of the 2018-2020 Plan on the electric rates and bills of customers that participate in Vectren South's energy efficiency programs compared to the electric rates and bills of customers that do not participate in the Company's energy efficiency programs?

A. The long-term effect on rates and bills of participants are demonstrated through the Participant Test, which compares the benefits to the participant through bill savings plus incentives from the utility relative to the incremental costs to the participant for implementing the energy efficiency measure. A score greater than 1 indicates the customer is saving more money than expended, thus reducing the participant's energy bill over the life of the measure. All of the programs included in Vectren South's 2018-2020 Plan have a Participant Test score greater than 1, except for those programs where the Participant Test score could not be calculated because there were no costs to participants for participating in the program. As a result, all participants would benefit from the programs. The long-term effect on rates and bills of non-participants may be considered by the RIM Test, which is also called the non-participant test. It implies that lost revenues would be spread across all the utility's customer sales to enable the utility to cover its costs. If a program's RIM Test has a score lower than 1, it indicates that rates would likely have to increase over time. However, a rate increase in and of itself should not be viewed negatively given that DSM programs create a demand side resource that allows utilities to avoid the cost of a supply side resource, which has its own costs that would increase rates. As I stated earlier, the RIM Test does not tell us whether rates would increase more if the programs were not implemented, which is one reason the value of the RIM Test is limited. This is where the UCT Test provides greater insight on the long-run revenue requirements. A few of the programs in Vectren South's 2018-2020 Plan pass the RIM Test, but generally, programs that target energy efficiency tend to fail the RIM Test.

Q. Given your review of Vectren South's 2018-2020 Plan, the analysis of the goals and cost benefit modeling results, do you believe that the Company's 2018-2020 Plan is cost effective?

A. Yes.

IV. ENERGY EFFICIENCY COST PROJECTION IN VECTREN SOUTH'S 2016 IRP

Q. What is your understanding of EE modeling within the IRP?

A. It is my understanding that under the IURC's proposed Rule 170 IAC 4-7-6(b) and Ind. Code § 8-1-8.5-10 ("Section 10") , it is incumbent for electricity suppliers to provide the IRP process with a set of DSM options that can be incorporated into the development of a resource plan. The IURC's proposed Rule 170 IAC 4-7-6(b) states:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

In addition, under Section 10, whether an electricity supplier's plan is consistent with its IRP is a factor to be considered by the IURC in determining the overall reasonableness of the plan. Taken together, these jointly supportive requirements direct the electricity supplier to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the electricity supplier should be determined through the IRP process.

Q. How much DSM was made available in Vectren South's 2016 IRP?

A. Vectren South chose to make up to 2% of eligible retail sales as DSM resource options available for selection in the IRP process for each year beginning in 2018.

Q. Why was 2% of eligible retail sales as a DSM resource option selected?

A. At one extreme, one could argue that 100% of eligible retail sales of an energy company could be made available for selection as a DSM resource. However, that is not practical as some energy must be consumed in the course of economic activity. At the other extreme, one could argue that no DSM resource options are required as consumers make their own decisions on the tradeoffs between consumption of energy and investment in more efficient technologies. The result of those decisions would already be reflected in the Company's projection of electric loads.

However, there are barriers to the adoption of more efficient energy using technologies that can be overcome through the implementation of targeted energy company energy efficiency programs. Energy efficiency programs, as marketing programs, encourage customers to adopt higher levels of efficiency earlier than would happen naturally, basically advancing the timing of the energy efficiency. Guidance on the appropriate level of energy efficiency to be made available to the IRP process can be obtained from a market potential study. The Company's market potential study[2] found a Technical Potential of 11%, an Economic Potential of 8.2%, an Achievable High Potential of 6.2%, and an Achievable Low Potential of 3.5%. However, this is only for the years 2015 through 2019.

Information on longer-term estimates of market potential may be found in a study conducted by the Electric Power Research Institute (EPRI)[3] and in a meta-study produced by the American Council for an Energy Efficient Economy (ACEEE)[4]. The EPRI study estimated the market potential for the period 2013 through 2035 for the nation as well as selected regions including the Midwest. For the Midwest region, for the full period to the year 2035, the study found a Technical Potential of 23.7%, an Economic Potential of 13.8%, a High Achievable Potential of 11.1%, and an Achievable Potential of 8.9%. For the long-term studies summarized in

2 ELECTRIC DEMAND SIDE MANAGEMENT: MARKET POTENTIAL STUDY AND ACTION PLAN, April 2013 prepared by EnerNOC Utility Solutions Consulting.

3 U.S. Energy Efficiency Potential Through 2035. 1025477 Final Report, April 2014.

4 Max Neubauer. Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies. Report U-1407. August 2014.

the ACEEE report, that were completed post-2011, the average Technical Potential was 30.5%, the average Economic Potential was 22.4%, the Low Achievable Potential was 6.2%, the Medium Achievable Potential was 13.5%, and the Maximum Achievable Potential was 17.7%.

Technical potential is the maximum energy efficiency available, assuming that cost and market adoption of a technology are not a barrier. Economic potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the measure. The achievable potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. Not all customers will adopt a given technology. For example, CFL light bulbs have been cost effective for many years; however, some people choose not to adopt them for aesthetic reasons. Customer preferences can impact the potential that the Company could consider for inclusion in its set of DSM resource options.

However, one must also consider the impact on these market potential estimates from the fact that larger customers may opt-out of participation in Vectren South's energy efficiency programs. As a result of customer opt-outs, 41% of retail sales are not available for consideration in development of DSM resource options. In addition, another adjustment to the available market potential should be taken to capture the level of energy efficiency (EE) impacts expected to be already achieved in the 2013 to 2016 period as represented in Table RGS-2 below.

Table RGS-2 Vectren Historical Energy Efficiency Impacts[5]

Year	Eligible Retail Sales (GWh)	Gross Incremental Savings (GWh) - Less Opt Out Savings	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Incremental DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales Since 2013
2010	5,616.87	2.52	2.52	0.04%	0.04%	
2011	5,594.84	15.78	18.30	0.28%	0.33%	
2012	5,464.75	43.99	62.29	0.81%	1.14%	
2013	5,479.11	59.77	122.06	1.09%	2.23%	1.09%
2014	3,498.69	54.68	176.74	1.56%	5.05%	3.27%
2015	3,223.81	40.51	217.25	1.26%	6.74%	4.81%
Est2016	3,611.51	42.32	259.57	1.17%	7.19%	5.46%

This implies that the market potential estimates should be adjusted down to reflect the portion that has already been achieved. Using a conservative estimate of 5% of the potential already achieved, the remaining Technical Potential is estimated to be in the range of 18.7% to 25.5% (using the EPRI and ACEEE documents as rough guidance).

While some may contend that the full technical potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic. Rather, the potential should reflect some consideration of achievability. This can be estimated by taking the ratio of the achievable percentages to the technical potential percentage and applying that to the remaining estimate of technical potential percentage. This means that a range of 46.8% (11.1%/23.7%) to 58.0% (17.7%/30.5%) of the technical potential would be considered as the remaining High or Maximum Achievable Technical Potential for a range of 8.8% of retail sales (46.8% x 18.7%) to 14.8% (58% x 25.5%) of retail sales.

5 This information was the best available at the time of the preparation of the IRP.

Vectren South chose to make up to 2% of eligible retail sales as DSM resource options available for selection in the IRP process for each year beginning in 2018. This represents almost 40% of eligible retail sales, far above estimates of even technical market potential. The 2% applies to the level of retail sales after reduction for the level of load that has opted out.

Q. Please describe how up to 2% of eligible sales could be selected in the IRP.

A. To facilitate the IRP resource selection process, the 2% of eligible retail sales was broken into 8 blocks of 0.25% each. Taking this over the 18 year horizon means that over 144 incremental blocks of 0.25% each were available to be selected in the IRP process. From this structure, Vectren South expected that the appropriate IRP determined cost-effective level of EE would be identified. This process should provide substantial insight on the cost-effective level of energy efficiency. Table RGS-3 represents the structure and the sizes of the blocks.

Table RGS-3 DSM Resource Options Net of Free Riders

	DSM Resource Options: Blocks Net of Free-Riders									
Year	Eligible GWH Conservation Savings	Percent of Eligible Sales Potential	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016										
2017	3,493									
2018	3,525	2.0%	6,986	6,986	6,986	6,986	6,986	6,986	6,986	6,986
2019	3,545	2.0%	7,050	7,050	7,050	7,050	7,050	7,050	7,050	7,050
2020	3,571	2.0%	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089
2021	3,577	2.0%	7,141	7,141	7,141	7,141	7,141	7,141	7,141	7,141
2022	3,594	2.0%	7,154	7,154	7,154	7,154	7,154	7,154	7,154	7,154
2023	3,613	2.0%	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188
2024	3,640	2.0%	7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227
2025	3,654	2.0%	7,281	7,281	7,281	7,281	7,281	7,281	7,281	7,281
2026	3,672	2.0%	7,309	7,309	7,309	7,309	7,309	7,309	7,309	7,309
2027	3,692	2.0%	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344
2028	3,721	2.0%	7,384	7,384	7,384	7,384	7,384	7,384	7,384	7,384
2029	3,739	2.0%	7,442	7,442	7,442	7,442	7,442	7,442	7,442	7,442
2030	3,755	2.0%	7,477	7,477	7,477	7,477	7,477	7,477	7,477	7,477
2031	3,772	2.0%	7,511	7,511	7,511	7,511	7,511	7,511	7,511	7,511
2032	3,796	2.0%	7,543	7,543	7,543	7,543	7,543	7,543	7,543	7,543
2033	3,810	2.0%	7,592	7,592	7,592	7,592	7,592	7,592	7,592	7,592
2034	3,831	2.0%	7,620	7,620	7,620	7,620	7,620	7,620	7,620	7,620
2035	3,850	2.0%	7,663	7,663	7,663	7,663	7,663	7,663	7,663	7,663
2036	3,876	2.0%	7,701	7,701	7,701	7,701	7,701	7,701	7,701	7,701

Q. Please describe the basis for the EE blocks in the IRP.

A. The component programs for the blocks are assumed to initially be those defined in the 2016-2017 Electric DSM Plan. For the first two years of the IRP planning horizon (2016 and 2017), it was assumed that the current set of programs are being implemented. However, it is expected that the nature of the programs in the blocks may change over time as energy efficiency technology changes.

Q. Please describe whether future utility program energy efficiency impacts were included in the sales and demand forecast.

A. No minimum level of energy efficiency impacts was locked in for the planning process.

Q. Please describe whether the DSM resource options were net of free riders?

A. The table above provides 0.25% blocks of net impacts which already reflects a 20% adjustment for free riders. Free riders represent those participants that would have implemented the energy efficiency technology without the Company's programs.

Q. How does one project the cost of Vectren South's DSM resource options over a 20-year horizon with increasing market penetration?

A. That is the fundamental question. Projecting the cost of the Company's DSM programs that could be expected to achieve a 40% level of energy efficiency (EE) over a long period represents a significant challenge. Will costs per kWh rise, fall, or stay the same as the market penetration of EE rises from the current (2013 to 2016 cumulative) level of at least 5% to 45% of eligible retail sales (incremental 40%)? The energy efficiency literature does not provide adequate guidance.

The cost of Vectren South's 2016 energy efficiency programs was used as a starting point for 2016 DSM resource options. The Company's EE portfolio implemented in 2016 was designed to achieve approximately 36,000 MWh impacts on a net of free-rider basis at a cost of $0.20 per first year kWh[6] ($.03322 per kWh on a levelized basis). On a net of free-rider basis, the 2016

6 This value is estimated using the total cost of the program and dividing by the first year of EE savings.

plan is designed to achieve an additional 1% of available retail sales.

In an effort to allow the IRP model to inform Vectren South on the cost-effective level of EE to pursue in the resource plan, the Company has provided the IRP model with the ability to select from 8 blocks of EE impacts each year where each block represents 0.25% of eligible retail sales. This represents a possible additional 2% of available retail sales that could be selected each year from 2018 through 2036. On a cumulative basis, this means that almost 40% of available retail sales could be selected by the IRP process. In order to identify the cost-effective level of EE in the IRP process, it is imperative that estimates of the cost of EE achievement be developed that reflect how the costs could change as EE market penetration increases.

Based upon my research into this issue, I provided Vectren South with a methodology to estimate how the cost to achieve an increment of EE could change as the cumulative EE market penetration rises. My research examined the relationship between spending on EE programs and the level of first year impacts achieved through the implementation of EE programs as well as the cumulative level of EE impacts. The research relies upon EE cost and impact data collected through Form 861 by the Energy Information Administration (EIA). A copy of the research study is provided in Petitioner's Exhibit No. 2, Attachment RGS-2.

Q. What were the findings from your research study?

A. The study found that EE program costs per kWh increase as the cumulative penetration of EE increases, as measured by the percent of retail sales. The primary focus of the research was to examine if and to what extent the program cost of EE changes as the available supply (i.e., retail sales) of EE is consumed through implementation of EE programs. Based upon this research and Vectren South's projected level of EE available for selection by the IRP process, I developed a projected rate of growth in the cost of EE for the first four EE blocks which cumulatively represent 1% of eligible retail sales each year. This growth rate was applied to each of the first four 0.25% blocks.

The growth rate was developed from two separate econometric models of the EIA data as described in the attached study. The results from the two models were averaged to produce a growth rate in cost of 4.12% per 1% of eligible retail sales achievement or 1.04% per 0.25% EE block.

With this first 1% of eligible retail sales, Vectren South is planning to achieve an amount of energy efficiency that exceeds an expected high or maximum achievable level over the next 20 years. As a result, it is assumed that the second 1% of eligible retail sales must occur at a higher marketing cost than the first 1% of eligible retail sales. In other words, the methodology is that for the first 1%, for the full planning period, Vectren South is achieving actually more than what it should reasonably expect to achieve in the market place. The effort being undertaken is as if Vectren South were achieving the full 1% for 20 years or 20% of the market at a base level of cost. To get the next 1%, one has to step up to a higher marketing cost that assumes the first 1% has already been achieved. The next 1% is incremental to the first 1%. It is assumed that Vectren South will have to dramatically expand its marketing effort to essentially double the annual impact achievement. This would involve expanded advertising and possibly in person contact to get customers to take action. Essentially the second 1% has to be more expensive, not cheaper, than the first 1%.

As a result, the starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. Then, a different growth rate is applied for the remaining set of four 0.25% blocks available each, or the next 1% of eligible retail sales available for selection. The process of computing the applicable growth rate was similar to that of the first 1%. This resulted in a growth rate of 1.72% per additional 1% of eligible retail sales impacts or 0.43% per 0.25% block. So, this assumes that once the first four blocks have been selected in a year by the IRP, the cost increases first to the cost of the last block of the 1% of eligible retail sales and then by 0.43% per 0.25% block for the 5th to 8^{th} blocks. These growth rates form the basis for projecting how the block costs change for all of the blocks available for selection by the IRP process. The lower growth rate was applied to the second 1% of eligible retail sales (blocks 5 to 8) to allow for economy of operation within a given year, while the higher growth rate was applied to the first 1% of eligible retail sales to try to capture the impact on cost over time. Table RGS-4 provides the estimated levelized costs used for all of the blocks.

Table RGS-4 Costs per Saved kWh

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03356	$0.03391	$0.03426	$0.07811	$0.07844	$0.07878	$0.07911
2017	$0.03462	$0.03498	$0.03534	$0.03570	$0.07945	$0.07979	$0.08013	$0.08048
2018	$0.03607	$0.03645	$0.03682	$0.03721	$0.08082	$0.08117	$0.08151	$0.08186
2019	$0.03759	$0.03798	$0.03837	$0.03877	$0.08221	$0.08256	$0.08292	$0.08327
2020	$0.03917	$0.03958	$0.03999	$0.04040	$0.08363	$0.08398	$0.08434	$0.08470
2021	$0.04082	$0.04124	$0.04167	$0.04210	$0.08507	$0.08543	$0.08579	$0.08616
2022	$0.04254	$0.04298	$0.04342	$0.04387	$0.08653	$0.08690	$0.08727	$0.08764
2023	$0.04433	$0.04478	$0.04525	$0.04572	$0.08802	$0.08840	$0.08877	$0.08915
2024	$0.04619	$0.04667	$0.04715	$0.04764	$0.08953	$0.08992	$0.09030	$0.09069
2025	$0.04813	$0.04863	$0.04914	$0.04964	$0.09108	$0.09146	$0.09186	$0.09225
2026	$0.05016	$0.05068	$0.05120	$0.05173	$0.09264	$0.09304	$0.09344	$0.09384
2027	$0.05227	$0.05281	$0.05336	$0.05391	$0.09424	$0.09464	$0.09504	$0.09545
2028	$0.05447	$0.05503	$0.05560	$0.05618	$0.09586	$0.09627	$0.09668	$0.09709
2029	$0.05676	$0.05734	$0.05794	$0.05854	$0.09751	$0.09793	$0.09834	$0.09876
2030	$0.05914	$0.05976	$0.06038	$0.06100	$0.09919	$0.09961	$0.10004	$0.10046
2031	$0.06163	$0.06227	$0.06292	$0.06357	$0.10089	$0.10133	$0.10176	$0.10219
2032	$0.06422	$0.06489	$0.06556	$0.06624	$0.10263	$0.10307	$0.10351	$0.10395
2033	$0.06693	$0.06762	$0.06832	$0.06903	$0.10440	$0.10484	$0.10529	$0.10574
2034	$0.06974	$0.07046	$0.07119	$0.07193	$0.10619	$0.10665	$0.10710	$0.10756
2035	$0.07268	$0.07343	$0.07419	$0.07496	$0.10802	$0.10848	$0.10895	$0.10941
2036	$0.07573	$0.07652	$0.07731	$0.07811	$0.10988	$0.11035	$0.11082	$0.11130

Q. **Given your previous comments on the lack of guidance in the literature into this issue, have you developed alternate views on the projection of costs for use in the IRP analytical process?**

A. Yes, one should recognize that there is uncertainty associated with any forecast, including a forecast of the cost to implement energy efficiency programs. The previous discussion provided the Base Case projection of DSM resource costs. However, DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20 year implementation period, alternate views of the costs should be examined in the context of the scenario analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections.

To that end, high and low DSM resource cost trajectories were developed using the estimated standard errors of the model coefficients used in the development of the Base Case cost projection. These high and low cost trajectories were created by applying plus and minus one standard error to the model coefficients.[7] This produced alternate DSM resource cost growth rates summarized in Table RGS-5 below.

Table RGS-5 DSM Resource Cost Growth Rates

Sets of Four Blocks	Minus One Standard Deviation	Base Case	Plus One Standard Deviation
First 1%	0.85%	1.04%	1.22%
Second 1%	0.35%	0.43%	0.51%

These alternate growth rates were used to produce the following high, Table RGS-6, and low, Table RGS-7, tables of projected DSM resource costs.

7 Using the model coefficients and standard errors from the two econometric models referenced in my research, the coefficient range is developed by adding the standard error to or subtracting it from the coefficient estimate. For the first model, the coefficient is .278 with a standard error of .084. For the second model, the coefficient is .897 with a standard error of .131.

Table RGS-6 High Case Cost per kWh: Plus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03363	$0.03404	$0.03445	$0.09095	$0.09141	$0.09187	$0.09233
2017	$0.03487	$0.03530	$0.03573	$0.03617	$0.09280	$0.09327	$0.09374	$0.09421
2018	$0.03661	$0.03705	$0.03751	$0.03796	$0.09469	$0.09517	$0.09565	$0.09613
2019	$0.03843	$0.03890	$0.03937	$0.03985	$0.09662	$0.09710	$0.09759	$0.09809
2020	$0.04034	$0.04083	$0.04133	$0.04183	$0.09858	$0.09908	$0.09958	$0.10008
2021	$0.04234	$0.04286	$0.04338	$0.04391	$0.10059	$0.10110	$0.10161	$0.10212
2022	$0.04445	$0.04499	$0.04554	$0.04610	$0.10264	$0.10316	$0.10368	$0.10420
2023	$0.04666	$0.04723	$0.04781	$0.04839	$0.10473	$0.10526	$0.10579	$0.10632
2024	$0.04898	$0.04958	$0.05018	$0.05080	$0.10686	$0.10740	$0.10794	$0.10849
2025	$0.05142	$0.05205	$0.05268	$0.05332	$0.10904	$0.10959	$0.11014	$0.11070
2026	$0.05397	$0.05463	$0.05530	$0.05598	$0.11126	$0.11182	$0.11238	$0.11295
2027	$0.05666	$0.05735	$0.05805	$0.05876	$0.11352	$0.11409	$0.11467	$0.11525
2028	$0.05948	$0.06020	$0.06094	$0.06168	$0.11583	$0.11642	$0.11700	$0.11760
2029	$0.06243	$0.06320	$0.06397	$0.06475	$0.11819	$0.11879	$0.11939	$0.11999
2030	$0.06554	$0.06634	$0.06715	$0.06797	$0.12060	$0.12121	$0.12182	$0.12243
2031	$0.06880	$0.06964	$0.07049	$0.07135	$0.12305	$0.12367	$0.12430	$0.12493
2032	$0.07222	$0.07310	$0.07400	$0.07490	$0.12556	$0.12619	$0.12683	$0.12747
2033	$0.07581	$0.07674	$0.07768	$0.07862	$0.12811	$0.12876	$0.12941	$0.13006
2034	$0.07958	$0.08055	$0.08154	$0.08253	$0.13072	$0.13138	$0.13205	$0.13271
2035	$0.08354	$0.08456	$0.08559	$0.08664	$0.13338	$0.13406	$0.13473	$0.13541
2036	$0.08770	$0.08877	$0.08985	$0.09095	$0.13610	$0.13679	$0.13748	$0.13817

Table RGS-7 Low Case Cost Per kWh: Minus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03350	$0.03379	$0.03407	$0.06700	$0.06723	$0.06747	$0.06770
2017	$0.03436	$0.03465	$0.03495	$0.03524	$0.06794	$0.06818	$0.06841	$0.06865
2018	$0.03554	$0.03585	$0.03615	$0.03646	$0.06889	$0.06913	$0.06938	$0.06962
2019	$0.03677	$0.03708	$0.03739	$0.03771	$0.06986	$0.07011	$0.07035	$0.07060
2020	$0.03803	$0.03835	$0.03868	$0.03901	$0.07084	$0.07109	$0.07134	$0.07159
2021	$0.03934	$0.03967	$0.04001	$0.04035	$0.07184	$0.07209	$0.07234	$0.07260
2022	$0.04069	$0.04104	$0.04138	$0.04174	$0.07285	$0.07311	$0.07336	$0.07362
2023	$0.04209	$0.04245	$0.04281	$0.04317	$0.07388	$0.07413	$0.07439	$0.07465
2024	$0.04354	$0.04391	$0.04428	$0.04465	$0.07491	$0.07518	$0.07544	$0.07570
2025	$0.04503	$0.04542	$0.04580	$0.04619	$0.07597	$0.07623	$0.07650	$0.07677
2026	$0.04658	$0.04698	$0.04738	$0.04778	$0.07704	$0.07731	$0.07758	$0.07785
2027	$0.04818	$0.04859	$0.04901	$0.04942	$0.07812	$0.07839	$0.07867	$0.07894
2028	$0.04984	$0.05026	$0.05069	$0.05112	$0.07922	$0.07950	$0.07977	$0.08005
2029	$0.05155	$0.05199	$0.05243	$0.05288	$0.08033	$0.08061	$0.08089	$0.08118
2030	$0.05333	$0.05378	$0.05424	$0.05470	$0.08146	$0.08175	$0.08203	$0.08232
2031	$0.05516	$0.05563	$0.05610	$0.05658	$0.08261	$0.08290	$0.08319	$0.08348
2032	$0.05706	$0.05754	$0.05803	$0.05852	$0.08377	$0.08406	$0.08436	$0.08465
2033	$0.05902	$0.05952	$0.06003	$0.06053	$0.08495	$0.08524	$0.08554	$0.08584
2034	$0.06105	$0.06157	$0.06209	$0.06262	$0.08614	$0.08644	$0.08675	$0.08705
2035	$0.06315	$0.06368	$0.06422	$0.06477	$0.08735	$0.08766	$0.08796	$0.08827
2036	$0.06532	$0.06587	$0.06643	$0.06700	$0.08858	$0.08889	$0.08920	$0.08951

These high and low cost projections were used in the scenario analyses in the development of the IRP resource plan as covered in the testimony of Petitioner's witness Matthew E. Lind.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

VERIFICATION

I, Richard G. Stevie, Vice President, Integral Analytics, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Richard G. Stevie

Date: April 4, 2017

BENEFIT/COST TEST MATRIX

BENEFIT/COST TEST MATRIX

Benefits:	Participant Test	Utility Test	Ratepayer Impact Test	Total Resource Cost Test
1. Customer Electric Bill Decrease	X			
2. Customer Non-electric Bill Decrease	X			
3. Customer O&M and Other Cost Decrease	X			X
4. Customer Income Tax Decrease	X			X
5. Customer Investment Decrease	X			X
6. Customer Rebates Received	X			
7. Utility Revenue Increase			X	
8. Utility Electric Production Cost Decrease		X	X	X
9. Utility Generation Capacity Credit		X	X	X
10. Utility Transmission Capacity Credit		X	X	X
11. Utility Distribution Capacity Credit		X	X	X
12. Utility Administrative Cost Decrease		X	X	X
13, Utility Cap. Administrative Cost Decrease		X	X	X
14. Non-electric Acquisition Cost Decrease				X
15. Utility Sales Tax Cost Decrease		X	X	X
Costs:				
16. Customer Electric Bill Increase	X			
17. Customer Non-electric Bill Increase	X			X
18. Customer O&M and Other Cost Increase	X			X
19. Customer Income Tax Increase	X			X
20. Customer Capital Investment Increase	X			X
21. Utility Revenue Decrease			X	
22. Utility Electric Production Cost Increase		X	X	X
23. Utility Generation Capacity Debit		X	X	X
24. Utility Transmission Capacity Debit		X	X	X
25. Utility Distribution Capacity Debit		X	X	X
26. Utility Rebates Paid		X	X	
27. Utility Administrative Cost Increase		X	X	X
28. Utility Cap. Administrative Cost Increase		X	X	X
29. Non-electric Acquisition Cost Increase				X
30. Utility Sales Tax Cost Increase		X	X	X

Energy Efficiency Program Costs, Program Size, and Market Penetration

By

Richard Stevie[1]

1. Introduction

Utility sponsored[2] energy efficiency programs have been implemented in varying degrees for over 20 years across numerous customer segments. Demand response programs, however, have been around for decades beginning with interruptible or off-peak type rate offerings that existed in the 1940's and expanded to include cycling of end-use equipment and more sophisticated dynamic pricing structures.

Besides the fact that the implementation of energy efficiency and demand response programs involves significant complexity in marketing, communication, and cost-effectiveness analysis, information on the costs to implement are very difficult to unravel due to the multi-year life of measures in the portfolio of programs. The major source of historical data on costs and impacts is the Energy Information Administration (EIA) which is part of the Department of Energy. Using Form 861, the EIA has been collecting cost and load impact data, among other items, for energy efficiency and demand response efforts for all utility service areas in the United States since 1990.

This paper focuses only on the costs and load impacts associated with implementation of energy efficiency (EE) programs. Investigation of demand response costs is reserved for future

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[2] For purposes here, utility sponsored includes programs implemented by third parties, including third party administration efforts.

study. The energy efficiency cost and impact information available on the EIA web site includes current year direct program spending, indirect spending (e.g., administrative costs not directly associated with a program), current year energy efficiency MWH and MW impacts, as well as cumulative MWH and MW impacts for each utility service area for the period over which the EIA has been collecting the data[3]. However, the cost and impact data represent totals for the portfolio of energy efficiency programs. Values at the individual program level are not available from the EIA data. For the year 2012, the EIA data on direct plus incentive expenditures for the 50 states plus District of Columbia totaled $4.4 billion. Through this level of spending, the current year retail energy impacts were 21,478,470 MWH which results in a first year[4] cost of $0.205 per kWh. Furthermore, the cumulative[5] EE load impacts reported total 138,524,613 MWH. These on-going cumulative impacts represent the sum of the historical impacts achieved by the programs as reported to EIA.

The issue here is the cost. The value of $.205/kWh represents the total program spending per kWh in one year to gain a stream of kWh savings over the life of the installed measures. If one knew the life of the measures being implemented as well as the relevant discount rate, one could calculate a levelized cost in order to compute a levelized cost per kWh, a commonly used metric for comparing costs across supply-side and demand-side options. For example, for the $0.205/KWh first year costs cited above, if the discount rate were 8% and the measure life averaged to five years, the levelized cost per kWh converts to 5.1 cents/kWh.

To benchmark current costs and project future costs, there are three issues with this analysis. One, the discount rate and relevant measure life are unknown. Changes to either or both

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[3] EIA stated in the past that the cumulative impacts should represent total impacts since 1992. However, this may change in the future as the EIA has indicated it wants to incorporate measure life into these load impact estimates.
[4] First year cost is defined as the total program spending divided by the load impacts achieved in the first year of program implementation.
[5] For clarity, cumulative load impacts, defined as Annual by the EIA, represents the sum of the incremental load impacts.

significantly impact the resulting cost estimate. Two, the number represents an average. The cost for a specific program can vary substantially from this average estimate. And three, the level of historical penetration of EE in any one utility service area can be quite different from the average. In some utility service areas, the cumulative impacts can be large, exceeding 10% of retail sales. In other service areas, the cumulative impacts have been minor, less than 1%. Using an average cost estimate from the EIA data ignores all of the utility specific details that could affect cost. This raises a critical question. As the cumulative market penetration of EE rises, does the cost to achieve further incremental energy efficiency impacts rise or fall or stay the same? One typically expects the marketing cost to attract the early adopters to be somewhat elevated due to the cost of the startup. Then, as the program size expands, there can be some marketing economies of scale driving down the unit cost. But, as the cumulative market penetration rises, the marketing cost per unit to attract additional interest could be expected to rise.

This paper takes a new look at the EIA data in an effort to glean how the level of market penetration could affect unit implementation costs. By examining how the cost of implementing EE programs changes across the states, one can begin to gain insight on the incremental cost of EE through analysis of areas where the market penetration is low versus where it is high.

The following sections provide:

- Brief review of past studies of energy efficiency that reported implementation costs,
- Discussion of the modeling approach,
- Review of issues related to the use of the EIA data,
- Presentation of the modeling results, and
- Summary of the results along with comments on applicability and implications for future research.

2. Past Studies

A large volume of literature has been devoted to studies on energy efficiency and the costs associated with program implementation. Study categories include those that summarize costs and impacts based on other reports (meta-studies) and those that conduct a bottom-up analysis of end-use efficiency. The studies provide estimates of the market potential and the levelized cost to implement energy efficiency. The levelized cost estimates represent an average expected cost for implementing a program or measure or portfolio of programs.

Generally, the focus of these studies has been on market size and cost in a macro perspective, though a few examine the costs associated with individual programs or measures. As the spending on energy efficiency escalates due to energy efficiency portfolio standards (EERS) or potentially new EPA rules[6] requiring energy efficiency impacts of 1.5% of retail sales each year, the cost-effectiveness of energy efficiency programs and measures could change as the market penetration of energy efficiency increases. The research to-date has not provided any insight or guidance on this issue.

The American Council for an Energy Efficient Economy (ACEEE) has produced numerous reports, studies, and meta-studies on energy efficiency market size and cost-effectiveness[7]. The ACEEE reports tend to focus on the estimates of program costs per kWh. In addition to estimating the size of the potential, ACEEE compiled information on unit cost estimates from reports by state utility commissions as well as individual utility reports. While these reports provide a significant

[6] See Section 111d on energy efficiency in the U.S. EPA's GHG Abatement Measures in Docket ID No. EPA-HQ-OAR-2013-0602.
[7] See Chittum (2011), Eldridge et. al. (2010), Elliott et. al. (2007), Friedrich et.al. (2009), Kushler (2004), Laitner et. al. (2012), Nadel and Herndon (2014), Neubauer et. al. (2009), Neubauer and Neal (2012), Neubauer and Elliott et. al. (2009), Shipley and Elliott (2006), and Takahashi and Nichols (2008).

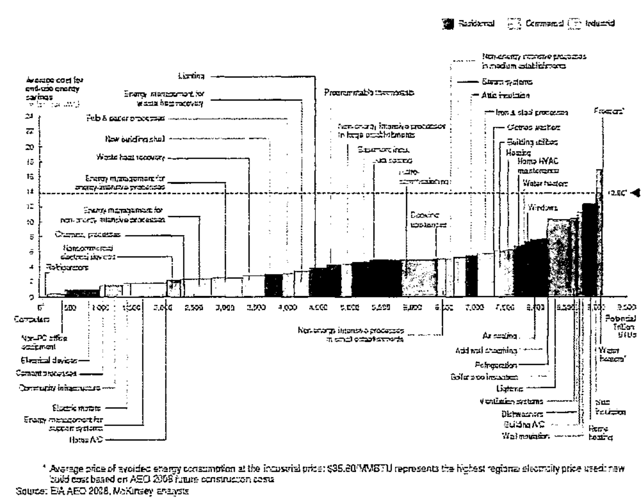
volume of cost related information, none of the reports investigate or estimate how the unit costs might vary as the cumulative market penetration increases.

The Electric Power Research Institute investigated the market potential for EE in two relatively recent reports[8]. These reports also examined program cost-effectiveness as well as market size. But again, neither of these reports provided insight on how the unit costs might vary as the cumulative market penetration increases.

McKinsey & Company also produced a report[9] on EE potential in 2009. In addition to providing estimates of market potential, McKinsey presented a graphical view of the EE supply curve as shown in Figure 1. The chart cleverly combines energy efficiency market potential for each end-use with the average annualized cost to implement the efficiency improvement on a dollars per MMBTU basis. The width of the bars represents the market potential while the height depicts the unit costs.

Figure 1

Exhibit D: U.S. energy efficiency supply curve – 2020



[8] See Electric Power Research Institute (2014) and Rohrmund et. al. (2008).
[9] See McKinsey & Company (2007) and (2009). See the Executive Summary page 6.

While the chart demonstrates that unit costs will increase as the market potential for the portfolio of programs is achieved, the report does not provide guidance on how the costs vary as the cumulative market penetration changes for each measure.

Several other studies[10] presented estimates of the market potential and/or the unit costs for energy efficiency. However, these studies also do not examine how the unit costs may change as the cumulative market penetration increases.

Four additional studies investigated the presence of economies of scale in the implementation of energy efficiency programs[11]. Two of these[12] essentially relied on the same research results. Both studies reported declines in the unit costs with increases in incremental first year energy saving (as measured by percent of retail sales). However, neither study considered the impact of cumulative market penetration in unit costs. A very recent report[13] published by Lawrence-Berkeley National Laboratory that found a slight decline in the levelized unit cost curve as participation increases for a specific program, appliance recycling. However, the report indicates that this relationship was not statistically significant for any other program studied. While the study claims that cost efficiency exists for this one program, the report does not indicate whether the unit cost estimates could have been influenced by the size of the different markets or whether or not unit costs decline as cumulative market penetration increases.

The fourth study[14] is the first identified to pose the question as to the existence of increasing returns to scale with diminishing marginal returns. In other words, the researchers contend that the unit costs of implementing energy efficiency programs will decline with increases

[10] See Barbose et. al. (2009), Brown et. al. (2010), Cappers and Goldman (2009), Chandler and Brown (2009), Energy Center of Wisconsin (2009), Forefront Economics et. al. (2012), Forefront Economics and H. Gil Peach and Associates (2012), GDS Associates (2006), GDS Associates (2007), Itron, Inc. et. al. (2006), La Capra Associates, Inc. et. al. (2006), McKinsey & Company (2007), Nadel and Herndon (2014), Midwest Energy Alliance (2006), Western Governors' Association (2006), Wilson (2009), and U.S. Department of Energy (2007).
[11] See Billingsley et. al. (2014), Hurley et. al. (2008), Plunkett et. al. (2012), and Takahashi and Nichols (2008).
[12] See reference number Hurley et. al. (2008) and Takahashi and Nichols (2008).
[13] See Billingsley et. al. (2014).
[14] See Plunkett et. al. (2012).

in scale (measured by percent of retail sales), but at some point unit costs for the first year savings will increase due to diminishing returns. The researchers arrive at this conclusion based on an econometric analysis that suffers from over-fitting of the data and an application that leads to a bias in the coefficients[15]. Further, this research only examined unit costs associated with incremental first year savings, not cumulative market penetration. While one of the first studies, if not the first, to pose the right questions, the research falls short of providing any enlightenment on the impact of cumulative market penetration on unit costs.

Finally, one study by Cicchetti[16] conducted extensive analysis on the unit cost of energy efficiency. Using the data compiled by the EIA, Cicchetti computed costs on a first year as well as a levelized basis. Cicchetti conducted an extensive analysis of the costs, however, again there is no insight provided on the impact of market penetration on costs.

In summary, this review of past studies on the costs of energy efficiency reveals that a significant void exists in our understanding of how the implementation costs of energy efficiency are affected by the level of market penetration. Assume for a moment that the cost-effective economic market potential for a utility service area is 20% of retail sales and that the levelized unit cost is assumed to be 5 cents/kWh. Then, the unanswered question is whether or not the 5 cents/kWh cost remains constant as the achieved percent of market potential rises from 10% (of the 20% economic potential) to 50% to 100% (see Figure 2). Can one reasonably assume that the cost to acquire the first 10% of market potential is the same as the cost to acquire the last 10% percent of the market? Or, does the unit cost become higher or lower as the portion of the market potential achieved increases?

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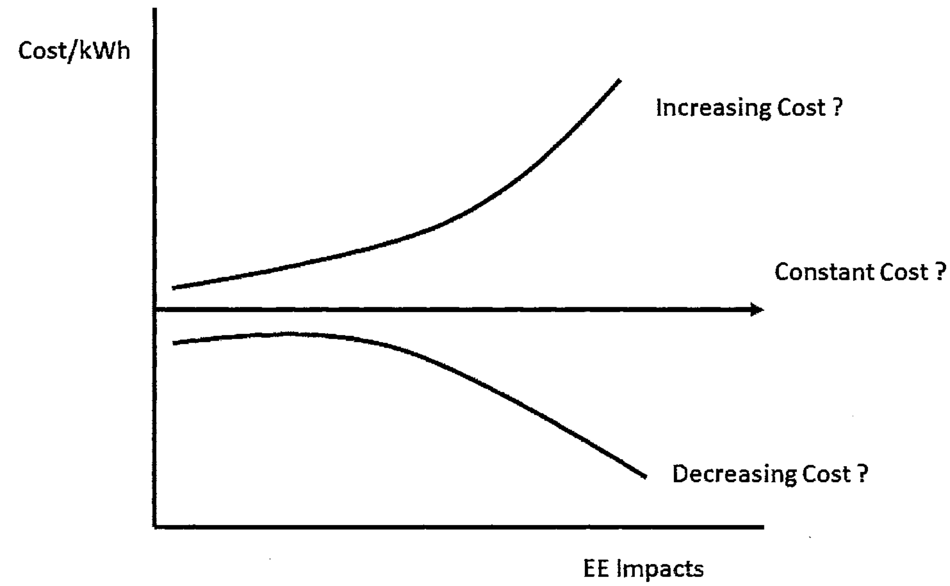
[15] The researchers apparently tried multiple mathematical forms until they found the one with the best fit. In addition, besides using a model with specification issues, the researchers boosted the fit of the model by dropping the intercept term, an arbitrary approach that produces biases in coefficients.
[16] See Cicchetti (2009).

Figure 2



The following sections of this study will provide an initial attempt to shed light on this issue.

3. General Model Discussion

The cost of energy efficiency implementation depends significantly on the type of program or measure being implemented. The typical cost components include project administration, marketing, financial incentives paid to customers or marketing channels, and evaluation, measurement and verification. Indirect / overhead costs are not included in this list. Inclusion of indirect items could add another 30% to the total program costs[17].

The key drivers of annual cost are the number of measures or participants (program size) in a given year, which affects the volume of incentive payments and level of marketing. In other words, program size and marketing represent the key factors that influence the level of spending in a given year. Marketing costs will vary by type of program. Some programs can be implemented through direct marketing (e.g., mail, email, door-to-door) while others through marketing channels

[17] The program costs do not include incremental participant costs because the focus here is on the program administration costs which represent the costs recovered from ratepayers.

such as equipment distributors as well as retail suppliers. The issue under investigation here is whether or not the level of marketing and hence program cost is affected by the program size and how much of the market has already been reached. With regard to program size, marketing economies of scale could develop as the current period level of effort rises. However, there is a limit to the program size due to measure life of the end-use. For example, if a heat pump has a 20 year life, not all of the heat-pumps in a utility's service area become available for replacement at a given point in time. Instead, in this example, one can expect that 5% (1/20) of the heat pumps will be replaced each year. While there may be marketing cost efficiency gains in a given year, there is a natural limit based on the available equipment turnover[18]. In addition, as market penetration increases, energy efficiency implementation costs are expected to rise at higher levels of penetration of the market. The degree of impacts on program costs, from these factors, is a question to be empirically analyzed.

In addition to historical market penetration, other drivers that could potentially affect the level of program costs are the level of electric rates and the health of the economy. Regarding customer electric rates, the issue to be investigated here is the whether or not higher electric rates make it easier to market energy efficiency measures. With higher electric rates, the customer bill savings would be greater, thus reducing the payback period and making the investment in energy efficiency more cost-effective for the participating customer. With respect to the health of the economy, many economic measures could be used. The issue at question is whether or not it is tougher to market energy efficiency when the economy is under stress, e.g., during a recession or its aftermath. Since the Great Recession ended in 2009, economic growth has been lackluster and unemployment levels have remained elevated. One could contend that higher unemployment rates make it harder to market energy efficiency because energy consumers do not have the spare

[18] The volume of replacements in this example could exceed 5% if the incentives encourage customers to perform early replacement before the end of the useful life. However, these situations are not the typical expectation.

funds to invest in more efficient equipment. Conversely, one could contend that marketing energy efficiency is easier because energy consumers need to find ways to cut costs. Evidence of a relationship between program costs and electric rates and/or economic health can be explored empirically.

4. General Model Development

Assuming that energy efficiency program costs are affected by program size, historical market penetration, electric rates, and health of the economy, then a model can be specified as follows:

$$Program\ Cost = f(Market\ Size, Market\ Penetration, Electric\ Rate, Economic\ Health) \quad (1)$$

To assess the impact of these factors on program cost first requires obtaining data that can facilitate the analysis. As previously mentioned, the EIA has been collecting aggregate data for each utility jurisdiction on the impacts and costs associated with implementing energy efficiency. A discussion of the data as well as its limitations will be provided in the next section. However, the model variables need further specification for clarity prior to the actual data collection.

To compile a dataset for analysis, the definition of the variables is critical. For purposes of analysis, given the types of data available from the EIA data base, the following variable definitions will be employed:

Dependent variable:

Program cost includes the level of direct program spending (dollars) on energy efficiency programs only. Indirect costs are not included.

Independent variables:

Program size refers to the current year achievement of energy impacts as a percent of current year retail kWh sales. As program size increases, one expects the cost to increase, though it may not be an equal proportional increase due to the potential for marketing efficiencies. For example, the current year market size achieved may be 1% of retail sales in one geographic area, but in another geographic area it may be 2% of retail sales. By studying the relative impact on program spending across multiple areas with different levels of achievement, one can begin to understand how costs change as the size of the program increases.

Market penetration represents the cumulative achievement of energy efficiency sales as a percent of retail kWh sales. For this variable, as the market penetration increases and the available market potential begins to be depleted, the cost to reach deeper into the market potential may increase due to the higher cost to acquire participants who may find that the energy efficiency program offers are less interesting or compelling relative to other demands on their time and financial resources. An analysis of program spending between areas with lower market penetration versus higher market penetration may provide insights on how costs change relative to changes in market penetration.

Electric rate reflects the cost of power ($/kWh) to customers in an area. The electric rate drives the level of bill savings from implementation of the energy efficiency measures. The higher the electric rate, the easier it is for a participant to cost-justify investment in energy efficiency because the bill savings generated by the energy efficiency are greater. In this situation, higher electric rates should make it easier and less costly to market the energy efficiency programs. Including a measure of the average cost of electricity in a region should aid in understanding whether or not electric rates impact energy efficiency marketing.

Health of the economy, the final independent variable under consideration here, can be measured in a number of different ways. For example, the rates of growth in employment, per capita disposable income, or gross national product are all reasonable candidates. At the same time, the unemployment rate provides a good measure of overall economic health that is contemporaneous and reflects the state of consumer well-being as well as business confidence. The interesting issue is whether or not a higher unemployment rate indicates greater difficulty funding energy efficiency or lower difficulty. On the surface, higher unemployment rates would seem to imply that consumers have less cash to invest in energy efficiency, thus potentially raising marketing costs. Conversely, it could also mean that there is more demand for energy efficiency as a way to reduce operating costs. Analysis of this factor should also improve understanding of the drivers of program costs.

In general form, Equation 1 can be re-written as an econometric model as follows:

$$PC = \alpha + \beta 1 \cdot CPR + \beta 2 \cdot CPT + \beta 3 \cdot EP + \beta 4 \cdot UR + \varepsilon \tag{2}$$

where:

PC	=	Program cost or spending
CPR	=	Current kWh impacts as a percent of retail sales
CPT	=	Cumulative kWh impacts as a percent of retail sales
EP	=	Average retail price of electricity adjusted for inflation (real dollars)
UR	=	National unemployment rate
ε	=	Error term

This represents the general form of the econometric model to be developed. It is expected, on an a priori basis, that the signs of the coefficients should be: $\beta 1 > 0$; $\beta 2 > 0$; $\beta 3 < 0$; and $\beta 4 > or < 0$.

The data for the model development will come from the EIA data base as well as national data on the unemployment rate and inflation.

5. Model Data

The Energy Information Administration's (EIA) Form 861 has been utilized to collect a wealth of information on energy efficiency and demand response program spending and load impacts. The EIA data for the years 1990 through 2012 may be found on the EIA website. It contains information on a number of items for each utility service area including the following:

- Direct spending on energy efficiency programs
- Direct spending on load management (demand response or demand side management (DSM)) programs
- Indirect program spending – costs not directly related to a specific program
- Incremental energy efficiency MWH and MW – current year annualized load impacts
- Annual energy efficiency MWH and MW – cumulative load impacts
- Incremental demand response MWH and MW – current year annualized load impacts
- Annual actual demand response MWH and MW – cumulative load impacts
- Incremental potential[19] demand response MWH and MW – cumulative load impacts
- Annual potential demand response MWH and MW – cumulative load impacts
- Information is also available on retail revenues and MWH sold to ultimate customers for each utility service area[20]

[19] Potential impacts reflect the expected load reductions under normal extreme weather conditions as opposed to the actual reductions achieved given the actual weather conditions.
[20] Revenues and sales for utility service areas in deregulated markets require careful handling to ensure a complete picture of revenues and sales.

- Information is also available on state level retail revenues and MWH sold to ultimate customers on EIA Form 826

Data on national inflation and unemployment may be found from numerous sources[21].

Unfortunately, the data collected through the use of EIA Form 861 has several limitations. These limitations include lack of information on the life of the measures in the portfolio of programs, consistency in reporting over time, consistency in treating effects such as free-riders, consistency in reporting program costs versus indirect costs, and impacts due to changes over time in the structure and instructions associated with Form EIA 861.

With respect to measure life, Form EIA 861 seeks data on current year annualized incremental impacts. However, the life expectancy of those impacts is unknown. Impacts from some measures could last 20 years while other associated with behavioral type programs might last just one year and require constant reinforcement to maintain the impacts. For this reason, the analysis conducted here looks at total annual spending relative to the first year impacts. Trying to compute a levelized cost requires knowledge that is just not available. While one might intuit an expected measure life for a portfolio, it is only a guess and could lead to misleading conclusions. In reviewing the EIA data, it is apparent that the reporting is not consistent. For example, kWh could be reported instead of MWH or dollars instead of thousands of dollars as specified in the instructions to the form. For this reason, this study will focus on the last three years of data for the years 2010 through 2012. Use of the most recent data should provide the best quality of data from the data base.

Regarding cost data, it is unclear what could be included in indirect costs. The categorization of costs across utility service areas will certainly be different, especially with respect

[21] See the website Freelunch.com sponsored by Moody's Analytics for general macroeconomic data including inflation and unemployment.

to treatment of overheads and utility financial incentives. For purposes of this study, only the direct program costs including incentive payments to participants will be considered in the analysis. Finally, to facilitate the research, costs and impact data is aggregated to a state level[22]. This provides a useful data set for the 50 states plus the District of Columbia.

6. Model Development

Using data for the period 2010 to 2012 opens the possibility of taking two approaches to the analysis. In attempting to glean from the data how costs are affected by program size and market penetration, use of multiple approaches can help put a range around an issue afflicted with a lot of uncertainty.

The first approach involves using all the state level data for the 2010 to 2012 time period. This involves estimating a cross-sectional / time-series model. It is cross-sectional given use of data for the 50 states plus the District of Columbia. It is time-series since it covers the period 2010 to 2012. To estimate this model over time with the cross-section requires the use of a fixed-effects panel data modeling approach that captures the underlying relationship between cost and the independent variables while letting the intercept terms capture the inherent underlying differences across the various geographies. The model estimates a separate intercept term for each of the 51 geographic areas while developing estimates for the independent variables that are the same for all the geographic areas. The methodology is designed to uncover the fundamental relationship between cost and the independent variables while differences in the characteristics of each geographic area are captured in the intercept terms.

Algebraically, Model 1, the fixed-effect panel data model, is described as follows:

$$PC_{it} = \alpha_i \; + \beta 1 \cdot CPR_{it} + \beta 2 \cdot CPT_{it} + \beta 3 \cdot EP_{it} + \beta 4 \cdot UR_t + \varepsilon_{it}) \qquad (3)$$

[22] Future research will extend this analysis to an individual utility service area.

where:

PC_{it} = Program costs for geography i during year t

α_i = Constant term for geography i (the fixed-effect)

CPR_{it} = Current kWh impacts as percent of retail sales for geography i during year t

CPT_{it} = Cumulative kWh impacts as percent of retail sales for geography i during year t

EP_{it} = Real electricity price for geography i during year t

UR_t = National unemployment rate for year t

ß = Estimated coefficients for ß1, ß2, ß3, and ß4

ε = Error term for geography i during year t.

The second approach involves using all the data for the most recent year, 2012[23]. This is a traditional cross-sectional approach. Cross-sectional models are extremely useful because they provide a view into the long-run since the data contains multiple points along the continuum of experience. This approach does not require the use of the fixed effects panel data approach. Instead, the model can be estimated using a traditional application of ordinary least squares regression. The model to be estimated is the same as that previous presented by Equation 2.

Algebraically, Model 2, the cross-sectional model, is described as follows:

$$PC_i = \alpha + \beta 1 \cdot CPR_i + \beta 2 \cdot CPT_i + \beta 3 \cdot EP_i + \varepsilon \qquad (4)$$

where:

[23] Data for Delaware and Louisiana were deleted since the EIA data indicates essentially zero cumulative impacts for the year 2012.

PC_i = Program cost or spending for geography i

CPR_i = Current kWh impacts as a percent of retail sales for geography i

CPT_i = Cumulative kWh impacts as a percent of retail sales for geography i

EP_i = Real average retail price of electricity for geography i

ε_i = Error term for geography i

The one difference from Equation 2 is that the national variable UR is removed since it would be the same in a given year for all geographic regions.

7. Model Results

Both models were estimated in logarithmic form using the data previously described. The benefit of estimating the model in logarithmic form is that the coefficients represent elasticities that enable one to compute how a percent change in the independent variable results in a coefficient adjusted percent change in the level of program costs. Table 1 below summarizes the results of the statistical analysis for both Model 1 and Model 2.

Table 1

Model 1			
Variable	Coefficient	t-statistic	Stat Significance
Log (CPR)	0.609	7.761	Yes
Log (CPT)	0.278	3.293	Yes
Log (EP)	-11.980	-1.863	Yes
Log (UR)	2.438	0.769	No
Adjusted R-squared	0.759		Yes

Model 2			
Variable	Coefficient	t-statistic	Stat Significance
Log (CPR)	-0.003	-0.055	No
Log (CPT)	0.897	6.865	Yes
Log (EP)	-0.837	-1.527	Yes at 7% level
Adjusted R-squared	0.543		Yes

For Model 1, the results indicate that strong statistical relationships exist between the level of program cost and program size, market penetration, and real electric price. All three independent variables are statistically significant using a one-tail test given the a priori view of the expected sign for the variables. Only the unemployment rate variable was not statistically significant.

For Model 2, the results indicate that strong statistical relationships exist between the level of program cost and market penetration, and real electric price. The market penetration variable is strongly significant, while the electric price variable is weakly significant. The program size variable is not significant in this model.

These results provide a first insight into the relationship between program costs and program size and market penetration. While the data is aggregate, these results do indicate how these costs can be expected to change. At this point in time, no other study has generated these types of results and insights.

The following section provides an example of how the results can be used to forecast program costs as market penetration increases.

8. Model Application

Often under an Energy Efficiency Resource Standard, there is a requirement to achieve X% cumulative load reduction by a specific year or to reduce load 1% per year for some number of years. Sometimes these values are based upon the results of a market potential study. As an example, let's assume a market potential study concluded that the economic potential over a 20 year period was 20%, or 1% per year. Then, the question becomes: how does the program cost change as one begins to achieve impacts that approach the economic potential, keeping in mind that economic potential implies that 100% of the cost-effective measures are installed?
Given both econometric models previously presented, simulations of the cost impacts can be performed under each model to provide a range on how costs could change as market penetration increases. Another factor to consider is the achievable potential. Data in the EPRI market potential studies[24] indicate that approximately 50% of the economic potential is realistically achievable and that 75% of the economic potential would represent a high achievable potential. Tables 2 and 3 provide examples of how the coefficients from each model can be used to estimate how costs increase as the market penetration increases. Given an economic market potential of 20% of retail sales or 1% per year for 20 years, the achievable potential would be 10% or 0.5% per year, and the high potential would be 15% or .75% per year. The tables depict how average costs change when the market penetration of energy efficiency increases from 50% to 75%.

[24] This applies in the 10 to 20 year time frame. See reference numbers 24 and 25.

Table 2: Impact of Changes in Market Penetration on Program Costs
Simulation of Model 1
Key Assumptions:

Assume the economic market potential is 20% of retail sales.
If the achievable potential is 50% of the market potential, then the achievable potential represents 10% of retail sales.
Increasing achievement from 50% of the market potential to 75% of the market potential impacts the unit cost of EE.
First year cost per kWh saved starts at $.20/kWh
Incremental annual impacts are 1% of retail sales or 100,000,000 kWh per year
The current cumulative market penetration starts at 3% to reflect some existing market presence

EE as % of Retail Sales					Change in Costs
Incremental Impact	Cumulative	Costs (Real $)	Incremental kWh	$/kWh	Due to Change in Cumulative %
1.0%	3.0%	$ 20,000,000	100,000,000	$ 0.2000	
1.0%	4.0%	$ 21,853,333	100,000,000	$ 0.2185	$ 1,853,333
1.0%	5.0%	$ 23,372,140	100,000,000	$ 0.2337	$ 1,518,807
1.0%	6.0%	$ 24,671,631	100,000,000	$ 0.2467	$ 1,299,491
1.0%	7.0%	$ 25,814,750	100,000,000	$ 0.2581	$ 1,143,119
1.0%	8.0%	$ 26,839,964	100,000,000	$ 0.2684	$ 1,025,214
1.0%	9.0%	$ 27,772,653	100,000,000	$ 0.2777	$ 932,689
1.0%	10.0%	$ 28,630,519	100,000,000	$ 0.2863	$ 857,866
1.0%	11.0%	$ 29,426,448	100,000,000	$ 0.2943	$ 795,928
1.0%	12.0%	$ 30,170,134	100,000,000	$ 0.3017	$ 743,687
1.0%	13.0%	$ 30,869,076	100,000,000	$ 0.3087	$ 698,941
1.0%	14.0%	$ 31,529,199	100,000,000	$ 0.3153	$ 660,123
1.0%	15.0%	$ 32,155,279	100,000,000	$ 0.3216	$ 626,080
1.0%	16.0%	$ 32,751,223	100,000,000	$ 0.3275	$ 595,945
1.0%	17.0%	$ 33,320,276	100,000,000	$ 0.3332	$ 569,053
1.0%	18.0%	$ 33,865,161	100,000,000	$ 0.3387	$ 544,885
1.0%	19.0%	$ 34,388,189	100,000,000	$ 0.3439	$ 523,029
1.0%	20.0%	$ 34,891,343	100,000,000	$ 0.3489	$ 503,154
1.0%	21.0%	$ 35,376,332	100,000,000	$ 0.3538	$ 484,990
1.0%	22.0%	$ 35,844,648	100,000,000	$ 0.3584	$ 468,315

Cost per first year kWh for 50% of economic potential		
Total Cost	$	198,954,991
kWh for 50%		800,000,000
Cost per first year kWH	$	0.249

Cost per first year kWh for next 25% of economic potential		
Total Cost	$	154,150,136
kWh for next 25% of retail sales		500,000,000
Cost per first year kWH	$	0.308
Percent increase in unt cost		24%

Model Elasticities	
Incremental	0.609
Cumulative	0.278

Table 3: Impact of Changes in Market Penetration on Program Costs
Simulation of Model 2
Key Assumptions:

Assume the economic market potential is 20% of retail sales.
If the achievable potential is 50% of the market potential, then the achievable potential represents 10% of retail sales.
Increasing achievement from 50% of the market potential to 75% of the market potential impacts the unit cost of EE.
First year cost per kWh saved starts at $.20/kWh
Incremental annual impacts are 1% of retail sales or 100,000,000 kWh per year
The current cumulative market penetration starts at 3% to reflect some existing market presence

EE as % of Retail Sales					Change in Costs
Incremental Impact	Cumulative	Costs (Real $)	Incremental kWh	$/kWh	Due to Change in Cumulative %
1.0%	3.0%	$ 20,000,000	100,000,000	$ 0.2000	
1.0%	4.0%	$ 25,980,000	100,000,000	$ 0.2598	$ 5,980,000
1.0%	5.0%	$ 31,806,015	100,000,000	$ 0.3181	$ 5,826,015
1.0%	6.0%	$ 37,512,014	100,000,000	$ 0.3751	$ 5,705,999
1.0%	7.0%	$ 43,120,060	100,000,000	$ 0.4312	$ 5,608,046
1.0%	8.0%	$ 48,645,588	100,000,000	$ 0.4865	$ 5,525,528
1.0%	9.0%	$ 54,099,974	100,000,000	$ 0.5410	$ 5,454,387
1.0%	10.0%	$ 59,491,939	100,000,000	$ 0.5949	$ 5,391.964
1.0%	11.0%	$ 64,828,365	100,000,000	$ 0.6483	$ 5,336,427
1.0%	12.0%	$ 70,114,824	100,000,000	$ 0.7011	$ 5,286,459
1.0%	13.0%	$ 75,355,907	100,000,000	$ 0.7536	$ 5,241,083
1.0%	14.0%	$ 80,555,465	100,000,000	$ 0.8056	$ 5,199,558
1.0%	15.0%	$ 85,716,768	100,000,000	$ 0.8572	$ 5,161,304
1.0%	16.0%	$ 90,842,631	100,000,000	$ 0.9084	$ 5,125,863
1.0%	17.0%	$ 95,935,496	100,000,000	$ 0.9594	$ 5,092,865
1.0%	18.0%	$ 100,997,504	100,000,000	$ 1.0100	$ 5,062,008
1.0%	19.0%	$ 106,030,547	100,000,000	$ 1.0603	$ 5,033,042
1.0%	20.0%	$ 111,036,305	100,000,000	$ 1.1104	$ 5,005,758
1.0%	21.0%	$ 116,016,283	100,000,000	$ 1.1602	$ 4,979,978
1.0%	22.0%	$ 120,971,836	100,000,000	$ 1.2097	$ 4,955,553

Cost per first year kWh for 50% of economic potential		
Total Cost	$	320,655,590
kWh for 50%		800,000,000
Cost per first year kWH	$	0.401

Cost per first year kWh for next 25% of economic potential		
Total Cost	$	376,571,330
kWh for next 25% of retail sales		500,000,000
Cost per first year kWH	$	0.753
Percent increase in unt cost		88%

Model Elasticities	
Incremental	0
Cumulative	0.897

000049

Under Model 1, the average cost increases from \$0.249/kWh to \$0.308/kWh or 24%. Under Model 2, the cost increases from \$0.401/kWh to \$0.753/kWh or 88%. The key point here is not the size of the unit cost numbers, but the percent increase. These values produce a range of average cost increases of 24% to 88% as market penetration increases. This is a wide range, but is based on actual program cost experience. It provides guidance on the expectation that as the market penetration of energy efficiency increases, the unit cost increases.

9. Implications for Future Research

From the review of other studies, it is apparent that little to no evidence exists on the relationship between program costs, program size, and market penetration. But now, the research conducted in this study provides an initial insight into this relationship. While the range of estimated impacts on cost is rather wide, selecting a market penetration driven percent increase in energy efficiency costs in the middle of the range seems appropriate. This percent increase would be applied in estimating costs when the program impacts are expected to exceed the achievable potential. At the same time, efforts to improve targeted marketing can help with cost management.

It should be obvious that further research in this area is warranted. As mentioned, this study is the first to investigate how costs can rise with increases in program size and market penetration. The findings point to the existence of cost efficiencies with respect to program size, but rising costs as market penetration increases. The results developed here are at a very high level. The potential for greater insights may exist by monitoring individual program costs over time. Future research along that direction seems appropriate. The results could vary significantly from one program to the next. Analysis could also be conducted at the portfolio level for individual utility energy efficiency efforts or a cross-section of individual utilities. Only through further research can the range be narrowed and/or confirmed.

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