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April 17, 2012

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Alanna Gillis, A/Commission Secretary
By Web Posting and courier

Dear Madam:

Re: British Columbia Hydro and Power Authority
F2012-F2014 Revenue Requirements Application
Project No. 3698622/Order G-40-11
BCSEA-SCBC evidence

Attached please find the following evidence filed by the intervenors B.C. Sustainable Energy Association and the Sierra Club of British Columbia :

1. Direct testimony of John Plunkett, Green Energy Economics Group, dated April 17, 2012, with the following attachments
   - Exhibit JJP-1, John Plunkett, Qualifications
   - Exhibit JJP-2, "Electric Energy Efficiency Resource Acquisition Options for BC Hydro," GEEG, April 17, 2012
   - Exhibit JJP-3, PIP Incentive Comparison
   - Exhibit JJP-4, AEEE Paper 284 draft, "A Win-Win-Win for Municipal Street Lighting: Converting Two-thirds of Vermont's Street Lights to LED by 2014."

An electronic version will be filed on the Commission website and 20 hardcopies will be delivered to the Commission office.

Yours truly,

William J. Andrews

Barrister & Solicitor

cc. Distribution List by email

Before the British Columbia Utilities Commission

RE: British Columbia Hydro and Power Authority (BC Hydro) Amended F2012 to F2014 Revenue Requirements Application (Amended F12-F14 RRA or Amended Application)	**))))**	**BCUC Project No. 3698592**

Direct Testimony of

John Plunkett

on behalf of

The British Columbia Sustainable Energy Association and the Sierra Club of British Columbia

GREEN ENERGY ECONOMICS GROUP, INC.

April 17, 2012

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I. Introduction and Summary

A. Identification and Qualifications

Q: State your name, occupation, and business address.

A: I am John J. Plunkett. I am a partner in and president of Green Energy Economics Group, Inc., an energy consultancy I co-founded in 2005. My office address is 1002 Jerusalem Road, Bristol Vermont 05443.

Q: Summarize your qualifications.

A: I have worked for over thirty years in energy utility planning, concentrating on energy efficiency as a resource and business strategy for energy service providers. Throughout my career I have played key advisory and negotiating roles on all aspects of electric and gas utility demand side management ("DSM"), including residential, industrial, and commercial program design; implementation management and oversight; performance incentive design; and monitoring, verification, and evaluation. I have led, prepared, or contributed to numerous analyses and reports on the economically achievable potential for efficiency and renewable resources. Over the past two decades, I have been involved in the review or preparation of many gas and electricity DSM investment plans. I have worked on these issues throughout North America and in China on behalf of energy service providers, citizen and environmental groups, state consumer advocates, utility regulators, and government agencies at the local, state, provincial, and national levels.

I earned my B.A. in Economics with Distinction from Swarthmore College, where I graduated Phi Beta Kappa and was awarded the Adams Prize in Economics. My resume is attached as Exhibit JJP-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have testified as an expert witness over two dozen times before regulators in a dozen states and three Canadian provinces.

Q: Have you testified previously before the British Columbia Utilities Commission (the Commission)?

A: Yes, I have presented evidence regarding energy efficiency resource acquisition before the Commission on five previous occasions. I testified twice regarding BC Hydro's 2006 and 2008 Integrated Electricity Plan and Long Term Acquisition Plans (Project Nos. 3698419 and 3698514, respectively). I submitted testimony concerning DSM plans by Terasen Gas in October 2008 (Project No. 3698512) and in November 2011by its successor, Fortis Energy Utilities BC Gas (Project No. 3698627). I testified regarding FortisBC Electric's DSM Plan in March 2012 (Project No. 3698620).

Q: Summarize your work on energy efficiency and conservation investment in the U.S. over the past five years.

A: For the last twelve years, I have served as economic policy advisor for Efficiency Vermont, the first statewide energy-efficiency utility administered under four successive three-year performance contracts administered by the Vermont Energy Investment Corporation (VEIC).[1] In this capacity I have helped develop and implement economic policy and practice for guiding energy-efficiency investment. I testified in 2010 in the Public Service Board proceeding that led to a twelve-year order of appointment for VEIC that began this year. The order of appointment includes non-electric energy

[1] The efficiency utility model was recently replicated in Canada by Efficiency Nova Scotia.

efficiency investment. I led the technical analysis behind two long-range assessments by VEIC of the economically achievable electricity savings in Vermont in 2009 and again in 2011 from continued efficiency investment for twenty more years under several scenarios. The 2011 analysis was instrumental in the PSB's decision establishing performance targets and budgets for 2012-14 and savings and spending targets for the subsequent 17 years. I have also worked with the state's utilities and regulators on targeting energy efficiency retrofits geographically to help relieve transmission and distribution capacity constraints occasionally since 1999.

In support of the proposed acquisition of the state's largest utility, I testified on behalf of Green Mountain Power (GMP) and Gaz Metro on the economic merits of the proposal by the combined companies to invest $21 million on additional energy-efficiency in the acquired utility's service area rather than refunding the same amount due those customers for prior emergency rate relief.

Q: Where else in North America have you worked on efficiency resource planning and management?

A: Since 2008, GEEG has been engaged by Philadelphia Gas Works ("PGW"), a natural gas utility serving the city of Philadelphia, to assist with the development, regulatory review, and implementation of a five-year, $50 million DSM portfolio. I submitted testimony in support of PGW's plan with the Pennsylvania Public Utility Commission, which was approved for implementation in 2010.

GEEG was engaged in May 2011 by Shaw Engineering and Infrastructure to assist in the economic assessment and guidance of statewide gas and electric energy efficiency investment in its administration of Wisconsin's Focus on Energy (FOE) portfolio.

Since 2008, GEEG has assisted Peoples Gas with economic analysis in the planning and implementation of its Chicagoland Natural Gas energy efficiency programs and portfolio. I testified on behalf of Peoples Gas before the Illinois Commerce Commission in 2010 regarding cost recovery of first-year program expenditures; I again submitted testimony in 2011 concerning the prudence of second-year expenditures.

GEEG is in the process of preparing a report for the City of Austin's consumer advocate recommending efficiency savings targets and budgets. We prepared a report on achievable efficiency savings and costs in Nevada for the Sierra Club in January. GEEG provided technical support and expert testimony for the Sierra Club (U.S.) in 2011 on the potential for energy-efficiency investment to substitute for coal-fired generation in several proceedings, including an Oklahoma Gas & Electric rate case in November. In October I prepared comments on Maryland utilities' ability to scale up efficiency investment to meet that state's energy-efficiency resource standards (EERS) for Sierra Club of Maryland and other citizens groups.

I worked for New York City's Economic Development Corporation in 2007 and 2008 on three parallel assignments, including the Public Service Commission's Energy Efficiency Portfolio proceeding to establish programs for Consolidated Edison's customers to reduce by 15% the forecasted electricity and gas requirements for 2015. I also assisted the city in collaborative negotiations concerning Consolidated Edison's gas DSM programs for 2009-2010, and in the design and evaluation of its geographically targeted electric DSM program to defer transmission and distribution investment.

I testified in October 2008 before the Connecticut Department of Public Utility Control regarding the demand-side component of the proposed

integrated resource plans of the Connecticut Light and Power and the United Illuminating Companies.

Q: What is your experience with energy efficiency and conservation investment in China?

A: I am currently working with the China Program of the Regulatory Assistance Project (RAP) to develop a "blueprint" for regulatory oversight of DSM implementation by grid companies under new rules requiring them to reduce energy and peak load by 0.3 percent (kWh) annually.

I consulted on energy efficiency and conservation at the national and provincial levels in China for several non-governmental organizations for five years between 2003 and 2010. From July 2003 through 2007, I was the consulting team leader for the Natural Resources Defense Council on the development, assessment, and implementation of Chinese demand side management investment portfolios. I led the modification and application of U.S.-based program and portfolio economic analysis tools for DSM planning in Jiangsu Province. There I assisted with the design and planning for first-stage implementation of DSM programs investing $12 million annually on high-efficiency retrofits to industrial motors and drives and commercial lighting and cooling. I provided training and technical support on economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers in 2007 and 2008.

My final assignment for NRDC in China was to draft sections for a national DSM program procedures manual, sponsored by the PRC's National Development and Reform Commission. Working with California's investor-owned utilities and American and Chinese experts, I wrote chapters concerning performance indicators and cost-effectiveness analysis. The

Chinese central government approved and issued the national DSM procedures manual in April 2009.

For the Asian Development Bank in 2006-2007, I led a team of Chinese and American experts in a pre-feasibility study of a 24-year, $120 million loan to Guangdong Province to establish a revolving financing facility for industrial and commercial / institutional efficiency retrofit investments. This consisted of technical, economic, and financial analysis of the ”efficiency power plant” portfolio, case studies of ten “subprojects,” and procedures and tools for qualifying prospective projects for financing. ADB’s Board of Directors unanimously approved the loan in June 2008.

From 2007 to 2010, I provided technical support on the economic and financial assessment of energy efficiency and conservation investment projects in Guangdong Province for the Montpelier, Vermont-based Institute for Sustainable Communities.

B. Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the British Columbia Sustainable Energy Association (“BCSEA”) and the Sierra Club of British Columbia (“SCBC”).

Q: What is the purpose of your direct testimony?

A: BCSEA-SCBC engaged me to assess the adequacy of the electric energy-efficiency program savings and expenditures contained in BC Hydro's F2012-F2014 Revenue Requirements Application and F2012-F2013 DSM Expenditure Schedule (and amendments thereto).

Q: What documents did you review?

A: I reviewed the following materials filed in this proceeding:

- Amended New Appendix II, F12/F13 DSM Expenditures, Exhibit B-1-3B, and Errata at Exhibit B-1-3C; and New Appendix II, F12/F13 DSM Expenditures, Exhibit B-1-3 (replaced by B-1-3B)
- Amended F2012 to F2014 Revenue Requirements Application, portions concerning DSM, Exhibit B-1-3
- BC Hydro Responses to BCUC IR1 concerning DSM, Exhibit B-15
- BC Hydro Responses to Intervenor IR1 concerning DSM, Exhibit B-16
- BC Hydro Responses to BCUC IR2 concerning DSM, Exhibit B-23
- BC Hydro Responses to Intervenor IR2 concerning DSM, Exhibit B-25.
- Appendix K to BC Hydro's 2008 LTAP

Q: Summarize your findings, conclusions, and recommendations.

A: Based on my review of BC Hydro's evidence and my analysis of energy-efficiency spending and savings elsewhere, all indications are that BC Hydro could lower revenue requirements and rates by *raising*, not lowering the pace of cost-effective efficiency resource acquisition. BC Hydro's updated analysis indicates that its planned level of DSM investment in F12/F13 is highly cost-effective for ratepayers (as measured by the utility test) and for the provincial economy (as measured by the Total Resource Cost (TRC) test) yielding benefits twice to three times the costs incurred. Its updated rate and bill analysis further shows that planned expenditures will lower average rates in the test period.

I find no credible reason not to believe that acquiring more cost-effective efficiency resources than BC Hydro has proposed would further lower total costs of electric service, revenue requirements, and rates to BC Hydro's customers during the test period and beyond. On the contrary, there is ample evidence that BC Hydro could double the scale of savings it

currently plans, at costs that, while higher than BC Hydro has experienced thus far, would still be highly cost-effective. I find that BC Hydro could do so by joining the top savings performance tier of North America's leading DSM portfolio administrators and using best industry practices for achieving higher participation rates and realize deeper cost-effective electricity savings among participants.

I conclude that it is reasonable for BC Hydro to increase DSM program expenditures to ramp up annual portfolio savings by 0.5% of sales in F2013 and by another 0.5% of sales in F2014, producing total annual depths of savings from DSM programs of 1.5% in F2013 and 2.0% in F2014 and each year thereafter. Following this expansion path will subject BC Hydro's program portfolio to the opposing forces of scale economies in the near team which will become dominated by diminishing returns in the long run.

Based on my analysis of selected data on efficiency portfolio expenditures and savings, I estimate in Table 16, Section II-C-3 of Exh. JJP-2, that as much as $225 million in F2013 and $279 million in F2014 would be required to meet these higher savings targets.

There I present expected DSM costs through F2032 of maintaining annual incremental savings acquisition at 2 percent of annual sales to indicate the long-term trajectory toward which the next two years' expenditures would be aiming. I show that this increased spending is likely to be cost-effective under BC Hydro's long-run avoided costs, and that it will lower long-term revenue requirements and rates.

Least-cost integrated resource planning principles dictate that monopoly energy utilities such as BC Hydro should plan and seek to acquire all demand-side resources achievable for less than the marginal costs of supply they avoid. As BC Hydro acknowledges, lowering savings levels in the test

period reduces the capability to deliver higher savings in the future. Indeed, raising the pace of efficiency resource acquisition in F13/F14 increases the probability that BC Hydro will be capable of acquiring the higher savings that are likely to be needed in the future, especially if the risk of accelerated load growth materializes. Thus, I conclude that increasing DSM acquisition in the F2013-F2014 test period would lower the risk of having to acquire more expensive supply to meet greater resource deficits later.

Accordingly, I recommend that the Commission authorize and direct BC Hydro to raise F2013-F2014 DSM budgets to as much as the $504 million that I estimate will be needed to achieve 1.5% and 2.0% savings in each year, respectively. Toward that end, I also recommend that BC Hydro streamline, consolidate and strengthen the design and implementation of several of its current program offerings. The recommendations are based on my review of BC Hydro's amended DSM plan, the Commission's recent decision on the Fortis Energy Utilities ("FEU") DSM plan, and my own knowledge of current industry best practices.

Q: How have you organized the rest of this testimony?

A: The following section assesses prospects for increasing BC Hydro's acquisition of cost-effective DSM resources. Section III deals with Hydro's concerns about managing the risks of scaling up DSM resource acquisition. Section IV covers industry best practices and how BC Hydro can apply them as it redeploys its proposed DSM programs to achieve annual savings equal to two percent of annual forecast electricity sales. I state my main conclusions and recommendations for Commission action in the last section.

II. Achievable DSM Savings and Costs for BC Hydro

Q: What is the scope of your evidence with respect to DSM?

A: My evidence is confined to energy-efficiency programs proposed in BC Hydro's Amended DSM Plan. It does not consider what BC Hydro designates as Load Displacement, Rates, or Codes and Standards.

A. BC Hydro's DSM Plan

Q: How much energy efficiency does BC Hydro propose to acquire in its amended DSM Plan?

A: According to Exhibit B-1-3B - Attachment 5, BC Hydro plans to acquire approximately 758 GWH and 99 MW/yr in incremental annual efficiency energy and winter peak demand savings in F2013 and F2014 from energy efficiency programs. On an annual basis these savings are equivalent to approximately 0.7% percent of BC Hydro's total energy sales.[2]

Q: What about savings beyond F2013?

A: BC Hydro has not yet decided on the DSM spending and savings it plans to pursue in the long term. Until it completes its Integrated Resource Plan (IRP), BC Hydro is merely using a placeholder for DSM savings from its 2008 Long-Term Action Plan (2008 LTAP) for F2017 and beyond, while using a linear extrapolation between F2014 and F2017 for F2015 and F2016 values. According to the 2008 LTAP, BC Hydro aims to get savings of approximately 0.8% percent of BC Hydro's total projected sales from DSM programs.[3]

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[2] Savings come from Exhibit B-1-3B Attachment 5, Table 5 and sales from Attachment 2, Amended Table 1.

[3] "BC Hydro – Option A" from Appendix K to 2008 LTAP, Table 13

Q: How much does BC Hydro expect to spend to acquire efficiency resources contained in its long-term resource plan?

A: BC Hydro plans to spend $141 million in F2013 and $146 million in F2014 for energy efficiency programs (excluding load displacement). Spending continues to ramp up in F2015-16 when it reaches approximately $233 million per year in F2019 before dipping to around $160 million in F2020. Spending then climbs back up to $200 million per year by F2025.[4]

Q: How much is BC Hydro intending to spend per kWh of annual savings?

A: Dividing historic spending by the annual incremental energy savings indicates that BC Hydro spent $0.20-$0.22 per annual kWh in F2009-10. In F2011, BC Hydro spent $0.51 per annual kWh in F2011 due to one-time write-downs from an industrial program[5]. I refer to this as the unit cost of annual savings.

I was unable to obtain a reasonable estimation of unit costs going forward since I did not obtain incremental savings projections, only cumulative. An estimation of incremental savings from cumulative projections would not be meaningful because there is no way to account for savings from previous years dropping out of the cumulative total.

Q: Does this mean that BC Hydro spent 22 cents for each kWh it saves?

A: No; $0.22/kWh-yr is the amount BC Hydro spent per kWh of savings lasting an average of 15 years. The levelized cost of saved energy, by contrast, accounts for the longevity of DSM savings. It is a function of the discount rate and life expectancy of the resulting savings. At an assumed average

[4] Exhibit B-1-3B Attachment 5, Table 5.

[5] Values come from prior DSM performance reports that were included as Attachment 8 to Exhibit B-1-3B.

measure life of 15 years and a real discount rate of 5.5 percent, the unit cost of annual savings $0.22/kWh-yr translates to a levelized cost of $0.0219/kWh over the lifetime of the savings. Using the same assumptions, the levelized cost of savings of $0.51 in F2011 was $0.0508/kWh.

Q: Is the levelized cost of saved energy directly comparable with the avoided marginal cost of energy supply?

A: Yes. So levelized cost of $0.0219/kWh over the lifetime of the savings is well below the BC Hydro's estimate of avoided supply costs of $0.14268/kWh, making the demand-side resources it plans to acquire highly cost-effective.[6]

B. Acquiring Additional DSM resources for BC Hydro

Q: If demand-side resources are so cost-effective compared to supply, shouldn't BC Hydro acquire more of them?

A: Yes.

Q: How much more?

A: Like any utility seeking to minimize the total resource cost of supplying reliable electric service, BC Hydro should plan on acquiring all the cost-effective demand side resources that it can. The requirement that BC Hydro achieve 66 percent of future load growth should be considered a minimum, not a maximum target.

Q: On what basis do you find that BC Hydro can cost-effectively increase its annual achievement of electric efficiency savings?

A: My primary reason is that leading North American electric efficiency portfolio administrators have been and plan to continue saving two percent of

[6] In 2011 dollars. Exhibit B-1-3B, Amended New Appendix II, Attachment 6, p. 191.

total retail electric energy sales annually for half the long-run marginal costs of supply they avoid. BC Hydro could do likewise by following industry best practices in scaling up participation and savings and thereby increasing portfolio savings starting in F2012.

Q: What industry experience supports your finding that industry leaders have achieved or plan to achieve savings in the two-percent range?

A: This experience is documented in a report prepared by GEEG for BCSEA-SCBC (*Electric Energy Efficiency Resource Acquisition Options for BC Hydro* dated April 17, 2012 and included as Exhibit JJP-2) It contains annual spending and savings by selected North American efficiency portfolio administrators going back as far as 2001 and in several jurisdictions future projections for up to 20 years. Exhibit JJP-2 provides information for electric DSM portfolios with the highest percentage of annual savings as well as others with lower savings. On the basis of results and plans of leading jurisdictions, it projects the annual expenditures BC Hydro would need to make to achieve annual savings equal to two percent of electric energy sales starting in F2013.

Q: What do you find from the information in Exh. JJP-2?

A: Portfolio performance falls into a range spanning four savings tiers.

Tier 1 (≥1.5%): In the top tier, states are achieving at or near 2 percent of sales. It contains 9 program years of experience, including California for 4 out of the past 5 years, Vermont 4 out the past 5 years, as well as Connecticut as of last year.

Tier 2 (≥0.67% and <1.5%): States in the second tier are saving at or near 1 percent of annual sales, with annual savings ranging from two-thirds (2/3) of one percent to 1.5 percent of sales. In addition to earlier years'

performance by California, Vermont, and Connecticut, this group also includes 60 program years of experience from efficiency portfolios in Iowa, Maine, Massachusetts, Nevada, New York, Rhode Island, Hawaii, the Pacific Northwest, British Columbia, and Nova Scotia.

Tier 3 (≥0.33% and <0.67%): States with savings at or near 0.5% of sales fall into the third tier. This group contains 26 program years of results, and includes savings in even earlier years for states in the first two tiers, plus Arkansas, New Jersey, and Wisconsin.

Tier 4 (<0.33%): All other states with savings less than one-third (1/3) of a percent of sales fall into the lowest tier. This group saved around 0.25% of sales and includes earlier results for some states with performance in Tier 3, as well as Texas, and Arkansas.

Q: Into which performance tier does BC Hydro's long-term DSM plan fall?

A: BC Hydro's average proposed savings from DSM programs of 0.7-0.8% percent of annual sales going forward from its 2008 LTAP places it squarely in the second-to-top performance tier.

Q: Does it matter where a portfolio administrator is located in terms of how much energy savings it achieves?

A: Not according to the data I have analyzed. The geographic, socio-economic, and climatic diversity of these results and plans strongly suggests that where a portfolio is located geographically has little bearing on whether it can be reasonably expected to achieve top-tier energy savings. This is because almost all electric end-uses have cost-effective savings potential, no matter where they are. For example Vermont, Hawaii and California have quite different geographic, socio-economic and climatic situations, but efficiency

program administrators within each state plan to continue to achieve savings in the 2% range.

Such successful experience under such diverse conditions elsewhere leaves little doubt that BC Hydro can scale up to top-tier efficiency portfolio performance. The salient question is how much it will cost to apply best industry practices to increase participation and savings per participant throughout the service area.

Q. Why do you gauge savings performance as a percentage of total sales, rather than percentage of forecast sales growth as BC Hydro does?

A. I do so for two reasons. First, total sales correlates more closely to the size of total efficiency savings opportunities that are available in a particular utility's service area than just the amount of additional load expected to be added to the future (which does correlate will with the amount of savings potential from new construction). Second, it is difficult to come by information on electric utility load forecasts, which are often considered confidential and change frequently.

C. Costs and Benefits of Acquiring Additional Efficiency Resources

Q: How do energy efficiency resource costs change as portfolios scale up efficiency resource acquisition?

A: The cost of acquiring efficiency resources is subject to two opposing economic forces: economies of scale and diminishing marginal returns. Some portfolio administration costs are fixed with respect to the level of participation and savings actually achieved, like development, planning, marketing, and management. Beyond a certain level of participation, fixed

program costs per unit of saved energy are spread over more savings and tend to level off or decline gradually.

Q: What about prospects for diminishing returns as BC Hydro scales up its efficiency portfolio to achieve double its currently planned electricity savings?

A: As efficiency portfolios scale up activity levels and savings, the law of diminishing returns can increase the acquisition costs of efficiency savings in two mutually reinforcing ways. First, available efficiency opportunities become more expensive as the depth of savings increases at the measure and project level. Second, experience shows that higher financial incentives are required to achieve participation rates in the 75-90 percent range, especially for more costly efficiency measures with deeper savings. These two factors can interact to raise the cost to portfolio administrators of acquiring additional savings. The upshot is that BC Hydro's electric efficiency resource supply curve will eventually become progressively steeper as the portfolio invests in acquiring more of its service area's achievable efficiency potential.

Q: What about the costs that participants incur for electric efficiency investments?

A: Participant costs of efficiency investments not covered by program administrators must be counted in the Total Resource Cost (TRC) test, the primary indicator of DSM cost-effectiveness under Provincial statute and regulation. Participant costs include the share of efficiency investment costs borne directly by program participants, as well as any non-energy cost savings resulting from efficiency investments. These include reduced operation and maintenance costs (e.g., less water usage from high-efficiency washers) and capital costs (e.g., less frequent equipment replacement due to

longer life expectancy of high-efficiency alternatives). Total resource costs of electric efficiency savings must also account for any net costs or savings from non-electric energy savings (e.g., gas heating cost increases due to improved lighting efficiency, gas heating savings from improved building thermal integrity). As BC Hydro notes in its newly amended DSM Plan, the value of these non-electric savings can offset some, all, or even more than all the installed cost of efficiency measures.[7] This means that the net resource costs of some efficiency measures are actually negative.

The data I collected and analyzed from other jurisdictions only includes expenditures reported by DSM portfolio administrators.

Q: How do total resource costs vary relative to program administrator costs as the scale of total efficiency savings increases?

A: Like program administrator costs, total resource costs of efficiency measures are subject to diminishing returns.[8] Because the cheapest efficiency savings in terms of total resource costs are negative, they are necessarily less than program administrator costs at low levels of efficiency resource acquisition. As the cheapest opportunities are exhausted, participant costs become positive, and programs cover a progressively larger share of rising total resource costs of additional electric efficiency savings.

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[7] BC Hydro reports levelized TRC costs of its amended DSM plan in Exh. B-1-3B, p.II-2-15.

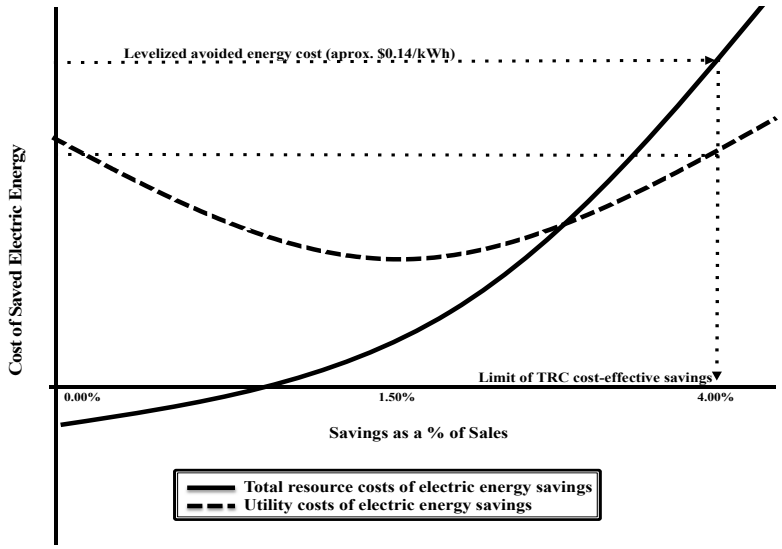
[8] To the extent that DSM programs can drive down supply costs through higher volumes, total resource costs are also subject to economies of scale, especially over 3-5 years, as demonstrated most recently by North American experience with compact fluorescent and, increasingly, solid state lighting technology. BC Hydro's long-term DSM resource assessment should account explicitly for further market transformation.

Q: Can you illustrate the interplay between efficiency resource acquisition from both the total resource costs and program administrator perspective?

A: Yes. Figure 1, below, presents stylized cost curves from both perspectives.[9] It illustrates that as efficiency resource acquisition scales up, program administrator costs approach total resource costs as programs have to pay participants increasingly higher shares of ever-higher total resource costs to reach maximum achievable market shares.

[9] By "stylized" I mean the supply curves in Figure 1 were drawn by hand using Microsoft Excel's graphic manipulation capabilities, not plotted using numerical data.

Figure 1 – Total Resource Costs vs. Administrator Costs of Electric Energy Savings



Q: How have scale economies and diminishing returns played out in the past?

A: Among North American jurisdictions, the data suggest that scale economies and diminishing returns have tended on average to cancel each other out. Across all four performance tiers spanned by the data in Exhibit JJP-2, the cost of saved energy has averaged roughly 0.25 cents per annual kWh saved. In other words, the average cost per kWh saved annually has been roughly the same no matter how high the savings as a percentage of total sales (JJP-2, Table 5, p. 17)

Exh. JJP-2 also shows that portfolio administrators ramping up from low levels of program activity can expect to see costs decline due to economies of scale before diminishing returns set in. As reported on p. 20 of JJP-2, "… program-year data reveal that several states with DSM portfolios in the top two performance tiers over time have progressed through lower tiers. Also evident from program year performance data is that moving up

from one tier to the next is common, especially to and from the second tier. For example, Connecticut increased annual savings from 0.37 percent to 1.52 percent of sales between 2003 and 2010, moving from Tier 3 to Tier 1. Nova Scotia recently went from 0.17 percent of sales in 2008, Tier 4 results, to 0.68 percent of sales in 2010, Tier 2 results."

Q: How should the Commission expect scale economies and diminishing returns to affect DSM expenditures if BC Hydro doubles the currently planned scale of efficiency resource acquisition as you recommend?

A: Due to changes now on the horizon, the Commission should expect diminishing returns to dominate scale economies raise the incremental costs of saved energy in the future, particularly after 2013, as BC Hydro moves from Tier 2 to Tier 1 savings performance. This is because of federal lighting efficiency standards in Canada and the U.S. that begin taking effect this year. Compact fluorescent lamps (CFLs), a predominant source of efficiency portfolio savings since 2006, will shortly become "the new normal" for more and more lamp types by 2020. This means that CFLs will rapidly shrink as a source of low-cost program savings in the next several years. Emerging solid-state technology saves 50 percent or more lighting energy than CFLs but is currently more expensive, raising the cost of future energy efficiency investments in the near term.

Over time, however, the costs of these emerging solid-state lighting technologies is expected to decline while performance is expected to improve, so these cost increases should moderate in the future as volumes increase. Thus, leading efficiency administrators such as Vermont are promoting solid-state lighting in their energy-efficiency programs, where it is already making significant inroads in the business market.

Q: Have you estimated what it would cost for BC Hydro to scale up its portfolio to achieve annual electricity savings of 1.5 percent in F2013 and to 2 percent of sales by F2014 and in subsequent years?

A: Yes. Table 1, below, presents annual projection of annual program budgets and incremental annual energy savings for the residential and nonresidential sectors, as well as portfolio-wide peak demand savings associated with portfolio energy savings. In my opinion, these values provide a reasonable basis for setting budgetary expectations for scaling up BC Hydro's efficiency resource acquisition, starting in F2013.

Q. How did you develop these projections?

A: I did so using a two-stage process. The first stage is to estimate portfolio administrator costs of achieving the savings goals I recommend, expressed in terms of expenditures per annual kWh saved (i.e., unit costs). Next I translated unit acquisition costs by sector to sector-level budgets.

Q: Explain how you developed your projections of BC Hydro's future efficiency resource acquisition costs for reaching the savings targets you recommend.

A: As explained in Exh. JJP-2, Section II.C (pp. 26-28), GEEG has developed an empirical model based on data on historical and planned performance that predicts acquisition costs based on several explanatory variable. These include savings as a percentage of sales; residential vs. nonresidential sector; maturity of the portfolio; starting year for projections; and location. The coefficients of this equation were estimated using ordinary least squares regression analysis on the historical and planned data presented in Exh. JJP-2. Tables 13 and 14 of Exh. JJP-2 show that the estimated coefficients and the entire equation are highly statistically significant. All coefficients are

statistically significant, with confidence levels beyond 99 percent; the regression equation accounts for 87 percent of the variance in the dependent variable, portfolio administrator cost per annual kWh saved.

Q: What did your regression analysis reveal about the relationship between efficiency resource acquisition costs and the explanatory variables you examined?

A: Three findings stand out. First, the estimated equation is a polynomial function of savings depth that reveals the influence of both scale economies at savings depths below 2.5% and diminishing returns beyond that (see the cost curve depicted Table 15, p. 27 of Exh. JJP-2). Second, costs increase as a function of the maturity of the portfolio, the starting year of the prediction, and whether the period covered by the prediction applies to plans for the future (as opposed to predicting historical performance). Taken together, results indicate a secular trend of increasing efficiency resource acquisition costs over time, independent from the depth of savings. Third, certain locations matter – specifically, efficiency portfolios in California and New England tend to be more expensive than elsewhere, all else equal.

Q: What unit costs of efficiency resource acquisition does the model predict for BC Hydro?

A: According to Exh. JJP-2, Table 15, pp. 27-28, "residential costs start at $0.332/kWh-yr, falling to as low as $0.301 by 2014, and then rising monotonically thereafter to nearly $0.45 by 2032. Non-residential costs start at $0.256/kWh-yr range, falling to around $0.226/kWh-yr, and ending up near $0.37/kWh-yr." The report comes to the conclusion that "these findings are in line with recent analysis done by ISO New England on calculating the

future costs of state-sponsored energy efficiency for 2014-2020.[10] ISO-New England is currently using cost assumptions of $0.45/kWh for future energy efficiency activity in Maine, Vermont, Connecticut, Rhode Island, Massachusetts, all but one of which have aggressive energy efficiency targets in the years ahead."

Q: How did you translate these unit costs into sector-level DSM budgets for BC Hydro?

A: Multiplying these sector-level unit costs of energy savings ($/kWh-yr) by annual MWh savings representing two percent of forecast service-area sales for residential and nonresidential customers provides annual budgets for BC Hydro by year. Table 1, below, shows projected BC Hydro DSM program budgets yielding 2% depth of savings from F2013 to F2032. The derivation of the values in Table 1 is detailed in Exh. JJP-2.

[10] Ehrlich, David, and Eric Winkler. "ISO-NE Proof of Concept Forecast of New State-Sponsored Energy Efficiency 2014-2020". PAC Meeting. November 16, 2011.

Table 1 – Projected BC Hydro DSM Program Budgets and Electricity Savings From Increased Efficiency Resource Acquisition from F2013 to F2032

Fiscal Year	Budgets (Millions 2012$)			Incremental GWh			Incremental MW
	Residential	C&I	Total	Residential	C&I	Total	
2013	$94.58	$130.49	$225.07	285	509	794	147
2014	$116.68	$162.65	$279.33	388	721	1,108	203
2015	$122.27	$177.79	$300.07	396	760	1,155	209
2016	$128.46	$191.54	$320.00	405	791	1,196	216
2017	$133.90	$204.80	$338.69	411	818	1,229	223
2018	$139.57	$217.48	$357.05	418	841	1,259	228
2019	$145.36	$229.23	$374.60	425	859	1,284	232
2020	$151.72	$240.27	$391.99	433	873	1,307	237
2021	$157.09	$249.86	$406.95	438	882	1,320	239
2022	$162.89	$259.66	$422.55	444	891	1,335	242
2023	$168.93	$268.34	$437.27	451	895	1,346	244
2024	$175.76	$277.72	$453.48	459	902	1,360	246
2025	$181.66	$286.22	$467.89	464	905	1,369	248
2026	$188.03	$288.34	$476.36	470	889	1,359	246
2027	$194.51	$298.16	$492.67	477	896	1,373	249
2028	$201.06	$309.00	$510.07	483	906	1,390	252
2029	$207.68	$320.10	$527.79	489	917	1,406	255
2030	$214.13	$333.28	$547.41	495	933	1,428	258
2031	$220.86	$348.99	$569.85	501	955	1,456	264
2032	$228.81	$366.88	$595.69	510	981	1,491	270

Q: Why do you expect that it will cost BC Hydro so much more than it has spent in the past and plans to spend in the future, to acquire annual savings at the 2% depth of annual savings?

A: The projected costs of annual energy savings reflect the increasing influence of diminishing returns relative to that of scale economies in future energy-efficiency resource acquisition as BC Hydro scales up to the top tier of efficiency portfolio savings performance.

Q: Have you calculated the levelized costs per kWh of savings associated with the annual budgets you estimate?

A: Yes. As explained earlier, levelized costs are a function of the discount rate and the average life expectancy of portfolio savings, which depends in turn on the composition of the efficiency measure mix within and between the residential and nonresidential sectors. Given that high-efficiency lighting and HVAC equipment will predominate in both sectors, and that solid-state lighting will increase the longevity of residential lighting savings, average savings lifetimes of 10 and 15 years are reasonable assumptions for each respective sector. Applying these lifetimes to the residential and nonresidential costs of annual savings yields estimates of levelized cost of saved energy for the residential sector of between 3.99 to 5.96 cents/kWh and 2.25 to 3.72 cents/kWh for the commercial/industrial sectors. On a sales-weighted basis, this translates into an average acquisition cost of roughly 2.84 – 4.49 cents/kWh for the entire portfolio (in constant 2012 dollars, using the Company's residential-nonresidential sales split and a real discount rate of 5.5 percent).

Q: Should the Commission expect these additional savings and spending levels to be cost-effective?

A: Yes. On a levelized basis, the life-cycle costs of achieving the higher savings I recommend are roughly between a third and a half the long-run marginal costs of electricity energy and capacity that they will substitute for. BC Hydro's estimate of that value is $0.14268/kWh.

Q. Is there any evidence that increasing cost-effective efficiency resource acquisition beyond BC Hydro's current plans would lower average rates?

A: Yes. BC Hydro analyzed the impact on rates and bills of its proposed DSM investment in its amended DSM Plan. It found that compared to no

additional DSM investment, its Plan for cost-effective efficiency investment would lower average rates over the 20-year planning horizon.[11] Much of this favorable rate impact is due to amortization of DSM expenditures and recovery through rates over 15 years, which more closely matches the pattern of DSM cost recovery with the flow of benefit in terms of future utility system cost reductions from DSM investment. So long as increased efficiency investment is cost-effective under the utility test, it is reasonable to expect the higher level of DSM expenditures I recommend to lower average rates still further, at least for the F2013-14 test period.[12]

Q: Would acquiring so much more efficiency resources benefit British Columbia's economy?

A: Acquiring energy efficiency resources equivalent to two percent of BC Hydro's total electricity sales so much more cheaply than supply will be a powerful stimulus to the economy the Company serves in the years ahead. The present worth of the net benefits from the efficiency portfolio investment over the next two decades is $13.7 billion using BC Hydro's avoided supply costs.[13] BC Hydro acknowledges that net resource cost savings from cost-effective efficiency investment will multiply throughout the economy served by BC Hydro as households and businesses spend or invest the extra

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[11] BC Hydro Exh. B-1-3B, p. 65.

[12] Another necessary condition for no adverse rate impact from additional DSM investment is long-run avoided marginal supply costs continue to exceed the marginal revenue losses from retail sales reductions due to electricity savings. This may not remain the case throughout the planning period; especially as inclining block rates based on long-run marginal costs are introduced to more BC Hydro customers.

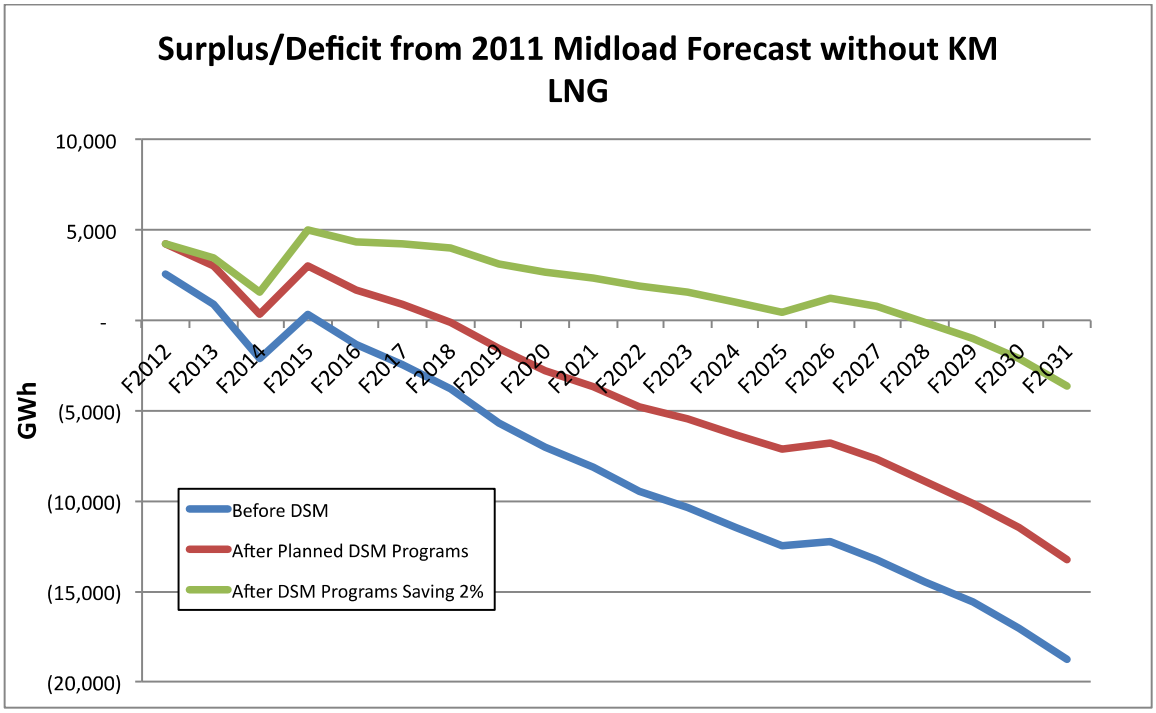
[13] Using a 5.5% nominal discount rate, and a long-run avoided costs of $142.68/MWh inflated to 2012 dollars (Assumptions from found in BC Hydro Exh. B-1-3B, p. 191).

disposable income on other goods and services, increasing economic activity.[14]

Q: What effect would acquiring efficiency resources equal to two percent of annual sales have on the resource gap BC Hydro anticipates under its DSM Plan?

A: It would eliminate the energy gap for many years longer than would be the case under BC Hydro's current DSM planning, as depicted in Figure 2, below.

Figure 2 – Projected Surplus/Deficit Gap with BC Hydro DSM Plan versus 2% Annual Savings[15]



[14] BC Hydro Exh. B-1-3B, p. 66.

[15] "Before DSM" values come from Exh. B-1-3B, p 114. "After Planned DSM Programs" add planned savings from DSM program excluding load management found in Exh. B-1-3B, p. 171 to "Before DSM".

D. DSM Risk Management

Q: What kinds of performance risks do energy-efficiency resources pose for BC Hydro and its customers?

A: Like any resource, demand-side resources pose the risk that electricity savings will not materialize in the magnitudes at the times and at the acquisition costs that BC Hydro plans on. However, BC Hydro and other utilities consider DSM to be fundamentally different from supply because participation in DSM programs is voluntary and measures savings may not materialize or persist as projected. Whereas customers can choose whether to participate in BC Hydro programs or to install recommended measures, supply resources are dispatchable (either directly or by contract). To supply planners, a resource that depends on voluntary participation by thousands of customers looks much less dependable than supply.

The risk that increasing demand-side resource acquisition will not deliver planned savings is easily overstated, however. Widespread under-performance or removal of efficiency technologies installed by efficiency programs is highly impractical and therefore improbable; there is no reason or evidence to suggest such behavior should be expected after higher market penetration of efficiency technologies due to scaled-up efficiency resource expenditures.

Moreover, efficiency resource acquisition is subject to far less uncertainty and variation in potential outcomes than is underlying long-term load growth. As BC Hydro indicates in its 2011 load forecast, how much load growth materializes over the next thirty years depends on a host of uncertain variables such as changes in population, secular trends in various

sectors of the economy BC Hydro serves, and prices of electric energy sources and alternatives.

Q: Can't DSM program administrators exert substantial control over the level of program savings via changes in program strategies, such as financial incentives?

A: Yes. In contrast with its inability to influence these forces determining electricity demand, BC Hydro can exercise significant control over the pace of efficiency resource acquisition. Lessons learned from industry leaders demonstrate that voluntary program participation can be counted on if portfolio administrators employ best practices in program design and implementation to maximize participation and participant savings.

Q: How can aggressive financial and delivery strategies reduce the risk of shortfalls in program participation and participant savings?

A: Evidence abounds that stronger financial incentives and delivery methods are necessary to maximize the realization of cost-effective efficiency savings through increased market penetration of high-efficiency measures. Experience in Maryland, for example, shows that higher financial incentives for retrofit measures recommended by energy assessments through Baltimore Gas and Electric's (BG&E's) Home Performance with Energy Star (HPwES) (analogous to BC's LiveSmart) program led to increased measure installation. Potomac Electric Power Company's (PEPCO's) Shop Doctor Program in the 1990s offered free direct installation of cost-effective lighting retrofits and achieved participation rates over 80 percent.

By contrast, requiring customers to put up two year's worth of estimated bill savings (as BC Hydro does in its commercial and industrial programs) poses an obstacle to participation, particularly in the present uncertain

economy this economy, and therefore is associated with lower participation rates. As the Maryland Public Service Commission Staff observed in its comments on BG&E's results for the first half of 2011,

> "EmPower Maryland programs that require low initial out-of pocket expenditure from both a residential and commercial customer perspective, have been relatively successful at meeting and exceeding participation and energy savings targets. These successful programs include Lighting and Appliances, QHEC and the Low Income programs for residential customers and the Small Commercial Lighting Solutions and Prescriptive programs on the Commercial side. Programs that may require a higher initial out-of-pocket expenditure have had trouble attracting participation and the corresponding energy savings. These poor performing programs include the HPwES program for the Residential sector and the Re-commissioning program on the Commercial side."[16]

Vermont and California experienced significant declines in participation when they switched from covering all retrofit costs to requiring customers to contribute a year's worth of estimated bill savings. Leading portfolio administrators also have also found that covering most or all the incremental costs of premium-efficiency technologies is necessary for programs to ramp up market penetration in new construction and replacement.

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[16] Maryland PSC Staff comments on BG&E's first and second quarter 2011 results, Case No. 9154, p. 16.

Q: Is there any other way that using more aggressive DSM program strategies reduces the risk of not achieving savings goals?

A: Yes. Another positive contribution to higher program savings from stronger financial incentives is an improvement in net savings relative to gross savings -- that is, relatively more of the program's total gross savings will be attributed to the program relative to what would have happened without it. This is because the amount of savings that would result from customer efficiency investment absent the program is fixed. As program participation increases due to higher incentives, the share of total program savings attributable to free-ridership necessarily declines. Conversely, lowering financial incentives lowers the level of program-induced participation relative to the fixed amount of savings that would have occurred due to customer efficiency investment without the program.

Q: How does this dynamic affect DSM expenditures associated with higher levels of DSM resource acquisition?

A: Higher incentives to achieve higher participation will definitely increase the portfolio administrator's costs of achieving total savings disproportionately, as explained above (section II.C, pp.15-16). This works in the opposite direction as well. Lowering incentives will not only lower total expenditures disproportionately; it will reduce net program savings disproportionately because a smaller fraction of the ensuing lower gross savings resulting from the loss of participation will be attributable to the program. BC Hydro should take these risk-mitigating advantages of more aggressive program strategies into account in its risk and cost-effectiveness assessment of increasing efficiency resource acquisition in its next IRP.

Q: How does the ability to ramp up efficiency resource acquisition compare to the risks posed by BC Hydro's new supply options?

A: This ability to scale efficiency resource acquisition up or down in small increments relative to supply resources constitutes one of several risk-mitigating advantages of DSM. The Vermont Public Service Board recognized this value by assigning a ten-percent "adder" to electric avoided costs in cost-effectiveness analysis.

Another unique advantage to efficiency resources is the ability to shape efficiency savings to match the system's energy and capacity gaps over time. In general, savings from energy-efficiency lighting and HVAC will be greatest when those end-use loads are highest. This tendency to co-vary with load also applies to load growth over time. Load growth accelerates during times of economic expansion, which increases the eligible population for efficiency investment in new construction and thus potential efficiency savings, and vice versa.

BC Hydro apparently accords no weight to such risk-mitigating attributes in the Company's decision not to increase DSM spending in F2012-13.

Q: Does BC Hydro recognize that it can reduce the risk of falling short of savings targets by strengthening financial incentives?

A: Yes. In the discussion of managing the risks of DSM performance in its Amended DSM F12/F13 Expenditure Schedule Proposal, BC Hydro discusses steps it can take to improve the likelihood that programs achieve planned participation targets and that participants achieve planned savings. These include improving estimates of potential savings and strengthening

program designs to increase participation and savings depth per participant. According to BC Hydro,

"To minimize the risk of lower participation than planned, DSM programs are designed to address barriers to energy efficiency and elicit customer participation using information from BC Hydro customers, trade allies and other jurisdictions. BC Hydro also undertakes comprehensive market and technical research into current and future DSM opportunities to develop the most effective Program Initiative designs. …

Programs also face a risk of delivering lower savings per participant than planned. This risk is mitigated by using a variety of sources on unit savings to forecast overall program savings, including market research, technical reviews of projects, M&V, and program evaluations.

If DSM program electricity savings fall below plan, BC Hydro can modify the program to respond and increase participation, for example by:

- Increasing or modifying program advertising;
- Modifying the program application process or eligibility criteria;
- Increasing or modifying program incentives; and
- Revising the list of qualifying products."[17]

Q: In your opinion, has BC Hydro adequately reflected its ability to manage DSM risks in its decision to curtail energy-efficiency investment in its DSM Proposal?

A: No. BC Hydro's reluctance to scale up efficiency resource acquisition appears not to fully appreciate the high degree of control it can exert over

[17] Exh. B-1-3B, Page 94 of 271, Amended New F12/F14 RRA -Appendix II F12/F13 DSM Expenditures Chapter 4 - DSM Performance Management, Page II-4-14.

these variables with aggressive marketing, financial, and implementation strategies employed by highest-performing efficiency portfolios elsewhere.

Q: Does BC Hydro expect its amended DSM expenditures to lower its ability to meet its F2013-2014 savings targets?

A: No. In its response to BCSEA IR 2.41.1 (Exhibit B-15), BC Hydro states: "As noted in the response to BCUC IR 1.453.4, the Government Review prompted BC Hydro to make a more concerted effort to reduce DSM costs. BC Hydro determined the acceptability of specific tradeoffs in the process of reducing DSM costs. *BC Hydro chose to reduce selected DSM costs that would not result in lower electricity savings in the short term but that could increase the risk of not achieving the electricity savings in the long term" (emphasis mine).*

Q: Do you agree with BC Hydro's expectations?

A: I agree with BC Hydro about the long term but disagree about the short term. BC Hydro is correct that the proposed cuts to F12/F13 DSM expenditures increase the risk that BC Hydro will not be capable of delivering enough savings to achieve long-term savings goals, especially if these absolute (i.e., MWh) goals increase, to keep up with the goal of meeting two-thirds of possibly substantially higher load growth. [18] This is why I conclude that BC

[18] BC Hydro declined to respond to BCSEA's request in IR 2.42.5 "to provide an analysis of the implications of short-term (F2014) DSM spending ramp-up versus spending maintenance in conjunction with the contingency of LNG load materializing versus not materializing." BC Hydro stated BC Hydro declines to respond to this IR because it refers to DSM expenditures in F2014, which fall outside the F12/F13 DSM Expenditures and the subject of this DSM expenditure application. The IRP will consider how much DSM BC Hydro should pursue in F2014 and beyond and will inform a future section 44.2 application for DSM expenditures in F2014 and beyond." In my opinion, DSM expenditures in F2014 (beginning April 1 2013 and ending March 31, 2014) should be relevant to DSM spending in F12-F13.

Hydro and its ratepayers would be better off if BC Hydro scales up DSM resource acquisition in the next two fiscal years. It would increase BC Hydro's capability to acquire more cost-effective efficiency resources when they are likely to be especially needed, even though the magnitude and timing of that additional need is still uncertain.

I do not agree with BC Hydro's contention that the proposed DSM program portfolio budget cuts will not jeopardize its ability to meet the modest electricity savings goals it proposes for F2013-2014.

Q: What leads you to this conclusion?

A: Despite past success in meeting savings targets, BC Hydro's recent performance has become problematic. BC Hydro failed to attain F2011 DSM program savings goals, while at the same time under-spending its authorized budget.[19] I have seen information indicating cuts to financial incentives in BC Hydro's commercial/industrial Prescriptive Incentive Program (PIP) that BC Hydro is planning that will likely lead to reduced program participation and lower savings per program participant in F2013. If so, then BC Hydro would experience the disproportionate drop in program savings and spending that I predicted earlier in my testimony (page 20) from lowering incentives.

Q: What evidence are you referring to?

A: Exhibit JJP-3 shows the simple payback period expected under three vintages of BC Hydro program incentives, based on assumed values for incremental costs and savings for a selected sample of prescriptive incentives for solid-state lighting technologies. It clearly indicates that the new cuts in incentives BC Hydro proposes to take effect next month will lengthen the payback

[19] Table 1 on page 212 of Exhibit B-1-3B shows that "Total Program" spending for F2011 was 39% less than planned, and savings were 60% less than planned.

period after incentives to beyond one year; in one case, BC Hydro proposes to eliminate incentives entirely.

Q: On what basis do you conclude that these cuts are likely to lead to diminished participation and savings?

A. I understand that private contractors use BC Hydro's incentives to help them sell efficiency retrofits to prospective customers. Customers are typically reluctant or unable to raise the capital required to pay for efficiency measures with payback periods longer than one year. By lowering incentives and lengthening customer payback periods beyond a year, BC Hydro can expect fewer customers to participate; and of those that do, fewer will install the more expensive measures with longer payback periods that save more energy. The result will be a disproportionate drop of total program savings, in addition to the desired (and again disproportionate) reduction in program spending.

While I have not communicated with any contractors serving BC Hydro's territory, I can only imagine from experience elsewhere that these incentive reductions will not help BC Hydro's business relationships with these and other upstream links of the Province's efficiency supply chain. Damage to the efficiency supply chain is the type of risk to BC Hydro's future capability to deliver efficiency savings that BC Hydro seeks to avoid in its Amended DSM Plan.[20]

Q: Are you testifying that BC Hydro should merely restore program budget cuts for F2013-14?

[20] BC Hydro Exh. B-1-3B, pages II-1-4, -5; II-2-22, -23.

A: No. I believe that BC Hydro should go even further and increase both its F2013-14 savings targets and the budgets to support them. If it does not increase EE savings and the spending necessary to achieve them in F2013-14, BC Hydro risks not being able to meet goals in the test period and beyond. This risk increases the higher the level of future DSM acquisition goals resulting from the 2012 IRP, which in turn depend on the rate of future load growth.

BC Hydro needs to build the capability now to deliver higher savings later if they are needed. Fortunately, doing so constitutes a "no-regrets" hedge against its long-term DSM resource acquisition risk, since in the long run, increasing acquisition of cost-effective DSM in the short term lowers both average utility bills (because of lower revenue requirements) and average utility rates (as shown by BC Hydro's rate impact analysis).

III. Strategies for Acquiring Additional Cost-effective Energy Efficiency Resources in BC Hydro's Service Area

A. Best Industry Practices for Scaling Up BC Hydro Efficiency Resource Acquisition

Q: What do you mean by best industry practices in energy-efficiency resource acquisition?

A: Best practices in energy-efficiency resource procurement have been developed based on lessons learned from over twenty years of experience with program design and implementation throughout North America. These lessons have been distilled by Pacific Gas and Electric (PG&E) in

collaboration with numerous electric and gas utilities.[21] In my opinion, these lessons can be distilled into the following guiding principles for maximizing achievement of cost-effective efficiency resources in long-range electric and gas energy-efficiency resource planning:

1) Scale up portfolio electricity savings by choosing the pace, scale and target customer populations for discretionary efficiency resource investment that maximizes net economic benefits.
2) Avoid cream-skimming and the creation of lost opportunities by encouraging comprehensive treatment and deeper savings per participant.
3) Use uniform program designs across utilities and energy sources. This applies to BC Hydro and the customers it shares with Fortis gas, as well as to BC Hydro's programs in relation to those operated in neighboring territory by FortisBC electric.

Q: What are discretionary efficiency resources?

A: Unlike market-driven efficiency opportunities that arise in new construction and end-of-life equipment replacement, discretionary efficiency resources involve retrofits that can be timed to suit a utility's resource needs. Such retrofits entail early retirement and replacement of existing inefficient equipment, and/or the installation of supplemental measures (such as insulation or controls).

Q: How can program administrators maximize economic benefits by timing and targeting discretionary efficiency investment?

A: Utilities can choose how long they want to take to reach the entire eligible population and realize the achievable potential for cost-effective electricity

[21] www.eebestpractices.com

savings they offer. They can then target subsets of the total population offering the greatest potential for cost-effective electricity savings. One effective approach is to identify and target customers with the highest usage, since efficiency savings potential is highly correlated with total usage. For example, programs can target customers in the top usage quintile first, and then work down to the fourth quintile over the chosen investment period.

Another effective means of maximizing economic value from discretionary resource acquisition is to target retrofit investment geographically. Doing so lowers resource acquisition costs through improved efficiencies in the marketing and delivery of program services. Geographically targeting retrofit programs can also deliver electricity savings where they are most valuable to the utility. For example, utilities can geographically target retrofit programs to deliver a particular amount of peak demand savings in areas of the system where load growth is expected to necessitate transmission and/or distribution capacity expansion. The avoided costs from deferring such investments add significantly to value of efficiency resources acquired in the targeted area. Vermont electric utilities have been with the state's efficiency utility to plan "geo-targeted" efficiency investment for the past three years, and plan to continue doing so for a least the next three.

Q: What do you mean by "cream skimming?"

A: Cream-skimming occurs when an efficiency program captures some low-cost savings while deliberately or inadvertently leaving behind savings opportunities that would not be cost-effective on their own but that would have been cost-effective if they had been included in the program. An example of cream-skimming is installing equipment that is less efficient than

economically optimal (e.g., early retirement of an inefficient central air conditioner and replacing it with one with an SEER of 15 rather than one with an 18 SEER if the latter would be cost-effective). The opportunity to achieve the savings from the efficiency upgrade at the relatively low incremental cost at the time of installation is lost for the life of the new inefficient equipment. This example illustrates how an energy-efficiency program could actually create lost opportunities for efficiency savings.

Q: How?

A: Consider the opportunity to achieve cost-effective residential lighting retrofit savings. It would almost certainly not be cost-effective for BC Hydro to field a program that only installed high-efficiency lamps in its customers' homes, even if the program installed 15 compact fluorescent lamps apiece (about half the average home's sockets, routinely achieved in Vermont, for example). But a Fortis Gas residential retrofit program would only incur the incremental cost of lamp installation in initial diagnostic and treatment visits. If it declined to integrate lighting direct installation with its gas retrofit program BC Hydro would be creating significant electric efficiency lost opportunities.

Failure to capture such lost-opportunity efficiency resources needlessly raises the cost of energy service to the province's consumers, either by forfeiting cost-effective savings entirely – and over-allocating resources to more expensive supply – or by requiring programs to return for them later as higher-cost retrofits.

Q: How does uniformity of program designs help maximize cost-effective electricity savings?

A: Customers vary by utility service area; the Province's supply chains for efficiency products and services do not. Making suppliers and contractors learn and comply with different sets of financial incentives and minimum efficiency requirements between BC Hydro and FortisBC Electric raises the costs of and therefore discourages participation in electric utility DSM programs. Combining forces to market programs under a single umbrella also heightens market awareness up and down the supply chain. At a minimum, the Commission should direct BC Hydro and FortisBC Electric, wherever possible, to increase standardization of common program features, including marketing, financial incentives, and eligibility requirements in markets for efficient retail products; HVAC, lighting and other equipment replacement; and new construction. These improvements will help promote market demand and supply of high-efficiency products, equipment and services, scale economies in program administration and implementation, and accelerate cost declines in premium-efficiency technologies.

Q: Why is it so important that utilities address electricity and gas savings from efficiency measures in combination?

A: Some residential efficiency upgrades save both gas and electricity, such as building shell improvements that save gas heating and gas cooling. Typically such measures are cost-effective when both (gas and electricity) savings are counted but not so on the basis of one or the other. This applies in both residential new construction and residential retrofit. Failure to integrate electricity and gas savings into program design and delivery could easily lead to the false conclusion that efficiency investments are not cost-effective.

Having BC Hydro and FortisBC Gas operate two separate efficiency programs for the same customers simultaneously would result in higher

program costs, lower market penetration and less comprehensive savings among participants. Some BC Hydro customers use electricity to cool and natural gas to heat their homes and businesses. Many efficiency retrofit opportunities involve efficiency measures that save both forms of energy. Dealing with separate programs poses a barrier to customer and supplier participation.

Conversely, addressing all of a customer's inter-related efficiency opportunities comprehensively makes participation and additional efficiency measures more attractive, maximizing the amount of cost-effective electricity and gas savings realized from efficiency portfolio investment. This is especially critical for retrofit programs and for BC Hydro programs targeting new construction and remodeling in all customer sectors because opportunities to save both electricity and gas cost-effectively are so abundant in these markets. Taking a comprehensive approach also reduces fragmentation that comes with having separate programs that focus on individual efficiency technologies (e.g., thermostats).

Best industry practice is to assess gas and electric efficiency cost-effectiveness jointly, and then formulate financial strategies and deliver program services to achieve comprehensive savings of both at the same time.

Q: Do commercial and industrial gas efficiency programs offer similar opportunities for optimizing results through tight integration with electric efficiency opportunities?

A: Yes. Among larger customers, the primary concern is that the planning and execution of electric and gas efficiency upgrades in both market-driven equipment replacement and efficiency-driven retrofits be coordinated with business capital budgeting cycles. Many retrofit projects produce both gas

and electricity savings, so it is imperative that customized offers be made on the basis of cash flows they produce in combination. In this way BC Hydro can maximize customer contributions toward gas and electric efficiency investments, thereby minimizing the share of investment costs borne by ratepayers at large and maximizing the savings that can be achieved with a fixed program budget.

Q: How can BC Hydro make sure that its electric DSM programs are sufficiently integrated with FortisBC Energy Utilities' natural gas DSM programs?

A: Based on the experience of efficiency industry leaders, the Company should field programs that target both electric efficiency and natural gas efficiency under a single umbrella. Combined electricity and gas programs should be created for residential and nonresidential construction (both new and renovation) and retrofits.

For residential programs, it makes sense for FEU (gas) to form the platform on which FBC electricity efficiency measure are "piggybacked." This is because FEU is already incurring the relatively high cost of reaching residential customers and cost-effective gas savings are likely larger than cost-effective electricity retrofit savings in homes in the FBC service area. Conversely, for non-residential programs, gas efficiency savings should piggyback on the electric efficiency program platform, since the magnitude and value of cost-effective electric efficiency savings will tend to outweigh gas savings in these settings.

Q: Doesn't this joint approach risk cross-subsidization between gas and electric ratepayers?

A: Not if BC Hydro, FBC (electric) and FEU (gas) allocate common program costs and energy savings appropriately. It is common for separate electric and gas utilities to allocate program and fixed costs for measures that save both electricity and gas, in proportion to the present worth of benefits derived from each.

B. Changes in BC Hydro's DSM Planning to Acquire Additional Cost-effective Efficiency Resources

Q: What steps should BC Hydro take in its DSM planning to acquire the higher levels of cost-effective electricity savings you recommend?

A: BC Hydro should modify its DSM program plans to increase annual electricity savings based on best industry practices discussed in the foregoing section of my testimony. I have several specific program suggestions for accomplishing this. BC Hydro should incorporate these program modifications into a new long-range assessment of the achievable potential for cost-effective efficiency resources as part of its next integrated resource plan.

Q: In which areas do you recommend that BC Hydro change its current DSM program planning?

A: I recommend that BC Hydro make changes in the following program areas:

- full integration of electric and gas in new construction and retrofit programs;
- program enhancements designed to achieve comprehensive retrofits among most low-income, other residential, and small-to-medium commercial/industrial customers over the planning period;

- redesign of prescriptive financial incentives for nonresidential customers;
- accelerated conversion of all streetlighting to solid-state technology; and
- a long-term capital plan for BC Hydro to realize all cost-effectively achievable efficiency savings in its own facilities through its Lead by Design program.

Q: Doesn't BC Hydro already integrate its DSM programs with FEU's gas DSM programs?

A: Yes, to some extent. In fact, BC Hydro appears to be heading increasingly in this direction. As the Commission recently found in its decision on FEU's DSM Plan, however, room for improvement remains.[22] BC Hydro should fully integrate its LiveSmart new construction and retrofit programs in all sectors with FEU in F2013 and F2014.

Q: What types of enhancements do you have in mind for BC Hydro's discretionary DSM resource acquisition programs?

A: First, I recommend that BC Hydro redesign its low-income retrofit program to incorporate best practices for achieving comprehensive electric and gas efficiency savings. Using programs in Connecticut, Long Island, Massachusetts, and New Jersey as models, BC Hydro should directly install all cost-effective efficiency measures, including equipment replacement, instrumented air- and duct-sealing, and cavity insulation. This approach will lead to deeper electricity savings and improve program cost-effectiveness.

Second, I recommend that BC Hydro develop and implement programs to promote comprehensive retrofit investment on the part of single-family

[22] BCUC Order G-44-12, Reasons for Decision, pp.179-180.

residential, multi-family residential, and small to medium commercial and industrial customers. These programs should combine financing innovations and financial incentives structured to provide customers with positive cash flow from their contribution toward their customized efficiency investment project. This is possible if participants can repay the money they borrow for their share of the efficiency investment for at least one year longer than the payback period on the project after program financial incentives. This approach will increase both participation and savings per participant, while keeping down program cost by maximizing participant contribution toward the costs of efficiency investments.

Q: What innovative financing approaches do you have in mind?

A: Two separate financial strategies offer the potential for expanding BC Hydro's customers' access to capital for retrofit efficiency investment: on-bill financing, and loan-loss guarantees or reserves. They are mutually reinforcing in terms of their potential impacts on increasing the volume and lowering the cost of capital accessible to BC Hydro customers to pay for efficiency investment.

Q: How would on-bill financing enable customers to pay the full costs of retrofits?

A: Participating customers would pay fixed monthly installments as an individualized line item on their bills. Monthly payments would be calculated to be less than one-twelfth the estimated annual bill savings, thereby accomplishing positive cash flow for participating customers. In practice this is done by setting the length of the repayment term to one year longer than the simple payback period of the retrofit investment.

Q: Would utilities have to lend money directly to customers?

A: No. BC Hydro would not have to enter the banking business. Instead, one or more lending institutions would advance the funds to pay for individual customers' efficiency retrofits. BC Hydro's role would be to collect the money borrowers pay on their bills and remit it to lenders over time. BC Hydro would pay lenders fees for loan origination and administration, plus prepayment of any interest-rate discount built into the on-bill installment payment.

Q: Why would you expect this to lower program costs?

A: Rather than paying most or all efficiency investment costs as would ordinarily be necessary to achieve high customer participation, BC Hydro (with FEU for projects involving efficiency measures that save gas) would pay lenders fees representing a much smaller percentage of project costs.

Q: Why would you expect the fees BC Hydro would have to pay lenders to be so much lower as a percentage of project costs?

A: Costs would be significantly lower for lenders because the administrative tasks having to do with billing and collection would be handled by BC Hydro instead of the bank, and because the credit risks and related costs associated with electric bill financing are much lower than they would be for a separate loan administered by a bank.

Q: What about the risk of nonpayment?

A: Ultimately this would be a cost of doing business. All the evidence I have seen suggests the risk would be low. According to a recent report by the American Council for an Energy-Efficient Economy ("ACEEE") surveying experience of utilities in several jurisdiction, default rates on utility-sponsored efficiency loans has historically been in the low single digits. Programs with on-bill repayment have experienced default rates of 2 percent

or lower.[23] One way to addressing this risk systematically and cost-effectively would be for BC Hydro to establish a loan-loss reserve fund. It is far cheaper to pay the full cost of one out of fifty or even twenty efficiency retrofits than to pay fully for all of them.

Q: How would a loan loss reserve fund work?

A: BC Hydro would negotiate a fixed percentage of the face value of each loan to set aside and post to a reserve fund for lenders to draw against for any loans BC Hydro notifies them have defaulted. Given the lack of experience with large volumes of such lending in Vermont, financial institutions would likely demand a loss reserve one or more percentage points above the predicted default rate. The lender would then draw upon the loan loss reserve fund to close the loan account and pay itself the uncollected principal. BC Hydro's actual expense for maintaining the loan loss reserve fund would be limited to actual amount of unpaid loan principal and interest. Once lending institutions establish a track record for loan performance, over time they can be expected to accept a loan loss reserve percentage closer to the historical default rate.

Q: Is a loan-loss reserve fund the only option for protecting lenders against potential loan losses?

A: No. Another option could be to contract for loan guarantees through a third party. BC Hydro or participating financial institutions could eventually purchase this service after several years of experience.

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[23] ACEEE, "On-Bill Financing For Energy-Efficiency Improvements: A Review of Current Program Challenges, Opportunities, and Best Practices," December 2011.

Q: What about BC Hydro's own costs of administering these innovative financing approaches?

A: BC Hydro's costs would be confined to the one-time set-up costs for developing and launching the on-bill installment payment billing and processing, plus ongoing costs of operating and maintaining the system over time.

Q: Are other jurisdictions pursuing on-bill financing?

A: Yes. Pursuant to recent legislation, New York utilities are planning on offering on-bill financing for efficiency measures in the next year.

Q: How should BC Hydro set annual participation and electricity savings goals for each of the four targeted retrofit market segments?

A: BC Hydro should commit to achieve a specific fraction of the eligible population by the end of long-range planning period, e.g., 75 percent in 20 years. It should work with DSM stakeholders to choose a reasonable trajectory of annual participation rates as DSM planning goals for period covered by BC Hydro's IRP. It should also employ community-wide geographic targeting to maximize participation and economic benefits and minimize program delivery costs, as I discussed earlier in my testimony. Following this approach will establish BC Hydro's capability to deliver savings using these new retrofit program strategies in F2013 and F2014, enabling it to scale participation up or down as dictated according to its next long-range IRP.

Q: Explain your recommendation that BC Hydro embark on a campaign to convert all streetlighting to solid-state lighting technology.

A: Compared with existing streetlighting, LED technology offers large and long-lasting electricity savings, significant non-electric cost savings, and improved

lighting quality. The technology has evolved to the point that it is now ready for widespread adoption, including in British Columbia. As explained in the forthcoming paper (attached as Exh. JJP-4), Vermont's largest utilities have committed to convert most streetlighting to LEDs over the next five years in partnership with the state's energy-efficiency utility. BC Hydro should follow a similar course. While the electricity savings from this program may not contribute significant peak demand savings, they will occur during periods BC Hydro may be importing coal-fired generation (e.g., from Alberta) to preserve hydroelectric capacity and energy for use during periods of peak load.

Q: Why should BC Hydro accelerate efficiency investment in its own facilities?

A: BC Hydro faces none of the market barriers preventing its customers from investing in cost-effective efficiency investment. Unlike its customers, BC Hydro has or should have access to the information necessary to determine how much electricity it can save cost-effectively. Compared to its customers, BC Hydro has superior access to capital to finance cost-effective efficiency investments. And since there are no revenue losses associated with BC Hydro's own efficiency investments, acquiring additional efficiency resources literally from itself will automatically lower total costs of service and customer rates. BC Hydro's responses to BCSEA IR1.1.22 (Exhibit B-16) and BCSEA IR2.39.1-3 (Exhibit B-25) reveal a somewhat relaxed approach to harvesting these opportunities to lower revenue requirements and rates. This is why I recommend that the Commission direct BC Hydro to prepare a multi-year plan to realize all cost-effectively achievable efficiency savings that it can from all its facilities over the planning period, and proceed

to implement this plan in F2013-14. Only then can BC Hydro legitimately claim to be leading its customers by example.

Q: Is a whole new DSM program potential assessment really necessary now?

A: Yes. In my opinion, BC Hydro's 2007 Conservation Potential Review (CPR) is considerably out of date. New research and analysis is needed to estimate the long-range potential for cost-effective efficiency resources that reflects updated expectations of lighting standards, as well as the implications of employing best practices in program design and implementation as I recommended in this section of my testimony.

IV. Conclusions and Recommendations

Q: On the basis of your foregoing testimony, what are your conclusions and recommendations?

A: I conclude the following:

- All evidence indicates BC Hydro should be able to double the scale of its DSM resources for less than half the long run marginal cost of additional supply. While Additional cost-effective efficiency investment will lower rates, according to BC Hydro's rate and bill analysis. Consequently, it is time for BC Hydro to scale up its efficiency resource acquisition to the top tier of industry performance in F2013 before it completes its next IRP. I recommend that the Commission direct BC Hydro to do so, and to include a DSM scenario with electricity savings and expenditures designed to save two percent of forecast electricity sales annually in its next IRP.

- While there is uncertainty about how much and how fast BC Hydro's load will grow, there is little or no doubt that BC Hydro will need additional resources in the next decade. Its amended DSM plan runs the serious risk of leaving BC Hydro without the capability to deliver efficiency resources on the scale at which they are likely be needed to provide reliable electric service in the future. Accordingly, I urge the Commission to direct BC Hydro to reverse course on its pending plans to lower or eliminate incentives for LED technologies in the nonresidential prescriptive incentive program. In doing so, BC Hydro should restructure incentives so that they reduce payback periods for customers to one year, or two at the longest. In the custom retrofit programs I recommend in the previous section, BC Hydro can extend payback periods longer than one year if it is successful in putting in place the financing innovations I discuss there.
- At five years old, BC Hydro's 2007 CPR is out of date given the energy efficiency standards enacted since then which will profoundly alter the lighting marketplace over the next decade. The Commission should therefore direct BC Hydro to conduct a new long-range CPR to account for the new market outlook, assuming programs are redesigned and implemented according to the latest industry best practices as I describe in Section III.A.
- If BC Hydro proves incapable of administering an energy-efficiency portfolio that meets the province's electricity savings goals, then the Commission should consider whether these responsibilities should be outsourced, as has been done in other North American jurisdictions such as the province of Nova Scotia and the states of Hawaii, Maine, Oregon, Vermont, and Wisconsin.

Q: Does this complete your direct testimony?

A: Yes, it does.

RESUME

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Trained as an economist, John Plunkett has worked for over 30 years in energy utility planning, concentrating on energy efficiency and renewables investments as resource and business strategies for energy service providers. He has played key advisory and negotiating roles on all aspects of electric and gas utility demand-side management, including residential, industrial and commercial program design, implementation, oversight, performance incentives, and monitoring and evaluation, and their respective roles in business, regulatory, ratemaking, resource planning and policy decisions. He has led, prepared or contributed to numerous analyses and reports on the economically achievable potential for efficiency and renewable resources.

Plunkett has worked throughout North America and in three Chinese provinces. He has provided expert testimony before regulators in Connecticut, Delaware, the District of Columbia, Florida, Illinois, Indiana, Louisiana, Maine, Maryland, Massachusetts, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, and Vermont, as well as in the Canadian provinces of British Columbia, Ontario, and Quebec.

EMPLOYMENT HISTORY

2005-present

Partner and co-founder, **Green Energy Economics Group, Inc**., Bristol, VT
Three-person consultancy specializing in energy-efficiency and renewable resource portfolios investing in electricity and gas savings. Technical and strategic assistance with development, design, economic and financial analysis, planning, administration, implementation management support, oversight, performance verification and evaluation, design of performance incentive and pricing mechanisms, and regulatory and ratemaking treatment of utility-funded electricity and gas energy-efficiency portfolios.

1996 – 2005

Partner and co-founder, **Optimal Energy, Inc.**, Bristol, VT.
Strategic planning, implementation management and regulatory support on energy-efficiency investment by regulated and unregulated businesses. Lead consultant for Natural Resources Defense Council on demand-side management portfolio design and economic analysis in two Chinese provinces. Lead author and expert witness on report recommending revamped performance incentive for Connecticut efficiency program administrators, on behalf of Office of Consumer Counsel. Led statewide efficiency and renewable potential study for New York and efficiency potential study for Vermont. Lead author and expert witness on assessment of economically achievable transmission capacity from efficiency resources for Vermont's

transmission utility. Advisor on economic analysis of clean energy initiative for the Long Island Power Authority, program cost-effectiveness in Massachusetts and New Jersey collaboratives, and regional market transformation initiatives for Northeast Energy Efficiency Partnerships.

1990 – 1996
Senior Vice President, **Resource Insight, Inc.**, Middlebury, VT.
Provided analysis of DSM resource planning/acquisition and integrated resource planning in numerous states. Investigated regulatory and planning reforms needed to integrate demand-side resources with least-cost planning requirements by public utility commissions. Prepared, delivered and/or supported testimony on wide variety of IRP, DSM, economic, cost recovery and other issues before regulatory agencies throughout North America. Consulted and provided technical assistance regarding utility filings. Responsible for presentations and seminars on DSM planning and evaluation.

1984 – 1990
Senior Economist, **Komanoff Energy Associates**, New York, NY.
Directed consulting services on integrated utility resource planning. Testified on utility resource alternatives, including energy-efficiency investments and independent power. Examined costs and benefits of resource options in over twenty-five proceedings. Supported major investigation into utility DSM investment and integrated resource planning. Designed and co-wrote microcomputer software for evaluating the financial prospects of customer-owned power generation. Wrote and spoke widely on integrated planning issues. Contributed to least-cost planning handbooks prepared by the National Association of Regulatory Utility Commissioners and by the National Association of State Utility Consumer Advocates.

1978 – 1984
Staff Economist, **Institute for Local Self-Reliance**, Washington, D.C.
Project development and management for a non-profit consulting firm specializing in energy and urban economic development. Project manager and economist for an investigation into the economic impact on small generators from electric utilities' grid-interconnection requirements. Coordinated research by three electrical engineers, and analyzed the impact of interconnection costs on wind, hydroelectric and cogeneration projects in seven utility service areas in New York. Provided technical coordination in cases before the District of Columbia Public Service Commission involving gas and electric utility demand management investment, non-utility generation pricing, both for the D.C. Office of People's Counsel.

1977-78
Energy Project Director, **D.C. Public Interest Research Group**, Washington, D.C. 1977. Led energy research and advocacy on campuses of Georgetown and George Washington Universities.

EDUCATION

B.A., Economics, with Distinction, *Phi Beta Kappa*, Swarthmore College, Swarthmore, PA, 1983. Awarded departmental Adams Prize in Quantitative Economics.

(Georgetown University School of Foreign Service, Washington, DC, 1975-1977.)

EXPERIENCE

ONGOING AND RECENT ASSIGNMENTS -- 2006-PRESENT

Vermont

Senior Policy Advisor to Efficiency Vermont, the world's first Energy Efficiency Utility, operating under contract with the Vermont Public Service Board to deliver statewide energy-efficiency programs for the customers of Vermont's electric utilities. Senior management team member from 2000 through 2007; led program development and planning, 2000-2002. Responsibilities include economic, policy, and evaluation research, analysis and advice. Contract negotiation team member advising on performance goals and incentive mechanism for four successive contracts over twelve years. Testified in support of 12-year order of appointment granted by the PSB December 2010. Recent assignments include technical direction of 20-year forecast of electricity savings under alternative investment scenarios.

Program design and regulatory support for 5-year investment of $9 million Energy Efficiency Fund, supplementing Efficiency Vermont investment, on behalf of Green Mountain Power. February 2007 – present. Rebuttal testimony on achievable value from additional energy-efficiency investment in utility service area, on behalf of Green Mountain Power in its merger approval applications in Dockets 7213 and 7770. December 2006-January 2007; January 2012-present.

Pennsylvania

Conservation program design, implementation planning, and regulatory support, for Philadelphia Gas Works. August 2008 – present. Testimony before the Pennsylvania Public Utility Commission in Docket R-2009-2139884, December 2009 and April 2010.

Analysis and report on costs and benefits of meeting all statewide load growth with energy-efficiency investment, on behalf of Citizens for Pennsylvania's Future (Pennfuture). September 2007.

Direct and surrebuttal testimony for Citizens for Pennsylvania's Future (Pennfuture) on appropriate levels of efficiency portfolio investment in two rate cases before the Pennsylvania Public Utility Commission: Docket Nos. 00061366 and 00061367 re Metropolitan Edison Company and Pennsylvania Electric Company; and Docket No. R-00061346 re Duquesne Light Company. May - August 2006.

Wisconsin

Cost-effectiveness calculator development and application assistance for Shaw Engineering and Infrastructure, administrator for Wisconsin's Focus On Energy gas and electric energy efficiency investment portfolio. June 2011 – present.

Oklahoma

Analysis, technical assistance and expert testimony on potential for energy-efficiency investment to substitute for fossil generation in proceedings before the Oklahoma Commerce Commission on behalf of the Sierra Club, May 2011 – present.

Illinois

Cost-effectiveness calculator development, oversight of cost/benefit analysis, and regulatory support for 3-year energy-efficiency portfolio for Peoples Gas. September 2008 – present.

Rebuttal and surrebuttal testimony opposing disallowances recommended by ICC Staff for Peoples Gas. April – September 2010; December 2011 – present.

New York

Advisor on energy-efficiency portfolio design and implementation, for the Economic Development Corporation of the City of New York, in three proceedings before the New York Public Service Commission. One is the PSC's investigation into an energy-efficiency portfolio standard for meeting statewide energy savings goals of 15% by 2015. The second is a collaborative effort with Consolidated Edison's gas division to design a portfolio of gas efficiency programs. The third is evaluation and future redesign of Con Ed Electric's $125 million network-targeted demand-side program. July 2007-December 2008.

Connecticut

Testimony regarding long-range energy-efficiency procurement plan of the Energy Conservation Management Board, on behalf of the Connecticut Office of Consumer Counsel. August – October 2008.

Florida

Direct testimony on the effect of economically achievable energy efficiency on the need for new coal-fired generation, on behalf of the Sierra Club and other environmental intervenors, Florida Public Service Commission Docket No. 070098-EI. March-April 2007.

British Columbia, Canada

Direct testimony on reasonableness of gas DSM Plan by Fortis Energy Utilities before the British Columbia Utilities Commission, BCUC Project No. 3698627**,** on behalf of the BC Sustainable Energy Association and Sierra Club (BC Chapter), May – November 2011.

Direct testimony and technical support on assessment of FortisBC Electric's long-term DSM plan, before the BCUC, on behalf of BCSEA/SCBC, August 2011 – present.

Direct testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC, on behalf of BCSEA/SCBC, November 2008 – March 2009; October 2011 - present.

Direct testimony on assessment of Terasen Gas conservation plans before the BCUC, on behalf of BCSEA/SCBC. October 2008.

Direct testimony on energy-efficiency investment spending and savings, British Columbia Hydro and Power Authority, 2006 Integrated Electricity Plan and Long Term Acquisition Plan, Project No. 3698419; and F2007/F2008 Revenue Requirements Application, Project No. 3698416, on behalf of BCSEA/SCBC et al. September 2006 – January 2007.

People's Republic of China

Central Government

Consulting team member on a project developing a national DSM implementation manual for China, sponsored by the National Development and Reform Commission, led by the Natural Resources Defense Council, in cooperation with California's investor-owned utilities, and funded by the international Renewable Energy and Energy Efficiency Programme (REEEP). Wrote chapters concerning performance indicators and cost-effectiveness analysis. 2007-Spring 2008. Manual approved by NDRC May 2009 and issued May 2010.

Guangdong Province

Consultant for the Institute for Sustainable Communities to assist Chinese experts with technical, economic, and financial assessments of industrial retrofit projects. Economic and financial assessment of efficiency retrofits to a ceramics manufacturing plant. 2007-2008. Training and technical assistance to Chinese trainers on economic and financial assessment of energy-efficiency and renewable investment projects in Guangdong and Jiangsu provinces. 2009-2010.

Team leader for Chinese and international consultants on a pre-feasibility analysis for the Asian Development Bank of a 24-year loan to support a $120 million demonstration Efficiency Power Plant (EPP) project in Guangdong province, focusing on industrial, commercial and institutional retrofits. June 2006 – 2007. ADB Board of Directors unanimously approved the loan and its first tranche of projects in June 2008.

Jiangsu Province

Consulting team leader on development, assessment, and implementation of demand-side management investment portfolios for China, for the Natural Resources Defense Council. (July 2003 – 2007) Responsible for program implementation planning and support (2005-2007). Led modification and application of US-based program and portfolio economic analysis tool for DSM planning. Assisted Jiangsu Province with design and planning for first-stage implementation of Efficiency Power Plant (EPP) programs investing $12 million annually on high-efficiency retrofits to industrial motors and drives and commercial lighting and cooling. Directed economic and financial analysis of industrial retrofits for several manufacturers to determine financial incentives offered by the program. October 2005 – 2007. Training and technical support on economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers (2007-2008).

Regulatory Assistance Project

Technical and policy advice on clean energy investment on Global Power Sector Best Practices Project. June 2011 – present.

PRIOR ASSIGNMENTS (OPTIMAL ENERGY) -- 1996-2005

- Policy and economic advisor for Massachusetts energy efficiency collaboratives, focusing on regulatory, cost-effectiveness, shareholder incentives and other policy issues and strategies, on behalf of Massachusetts Collaborative Non-Utility Parties. (January 1999 – 2005)

- Co-author (with Optimal Energy and Vermont Energy Investment Corporation), Comments on Efficiency Maine's 2006-2008 Program Plan, on behalf of Maine's Office of Public Advocate. September 2005.

- Team leader providing technical assistance supporting rulemaking to implement energy-efficiency provision of renewable portfolio standard for Pennsylvania, on behalf of Citizens for Pennsylvania's Future (PennFuture). Lead consultant on development of protocols for measuring savings from energy-efficiency investments as tradable credits toward the electricity resource portfolio standard. Protocols adopted by the Pennsylvania Public Utilities Commission. 2005. (February – September 2005)

- Leader of analysis of economically achievable potential for energy-efficiency resources to offset loss of output in the event of early retirement of the Indian Point nuclear generation station, on behalf of the National Academy of Sciences. May-October 2005.

- Co-author (with Paul Chernick) of testimony assessing planned energy-efficiency investments by British Columbia Hydro, on behalf of the British Columbia Sustainable Energy Association and British Columbia Sierra Club, August 2005.

- Written testimony recommending energy-efficiency portfolio investment levels and savings goals in utility merger application before the Pennsylvania Public Utility Commission, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group with and into Exelon Corporation, on behalf of the Pennfuture Parties, June 28, 2005.

- Co-author of and expert witness supporting "Getting Results: Review of Hydro Quebec's Proposed 2005-2010 Energy Efficiency Plan," before the Quebec Energy Board, on behalf of a coalition of business, municipal, and environmental groups (January-March 2005)

- Testimony (with Ashok Gupta) before the New York Public Service Commission supporting joint settlement proposal for 300 MW of additional efficiency investment in Con Edison territory, on behalf of the Natural Resources Defense Council, Pace Energy Project, and the Association for Energy Affordability (December 2004 – January 2005).

- Report and testimony on performance incentives for administrators of conservation and load management programs in Connecticut, on behalf of Connecticut Office of Consumer Counsel. (February 2003 – August 2004). DPUC adopted recommended performance incentive mechanism for 2006 program year.

- Project leader, including report and testimony, for consulting team projecting potential for demand-side resources to defer the need for the Northwest Reliability Project, a major transmission upgrade, on behalf of Vermont Electric Power Company. (November 2001 – December 2004)
- Report and testimony on Opportunities for Accelerated Electrical Energy Efficiency in Québec 2005 – 2012, on behalf of Regroupement National des Conseils Régionaux de L'environnement du Québec, Regroupement des Organismes Environnementaux en Energie and Regroupement pour la Responsabilité Sociale des Entreprises. (March – June 2004)

- Project leader for consulting team assessing technical, achievable and economic potential for energy-efficiency and renewable resources in New York State and five sub regions over 5, 10 and 20 years, on behalf of New York State Research and Development Authority. (January 2002 – August 2003)

- Project leader for consulting team updating statewide projection of economically achievable efficiency potential for state of Vermont, on behalf of the Vermont Department of Public Service. (October 2001 – 2003)

- "A Conservation Contingency Plan for Indian Point: Using California's Success Beating Blackouts to Replace Nuclear Generation Serving Greater New York," prepared for the Natural Resources Defense Council, October 2003.

- "The Achievable Potential for Electric Efficiency Savings in Maine." Projected and compared 10-year C&I costs, savings and benefits (based on technical potential analysis prepared by Exeter Associates). Expert testimony on behalf of the Office of Public Advocate, before the Maine PUC. (October 2002)

- Project leader for consulting team supporting utilities in targeting demand-side resources to optimize distribution investment planning in statewide distributed utility planning collaborative, on behalf of the Vermont Department of Public Service. (September 2001 – December 2002) Led development of DSM scoping tool, an MS Excel spreadsheet for preliminary analysis of the economically achievable potential for energy-efficiency to defer or displace planned distribution investments.

- Advisor on economic analysis for program planning and implementation of multi-year statewide energy-efficiency programs in the New Jersey Clean Energy Collaborative involving all the state's electric and gas utilities and the Natural Resources Defense Council. (April 2000 – June 2003, on behalf of NRDC). Co-directed collaborative work on program development, planning, and implementation for Conectiv. (November 1996 – 2000)

- Analysis and testimony before the Connecticut Siting Council on integrating potential demand reductions from targeted demand-side resources into need assessment for

transmission upgrades, on behalf of the Connecticut Office of Consumer Counsel. Docket No. 217. (February 2002 – February 2003)

- Advice and negotiation on policy and scope of utility activities regarding targeted DSM to optimize distribution investment planning, involving Consolidated Edison, PECO Energy, and Orange and Rockland Utilities, on behalf of the Natural Resources Defense Council (Con Ed and PECO) and Pace Energy Project (O&R). (1999 – 2000)

- "Examining the Potential for Energy Efficiency in Michigan: Help for the Economy and the Environment," for American Council for an Energy-Efficient Economy (ACEEE). Analysis and report projecting costs and benefits of aggressive energy-efficiency investment. (January 2003)

- Led consulting team in the preparation of detailed recommendations for implementing strategic plan for acquiring clean power resources for the Jacksonville Electric Authority. (May – September 2001)

- Consultant to Citizens Utilities Corporation, supporting planning and management of investments pursuing maximum achievable levels of optimally cost-effective energy-efficiency in its Vermont Electric Division. (1997 – 2001)

- Consultant to PEPCo Energy Services on building energy-efficiency into retail service offerings. (2000 – 2001)

- Consultant to California Board for Energy-Efficiency, the agency responsible for administering wires-charge funded statewide energy-efficiency programs. Technical service consultant on nonresidential program design. (1997 – 1999)

- Lead consultant on energy product development for consumer energy cooperative, on behalf of Vermont Energy Futures, a non-profit organization spearheading development of a consumer-owned energy cooperative that will bundle electricity with energy-efficiency, renewables, and fossil fuels for residential, low-income, and small non-residential customers. One of key team members who prepared grant application to federal Health and Human Services Department for $800,000 grant supporting development of the co-op. (1997 – 2000)

- Led feasibility analysis and prepared preliminary business plan for bundling electricity, fuel, efficiency services, and green power initially targeting low-income and environmentally-conscious consumers, on behalf of the Energy Coordinating Agency and Conservation Consultants, Inc. (July – December 1997). Consultant on energy and business strategy and planning for Energy Cooperative Association of Pennsylvania, a buyers' cooperative offering electricity, fuel oil, energy-efficiency, and renewable energy to residential and non-profit consumers in eastern and western Pennsylvania. (1998 – July 1999)

- Lead consultant on energy efficiency program design and planning for Maryland Office of People's Counsel and Maryland Energy Administration. Led research, analysis, and program

descriptions and budgets for use in restructuring workshops and legislative development on efficiency and renewable programs supported by system benefits charge. (1998)

- Lead consultant for the Vermont Department of Public Service regarding energy-efficiency investment during and after the transition to electricity restructuring. Lead author of *The Power to Save: A Plan to Transform Vermont's Efficiency Markets*, the DPS filing which calls for development of centrally delivered statewide core programs by an efficiency utility. Prepared written testimony, on behalf of the Vermont Department of Public Service in Docket 5980. (1997 – 1999)

- Technical support to the Burlington (VT) Electric Department in developing energy efficiency programs and policies as part of their resource and business planning. (November 1996 – May 1997)
- Consultant to Vermont Senate Natural Resources and Finance Committees on efficiency and renewable policies in restructuring legislation passed by the Senate but not adopted by the House. Provided technical assistance to support drafting and passage of utility restructuring legislation (S.62). (1997)

- Support to the Vermont Department of Public Service in assessing the performance and expenditures of Green Mountain Power's commercial and industrial DSM programs. Also provided support to the DPS in the evaluation of GMP's actions surrounding the Vermont Joint Owners contract with Hydro Quebec including prudence. (1997).

- Direct testimony and cross-examination relating to the future of DSM under the proposed BG&E/PEPCo utility merger. Case No. 8725 In the matter of Application of BGE, PEPCo & Constellation Energy Corporation for Merger. (1996)

- Written report to the Ontario Energy Board assessing the 1997 DSM Plan filed by Union and Centra Gas LTD in light of prior OEB decisions, as well as specific program plans for residential and non-residential customers. The report also addressed potential changes in gas DSM regulation, cost recovery, and incentives. [*Assessment of the Centra/Union Gas Fiscal 1997 DSM Plan*, Plunkett, Hamilton, and Mosenthal, August 30, 1996.] Testimony before the OEB concerning the report's findings and recommendations. Union/Centra Rate Case, EBRO 493/494. Also prepared a report and testified on Union Gas's DSM program design in EBRO 496/94/95. (July 1996 – November 1996)

PRIOR ASSIGNMENTS (RESOURCE INSIGHT) – 1990-1996

- Consultant on energy-efficiency program design, planning, and policy issues for Maryland utilities including Potomac Electric, Baltimore Gas and Electric, Potomac Edison, Delmarva Power and Light, Southern Maryland Electric Cooperative, Washington Gas, on behalf of Maryland Office of People's Counsel. Coordinator and lead negotiator on DSM collaboratives for Washington Gas, Potomac Electric, Baltimore Gas and Electric, Delmarva Power and Light and Potomac Electric. Projects have included resource planning and allocation, program design, policy, cost recovery, mechanism design, and monitoring and evaluation planning. (1989 – 1997)

- Prepared testimony and supported settlement negotiations concerning the DSM Plan of Jersey Central Power and Light on behalf of the Mid Atlantic Energy Project and New Jersey Public Interest Research Group. Analyzed DSM policy and commercial and industrial programs. Docket No. EE9580349 In the matter of Consideration and Determination of Jersey Central Power and Light Company's Demand Side Management Resource Plan filed pursuant to N.J.A.C. 14:12. (1995)

- Support to the Iowa Office of Consumer Advocate with the review and analysis of MidAmerican's, Interstate Power's and Iowa Electric Services' existing energy efficiency plans. Developed proposals for changes to and modifications of the utilities commercial and industrial energy efficiency programs. (1995 – 1996)

- Testimony and technical support for the Iowa Office of Consumer Advocate in settlement negotiations re IES Utilities C/I DSM programs. Docket No. EEP-95-1. (February 1996)

- Technical support to Florida Power Corporation on development of alternative DSM programs for commercial and industrial customers. (1995 – 1997)

- Supported the development of testimony and negotiations regarding DSM program alternatives for Carolina Power & Light, on behalf of the Southern Environmental Law Center. Docket No. 92-209-E. (1995 – 1996)

- Reviewed and commented on Consumer Gas' C/I DSM programs on behalf of the Green Energy Coalition. (1995)

- Support to the Vermont Department of Public Service in negotiation settlement with Green Mountain Power regarding DSM program design and planning, focusing on target retrofits in load centers under T&D capacity constraints, and increased participation and comprehensiveness of lost-opportunity programs. (1995)

- Consulting services and expert testimony on behalf of the Green Energy Coalition concerning Ontario Hydro's DSM plans and acquisition of lost-opportunity resources. Before Ontario Energy Board H.R. 22. re: Ontario Hydro 1995 Rates and Spending. (1994) and re: Ontario Hydro's Bulk Power Rates for 1993. Ontario Energy Board HR-21. (1992)

- Reviewed Tennessee Valley Authority programs and environmental planning for the Tennessee Valley Energy Reform Coalition. (November 1994 – July 1995)

- Prepared and defended direct testimony on gas and electric Demand-Side Management/Integrated Resource Planning guidelines before the North Carolina Public Utilities Commission. Docket No. E-100, SUB 64A in the matter of Request by Duke Power Company for Approval of a Food Service Program, Docket E-100, SUB 71 In the matter of Investigation of the Effect of Electric IRP and DSM Programs on the Competition Between Electric Utilities and Natural Gas Utilities. (1994)

- Prepared and defended expert testimony and led analyses of demand-side management and fuel switching opportunities in Central Vermont Public Service territory, on behalf of the

Vermont Department of Public Service. Project involved detailed analysis of measure costs, savings, and cost-effectiveness. Vermont Public Service Board, Docket 5270-CVPS-1&3. (1994)

- Prepared and defended expert testimony for the Vermont Department of Public Service on prudence of demand-side management in CVPS rate case. Vermont Public Service Board, Docket 5724. (May – August 1994)

- Directed and supported the preparation of joint testimony for Enersave, an efficiency service provider. Before the New York Public Service Commission, Case No. 94-E-0334. (September 1994)

- Joint testimony with Jonathan Wallach for the New York Public Utility intervenors reviewing 1994 LILCo DSM Plan. Before the New York Public Service Commission. P.S.C. Case No. 93-5-1123. (May 1994)
- Contributed to the critique of PECO Demand-Side Management Plan for the Nonprofits Energy Savings Investment Program. (February 1994)

- Provided direct testimony in a proceeding to investigate restrictions on DSM that could give one utility (gas or electric) an unfair competitive advantage over another (electric or gas, respectively). Before the Louisiana Public Service Commission Docket No. U-20178 Re: Louisiana Power & Light Company Least Cost Resource Plan. (1994)

- Provided expert testimony in support of PEPCo's DSM implementation. Before the Public Service Commission of the District of Columbia. Case No. 929. (1993)

- Prepared written testimony for the Maryland Office of People's Counsel analyzing potential for demand-side resources to offset need for power for proposed coal-fired plant. Delmarva Power & Light Company Dorchester Power Plant Certificate of Public Convenience and Necessity. Maryland PSC Case No. 8489. (January 1993)

- Coordinated testimony assessing the planning process, screening analyses, and cost-recovery proposals of the Detroit Edison Company for its demand-side management programs. Estimated potential levels of savings; identified improvements to the utility's proposed cost-recovery, lost-revenue, and incentive mechanisms; and recommended regulatory signals consistent with least-cost planning. Provided economic and regulatory advice, consulting services, and oversaw preparation of testimony. Michigan PSC Case No. U-10102. (1992)

- Economic and regulatory advice, consulting services, and supervision of testimony preparation. Provided technical services encompassing demand-side management program monitoring and evaluation, cost recovery, and review of second efficiency plans. Before the Iowa Utilities Board, Iowa Power and Light Docket No. EEP-91-3 and Interstate Power Company Docket No. EEP-91-5. (1992)

- Consulting on policy and resource-allocation issues on behalf of the Vermont Department of Public Service as part of DSM-program-design collaboratives with Vermont Gas. (1990 –

1991), Citizens Utilities (1990 – 1991), Central Vermont Public Service Corporation (1990) and Green Mountain Power. (1990)

- Comprehensive assessment of Ontario Hydro's 25-year resource plan. Directed work by over a dozen consultants. The study encompassed load forecasting; assessing DM potential and costs; resolving DM-implementation, resource-integration, and institutional issues; assessing all resource costs, including externalities; assessing costs of all supply resources, including non-utility generators; and estimating avoided costs. (1990 – 1992)

- Support to the Pennsylvania Energy Office in its evaluation of Pennsylvania electric utility demand-management plans by preparing testimony and co-authoring a comprehensive, five-volume study of all aspects of demand management. This document surveys issues related to integration of demand-management resources into utility planning, and reconciling least-cost planning objectives with rate-impact constraints; discusses strategies for utility intervention to remove market barriers to energy conservation; evaluates cost-recovery mechanisms for demand-management expenditures by utilities; explores issues related to the screening demand-management measures and programs; and examines direct costs, risk, and externalities avoidable through demand management. (1991 – 1993)

- Provided analysis of 1991 - 1992 New York electric utility DSM plans, and support for the analysis of 1993 - 1994 DSM Plans on behalf of Pace University Center for Environmental and Legal Studies, and Vladeck, Waldman, Elias & Engelhard, P.C., Counsel for the Class of LILCo Ratepayers in County of Suffolk *et al*. v. LILCo *et al*. Proceeding to Inquire into the Benefits to Ratepayers and Utilities from Implementation of Conservation Programs that will reduce Electric Use, New York Public Service Commission Case No. 28223. (1990, 1992, 1994)

- Reviewed Demand Side Management regulations and DSM compliance filings of four New Jersey utilities on behalf of the New Jersey Division of Rate Counsel. Demand Side Management Resource Plan of Jersey Central Power & Light Company. Docket No. EE-92020103. (1992)

- Identified energy-efficiency resources missing from FPL's resource plan that could provide economical substitutes for proposed power supply option. Expert testimony also addressed environmental costs avoided by DSM. Florida PSC Docket No. 920520-EG, In Re: Joint Petition of Florida Power and Light and Cypress Energy Partners, Limited Partnership for Determination of Need. (1992)

- Technical assistance and expert testimony for the Indiana Office of Utility Consumer Counselor, In the matter of the Petition of Indianapolis Power & Light Company for a Certificate of Public Convenience and Necessity for the Construction by it of Facilities for the Generation of Electricity and Submission and Request for Approval of Plan to meet future needs for Electricity. Cause No. 39236. (August 1991 – May 1992)

- Technical assistance and expert testimony for the Indiana Office of Utility Consumer Counselor. In the matter of the Petition of PSI Energy, Inc. Filed Pursuant to the Public Service Commission Act, as Amended, and I.C. 8-1-8.52 for the Issuance of Certificates of

Public Convenience and Necessity to Construct Generating Facilities for the Furnishing of Electric Utility Service to the Public and for the Approval of Expenditures for such Facilities. Cause No. 39175. (June 1991 – February 1992)

- Testimony and surrebuttal for the Delaware PSC Staff. Before the Delaware Public Service Commission Staff, In the Matter of the Application of Delmarva Power & Light Company for Approval of 48 MW Power Purchase Agreement with Star Enterprise, PSC Docket No. 90-16. (January 1991)

- Prepared comments on IRP principles and objectives for the Southern Environmental Law Center. Commonwealth of Virginia State Corporation Commission Order Establishing Commission Investigation to Consider Rules and Policy Regarding Conservation and Load Management Programs, Case No. PUE900070. (1991)

PRIOR ASSIGNMENTS (KOMANOFF ENERGY ASSOCIATES) – 1984-1990

- Advisor to the Vermont Public Service Board. Supported formulating issues, conducting hearings, deciding policy, and drafting opinions and orders on DSM planning programs, and ratemaking. Advised the Board's hearing officer on numerous decisions concerning policy and process, including cost-benefit analysis, design and coverage of utility energy-efficiency programs and integrated planning requirements. Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy, Docket No. 5270. (1988 – 1990)

- Technical advisor to the Public Utility Law Project of New York. Recommended economic principles for planning utility DSM investment for low-income customers in New York. Proceeding on Motion of the Commission to Determine Whether the Major Gas and Combination Gas and Electric Utilities Subject to the Commission's Jurisdiction Should Establish and Implement a Low-Income Energy Efficiency Program, Case 89-M-124. (1990).

- Technical assistance and advice on behalf of the South Carolina Department of Consumer Affairs on all aspects of Integrated Resource Planning and DSM planning including cost-effectiveness tests for South Carolina PSC investigation into Electric Utility Least-Cost Planning, Docket No. 87-223-E. (1987 – 1992)

- Prepared and defended expert testimony for the Indiana Office of Utility Consumer Counselor on potential for DSM to defer need for new generating capacity. Petition of Southern Indiana Gas and Electric Co. for Approval of Construction and Cost of Additional Electric Generation and for Issuance of a Certificate of Need Therefore, Indiana Utility Regulatory Commission, Cause No. 38738. (September 1989)

- Prepared and defended expert testimony for the Illinois Citizens Utility Board on adequacy of Commonwealth Edison's DSM efforts. Rulemaking Implementing Section 8-402 of the Public Utilities Act, Least-Cost Planning, Illinois ICC Docket No. 89-0034. (July 1989)

- Supported the Vermont Public Service Board with analysis, findings, and conclusions regarding the need for power based on potential DSM resources. Application of Twenty-Four Electric Utilities for a Certificate of Public Good Authorizing Execution and Performance of a Firm Power and Energy Contract with Hydro-Quebec and a Hydro-Quebec Participation Agreement, Docket No. 5330. (1989 – 1990)

- Cost-benefit analysis for the City of Chicago examining alternatives to the renewal of Commonwealth Edison's franchise. (1989)

- Co-author (with J. Wallach) of *The Power Analyst*, integrated spreadsheet-based software for projecting the economic and financial performance of renewable and cogeneration projects, for the New York State Energy Research and Development Authority. Project manager, economic analysis. (1989)

- Advisor for the South Carolina Department of Consumer Affairs. Assessed costs and benefits of long-term power contract. In the Matter of Duke Power Company, Federal Energy

Commission, Docket No. ER89-106-000. (January 1989 – March 1990)

- Analyzed and provided expert testimony on the economic potential for cost-effective DSM to substitute for capacity and energy from a combined cycle generating plant. Application of Potomac Electric Power Company for Certificate of Public Convenience and Necessity for Station H, Maryland PSC Docket No. 8063 Phase II. (1988)

- Examined, compared, and recommended appropriate cost-effectiveness tests for the DSM portion of the Massachusetts Department of Public Utilities investigation into the Pricing and Ratemaking Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities. Docket No. 86-36. (1988)

- Testimony for the District of Columbia Office of People's Counsel on electric and gas utility least-cost planning. Application of the Potomac Electric Power Company for Changes to Electric Rate Schedules, D.C. PSC Formal Case 834 Phase II. (April and June 1987)

- Cross-examination for the Connecticut Division of Consumer Counsel to defend KEA's financial assessment of CL&P's ability to withstand Millstone 3 disallowance. Investigation into Excess Generating Capacity of Connecticut Light & Power Company, Connecticut DPUC Docket No. 85-09-12. (April 1986)

- Cross examination for the Connecticut Division of Consumer Counsel to defend financial and statistical model supporting KEA's findings of CL&P construction imprudence. Retrospective Audit of the Prudence of the Construction of Millstone 3, Connecticut DPUC Docket 83-07-03. (March 1986)

- Cross-examination for the Pennsylvania Office of Consumer Advocate, defended quantification of imprudence findings by O'Brien/Kreitzberg & Associates regarding PECO's construction management of the Limerick 1 project. Pennsylvania PUC v. Philadelphia Electric Company Docket R-850152. (February 1986)

- Prepared and defended direct and surrebuttal testimony for the Pennsylvania Office of Consumer Advocate critiquing utility conservation and cogeneration assumptions and presented alternative 20-year electricity sales projection. Pennsylvania PUC Limerick 2 Investigation Docket I-840381. (April 1985)

PRIOR ASSIGNMENTS (INSTITUTE FOR LOCAL SELF-RELIANCE) – 1978-1983

- Technical and economic analysis of small-generator grid interconnection of seven New York electric utilities for the New York Energy Research and Development Authority. Project manager, economic analysis. (1983)

- Written testimony on behalf of the Alaska Public Interest Research Group implementing PURPA 210. Before the Alaska PUC. (1981)

- Written and oral testimony in oversight hearings on state implementation of the Public Utility Regulatory Policy Act of 1978 (PURPA). U.S House of Representatives Subcommittee on Energy Conservation and Power. (1981)

- Written and oral testimony in rulemaking for the Public Utility Regulatory Policy Act of 1978 (PURPA) on behalf of ILSR, before the Federal Energy Regulatory Commission. (1979)

PUBLICATIONS/PRESENTATIONS

"'Walking the Walk' of Distributed Utility Planning: Deploying Demand-Side Transmission and Distribution Resources in Vermont, Part Dieux" with Bruce Bentley 2008 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2008.

"Demand-Side Management Strategic Plan for Jiangsu Province, China: Economic, Electric and Environmental Returns from an End-Use Efficiency Investment Portfolio in the Jiangsu Power Sector," with Barbara Finamore and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"'Walking the Walk' of Distributed Utility Planning: Deploying Demand-Side Transmission and Distribution Resources in Vermont's 'Southern Loop,'" with Bruce Bentley and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"Comparative Performance of Electrical Energy Efficiency Portfolios in Seven Northeast States," with Glenn Reed and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"Charting New Frontiers with Vermont's Deployment of Demand-Side Transmission and Distribution Resources," ACEEE National Conference on Energy Efficiency as a Resource, Berkeley, CA, September 27, 2005.

"Energy Efficiency and Renewable Energy Resource Potential In New York State: Summary of Potential Analysis Prepared For the New York State Energy Research and Development Authority", invited presentation to the National Academy of Sciences Committee On Alternatives to Indian Point, Washington, DC, January 2005.

"Estimating and Valuing Energy-Efficiency Resource Contributions: Toward a Common Regional Protocol," presented at the Northeast Energy Efficiency Partnerships conference on regional efficiency policy, November 2004.

"The Economically Achievable Energy Efficiency Potential in New England," presented at the Northeast Energy Efficiency Partnerships conference on regional efficiency policy, November 2004.

"Rewarding Successful Efficiency Investment In Three Neighboring States: The Sequel, the Re-Make and the Next Generation (In Vermont, Massachusetts and Connecticut)," (with P. Horowitz and S. Slote), 2004 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2004.

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"Yes, Virginia, You Can Get There From Here: New Jersey's New Policy Framework For Guiding Ratepayer-Funded Efficiency Programs" (with S. Coakley and D. Bryk), *2000 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2000.

"Integrated Market-Based Efficiency and Supply for Small Energy Consumers: The Consumer Energy Cooperative" (with B. Sachs and E. Belliveau) *2000 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2000.

"Comprehensive Energy Services At Competitive Prices: Integrating Least-Cost Energy Services to Small Consumers through a Retail Buyer's Cooperative" (with B. Sachs), *1998 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 1998.

"Capturing Comprehensive Benefits from Commercial Customers: A Comparative Analysis of HVAC Retirement Alternatives" (with P. Mosenthal and M. Kumm), *1996 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, August 1996. 5.169.

"Joint Delivery of Core DSM Programs: The Next Generation, Made in Vermont" (with S. Parker), *1996 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, August 1996. 7.127.

"Retrofit Economics 201: Correcting Common Errors in Demand-Side Management Cost-Benefit Analysis" (with R. Brailove and J. Wallach) *IGT's Eighth International Symposium on Energy Modeling*, Atlanta, Georgia, April 1995.

"DSM's Best Kept Secret: The Process, Outcome and Future of the PEPCo-Maryland Collaborative" (with R. D. Obeiter and E. R. Mayberry), *Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings*, Monterey, California, August 1994. 10.199.

Louisville Gas and Electric Company. Invited to make presentation on commercial program design. March 10, 1994.

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DSM Training Institute - *Training for Ohio DSM Advocates: Effective DSM Collaborative Processes*. Seminar co-presenter. Cleveland, Ohio, August 1993.

"Demand-Management Programs: Targets and Strategies," Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with J. Wallach, J. Peters, and B. Hamilton), Coalition of Environmental Groups, Toronto, ONT, November 1992.

"DSM Program Monitoring and Evaluation: Prospects and Pitfalls for Consumer Advocates," *Proceedings from the Mid-Year NASUCA Meeting,* Saint Louis, Missouri, June 8, 1993.

"Twelve Steps To Comprehensive Demand-Management Program Development: A Collaborative Perspective", *Proceedings from the IRP Workshop: The Basic Landscape, NARUC-DOE Fourth IRP Conference*, Burlington Vermont, September 1992. 45.

"Demand-Side Cost Recovery: Toward Solutions that Treat the Causes of Utility Under-Investment in Demand-Side Resources" (with P. Chernick), *Proceedings from the Third NARUC Conference on Integrated Utility Planning*, Santa Fe, New Mexico, April 1991.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy?" (with P. Chernick and J. Wallach), *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, Columbus, Ohio, September 1990.

"Where Do We Go From Here? Eight Steps for Regulators to Jump-Start Least-Cost Planning" (with M. Dworkin), *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, Columbus, Ohio, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with P. Chernick) *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference,* September 1990. Also published in *Proceedings from the Canadian Electric Association's Demand-Side Management Conference*, St. John, Nova Scotia, September 1990.

"Carrots and Sticks: Do Utilities Need Incentives to Do the Right Thing on Demand-Side Investment?", *Proceedings from the National Association of State Utility Consumer Advocates* Santa Fe, New Mexico, June 1990.

"New Tools On the Block: Evaluating Non-Utility Supply Opportunities with the Power Analyst" (with J. Wallach), *Proceedings from the Fourth National Conference on Microcomputer Applications in Energy*, Phoenix, AZ, April 1990.

"Breaking New Ground in Collaboration and Program Design," *The Rocky Mountain Institute Competitek Forum* (Moderator), Aspen, Colorado, September 1989.

"Lost Revenues and Other Issues in Demand-Side Resource Evaluation: An Economic Reappraisal" (with P. Chernick), *1988 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, September 1988.

"Pursuing Least-Cost Strategies for Ratepayers While Promoting Competitive Success for

Utilities", *Proceedings from the Least-Cost Planning Conference, National Association of Regulatory Utility Commissioners,* Aspen, Colorado, April 1988.

"Balancing Different Economic Perspectives in Demand-Side Resource Evaluation", Workshop on Demand-Side Bidding, Co-sponsored by New York State PSC, ERDA, and Energy Office, Albany, New York, March 1988.

"There They Go Again: A Critique of the AER/UDI Report on Future Electricity Adequacy through the Year 2000" (with C. Komanoff, H. Geller and C. Mitchell), Presentation NASUCA (also debated AER/UDI co-author before NARUC annual meeting), New Orleans, Louisiana, November 1987.

"Saying No to the No-Losers Test: Correctly Assessing Demand-Side Resources to Achieve Least-Cost Utility Strategies", *Proceedings from the Mid-year NASUCA meeting*, Washington, D.C., June 1987.

"The Economic Impact of Three Mile Island" (with C. Komanoff), *Proceedings from the American Association for the Advancement of Science symposium*, May 1986.

"Facing the Grid" (with D. Morris), *New Shelter*, May - June 1981.

Electric Energy Efficiency Resource Acquisition Options for BC Hydro

Prepared for the British Columbia Sustainable Energy Association and the Sierra Club of British Columbia

April 17, 2011

GreenEnergy EconomicsGroup

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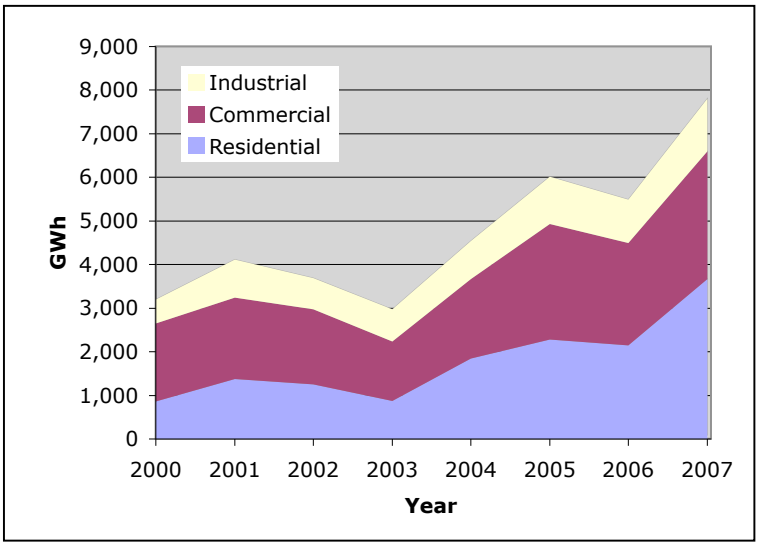
I. Electric Energy Efficiency Portfolio Performance and Costs in Other Jurisdictions

Utilities across North America have been relying on energy efficiency investment to reduce electric energy and capacity requirements for well over two decades. The US Department of Energy's Energy Information Administration (EIA) statistics on demand-side management show that reported electric savings have more than doubled since 2000.[1]

Figure 1: Electric Energy Savings in the US by Sector



Green Energy Economics Group (GEEG) estimates that if the British Columbia Hydro and Power Authority ("BC Hydro") followed the examples of leading efficiency portfolio administrators in the United States and Canada, after 20 years it could be providing cumulative annual savings of 15,388 GWh at costs of about $0.046 per kWh.

[1]*Energy Information Administration (2009). Demand-Side Management Program Incremental Effects by Sector. Retrieved from http://www.eia.doe.gov/cneaf/electricity/epa/epat9p5.html*

A. ACEEE State Energy Efficiency Scorecards

According to the American Council for an Energy-Efficient Economy (ACEEE), electric utility ratepayers throughout the U.S. supported $4.2 billion (2011 dollars) in demand-side management portfolios in 2006 and 2007, with planned spending in 2009 reported at over $3.5 billion. Efficiency portfolio investment in 2006-7 lowered electric energy requirements by a reported total of 17,650 GWh annually, the equivalent to the output of 4.5 600-MW coal-fired stations.[2] At an average measure life of 10 years and a 6 percent real discount rate, between 2006 and 2007 the nation's ratepayers spent an average of 3.2 cents per kWh in constant 2011 dollars for energy-efficiency resources.

Efficiency savings can be compared across jurisdictions by first dividing incremental annual electric energy savings reported in any one year by corresponding electricity sales. Efficiency spending can be compared between jurisdictions either in terms of scale or yield. To compare spending between service areas, expenditures are divided by annual energy sales for each service area. To compare savings yields from DSM investment, annual expenditures are divided by annual savings to calculate the portfolio-wide cost to acquire an annual kWh of electricity savings.

1. Annual Energy Savings

Table 1 consolidates data tabulated in ACEEE's three most recent scorecards on electric utility energy efficiency investment performance and costs between 2008 and 2010. It presents information reported by demand-side management (DSM) portfolio administrators to the EIA regarding annual efficiency savings for all fifty states and the District of Columbia for 2006, 2007, 2008, and 2009 and compares savings achieved with annual sales reported for the same years.

Table 1: Savings by State as Reported by ACEEE

State	Total Incremental Elec. Savings (GWh)				Savings as a Percent of Electricity Sales			
	2006	2007	2008	2009	2006	2007	2008	2009
Vermont	62.9	105.2	148.5	90.2	1.08%	1.80%	2.59%	1.64%
Hawaii	67.9	124.8	204.6	113.2	0.64%	1.20%	1.97%	1.12%
Nevada	216.0	233.2	402.3	438.6	0.62%	0.65%	1.14%	1.28%
Connecticut	328.0	371.9	354.2	250.4	1.04%	1.10%	1.14%	0.84%
California	1,912.0	3,393.0	3,044.0	2,293.0	0.73%	1.30%	1.14%	0.88%
Minnesota	370.4	463.5	540.8	637.8	0.55%	0.68%	0.79%	1.00%

[2] Operating at a 75% capacity factor.

State	Total Incremental Elec. Savings (GWh)				Savings as a Percent of Electricity Sales			
	2006	2007	2008	2009	2006	2007	2008	2009
Wisconsin	344.2	467.7	545.1	583.5	0.49%	0.66%	0.78%	0.88%
Rhode Island	96.0	65.0	60.1	81.5	1.23%	0.81%	0.77%	1.07%
Idaho	150.9	103.0	182.1	185.7	0.66%	0.43%	0.76%	0.82%
Iowa	314.2	322.2	323.3	409.7	0.73%	0.71%	0.71%	0.94%
Utah	121.0	139.0	194.9	176.5	0.46%	0.50%	0.69%	0.64%
Massachusetts	455.0	489.6	388.3	458.7	0.82%	0.86%	0.69%	0.84%
Oregon	369.8	437.5	318.2	291.7	0.77%	0.90%	0.65%	0.61%
New Hampshire	73.9	78.5	70.3	68.1	0.67%	0.70%	0.64%	0.64%
Maine	74.8	107.7	74.3	94.0	0.61%	0.91%	0.64%	0.83%
Washington	630.7	635.1	530.0	665.2	0.74%	0.74%	0.61%	0.74%
Arizona	123.4	312.7	401.8	570.6	0.17%	0.41%	0.53%	0.78%
New Jersey	227.8	242.3	405.5	497.5	0.29%	0.30%	0.50%	0.66%
Colorado	60.0	146.6	203.3	254.6	0.12%	0.29%	0.39%	0.50%
Montana	64.7	43.3	52.1	57.3	0.47%	0.28%	0.34%	0.40%
New York	814.3	540.6	471.1	949.6	0.58%	0.36%	0.33%	0.68%
New Mexico	0.2	10.2	60.2	58.9	0.00%	0.05%	0.27%	0.27%
North Dakota	0.3	0.3	25.7	2.5	0.00%	0.00%	0.21%	0.02%
Texas	397.3	457.8	734.5	750.6	0.12%	0.13%	0.21%	0.22%
South Dakota	-	0.1	18.8	21.8	0.00%	0.00%	0.17%	0.20%
Florida	301.1	348.2	348.4	364.6	0.13%	0.15%	0.15%	0.16%
Maryland	0.2	0.2	85.0	274.2	0.00%	0.00%	0.13%	0.44%
Arkansas	0.0	6.2	50.8	59.8	0.00%	0.01%	0.11%	0.14%
Tennessee	61.3	63.5	97.9	120.8	0.06%	0.06%	0.09%	0.13%
Georgia	2.5	3.0	61.9	53.6	0.00%	0.00%	0.05%	0.04%
Kansas	-	34.7	13.9	1.0	0.00%	0.09%	0.04%	0.00%
South Carolina	14.7	13.4	26.9	45.6	0.02%	0.02%	0.03%	0.06%
Ohio	0.4	29.8	54.6	530.1	0.00%	0.02%	0.03%	0.36%
Alabama	8.4	7.7	14.5	63.4	0.01%	0.01%	0.02%	0.08%
Mississippi	5.5	3.5	11.2	31.2	0.01%	0.01%	0.02%	0.07%
Missouri	3.9	4.5	20.0	86.3	0.00%	0.01%	0.02%	0.11%
Kentucky	118.0	17.9	21.3	64.7	0.13%	0.02%	0.02%	0.07%
Nebraska	5.4	6.9	5.2	65.2	0.02%	0.02%	0.02%	0.23%
Michigan	-	-	8.9	375.7	0.00%	0.00%	0.01%	0.38%
North Carolina	3.1	1.4	15.2	51.9	0.00%	0.00%	0.01%	0.04%
Alaska	1.1	1.4	0.9	1.0	0.02%	0.02%	0.01%	0.02%
Indiana	12.6	20.7	11.5	39.9	0.01%	0.02%	0.01%	0.04%
District of Columbia	-	-	-	55.9	0.00%	0.00%	0.00%	0.46%
Pennsylvania	2.3	3.8	2.7	278.9	0.00%	0.00%	0.00%	0.19%
Oklahoma	-	0.2	2.3	20.3	0.00%	0.00%	0.00%	0.04%

State	Total Incremental Elec. Savings (GWh)				Savings as a Percent of Electricity Sales			
	2006	2007	2008	2009	2006	2007	2008	2009
Illinois	0.2	0.3	6.4	553.2	0.00%	0.00%	0.00%	0.40%
Virginia	0.1	0.1	0.0	1.0	0.00%	0.00%	0.00%	0.00%
Wyoming	-	-	-	7.4	0.00%	0.00%	0.00%	0.04%
Delaware	-	-	-	0.5	0.00%	0.00%	0.00%	0.00%
Louisiana	-	-	-	-	0.00%	0.00%	0.00%	0.00%
West Virginia	-	-	-	-	0.00%	0.00%	0.00%	0.00%

Sources

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For utilities that did report savings in 2006 and 2007, the average (weighted by sales) was 0.35 percent, with values ranging from 0.01 percent for four jurisdictions (Arkansas, Alabama, Missouri, and Mississippi) up to 2 percent and above (Hawaii and Vermont).

2. Annual Expenditures

Table 2reproduces ACEEE's scorecards of total portfolio expenditures for 2006 and 2007, along with planned spending in 2009 and 2010(ACEEE stopped reporting previous-year spending in 2009). Nominal expenditures were converted to 2011 dollars using the U.S. Bureau of Labor Statistics all-urban Consumer Price Index.

Table 2: Spending and Budgets by State as Reported by ACEEE

State	Total Spending (Million 2011$)				2011¢/ kWh Sold			
	2006 Actual*	2007 Actual*	2009 Budgets	2010 Budgets	2006 Actual	2007 Actual	2009 Budgets	2010 Budgets**
Vermont	$17.5	$25.6	$32	$35	0.3027¢	0.4359¢	0.5825¢	0.6347¢
Hawaii	$14.3	$17.9	$37	$20	0.1355¢	0.1688¢	0.3656¢	0.1956¢
Nevada	$26.6	$30.5	$44	$46	0.077¢	0.0856¢	0.1274¢	0.1347¢
Connecticut	$77.2	$103.3	$77	$130	0.2438¢	0.3026¢	0.2576¢	0.4381¢
California	$396.2	$815.0	$1,041	$1,188	0.1507¢	0.3084¢	0.401¢	0.4577¢
Minnesota	$53.4	$98.4	$116	$164	0.08¢	0.1443¢	0.1812¢	0.2568¢
Wisconsin	$81.3	$86.9	$105	$95	0.1165¢	0.1219¢	0.1591¢	0.1429¢
Rhode Island	$19.1	$19.4	$31	$33	0.2444¢	0.2415¢	0.4038¢	0.4323¢
Idaho	$22.7	$18.0	$33	$37	0.0996¢	0.0756¢	0.1444¢	0.1628¢
Iowa	$58.0	$61.0	$58	$70	0.1338¢	0.1347¢	0.1329¢	0.1594¢
Utah	$18.6	$15.1	$47	$57	0.0707¢	0.0542¢	0.1716¢	0.2064¢
Massachusetts	$138.7	$129.7	$192	$310	0.2484¢	0.2269¢	0.3526¢	0.5698¢
Oregon	$70.3	$74.6	$88	$93	0.1462¢	0.1531¢	0.1857¢	0.1965¢
New Hampshire	$19.5	$20.2	$16	$27	0.1755¢	0.1794¢	0.1482¢	0.2522¢
Maine	$12.2	$18.2	$22	$14	0.0994¢	0.1536¢	0.1922¢	0.1273¢
Washington	$125.7	$136.7	$153	$190	0.1479¢	0.1594¢	0.1694¢	0.2104¢
Arizona	$18.2	$34.4	$51	$95	0.0248¢	0.0446¢	0.0699¢	0.129¢
New Jersey	$92.3	$103.5	$138	$203	0.1158¢	0.1263¢	0.1821¢	0.2682¢
Colorado	$12.2	$16.5	$49	$66	0.0245¢	0.0322¢	0.0954¢	0.1301¢
Montana	$9.2	$7.2	$14	$9	0.0667¢	0.0463¢	0.0961¢	0.0637¢
New York	$249.6	$260.6	$395	$599	0.1755¢	0.1759¢	0.2817¢	0.4276¢

State	Total Spending (Million 2011$)				2011¢/ kWh Sold			
	2006 Actual*	2007 Actual*	2009 Budgets	2010 Budgets	2006 Actual	2007 Actual	2009 Budgets	2010 Budgets**
New Mexico	$1.1	$3.2	$15	$18	0.0052¢	0.0143¢	0.0694¢	0.0829¢
North Dakota	$0.6	$0.7	$0	$1	0.0051¢	0.0061¢	0.0008¢	0.0105¢
Texas	$64.1	$85.8	$103	$132	0.0187¢	0.0249¢	0.0298¢	0.0382¢
South Dakota	$0.7	$2.5	$3	$4	0.0068¢	0.0239¢	0.0256¢	0.0326¢
Florida	$74.4	$99.9	$138	$126	0.0326¢	0.0432¢	0.0615¢	0.0562¢
Maryland	$0.1	$2.7	$40	$91	0.0002¢	0.0042¢	0.0633¢	0.1456¢
Arkansas	$-	$1.7	$8	$13		0.0036¢	0.0186¢	0.0311¢
Tennessee	$6.1	$10.8	$25	$50	0.0059¢	0.0101¢	0.0267¢	0.053¢
Georgia	$11.1	$5.2	$22	$22	0.0082¢	0.0038¢	0.017¢	0.0169¢
Kansas	$0.4	$7.3	$4	$6	0.0009¢	0.0182¢	0.0101¢	0.0145¢
South Carolina	$6.5	$9.6	$15	$13	0.0081¢	0.0118¢	0.0199¢	0.0165¢
Ohio	$31.9	$31.0	$19	$157	0.0208¢	0.0192¢	0.0133¢	0.1072¢
Alabama	$0.5	$2.5	$9	$18	0.0006¢	0.0027¢	0.0115¢	0.0219¢
Mississippi	$0.5	$0.3	$10	$13	0.001¢	0.0007¢	0.0208¢	0.0279¢
Missouri	$2.4	$1.4	$24	$42	0.0029¢	0.0017¢	0.0297¢	0.0521¢
Kentucky	$6.6	$19.3	$18	$28	0.0074¢	0.0209¢	0.0202¢	0.0313¢
Nebraska	$1.0	$1.0	$7	$13	0.0035¢	0.0036¢	0.026¢	0.0469¢
Michigan	$11.1	$-	$52	$94	0.0103¢		0.0532¢	0.0957¢
North Carolina	$4.2	$7.3	$67	$46	0.0033¢	0.0055¢	0.0525¢	0.0364¢
Alaska	$0.2	$0.3	$-	$0	0.0029¢	0.0051¢		0.0065¢
Indiana	$4.1	$4.4	$14	$17	0.0039¢	0.004¢	0.0143¢	0.017¢
District of Columbia	$9.4	$-	$13	$10	0.0828¢		0.1069¢	0.0791¢
Pennsylvania	$4.2	$4.4	$101	$113	0.0029¢	0.0029¢	0.0703¢	0.0785¢
Oklahoma	$0.0	$0.2	$4	$29	0¢	0.0003¢	0.0073¢	0.0525¢
Illinois	$3.6	$0.9	$94	$170	0.0025¢	0.0006¢	0.0686¢	0.1242¢
Virginia	$0.1	$0.0	$0	$0	0.0001¢	0¢	0.0004¢	0.0002¢
Wyoming	$-	$-	$3	$4			0.0164¢	0.0266¢

State	Total Spending (Million 2011$)				2011¢/ kWh Sold			
	2006 Actual*	2007 Actual*	2009 Budgets	2010 Budgets	2006 Actual	2007 Actual	2009 Budgets	2010 Budgets**
Delaware	$-	$0.2	$-	$4		0.0019¢		0.0328¢
Louisiana	$-	$-	$2	$-			0.003¢	
West Virginia	$-	$-	$-	$-				

* Utility spending is on "ratepayer-funded energy efficiency" programs, or energy efficiency programs funded through charges included in customer utility rates or otherwise paid via some type of charge on customer bills. This includes both utility- administered programs and "public benefits" programs administered by other entities. We do not include data on separately funded low-income programs, load management programs, or energy efficiency research and development.

** Divided by 2009 sales since 2010 EIA sales data is not yet available

Table 2 shows that states with energy efficiency savings in 2006 and 2007 reported spending an average of 0.0745¢ per kWh sold per year over the two-year period in 2011 dollars. Spending ranged from 0.0001¢ per kWh sold per year for Virginia in 2006, up to 0.4348¢ per kWh sold per year in the state of Vermont in 2007.

3. Costs of Saved Energy

The annual electricity savings produced by energy-efficiency portfolios last between ten and twenty years, depending on the life expectancies of the efficiency measures installed in any particular year. To compute the levelized cost of efficiency portfolio savings, the average measure lifetime is necessary for levelizing the up-front costs of the investments. Levelized costs of efficiency investment are directly comparable to the levelized costs of electric energy supply alternatives.

ACEEE provides both cost and savings data only for 2006 and 2007. The first two columns in Table 3 calculate the cost of annual energy savings achieved in each state in 2006 and 2007 in 2011 dollars. The third and fourth columns estimate the levelized cost per kWh saved in 2006 and 2007 for each state, assuming that portfolios across the country were composed of measures lasting an average of 10 years. 10 years probably understates the true average measure lives of the efficiency portfolios in those years, given the range of efficiency technologies targeted (from compact fluorescent lamps lasting an average of 5 years to high-efficiency lighting and cooling lasting 15 to 20 years or longer).

Table 3: Cost of Saved Energy by State

State	2011$ / Annual kWh Saved		Levelized $/kWh saved	
	2006	2007	2006	2007
Vermont	0.28	0.24	0.038	0.033
Hawaii	0.21	0.14	0.029	0.019
Nevada	0.12	0.13	0.017	0.018
Connecticut	0.24	0.28	0.032	0.038
California	0.21	0.24	0.028	0.033
Minnesota	0.14	0.21	0.020	0.029
Wisconsin	0.24	0.19	0.032	0.025
Rhode Island	0.20	0.30	0.027	0.040
Idaho	0.15	0.17	0.020	0.024
Iowa	0.18	0.19	0.025	0.026
Utah	0.15	0.11	0.021	0.015
Massachusetts	0.30	0.26	0.041	0.036
Oregon	0.19	0.17	0.026	0.023
New Hampshire	0.26	0.26	0.036	0.035
Maine	0.16	0.17	0.022	0.023
Washington	0.20	0.22	0.027	0.029
Arizona	0.15	0.11	0.020	0.015
New Jersey	0.41	0.43	0.055	0.058

State	2011$ / Annual kWh Saved		Levelized $/kWh saved	
	2006	2007	2006	2007
Colorado	0.20	0.11	0.028	0.015
Montana	0.14	0.17	0.019	0.023
New York	0.31	0.48	0.042	0.066
New Mexico	5.87	0.31	0.798	0.042
North Dakota	2.22	2.71	0.301	0.368
Texas	0.16	0.19	0.022	0.025
South Dakota		29.15		3.960
Florida	0.25	0.29	0.034	0.039
Maryland	0.59	16.40	0.080	2.228
Arkansas	0.00	0.27	0.000	0.037
Tennessee	0.10	0.17	0.013	0.023
Georgia	4.38	1.75	0.595	0.237
Kansas		0.21		0.029
South Carolina	0.44	0.72	0.060	0.098
Ohio	81.21	1.04	11.033	0.142
Alabama	0.06	0.32	0.008	0.044
Mississippi	0.09	0.09	0.012	0.013
Missouri	0.62	0.31	0.085	0.043
Kentucky	0.06	1.08	0.008	0.147
Nebraska	0.18	0.15	0.024	0.020
Michigan				
North Carolina	1.38	5.26	0.187	0.714
Alaska	0.16	0.23	0.021	0.031
Indiana	0.33	0.21	0.045	0.029
District of Columbia				
Pennsylvania	1.85	1.16	0.252	0.157
Oklahoma		0.92		0.125
Illinois	18.34	2.85	2.491	0.387
Virginia	1.48	0.01	0.201	0.002
Wyoming				
Delaware				
Louisiana				
West Virginia				

States with blanks had either no costs or savings, or reported values too small to show up in the table.

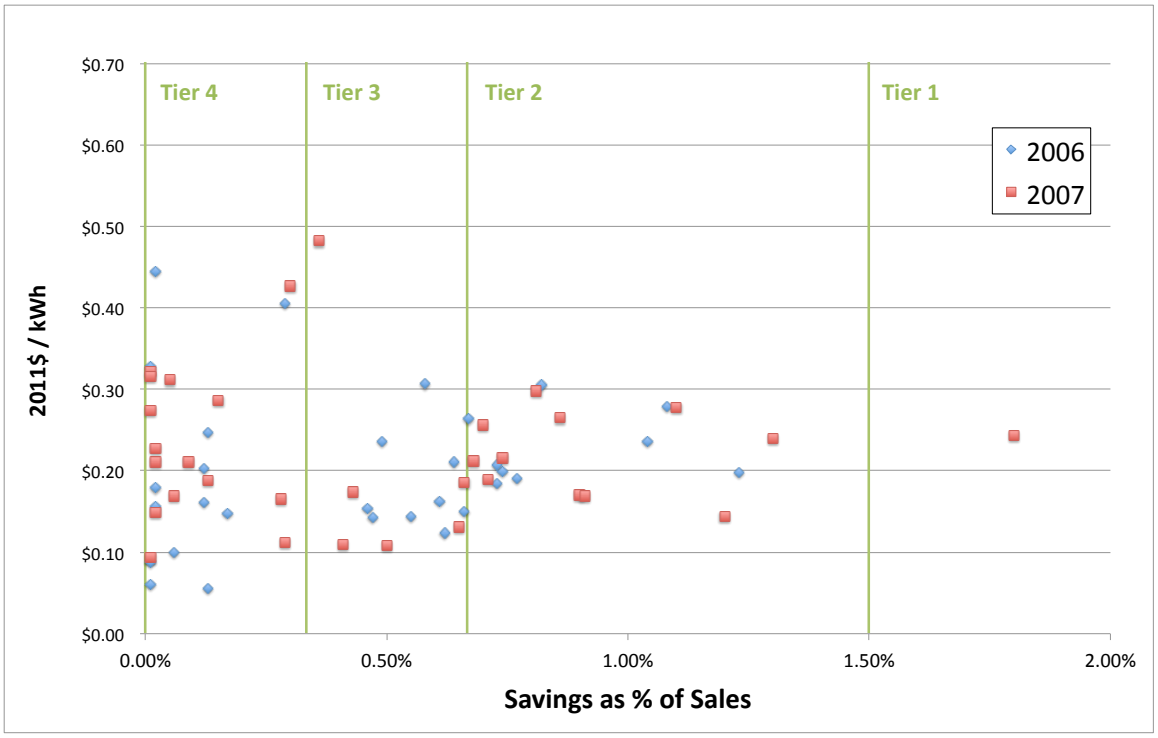
Table 3 shows that efficiency resources, excluding outliers, cost from around $0.03 to $1.0 per kWh per year saved in 2006 and 2007.

There are a number of outliers in the data above. In general, an outlier can be assumed to years with a cost of energy savings greater than $2.00 per annual kWh.

This includes New Mexico in 2006, North Dakota in 2006 and 2007, South Dakota in 2007, Maryland in 2007, Georgia in 2006, Ohio in 2006, North Carolina in 2007, as well as Illinois in 2006 and 2007. These extreme values are probably due to incomplete DSM savings data collected through form EIA 861.

The following figure uses the data in Table 3 to plot the cost per kWh/yr saved against savings as a percent of sales for each state in 2006 and 2007. For each state, a year's data was excluded if the savings as a percent of sales were less than 0.01 percent or if the cost per kWh in 2011 dollars was less than $0.01 or greater than $0.60, this left 31states for 2006 and 33 states for 2007.

Figure 2: ACEEE Costs and Savings for States by Year



B. Regulatory Filings

Although the three most recent ACEEE scorecards encompass the entire country, they do not provide cost data corresponding to reported savings beyond 2006 and 2007. Nor does ACEEE separately report portfolio savings and cost information for residential and non-residential sectors, for which efficiency opportunities differ significantly. Green Energy Economics Group (GEEG) has found that data on costs and performance reported to state regulators to be more consistent and reliable than that reported to EIA.

GEEG collected historical cost and savings data on efficiency portfolios reported to regulators for states with the greatest savings as a percentage of sales, including California and Northeastern states; for Midwestern and Western states with significant efficiency portfolios (Iowa, Nevada, and Wisconsin); and for neighboring jurisdictions of Arkansas and Texas. Where possible, GEEG obtained cost and saving data separately for the residential and nonresidential sectors. GEEG also collected efficiency spending and savings data for two Canadian provinces, British Columbia and Nova Scotia. Finally, GEEG assembled the latest information available on future plans for electric end-use efficiency investment in several leading states and provinces.

For the states mentioned above,
Table 4 presents historical data on annual savings as a percentage of electric energy sales, and spending per annual kWh of savings, by year, ranked in decreasing order in terms of savings as a percentage of sales.
Table 4 is an aggregation of the data found in Appendix A, which attempts to make a direct comparison between energy efficiency programs and the pool of energy sales that these programs directly influence. The ACEEE data provided in the previous section provides savings as a percentage of statewide sales, regardless of whether or not those sales occurred in territories where energy efficiency programs existed. Due to a more "apples to apples" comparison of savings to sales as well as differing sources, the data provided in
Table 4 tends to find higher savings as a percentage of sales.

Table 4: Statewide Totals by Year, Ranked by Savings as a Percent of Sales

State / Province	Year	Savings as a % of Sales	2011$/kWh/yr Saved
Tier 1			
CA	2008	2.52%	$0.20
VT	2008	2.33%	$0.26
CA	2010	1.98%	$0.26
VT	2010	1.94%	$0.33
VT	2011	1.83%	$0.35

State / Province	Year	Savings as a % of Sales	2011$/kWh/yr Saved
CA	2007	1.80%	$0.22
CA	2005	1.61%	$0.18
VT	2007	1.60%	$0.23
CT	2010	1.52%	$0.30
Tier 2			
VT	2009	1.46%	$0.36
HI	2008	1.38%	$0.11
NV	2009	1.35%	$0.09
CT	2008	1.28%	$0.30
NV	2008	1.24%	$0.07
Pacific Northwest	2008	1.24%	$0.12
IA	2009	1.14%	$0.20
MA	2010	1.12%	$0.40
CT	2007	1.12%	$0.29
Nova Scotia	2011	1.12%	$0.23
CT	2006	1.11%	$0.24
Pacific Northwest	2009	1.10%	$0.17
CT	2001	1.10%	$0.35
Pacific Northwest	2007	1.09%	$0.11
CA	2009	1.06%	$0.41
RI	2009	1.05%	$0.31
CT	2005	1.03%	$0.28
HI	2009	1.01%	$0.17
IA	2010	0.98%	$0.21
British Columbia	2010	0.98%	$0.22
CT	2004	0.97%	$0.27
CA	2004	0.93%	$0.19
RI	2006	0.91%	$0.27
ME	2008	0.87%	$0.13
VT	2005	0.87%	$0.35
VT	2006	0.86%	$0.34
MA	2007	0.86%	$0.26
NV	2006	0.86%	$0.06
CT	2009	0.85%	$0.31
CT	2002	0.84%	$0.43
IA	2006	0.84%	$0.16
Pacific Northwest	2002	0.83%	$0.19
IA	2007	0.83%	$0.16
CA	2006	0.83%	$0.28
ME	2010	0.82%	$0.17
RI	2005	0.82%	$0.28
Pacific Northwest	2001	0.82%	$0.17
RI	2007	0.81%	$0.27
VT	2003	0.81%	$0.36
British Columbia	2007	0.81%	$0.08
British Columbia	2005	0.81%	$0.10
VT	2004	0.81%	$0.37
MA	2005	0.80%	$0.31
MA	2004	0.79%	$0.34
MA	2009	0.78%	$0.46
RI	2008	0.77%	$0.26

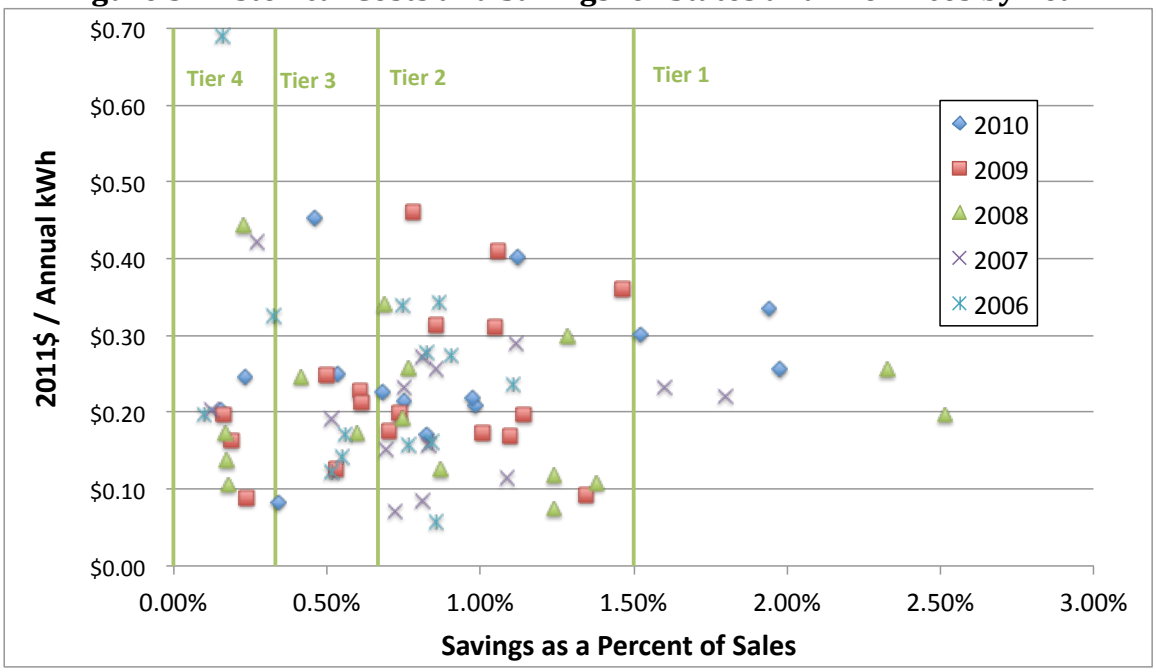
State / Province	Year	Savings as a % of Sales	2011$/kWh/yr Saved
Pacific Northwest	2006	0.77%	$0.16
British Columbia	2004	0.77%	$0.12
NY	2010	0.75%	$0.22
HI	2007	0.75%	$0.23
IA	2008	0.75%	$0.19
MA	2006	0.75%	$0.34
Pacific Northwest	2003	0.74%	$0.17
British Columbia	2009	0.74%	$0.20
NV	2007	0.72%	$0.07
Pacific Northwest	2005	0.72%	$0.17
ME	2009	0.70%	$0.18
ME	2007	0.69%	$0.15
MA	2008	0.69%	$0.34
IA	2005	0.69%	$0.18
Nova Scotia	2010	0.68%	$0.23
Pacific Northwest	2004	0.68%	$0.17
Tier 3			
IA	2004	0.65%	$0.20
VT	2002	0.64%	$0.39
VT	2001	0.62%	$0.34
WI	2009	0.61%	$0.21
NJ	2009	0.61%	$0.23
British Columbia	2008	0.60%	$0.17
MA	2003	0.57%	$0.46
NY	2005	0.56%	$0.17
NY	2006	0.56%	$0.17
ME	2006	0.55%	$0.14
WI	2010	0.54%	$0.25
Nova Scotia	2009	0.53%	$0.13
IA	2003	0.52%	$0.21
British Columbia	2006	0.52%	$0.12
NY	2007	0.51%	$0.19
NY	2009	0.50%	$0.25
NJ	2005	0.47%	$0.26
NJ	2010	0.46%	$0.45
MA	2002	0.45%	$0.59
British Columbia	2011	0.45%	$0.45
NJ	2004	0.42%	$0.33
NJ	2008	0.42%	$0.25
IA	2002	0.38%	$0.25
IA	2001	0.37%	$0.27
CT	2003	0.37%	$0.43
AR	2010	0.34%	$0.08
Tier 4			
HI	2006	0.33%	$0.32
NJ	2007	0.27%	$0.42
NY	2004	0.24%	$0.43
AR	2009	0.24%	$0.09
OK	2010	0.24%	$0.25
NY	2008	0.23%	$0.44
PA	2009	0.19%	$0.16

State / Province	Year	Savings as a % of Sales	2011$/kWh/yr Saved
AR	2008	0.18%	$0.11
Nova Scotia	2008	0.17%	$0.14
TX	2008	0.17%	$0.17
TX	2009	0.16%	$0.20
NJ	2006	0.16%	$0.69
TX	2010	0.15%	$0.20
TX	2007	0.12%	$0.20
TX	2006	0.10%	$0.20

* New York has rolled out a number of new programs in 2009 under the EEPS initiative. These programs have not yet been accounted for in this table. Additionally, savings values for NYSERDA from 2008 onward only include appliance savings from the New York Energy $martSM Products Program.

Figure 3 shows the annual state and province data for 2006 through 2010 from Table 4, with the cost per kWh saved per year in 2011$ mapped against the savings as a percent of sales.

Figure 3: Historical Costs and Savings for States and Provinces by Year



1. Annual Energy Savings

Table 4 shows that annual energy savings as a percentage of sales varies for leading efficiency portfolios and varies widely, both geographically and over time. Looking at savings as a percent of sales from highest to lowest, performance can be classified according to four tiers.

> **Tier 1 (≥1.5%):** In the top tier, states are achieving at or near 2 percent of sales. It contains 9 program years of experience, including California for 4 out of the past 5 years, Vermont 4 out the past 5 years, as well as Connecticut as of last year.
>
> **Tier 2 (≥0.67% and <1.5%):** States in the second tier are saving at or near 1 percent of annual sales, with annual savings ranging from two-thirds (2/3) of one percent to 1.5 percent of sales. In addition to earlier years' performance by California, Vermont, and Connecticut, this group also includes 60 program years of experience from efficiency portfolios in Iowa, Maine, Massachusetts, Nevada, New York, Rhode Island, Hawaii, the Pacific Northwest, British Columbia, and Nova Scotia.
>
> **Tier 3 (≥0.33% and <0.67%):** States with savings at or near 0.5% of sales fall into the third tier. This group contains 26 program years of results, and includes savings in even earlier years for states in the first two tiers, plus Arkansas, New Jersey, and Wisconsin.
>
> **Tier 4 (<0.33%):** All other states with savings less than one-third (1/3) of a percent of sales fall into the lowest tier. This group saved around 0.25% of sales and includes earlier results for some states with performance in Tier 3, as well as Texas, and Arkansas

Examination of the program-year data reveals that several states with DSM portfolios in the top two performance tiers over time have progressed through lower tiers. Also evident from program year performance data is that moving up from one tier to the next is common, especially to and from the second tier. For example, Connecticut increased annual savings from 0.37 percent to 1.52 percent of sales between 2003 and 2010, moving from Tier 3 to Tier 1. Nova Scotia recently went from 0.17 percent of sales in 2008, Tier 4 results, to 0.68 percent of sales in 2010, Tier 2 results. These observations support the feasibility of ramping up utility investment over time.

Another significant observation, not readily evident from the data, is that the top three tiers are all represented by both utility- and non-utility portfolio administrators. California, Connecticut, Rhode Island and Massachusetts portfolios are all administered by distribution utilities; Maine, Vermont, Hawaii, and

Wisconsin all have relied on non-utility (either government or non-government) administration for at least the last five years. New Jersey has changed from utility to non-utility program administration several years ago; New York has evolved in the opposite direction, supplementing government agency administration of statewide programs with utility-administered programs starting in 2009.

This finding supports the feasibility of scaling up BC Hydro's efficiency resource acquisition: the existing capabilities of BC Hydro need not be a binding constraint.

2. Costs of Energy Savings

The relationship between the cost ($/kWh/yr) and depth (savings as a % of sales) depends on whether the focus is on an individual efficiency measure, a single customer project, or a program serving a group of customers. At the individual measure or project level, the law of diminishing marginal returns applies generally: the next unit of efficiency savings costs more than the last. At the measure level, for example, it costs more per kWh saved to upgrade to a central air-conditioner with a seasonal energy efficiency rating ("SEER") of 20 from a SEER 16 system than it does to upgrade to a SEER 16 system from a SEER 13.

The same holds true at the individual customer level. It is always possible to assess the energy savings from all potential efficiency measures that could be installed over time for any customer, and compute the levelized costs per kWh saved. Whether at the household or factory level, costs and savings almost always can be ordered to present an increasingly steep series of steps of progressively more expensive savings. The cost of acquiring savings depends on how multiple opportunities are bundled and installed most effectively.

At the program or portfolio level, economies of scale combine with diminishing returns to determine the relationship between savings costs and depth. It depends on the effectiveness of the program in attracting participants, and how much it costs in marketing, technical assistance, and other program services to achieve that participation. The cost per kWh saved follows a downward trajectory at low levels of program activity. Beyond a certain level of participation, fixed program costs are spread over more savings and tend to level off.

As efficiency portfolios scale up, the law of diminishing returns takes over in two powerful and mutually reinforcing ways to increase the acquisition costs of efficiency savings. First, the available efficiency opportunities become more expensive as the depth of savings increases at the measure and project level. Second, experience shows that higher financial incentives are required to achieve participation rates in the 75-90 percent range. The upshot is that at the deeper end of the pool of achievable efficiency potential, the shape of the efficiency savings cost curve can be expected to become progressively steeper.

While Figure 3 shows that costs per kWh (in constant 2011 dollars) of annual energy savings vary widely between jurisdictions and from year to year, they also provide evidence that efficiency portfolio costs are subject to scale economies as well as diminishing marginal returns. The program year data suggest that some portfolio administrators have been working their way down their efficiency supply cost curves as they have ramped up activity levels; others appear to be encountering diminishing yields as programs invest in more expensive efficiency technology to achieve deeper savings along with more expensive program designs (e.g., higher financial incentives) to penetrate wider segments of eligible markets.

Some states appear to have experienced both dynamics, with scale economies offsetting diminishing returns; for example, Connecticut managed to increase savings from 1.10% to 1.51% of sales between 2001 and 2010, during which time costs of saved energy decreased from $0.35/kWh/year to $0.30/kWh/yr. In other words, savings increased by 36 percent while costs declined by 14 percent over the last decade.

Table 5 shows the minimum, maximum, and average cost per annual kWh savings for each tier.

Table 5: Minimum, Maximum, and Average Costs of Energy by Tier

	2011$/kWh/yr	State / Province	Year
	Tier 1		
Min	$0.18	CA	2005
Max	$0.35	VT	2011
Average	$0.26		
	Tier 2		
Min	$0.06	NV	2006
Max	$0.46	MA	2009
Average	$0.23		
	Tier 3		
Min	$0.08	AR	2010
Max	$0.59	MA	2002
Average	$0.27		
	Tier 4		
Min	$0.09	AR	2009
Max	$0.69	NJ	2006
Average	$0.27		
	TOTAL		
Min	$0.06	NV	2006
Max	$0.69	NJ	2006
Average	$0.25		

No clear correspondence emerges from visual examination of program year data between cost per kWh saved and savings depth. Nonetheless, several trends are apparent from
Table 4 and Table 5:

- Costs of saved energy are not readily distinguishable between the top two savings tiers, with values ranging from $0.06/kWh/year saved for NV in 2006 to achieve 0.86 percent savings, up to $0.46/kWh/year for MA in 2009 to achieve 0.78% savings.

- Costs of saved energy in the top two tiers are generally higher than the costs to achieve lower savings percentages in the bottom two tiers, with values in Tiers 3 and 4 ranging between $0.08/kWh/year for AR in 2010 to achieve 0.34 percent savings and $0.69/kWh/year for NJ in 2006 to achieve 0.16 percent savings.

- More recent experience shows costs increasing among portfolios in the top two tiers; for example, Massachusetts spent $0.40/kWh/year for 1.12 percent savings in 2010, increasing from $0.26/kWh/year for 0.86 percent savings three years before.

- Lower tiers show high costs as well as low, suggesting lower activity levels pursuing relatively low-cost efficiency measures have confined administrators on the downward sloping portion of their efficiency supply curves.

- The unweighted average cost per kWh/yr of savings is practically the same – roughly $0.25/kWh/yr -- across all four tiers. This is the most striking evidence that scale economies and diminishing returns cancel each other out when states expand and deepen their electric efficiency investment.

- Maximum and average costs go down slightly the higher the tier, showing that higher costs of ramping up have been offset by economies of scale. Minimum costs stay around the same until tier 1, when they essentially double, which suggests inexpensive and easy savings from low-hanging fruit by portfolios in the lower tiers.. The downward trend in average costs of saved energy from tier 4 to tier 2 also suggests economies of scale.

3. Plans for 2011 and Beyond

GEEG obtained efficiency investment expenditures and planned savings for several jurisdictions with portfolios that ranked in the top two tiers in
Table 4, as well as two nearby states, Nevada and Arkansas. Table 6 presents annual incremental savings as a percentage of electric energy sales for periods of varying length. Vermont projects savings in the neighborhood of 2 percent annually for the next 10 years.

Table 6: Planned Electric Energy Efficiency Portfolio Savings in the US and Canada

	SAVINGS AS A PERCENT OF SALES										
Year	**VT**	**Nova Scotia**	**Pacific Northwest**	**RI**	**CA**	**CT**	**MA**	**NV**	**PA**	**AR**	**MD**
2011			1.13%	1.32%	1.21%	1.19%	1.65%	0.89%	1.03%	0.26%	1.37%
2012	2.04%		1.21%	1.65%	1.23%		2.03%	0.51%	1.00%	0.50%	1.37%
2013	2.06%	1.08%	1.30%	2.04%				0.57%		0.74%	1.37%
2014	2.07%	1.11%	1.38%	2.43%						0.31%	1.37%
2015	1.96%	1.13%	1.41%								
2016	2.09%	1.16%	1.54%								
2017	2.16%	1.20%	1.61%								
2018	2.13%		1.64%								
2019	2.16%		1.67%								
2020	1.95%		1.67%								
2021	1.95%		1.65%								

Oklahoma Gas and Electric's (OG&E) service territory includes part of western Arkansas, and approximately 10% of OG&E's 2009 sales were in Arkansas[3]. In proceedings before the Arkansas Public Service Commission, OG&E estimated that "it could ramp up to savings of 'slightly less than 1% per year'"[4]. In effect, OG&E is stating that it is capable of elevating its OK portfolio savings from Tier 4 performance in 2011 to Tier 3 performance in 2012, and then to Tier 2 performance in 2013.

Table 7 presents planned efficiency expenditures per annual kWh of electric energy savings from efficiency portfolios listed in Table 6. Costs of saved energy are expected to increase in Tier 1 states to $0.40/kWh/year saved, as well as in the second tier jurisdictions of Connecticut and Massachusetts. Lower costs of savings projected for Nova Scotia are consistent with the fact that the province has only recently begun to ramp up efficiency investment in the last several years.

[3] From US Energy Information Administration's Form 861

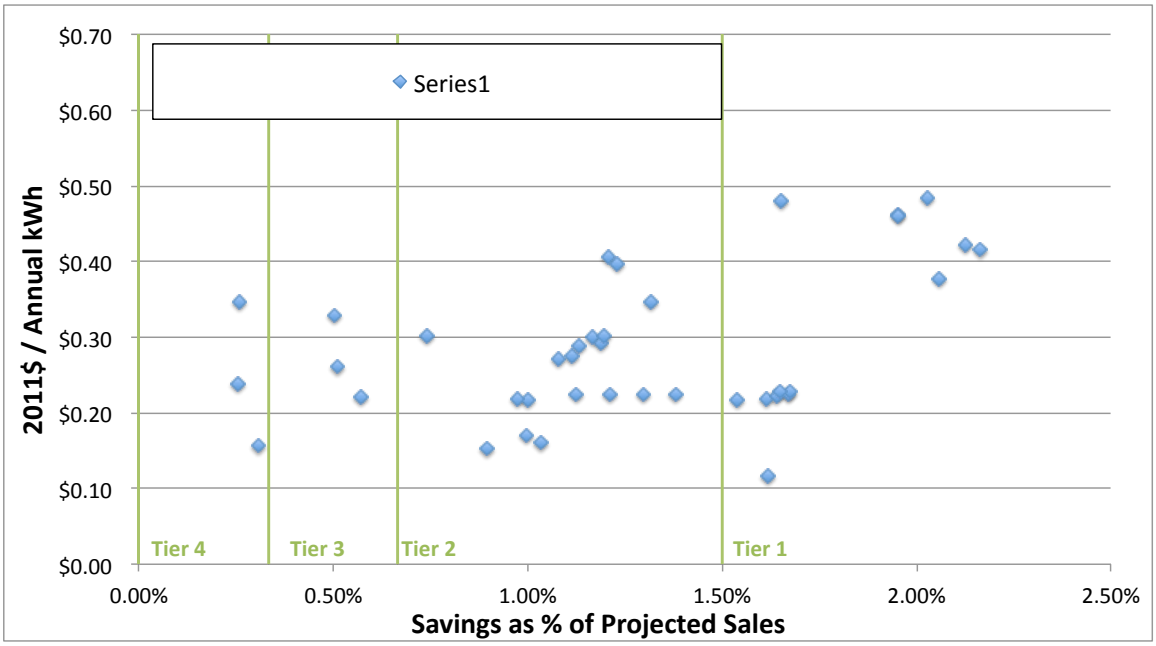
[4] Arkansas Public Service Commission: Docket No. 08-137-U, Order No. 1 (December 10, 2010). Page 12.

Table 7: Planned Electric Energy Efficiency Portfolio Costs in the US and Canada

	SPENDING PER KWH/YR SAVED (2011$)									
Year	VT	Nova Scotia	Pacific Northwest	RI	CA	CT	MA	NV	PA	AR
2011			$0.23	$0.35	$0.41	$0.29	$0.48	$0.15	$0.16	$0.35
2012	$0.36	$0.27	$0.22		$0.40		$0.48	$0.26	$0.17	$0.33
2013	$0.38	$0.28	$0.22					$0.22		$0.30
2014	$0.39	$0.29	$0.22							$0.16
2015	$0.42	$0.30	$0.21							
2016	$0.42	$0.30	$0.22							
2017	$0.42		$0.22							
2018	$0.42		$0.22							
2019	$0.42		$0.22							
2020	$0.46		$0.23							
2021	$0.46		$0.23							

Figure 4 shows cost per kWh saved per year in 2011$, from Table 6,plotted against the savings as a percent of sales, from Table 7, for a state or province's planned energy efficiency efforts.

Figure 4: Planned Costs and Savings for States and Provinces by Year



Prospectively, the positive correlation between the savings costs and savings depth is more pronounced in Figure 4 than it is in historical data depicted in Figure 2 and Figure 3.

4. State and Regional Policies

California

California has one of the most mature energy efficiency industries in the United States, and it continues to pursue a policy of energy efficiency as the first-priority resource for utility procurement. In 2008, the California Public Utility Commission adopted California's first Long Term Energy Efficiency Strategic Plan, which provides an integrated framework of goals and strategies to acquire energy efficiency resources across sectors from 2009 to 2020. While the plan does not contain explicit savings goals, it provides four very aggressive high-level goals that set the tone for energy efficiency efforts in California for the next decade. The goals are:

1. All new residential construction in California will be zero net energy by 2020
2. All new commercial construction in California will be zero net energy by 2030
3. The Heating Ventilation and Air Conditioning (HVAC) industry and market will be transformed to ensure that its energy performance is optimal for California's climate
4. All eligible low-income customers will be given the opportunity to participate in low-income energy efficiency programs by 2020

Northwest Power and Conservation Council (NWPCC)

Congress created the NWPCC in 1980 to help determine the future of electricity generated at, and fish and wildlife affected by, the Columbia River Basin hydropower dams, an area affecting Idaho, Montana, Oregon, and Washington. One of the main principal mandates of the NWPCC is to develop a 20-year electric power plan, which places energy conservation as one of its priorities. The Sixth Northwest Conservation and Electric Power Plan was released in February of 2010, with the following findings:

> "The plan finds enough conservation to be available and cost-effective to meet 85 percent of the region's load growth for the next 20 years. If developed aggressively, this conservation, combined with the region's past **successful development of energy efficiency could constitute a resource comparable in size to the Northwest federal hydroelectric system**." (Emphasis added)

Details on spending and savings levels can be found in Table 6 and Appendix B.

Pennsylvania

Pennsylvania has begun ramping up energy efficiency from basically nothing, as shown in the Table 1, to hopefully achieve the targets shown in Table 8. In 2008, the state passed "Act 129" with an overall goal of reducing energy consumption and

demand. In particular, all electric distribution companies with at least 100,000 customers had to develop and file an energy efficiency and conservation plan. The following table outlines the Pennsylvania Public Utility Commission's goals for each utility and the state as a whole.

Table 8: Pennsylvania Act 129 Electric Energy Savings Goals

Utility	Cumulative Annual GWh Goals		2009 Sales Base Line (GWh)
	PY 2010 - 1%	PY 2012 - 3%	
Duquesne	141	423	14,086
Met-Ed	149	446	14,865
Penelec	144	432	14,399
Penn Power	48	143	4,773
PPL	382	1,146	38,214
PECO	394	1,182	39,386
Allegheny	209	628	20,939
Total	**1,467**	**4,400**	**146,662**

Act 129 program years (PY) go from June of the given calendar year to May 31 of the next calendar year (ex.PY 2009 is June 1, 2009 to May 31, 2010)
Source: http://www.puc.state.pa.us/General/consumer_ed/pdf/EEC_Business-FS.pdf

Pennsylvania's goals can be met by each utility achieving incremental annual energy efficiency savings equivalent to 0.50% of the 2009 sales base in the first two program years, and 1.0% of 2009 sales in the second two program years.

II. Energy Efficiency for BC Hydro

A. Historical and Planned Savings

BC Hydro has pursued energy efficiency under a mandate from the British Columbia Government and has made it a part of its long-term resource planning. In recent years, this has translated to a goal of saving approximately 0.8% of sales from energy efficiency programs[5]. The following table shows the spending and savings achieved by BC Hydro since its fiscal 2004[6].

Table 9: BC Hydro's Historic Energy Efficiency[7]

Fiscal Year	Spending ($M)	Incremental Savings (GWh)	Savings as a % Sales
2004	$39.5	384	0.8%
2005	$36.5	414	0.8%
2006	$28.8	256	0.5%
2007	$32.1	413	0.8%
2008	$52.2	301	0.6%
2009	$73.2	370	0.7%
2010	$104.9	478	1.0%
2011	$102.9	203	0.4%*

* *BC Hydro had a large one-time write down of energy savings in one of its industrial programs in F2011. Savings going forward are expected to more closely reflect 2010 results.*

Table 9 shows that spending has ramped up significantly since F2004 while savings have stayed relatively flat.

BC Hydro is currently working on the 2012 update to its 2008 Long Term Acquisition Plan (2008 LTAP), and as part of this update has continued to refine projections for DSM activity. Table 10 shows the most recent projections that BC Hydro has provided.

[5] Page 31 of BC Hydro's Implementation Plan for Energy-Focused Demand Side Management, Appendix K to BC Hydro's 2008 LTAP

[6] BC Hydro's fiscal year goes from April of the previous year to March of the current year. So FY 2008 started in April 2007 and ended March 2008.

[7] See Appendix D for sources

Table 10: BC Hydro's Planned Energy Efficiency (Cumulative GWh)[8]

Fiscal Year	Cumulative Energy Savings Since 2008 (GWh)	Cumulative Spending Since 2008 ($M)
2012	1,682	$439.9
2013	2,031	$582.0
2014	2,440	$727.7
2015	2,668	$893.2
2023	4,891	$2,352.6
2033	5,482	$4,112.2

Results are for DSM programs excluding Load Displacement

B. Economically Achievable Efficiency Resource Acquisition Targets for BC Hydro

This report establishes the feasibility of a more aggressive scenario for acquiring energy efficiency resources than what is currently projected by BC Hydro. By following industry best practices discussed further in Section D, below, BC Hydro can continue to achieve savings of one percent or ramp up its planned efficiency investment to reduce forecast electricity sales by two percent annually beginning in F2014, as shown in Table 11. BC Hydro could choose to maintain this pace of annual savings going forward.

Table 11: Annual Incremental Electricity Savings as a Percentage of BC Hydro Forecast Annual Electric Energy Sales

Fiscal Year	Tier 1
2013	1.50%
≥ 2014	2.00%

This analysis considers "Year 1" to be the first year that DSM projections differ from those provided by BC Hydro. This analysis projects out new savings for 20 years beyond the shift to higher savings, to BC Hydro's Fiscal 2032. To calculate the savings values, BC Hydro's updated 2011 load forecast was used as the basis, with residential sector sales set to the values from the 2010 forecast and commercial/industrial sales set to the difference between the 2011 load forecast and 2010 residential forecast.

Figure 5 depicts, and Table 12 summarizes, the impact the two percent scenario would have on BC Hydro's future electric energy requirements. This analysis considers "Year 1" to be the first year that DSM projections differ from those provided by BC Hydro. This analysis projects out new savings for 20 years beyond

[8] See Appendix D for sources

the shift to higher savings, to BC Hydro's Fiscal 2032. To calculate the savings values, BC Hydro's updated 2011 load forecast was used as the basis, with residential sector sales set to the values from the 2010 forecast and commercial/industrial sales set to the difference between the 2011 load forecast and 2010 residential forecast.[9]

Figure 5: BC Hydro Electric Sales Forecast

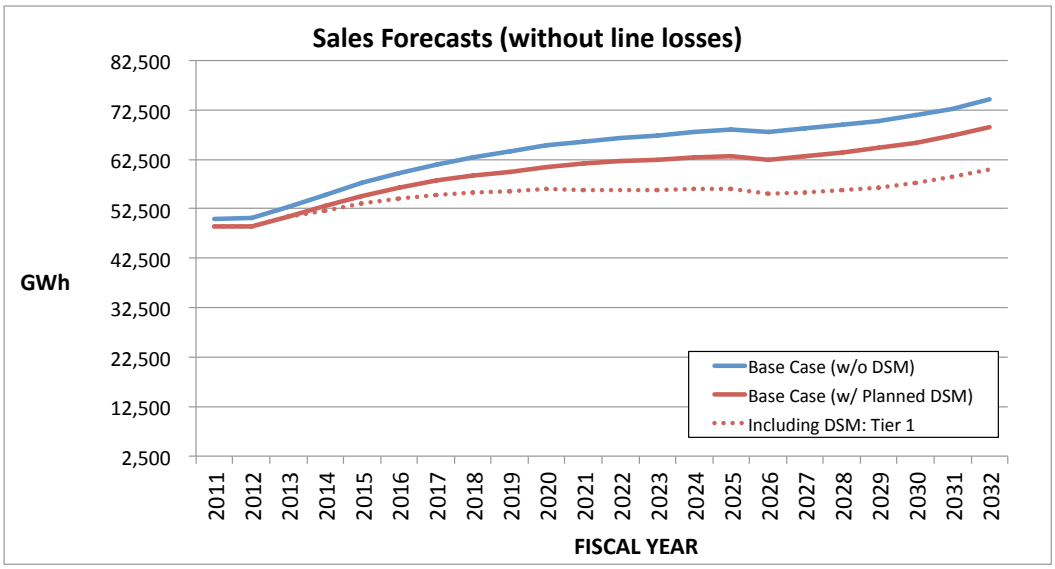


Table 12: BC Hydro Efficiency Savings (Cumulative Annual since 2008[10], with Line Losses[11])

Time Period		GWh	MW
Year 1	F2013	2,492	461
Year 2	F2014	3,587	657
Year 10	F2023	11,274	2,041
Year 20	F2032	15,388	2,786

Reducing BC Hydro's electric energy requirements by two percent annually would yield cumulative annual savings by F2032 of 15,388 GWh since F2008. Detailed savings and sales projections are in Appendix C.

[9] 2011 load forecast comes from BC Hydro's Amended New Appendix II, F12/F13 DSM Expenditures, Attachment 2, page 114. 2010 load forecasts come from BC Hydro's 2010 Electric Load Forecast, Table 6.1

[10] The cumulative savings incorporate measure decay. The decay is based analysis done by Efficiency Vermont on February 28, 2012 for the Vermont Department of Public Service. By the end of year 5, incremental residential savings will have decayed by 41% and non-residential savings will have decayed 6%. By the end of year 10, savings will have decayed by 92% and 37% respectively.

[11] Savings shown "with line losses" reflect the higher amount of energy required at generation to provide the net energy used by consumers. Conversely, energy "sales" are shown "without line losses".

C. Estimated Costs to Acquire Energy Efficiency Savings in BC Hydro

1. Model for Resource Acquisition Costs per kWh of Annual Savings

GEEG has developed an empirical model that predicts energy efficiency resource acquisition costs per kWh of annual savings as a function of four types of variables:

- Savings depth (% of annual sales)
- Time: Portfolio maturity (years); post-2011 plan vs. historical results; year that portfolio investment commenced
- Customer sector (nonresidential)
- Location (if the portfolio is in New England or California)

The model is estimated using ordinary least-squares regression analysis from a pooled (time series, cross section) sample of 470 observations of annual efficiency spending and savings data for portfolio administrators in 19 American states and two Canadian provinces[12]. In 220 cases (438 of the data points), spending and savings data are reported separately for residential and non-residential efficiency investment; in 32 other cases, data was available only at the portfolio level. In aggregate, the dataset represents approximately $25 billion of historical and planned investment (in 2011$), generating cumulative annual energy savings of over 105,000 GWh/yr.

All the model's estimated coefficients are highly statistically significant (with confidence levels beyond 99.9%). The model accounts for over 85 percent of the sample variance of the dependent variable, acquisition cost per kWh/yr (Adjusted R-square = 0.8742). Table 13 and Table 14 below show general information regarding the model.

Table 13: Linear Regression Model for Cost of Energy Savings

Variables		Coefficients	Std. Error	t value	Pr(>|t|)	Signf
Dol_kWh_Yr_201:	*Y*					
Intercept		0				
Per_Sav	X_1	(26.24)	3.07	(8.539)	< 2E-16	***
Per_Sav_Pow	$1/X_1$	0.00008	0.00002	4.880	1.5E-06	***
Per_Sav_Sq	X_1^2	534.2	86.6700	6.164	1.6E-09	***
Yr_1	X_2	0.00017	0.00001	16.796	< 2E-16	***
Maturity	X_3	0.0081	0.0013	6.442	3.0E-10	***
Nonres	X_4	(0.0752)	0.0110	(6.849)	2.4E-11	***
Planned	X_5	0.0654	0.0148	4.422	1.2E-05	***
CA	X_6	0.1727	0.0215	8.040	7.6E-15	***
NE	X_7	0.2025	0.0137	14.836	< 2E-16	***

*Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '+' 0.1 ' ' 1*

[12] The data points are derived from the tables in Appendices A and B.

Table 14: Linear Regression Model Summary Statistics

Regression Statistics		Residuals	
Residual standard error	0.1177 on 461 degrees of freedom	Min	-0.275
Multiple R-squared	0.8766	1Q	-0.070
Adjusted R-squared	0.8742	Median	-0.011
F-statistic	363.9 on 9 and 461 DF	3Q	0.057
p-value	< 2.2e-16	Max	0.531

The model predicts acquisition costs as a polynomial function of savings depth, indicating both scale economies for savings up to 2.5% of sales, and diminishing returns thereafter. It also predicts that acquisition costs increase with portfolio maturity and with each calendar year. Nonresidential efficiency acquisition costs are $0.0752/kWh-yr cheaper than residential or total portfolio costs. Acquisition costs are lower outside California and New England, with the former adding $0.1727/kWh-yr and the later adding $0.2025/kWh-yr to costs.

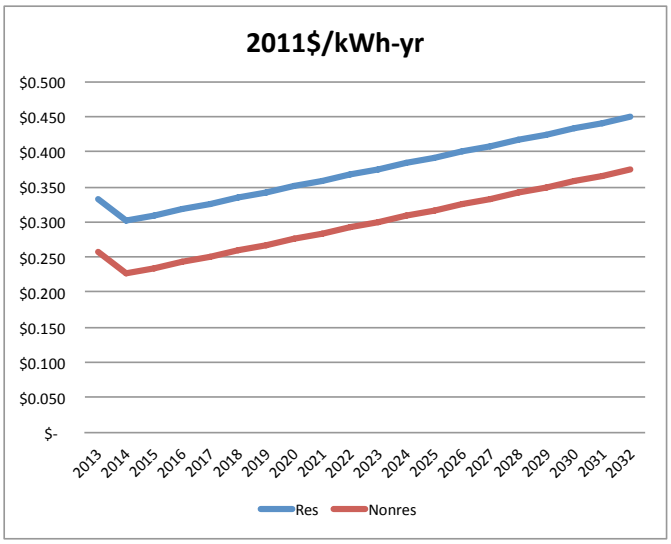
2. Energy Savings Acquisition Costs for BC Hydro

The linear model predicts portfolio administrator unit acquisition costs ($/kWh-yr) based on values selected for each explanatory variable. To achieve Tier 1 savings, BC Hydro would start by achieving 1.5% in F2013 and then 2.0% per year going forward, as shown in Table 11 .The regression model can predict acquisition costs each year using those values, by recognizing both that the savings are from investments planned for the future and that BC Hydro is a mature portfolio with over 20 years of experience starting in approximately 1990. Additionally, variables for California and New England are set to false. These assumptions are then used to forecast two scenarios; (1) forecast costs for residential energy efficiency resources, and, (2) forecasts for non-residential energy efficiency resources. Table 15 shows the costs predicted by the model.

Table 15: Cost of Energy Savings for BC Hydro

Predicted 2011$/kWh-yr

Year	Savings	Res	Nonres
2013	1.500%	$ 0.332	$ 0.256
2014	2.000%	$ 0.301	$ 0.226
2015	2.000%	$ 0.309	$ 0.234
2016	2.000%	$ 0.317	$ 0.242
2017	2.000%	$ 0.326	$ 0.250
2018	2.000%	$ 0.334	$ 0.259
2019	2.000%	$ 0.342	$ 0.267
2020	2.000%	$ 0.350	$ 0.275
2021	2.000%	$ 0.359	$ 0.283
2022	2.000%	$ 0.367	$ 0.292
2023	2.000%	$ 0.375	$ 0.300
2024	2.000%	$ 0.383	$ 0.308
2025	2.000%	$ 0.391	$ 0.316
2026	2.000%	$ 0.400	$ 0.324
2027	2.000%	$ 0.408	$ 0.333
2028	2.000%	$ 0.416	$ 0.341
2029	2.000%	$ 0.424	$ 0.349
2030	2.000%	$ 0.433	$ 0.357
2031	2.000%	$ 0.441	$ 0.366
2032	2.000%	$ 0.449	$ 0.374



The residential costs start at $0.332/kWh-yr, falling to as low as $0.301 by 2014, and then rising monotonically thereafter to nearly $0.45 by 2032. Non-residential costs start at $0.256/kWh-yr range, falling to around $0.226/kWh-yr, and ending up near $0.37/kWh-yr. These findings are in line with recent analysis done by ISO New England on calculating the future costs of state-sponsored energy efficiency for 2014-2020[13]. ISO-New England is currently using cost assumptions of $0.45/kWh for future energy efficiency activity in Maine, Vermont, Connecticut, Rhode Island, Massachusetts, almost all of which have aggressive energy efficiency targets.

3. Annual Expenditures

GEEG estimated annual budgets for each portfolio scenario by multiplying the sector-level acquisition costs in Table 15 by the annual incremental savings acquired (detailed on page C-2 of Appendix C). The table below shows BC Hydro spending by sector by year.

Table 16: BC Hydro Spending Projections (Millions of 2012$)

Year	Residential	Non-Residential	Total
2013	$95	$130	$225
2014	$117	$163	$279
2022	$163	$260	$423
2032	$229	$367	$596
NPV (@5.5%)	$1,425	$2,303	$3,728

4. Estimated Levelized Costs of Savings

GEEG calculated the levelized cost per kWh of electric efficiency savings using a real discount rate of 6 percent, and assuming an average savings lifetime of 10 years for residential programs and 15 years for nonresidential programs. This is consistent with expectations about the greater longevity of high-efficiency lighting, HVAC, and other equipment most likely to constitute the majority of future efficiency investments in each sector. The results are shown in Table 17. Achieving two percent annual savings is projected to cost between $29 and $46 per GWh saved.

Table 17: Levelized Cost of Energy Savings

	Levelized Cost $/GWh	
Sector	**Min (F2014)**	**Max (F2032)**
Residential	$41.0	$60.7
Non-Residential	$23.3	$38.1
Total	**$29.1**	**$45.8**

[13] Ehrlich, David, and Eric Winkler. "ISO-NE Proof of Concept Forecast of New State-Sponsored Energy Efficiency 2014-2020". PAC Meeting. November 16, 2011.

D. Characteristics of BC Hydro's Energy-Efficiency Investment Portfolio

1. Sources of Electric Savings in BC Hydro

Opportunities abound for BC Hydro's homes and businesses to reduce the amount of electricity consumed to operate appliances and equipment serving practically every end use – particularly lighting, cooling, ventilation, refrigeration, space and water heating, motors and drives, compressors. Together, these end uses constitute the vast majority of electricity consumption by BC Hydro's residential, commercial, and industrial electricity customers. Today's electricity demand results from millions of past choices about efficiency levels in the equipment and buildings that comprises BC Hydro's current capital stock. Future electricity demand depends on the efficiency of the turnover of, and additions to, BC Hydro's capital stock over time.

BC Hydro can acquire efficiency savings by intervening in the marketplace in either of two fundamentally different ways. One is to try to influence transactions that will take place anyway as people buy new products and equipment and build or renovate homes and business facilities (i.e., market-driven transactions). Long-lasting electricity savings from market-driven transactions are relatively inexpensive to acquire since costs are limited to the incremental cost of higher-efficiency technologies. The other is to stimulate transactions that otherwise would not have taken place in order to accelerate the turnover of existing capital stock. Retrofit investment involves early retirement of existing inefficient capital stock (e.g., installing high-efficiency lighting to replace functioning inefficient fixtures and lamps), and installation of supplemental technologies (e.g., insulation or controls). Early retirement is a more expensive proposition since it involves the full cost of the new equipment and installation labor.

Opportunities to influence decisions in market-driven transactions are extremely transitory, and will not resurface until the end of the useful life of the inefficient new equipment or building. The only way to acquire savings before then is to retire the inefficient equipment before the end of its life and replace it with new high-efficiency technology through retrofit investment. Efficiency savings from market-driven transactions are therefore considered "lost-opportunity" resources in the industry.

BC Hydro can follow the increasingly well-worn path leading efficiency investment portfolio administrators have taken to design and implement demand-side management program to capitalize on the myriad opportunities to help customers invest in cost-effective efficiency upgrades over time in all major markets. As discussed in Section I-B-2, jurisdictions with the most aggressive and mature efficiency programs are continuing, and in a growing number of cases deepening, their investments in the future. They have been deploying programs targeting the full array of electric (and in most cases gas) efficiency opportunities for all classes of

customer for 10 years or more. These programs follow what are widely recognized as best industry practices in program design and implementation. [14]

BC Hydro should likewise seek to maximize the depth of savings by pursuing comprehensive treatment whenever and wherever possible. The Company should also pursue maximum market penetration in the lost-opportunity markets involving building construction and equipment replacement as its top priority for achieving long-lasting savings at the lowest possible cost. Maximizing market penetration entails technical assistance and financial incentive covering most or all the price premium for the highest-efficiency products and equipment, working up and down the supply chain in each target market.

Unlike lost-opportunity resource, the timing of retrofit investment in early retirement and supplemental measures existing building in the residential, commercial, and industrial sectors, is purely discretionary. BC Hydro can choose the pace of retrofit investment to meet specific resource acquisition goals over time by deciding what fraction of the existing building stock it would need to reach in ten years to achieve the difference between each year's annual savings target and expected savings from lost-opportunity programs. Portfolio administrators can scale up retrofit programs by redeploying and/or re-designing programs to increase participation and the savings each participant realizes. Achieving both requires aggressive targeted marketing, close technical assistance, and financial incentives covering most or all of the installed costs of efficiency measures.

2. Feasibility of Achieving Projected Electricity Savings

a) Mandatory Federal Efficiency Standards

U.S. federal efficiency standards enacted in 2007 for a variety of products and equipment, especially lighting, will significantly change the baseline market conditions confronting DSM program design.[15] New standards will have the dual effects of lowering forecasts of future electricity demand, and reducing the amount of savings that DSM programs can achieve beyond market forces. Operating in tandem with tightening building codes and equipment standards, technological change is expected to increase the efficiency of a wide variety of products and equipment available in the next two decades, reducing the energy intensity of major household and business electricity end uses.

Most profound are changes under way in the lighting market. These changes are expected to radically alter the mix of lighting products available to and chosen by consumers over the next decade, with or without DSM programs. Predicting the magnitude and timing of the changes in the costs, performance, and market

[14] See http://www.eebestpractices.com/

[15] United States. Cong. House. *Energy Independence and Security Act of 2007.* 110th Cong. 1st sess. HR 6. Washington: GPO, 2007. Print

penetration of lighting technologies over the next ten years is extremely difficult. This complicates forecasting electricity demand, and forecasting savings from demand-side management programs designed to change market behavior from "business as usual." The same is true for other end uses, although to a far lesser degree than in the rapidly changing lighting market.

Tightening lighting standards and rapid technological advances will raise market efficiency baselines but will not eliminate the potential for cost-effective efficiency investment. The last wave of major U.S. federal electric end-use efficiency standards took effect in the 1990-92 timeframe, with minor incremental increases in stringency since then. It was during this period that most of the large-scale efficiency resource investment in the U.S. began, yielding large and cost-effective electric energy and peak demand savings. Technological innovation in the future will continue to outpace, and thus largely drive, future efficiency standard levels, as it has for the past 30 years. For example, the SEER 13 central air conditioner promoted as the high-efficiency option in 1992 is today's baseline, and DSM programs promote the SEER 14-16 central air conditioner. In other words, as the efficiency of baseline items increase, so too will the higher-efficiency options, and the gap between what is most cost-effective and what is commonly chosen in the marketplace at any given time can be expected to persist indefinitely.

Much, if not most, of the long-run potential for economically achievable efficiency savings originates in the existing capital stock. Energy efficiency retrofit investments will continue to provide large-scale savings potential, realized through changing standards covering the sale, importation, or manufacture of new products and equipment. Technological advances increase the potential for cost-effective investment in lighting retrofits as the gap between existing equipment and new high-efficiency lighting technology continues to widen over time.

APPENDIX A

Historic Spending and Savings
in the United States and Canada
by Administrator

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
ARKANSAS							
Entergy Arkansas	2008	0.1%	$0.29	0.2%	$0.07	0.18%	$0.11
	2009	0.1%	$0.25	0.3%	$0.05	0.24%	$0.09
	2010	0.6%	$0.08	0.2%	$0.08	0.34%	$0.08
CALIFORNIA							
SDG&E	2005	2.1%	$0.17	2.0%	$0.23	2.05%	$0.20
	2006	0.8%	$0.26	0.5%	$0.32	0.64%	$0.29
	2007	2.6%	$0.17	1.6%	$0.20	1.96%	$0.18
	2008	2.4%	$0.23	1.6%	$0.35	1.93%	$0.30
	2009	1.0%	$0.51	1.6%	$0.27	1.37%	$0.34
	2010	1.7%	$0.19	1.2%	$0.27	1.37%	$0.23
SCE	2004	1.6%	$0.14	0.9%	$0.19	1.16%	$0.17
	2005	1.8%	$0.15	1.6%	$0.20	1.67%	$0.18
	2006	1.3%	$0.20	0.6%	$0.24	0.86%	$0.22
	2007	2.7%	$0.14	1.3%	$0.26	1.75%	$0.20
	2008	2.6%	$0.14	1.4%	$0.24	1.78%	$0.19
	2009	1.5%	$0.25	0.7%	$0.43	0.98%	$0.33
	2010	3.1%	$0.20	1.5%	$0.24	2.09%	$0.22
PG&E	2004	0.9%	$0.26	0.6%	$0.20	0.68%	$0.23
	2005	1.3%		1.5%		1.45%	$0.18
	2006	1.1%	$0.42	0.8%	$0.24	0.84%	$0.34
	2007	2.1%	$0.30	1.6%	$0.22	1.81%	$0.25
	2008	3.8%	$0.18	3.2%	$0.19	3.40%	$0.18
	2009	1.5%	$0.41	0.8%	$0.61	1.06%	$0.51
	2010	2.7%	$0.33	1.6%	$0.27	2.01%	$0.30
CONNECTICUT							
Statewide (UI and CL&P)	2001	0.8%	$0.47	1.3%	$0.30	1.10%	$0.35
	2002	0.6%	$0.48	1.0%	$0.41	0.84%	$0.43
	2003	0.3%	$0.47	0.5%	$0.36	0.37%	$0.43
	2004	0.8%	$0.26	1.1%	$0.28	0.97%	$0.27

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
	2005	0.8%	$0.30	1.2%	$0.27	1.03%	$0.28
	2006	0.9%	$0.29	1.3%	$0.21	1.11%	$0.24
	2007	0.9%	$0.24	1.2%	$0.32	1.12%	$0.29
	2008	1.0%	$0.24	1.5%	$0.33	1.28%	$0.30
	2009	0.7%	$0.39	1.0%	$0.27	0.85%	$0.31
	2010	2.2%	$0.25	1.0%	$0.38	1.52%	$0.30
HAWAII							
Hawaii Energy	2006					0.33%	$0.32
	2007					0.75%	$0.23
	2008					1.38%	$0.11
	2009	1.4%	$0.22	0.8%	$0.11	1.01%	$0.17
IOWA							
Statewide (IOUs)	2001	0.2%	$0.72	0.4%	$0.17	0.37%	$0.27
	2002	0.3%	$0.60	0.4%	$0.16	0.38%	$0.25
	2003	0.3%	$0.68	0.6%	$0.12	0.52%	$0.21
	2004	0.4%	$0.56	0.7%	$0.12	0.65%	$0.20
	2005	0.7%	$0.33	0.7%	$0.13	0.69%	$0.18
	2006	0.7%	$0.32	0.9%	$0.11	0.84%	$0.16
	2007	0.7%	$0.34	0.9%	$0.11	0.83%	$0.16
Interstate Power & Light	2008	0.8%	$0.27	0.7%	$0.13	0.75%	$0.17
	2009	1.5%	$0.22	1.1%	$0.15	1.18%	$0.18
	2010	1.5%	$0.22	0.9%	$0.18	1.03%	$0.19
MidAmerican	2008	0.6%	$0.28	1.1%	$0.09	0.92%	$0.12
	2009	0.9%	$0.28	1.3%	$0.17	1.15%	$0.19
	2010	1.6%	$0.19	1.1%	$0.20	1.21%	$0.19
MAINE							
Efficiency Maine	2006	0.9%	$0.12	0.3%	$0.18	0.55%	$0.14
	2007	1.0%	$0.12	0.5%	$0.18	0.69%	$0.15
	2008	1.3%	$0.11	0.6%	$0.15	0.87%	$0.13
	2009	0.8%	$0.13	0.7%	$0.21	0.70%	$0.18

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
	2010	1.2%	$0.10	0.6%	$0.26	0.82%	$0.17
MARYLAND							
Statewide	2007	0.5%		0.6%		0.57%	
	2008	0.5%		0.6%		0.59%	
	2009	0.5%		0.6%		0.59%	
	2010	0.5%		0.6%		0.59%	
MASSACHUSETTS							
Statewide (IOUs)	2002	0.4%	$0.71	0.5%	$0.53	0.45%	$0.59
	2003					0.57%	$0.46
	2004					0.79%	$0.34
	2005					0.80%	$0.31
	2006	0.8%	$0.36	0.7%	$0.32	0.75%	$0.34
	2007	1.2%	$0.22	0.6%	$0.30	0.86%	$0.26
	2008	0.8%	$0.41	0.6%	$0.30	0.69%	$0.34
	2009	0.7%	$0.68	0.8%	$0.37	0.78%	$0.46
	2010	1.0%	$0.54	1.2%	$0.34	1.12%	$0.40
National Grid	2006	1.4%	$0.30	0.8%	$0.31	0.99%	$0.30
	2007	1.7%	$0.18	0.7%	$0.31	1.09%	$0.23
	2008	1.0%	$0.37	0.7%	$0.31	0.84%	$0.34
	2009	0.8%	$0.64	0.9%	$0.40	0.90%	$0.49
NSTAR	2006	0.7%	$0.45	0.8%	$0.33	0.76%	$0.36
	2007	1.2%	$0.24	0.8%	$0.29	0.91%	$0.27
	2008	0.8%	$0.42	0.8%	$0.28	0.78%	$0.32
	2009	0.7%	$0.66	1.0%	$0.34	0.91%	$0.42
Fitchburg Gas & Electric	2006	0.5%	$0.76	0.5%	$0.36	0.50%	$0.50
	2007	0.2%	$1.06	0.7%	$0.33	0.56%	$0.44
	2008	0.1%	$1.44	0.6%	$0.39	0.43%	$0.52
	2009	0.2%	$2.31	0.7%	$0.50	0.50%	$0.73
WMECo	2006	0.6%	$0.52	4.0%	$0.30	1.90%	$0.35
	2007	0.5%	$0.47	3.1%	$0.23	1.39%	$0.29

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
	2008	0.5%	$0.57	2.1%	$0.31	1.02%	$0.39
	2009	0.6%	$0.94	4.2%	$0.31	1.57%	$0.48
Cape Light	2005	0.5%	$0.52		$0.42	0.77%	$0.48
	2006	0.4%	$0.46	3.2%	$0.41	0.87%	$0.43
	2007	0.9%	$0.26	0.5%	$0.61	0.71%	$0.37
	2008	0.5%	$0.60	0.3%	$0.77	0.40%	$0.66
	2009	0.4%	$0.87	0.6%	$0.51	0.52%	$0.66
NEVADA							
Sierra Pacific Power	2006	0.9%	$0.09	0.8%	$0.04	0.86%	$0.06
	2007	1.4%	$0.06	0.5%	$0.09	0.72%	$0.07
	2008	2.7%	$0.05	0.8%	$0.12	1.29%	$0.08
	2009	2.1%	$0.07	1.0%	$0.11	1.35%	$0.09
Nevada Power	2008	1.8%	$0.05	0.8%	$0.10	1.22%	$0.07
NEW JERSEY							
Statewide (NJ CEP)	2004	0.4%	$0.58	0.4%	$0.19	0.42%	$0.33
	2005	0.3%	$0.73	0.6%	$0.11	0.47%	$0.26
	2006	0.1%	$2.24	0.2%	$0.25	0.16%	$0.69
	2007	0.4%	$0.55	0.2%	$0.23	0.27%	$0.42
	2008	0.8%	$0.28	0.2%	$0.17	0.42%	$0.25
	2009	1.3%	$0.23	0.2%	$0.24	0.61%	$0.23
	2010	0.8%	$0.56	0.3%	$0.28	0.46%	$0.45
NEW YORK							
NYSERDA	2004	0.2%		0.3%		0.24%	
	2005	0.6%	$0.23	0.5%	$0.13	0.56%	$0.17
	2006	0.6%	$0.20	0.5%	$0.12	0.57%	$0.15
	2007	0.4%	$0.36	0.5%	$0.11	0.47%	$0.18
	2008	0.1%	$1.94	0.2%	$0.32	0.15%	$0.67
	2009	0.3%	$0.71	0.6%	$0.13	0.48%	$0.25
LIPA	2006	0.7%	$0.28	0.4%	$0.31	0.51%	$0.29
	2007	1.0%	$0.19	0.6%	$0.30	0.78%	$0.23
	2008	1.0%	$0.13	0.4%	$0.18	0.72%	$0.15

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
	2009	0.8%	$0.23	0.4%	$0.25	0.62%	$0.24
	2010	1.0%	$0.23	0.5%	$0.19	0.75%	$0.22
OKLAHOMA							
Public Service of Oklahoma	2008					0.01%	
	2009					0.12%	
	2010	0.4%	$0.32	0.2%	$0.14	0.27%	$0.22
Oklahoma Gas & Electric	2008					0.03%	$0.00
	2009					0.21%	$0.00
	2010	0.2%	$0.91	0.2%	$0.04	0.21%	$0.27
Empire Direct	2008					0.00%	
	2009					0.01%	
	2010	0.0%	$2.88	0.0%	$22.88	0.00%	$4.91
PACIFIC NORTHWEST							
Northwest Power and Conservation Council (NWPCC)	2001					0.82%	$0.17
	2002					0.83%	$0.19
	2003					0.74%	$0.17
	2004					0.68%	$0.17
	2005					0.72%	$0.17
	2006					0.77%	$0.16
	2007					1.09%	$0.11
	2008					1.24%	$0.12
	2009					1.10%	$0.17
PENNSYLVANIA							
Allegheny	2009	0.0%	$0.91	0.0%	$0.77	0.03%	$0.83
Duquesne	2009	0.1%	$0.44			0.03%	$1.12
PECO	2009	1.1%	$0.08	0.1%	$0.17	0.21%	$0.18
PPL	2009	0.6%	$0.18	0.0%	$2.61	0.21%	$0.18
Met-Ed	2009	0.2%	$0.27	0.0%	$0.30	0.08%	$0.28
Penelec	2009	0.2%	$0.29	0.0%	$0.21	0.09%	$0.27
Penn Power	2009	0.3%	$0.14	0.0%	$0.34	0.12%	$0.17

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
RHODE ISLAND							
Narragansett Electric	2004	0.6%	$0.35	0.6%	$0.33	0.59%	$0.34
	2005	0.9%	$0.28	0.8%	$0.28	0.82%	$0.28
	2006	0.8%	$0.30	1.0%	$0.26	0.91%	$0.27
	2007	0.8%	$0.28	0.8%	$0.27	0.81%	$0.27
	2008	0.6%	$0.30	0.9%	$0.24	0.77%	$0.26
	2009	1.1%	$0.32	1.0%	$0.31	1.05%	$0.31
TEXAS							
Statewide (IOUs)	2006					0.10%	$0.20
	2007					0.12%	$0.20
	2008					0.17%	$0.17
	2009					0.16%	$0.20
	2010					0.15%	$0.20
VERMONT							
EVT	2001	0.8%	$0.38	0.5%	$0.29	0.62%	$0.34
	2002	0.8%	$0.44	0.5%	$0.35	0.64%	$0.39
	2003	0.6%	$0.52	0.9%	$0.29	0.81%	$0.36
	2004	0.9%	$0.36	0.7%	$0.38	0.81%	$0.37
	2005	1.1%	$0.29	0.7%	$0.42	0.87%	$0.35
	2006	1.2%	$0.32	0.7%	$0.37	0.86%	$0.34
	2007	2.3%	$0.19	1.2%	$0.29	1.60%	$0.23
	2008	3.3%	$0.14	1.7%	$0.39	2.33%	$0.26
	2009	1.7%	$0.26	1.3%	$0.45	1.46%	$0.36
	2010	2.3%	$0.23	1.7%	$0.42	1.94%	$0.33
	2011	2.3%	$0.26	1.6%	$0.43	1.83%	$0.35
WISCONSIN							
Focus on Energy	2009	0.4%	$0.37	0.7%	$0.18	0.61%	$0.21
	2010	0.4%	$0.37	0.6%	$0.22	0.54%	$0.25
CANADA							
Nova Scotia Power / Efficiency Nova Scotia	2008	0.3%	$0.12	0.1%	$0.17	0.17%	$0.14
	2009	0.9%	$0.10	0.3%	$0.18	0.53%	$0.13

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved
	2010	0.5%	$0.33	0.8%	$0.19	0.68%	$0.23
	2011	0.0%	$0.00	0.0%	$0.00	1.12%	$0.23
FortisBC	2005	0.5%	$0.12	1.2%	$0.07	0.80%	$0.09
	2006	0.6%	$0.10	1.0%	$0.08	0.76%	$0.09
	2007	0.8%	$0.09	1.0%	$0.08	0.91%	$0.09
	2008	0.7%	$0.11	1.2%	$0.09	0.88%	$0.10
	2009	0.5%	$0.19	1.6%	$0.08	0.90%	$0.11
	2010	0.6%	$0.17	1.5%	$0.09	0.95%	$0.12
	2011	0.6%	$0.17	2.1%	$0.14	1.18%	$0.15
BC Hydro	2003		$0.22		$0.10		$0.12
	2004	1.1%	$0.12	0.6%	$0.12	0.77%	$0.12
	2005	1.2%	$0.06	0.6%	$0.14	0.81%	$0.10
	2006	0.5%	$0.10	0.5%	$0.14	0.50%	$0.12
	2007	0.4%	$0.16	1.0%	$0.07	0.80%	$0.08
	2008	0.4%	$0.23	0.7%	$0.16	0.58%	$0.18
	2009	0.3%	$0.42	0.9%	$0.17	0.73%	$0.21
	2010	0.4%	$0.41	1.3%	$0.19	0.98%	$0.23
	2011	0.4%	$0.40	0.4%	$0.57	0.40%	$0.51

Notes

Savings % of Sales calculated from DSM annual kWh savings installed in that year divided by the applicable kWh sales for the same year.

Spending per annual kWh Saved calculated from program administrator DSM annual spending divided by DSM annual kWh savings at the customer meter installed in that year.

Data for states includes all program administrators for that state.

Savings values for NYSERDA from 2008 onward only include appliance savings from the New York Energy $martSM Products Program.

Pennsylvania values are for the Act 129 program year 2009, which went from June 1, 2009 to May 31, 2010.

Hawaii values are for a program year that starts on July 1st of a calendar year and goes to June 30th of the next calendar year.

BC Hydro Values are for a fiscal year that starts on April 1st of a previous calendar year and goes to March 31st of the given calendar year.

All sales data up until 2009 comes from the U.S. Energy Information Administration's historical values reported on Form 861, which can be found at <http://www.eia.gov/cneaf/electricity/page/eia861.html>. All "Savings as a Percent of Sales" for 2010 use 2009 sales figures unless otherwise noted below.

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved	Savings % of Sales	Spending per Annual kWh Saved

(i) Entergy Arkansas 2010 sales are forecasted values
(ii) Vermont 2010 sales are from the Vermont Department of Public Service
(iii) PSO'S 2010 sales are from its Annual Energy Efficiency Report for 2010
(iv) OG&E's 2010 sales are from the OG&E 2010 Annual Report
(v) Pennsylvania sales are baseline 2009 sales established by the Pennsylvania Public Utility Commission for Act 129.
(vi) BC Hydro's sales are from BC Hydro's 2010 load forecast
(vii) FortisBC's sales are from Fortis BC's 2012 Long Term Acquisition Plan

APPENDIX B

Planned Spending and Savings
in the United States and Canada
by Administrator

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved
ARKANSAS							
Entergy	2011	0.51%	$0.24	0.12%	$0.60	0.26%	$0.35
	2012	0.51%	$0.36	0.49%	$0.31	0.50%	$0.33
	2013	0.56%	$0.40	0.84%	$0.26	0.74%	$0.30
CALIFORNIA							
SDG&E	2011					0.97%	$0.48
	2012					0.92%	$0.46
	2013					0.77%	
SCE	2011					1.28%	$0.37
	2012					1.26%	$0.36
	2013					1.30%	
PG&E	2011					1.19%	$0.43
	2012					1.28%	$0.42
	2013					1.45%	
CONNECTICUT							
Statewide (UI and CL&P)	2011	1.58%	$0.22	0.86%	$0.39	1.19%	$0.29
HAWAII							
Hawaii Energy	2010	2.88%	$0.10	1.07%	$0.12	1.62%	$0.12
MARYLAND							
Statewide	2011	1.50%		1.26%		1.37%	
	2012	1.50%		1.26%		1.37%	
	2013	1.50%		1.26%		1.37%	
	2014	1.50%		1.26%		1.37%	
MASSACHUSETTS							
Statewide (IOUs)	2011	1.22%	$0.72	1.89%	$0.39	1.65%	$0.48
	2012	1.51%	$0.69	2.32%	$0.41	2.03%	$0.48

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved
NEVADA							
Nevada Power	2009	0.93%	$0.14	0.62%	$0.15	0.75%	$0.14
	2010	1.02%	$0.14	0.73%	$0.18	0.85%	$0.16
	2011	0.97%	$0.16	0.71%	$0.18	0.81%	$0.17
	2012	0.31%	$0.49	0.62%	$0.20	0.49%	$0.27
Sierra Pacific Power	2010	2.59%	$0.08	0.49%	$0.14	1.09%	$0.10
	2011	2.47%	$0.09	0.59%	$0.19	1.12%	$0.12
	2012	0.51%	$0.40	0.57%	$0.18	0.56%	$0.24
	2013	0.56%	$0.34	0.57%	$0.18	0.57%	$0.22
OKLAHOMA							
Public Service of Oklahoma	2011	0.51%	$0.36	0.48%	$0.41	0.49%	$0.39
	2012	0.47%	$0.36	0.46%	$0.42	0.46%	$0.40
	2013	0.45%	$0.36	0.44%	$0.42	0.45%	$0.40
	2014	0.43%	$0.37	0.43%	$0.43	0.43%	$0.41
	2015	0.41%	$0.37	0.41%	$0.43	0.41%	$0.41
Empire Direct	2011	0.09%	$0.74	0.04%	$0.78	0.05%	$0.76
	2012	0.09%	$0.72	0.04%	$0.76	0.05%	$0.74
PACIFIC NORTHWEST							
Northwest Power and Conservation Council (NWPCC)	2010	1.51%	$0.27	0.74%	$0.17	1.04%	$0.23
	2011	1.58%	$0.27	0.84%	$0.17	1.13%	$0.23
	2012	1.66%	$0.27	0.93%	$0.17	1.21%	$0.22
	2013	1.76%	$0.27	1.01%	$0.17	1.30%	$0.22
	2014	1.88%	$0.27	1.07%	$0.17	1.38%	$0.22
	2015	1.58%	$0.27	1.30%	$0.17	1.41%	$0.21
	2016	1.84%	$0.27	1.35%	$0.17	1.54%	$0.22
	2017	2.02%	$0.27	1.36%	$0.17	1.61%	$0.22
	2018	2.23%	$0.27	1.28%	$0.17	1.64%	$0.22
	2019	2.31%	$0.27	1.27%	$0.17	1.67%	$0.22
	2020	2.45%	$0.27	1.19%	$0.17	1.67%	$0.23
	2021	2.45%	$0.27	1.15%	$0.17	1.65%	$0.23

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved
PENNSYLVANIA							
Allegheny	2010	0.88%	$0.23	0.89%	$0.10	0.89%	$0.14
	2011	1.30%	$0.13	1.18%	$0.08	1.22%	$0.10
	2012	1.31%	$0.16	0.60%	$0.15	0.86%	$0.16
Duquesne	2010	1.08%	$0.16	1.18%	$0.13	1.15%	$0.13
	2011	1.08%	$0.16	1.18%	$0.12	1.15%	$0.13
	2012	1.08%	$0.16	1.18%	$0.12	1.15%	$0.13
PECO	2010	1.22%	$0.15	0.61%	$0.18	0.82%	$0.17
	2011	1.37%	$0.17	0.58%	$0.23	0.85%	$0.20
	2012	1.01%	$0.24	0.61%	$0.26	0.75%	$0.25
PPL	2010	0.97%	$0.18	0.86%	$0.16	0.90%	$0.17
	2011	0.99%	$0.19	1.19%	$0.16	1.11%	$0.17
	2012	1.00%	$0.20	1.58%	$0.16	1.35%	$0.17
Met-Ed	2010	1.36%	$0.26	0.74%	$0.12	0.99%	$0.20
	2011	1.36%	$0.24	0.74%	$0.11	0.99%	$0.18
	2012	1.22%	$0.14	0.67%	$0.11	0.89%	$0.13
Penelec	2010	1.51%	$0.26	0.75%	$0.11	1.00%	$0.18
	2011	1.51%	$0.23	0.75%	$0.10	1.00%	$0.17
	2012	1.40%	$0.14	0.67%	$0.11	0.91%	$0.12
Penn Power	2010	1.20%	$0.21	0.85%	$0.10	0.99%	$0.15
	2011	1.20%	$0.19	0.85%	$0.09	0.99%	$0.14
	2012	1.09%	$0.14	0.76%	$0.09	0.89%	$0.11
RHODE ISLAND							
Narragansett	2011	1.16%	$0.57	1.41%	$0.24	1.32%	$0.35
	2012					1.65%	
	2013					2.04%	
	2014					2.43%	
VERMONT							
	2012	1.90%	$0.29	2.15%	$0.41	2.04%	$0.36
	2013	1.91%	$0.30	2.17%	$0.43	2.06%	$0.38

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved
EVT	2014	1.97%	$0.32	2.15%	$0.44	2.07%	$0.39
	2015	1.77%	$0.37	2.10%	$0.46	1.96%	$0.42
	2016	1.96%	$0.37	2.19%	$0.45	2.09%	$0.42
	2017	2.08%	$0.38	2.23%	$0.44	2.16%	$0.42
	2018	2.04%	$0.38	2.19%	$0.45	2.13%	$0.42
	2019	1.98%	$0.36	2.30%	$0.45	2.16%	$0.42
	2020	1.88%	$0.47	2.01%	$0.46	1.95%	$0.46
	2021	1.92%	$0.46	1.98%	$0.46	1.95%	$0.46
	2022	1.94%	$0.46	1.97%	$0.46	1.96%	$0.46
	2023	1.95%	$0.46	1.95%	$0.46	1.95%	$0.46
	2024	1.94%	$0.46	1.91%	$0.47	1.92%	$0.47
	2025	1.96%	$0.46	1.89%	$0.47	1.92%	$0.47
	2026	1.94%	$0.46	1.87%	$0.48	1.90%	$0.47
	2027	1.90%	$0.46	1.84%	$0.48	1.87%	$0.47
	2028	1.89%	$0.46	1.82%	$0.49	1.85%	$0.48
	2029	1.87%	$0.46	1.81%	$0.50	1.84%	$0.48
	2030	1.84%	$0.46	1.80%	$0.50	1.82%	$0.48
	2031	1.84%	$0.46	1.78%	$0.51	1.81%	$0.49
BRITISH COLUMBIA							
Fortis BC	2012	0.83%	$0.26	1.27%	$0.18	1.00%	$0.22
	2013	0.86%	$0.25	1.15%	$0.18	0.97%	$0.22
NOVA SCOTIA							
Efficiency Nova Scotia	2013					1.08%	$0.27
	2014					1.11%	$0.28
	2015					1.13%	$0.29
	2016					1.16%	$0.30
	2017					1.20%	$0.30

Notes

Program Administrator, State, or Province	Year	Residential		Non-Residential		Total	
		Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved	Savings % of Sales	Spending per annual kWh Saved

Unless otherwise noted in the source material, all dollar figures were assumed to be nominal. An inflation assumption of 2.6% was used to provide 2011 dollars.

Data for California does not contain spending or savings for the Low Income Energy Efficiency programs.

Pennsylvania IOUs have program years that go from June 1st of a given calendar year and go to May 31st of the next calendar year.

Hawaii Energy's program year goes from July 1s of a given calendar year and goes to June 30th of the next calendar year.

Information for Entergy Arkansas uses sector sales forecasts from EAI's 2009 IRP process, resulting in savings as a percent of sales that are slightly less than the AR PSC's goals, which were taken as a percent of 2010 sales.

Spending levels for the NWPCC are suggested based on results from 2006

APPENDIX C

Detailed Projections for BC Hydro
Assuming Tier 1 DSM

Appendix C – Detailed Projections for BC Hydro, Assuming Tier 1 DSM

PROJECTION ASSUMPTIONS

Sector	Measure Life
Residential	10
Non-Residential	15
Real Discount Rate	5.50%
Line loss factor	8.83%

Fiscal Year	Savings as a Percent of Sales	2011$/kWh-yr	
		Residential	Non-residential
2013	1.50%	$0.332	$0.256
2014	2.00%	$0.301	$0.226
2015	2.00%	$0.309	$0.234
2016	2.00%	$0.317	$0.242
2017	2.00%	$0.326	$0.250
2018	2.00%	$0.334	$0.259
2019	2.00%	$0.342	$0.267
2020	2.00%	$0.350	$0.275
2021	2.00%	$0.359	$0.283
2022	2.00%	$0.367	$0.292
2023	2.00%	$0.375	$0.300
2024	2.00%	$0.383	$0.308
2025	2.00%	$0.391	$0.316
2026	2.00%	$0.400	$0.324
2027	2.00%	$0.408	$0.333
2028	2.00%	$0.416	$0.341
2029	2.00%	$0.424	$0.349
2030	2.00%	$0.433	$0.357
2031	2.00%	$0.441	$0.366
2032	2.00%	$0.449	$0.374

Appendix C – Detailed Projections for BC Hydro, Assuming Tier 1 DSM

SERVICE TERRITORY SAVINGS SUMMARY

BC Hydro Efficiency Savings (Cumulative Annual GWh since F2008, without losses)

Time Period		Tier 1
Year 1	F2013	2,290
Year 2	F2014	3,296
Year 10	F2022	10,359
Year 20	F2032	14,140

BC Hydro Efficiency Savings (Cumulative Annual MW since F2008, without losses)

Time Period		Tier 1
Year 1	F2013	423
Year 2	F2014	604
Year 10	F2022	1,875
Year 20	F2032	2,560

BC Hydro Efficiency Savings (Cumulative Annual GWh since F2008, with losses)

Time Period		Tier 1
Year 1	F2013	2,492
Year 2	F2014	3,587
Year 10	F2022	11,274
Year 20	F2032	15,388

BC Hydro Efficiency Savings (Cumulative Annual MW, with losses)

Time Period		Tier 1
Year 1	F2013	461
Year 2	F2014	657
Year 10	F2022	2,041
Year 20	F2032	2,786

Appendix C – Detailed Projections for BC Hydro, Assuming Tier 1 DSM

INCREMENTAL SAVINGS

Projected Incremental Annual Energy Efficiency Savings (without losses)

Fiscal Year	GWh	MW
2013	794	147
2014	1,108	203
2015	1,155	209
2016	1,196	216
2017	1,229	223
2018	1,259	228
2019	1,284	232
2020	1,307	237
2021	1,320	239
2022	1,335	242
2023	1,346	244
2024	1,360	246
2025	1,369	248
2026	1,359	246
2027	1,373	249
2028	1,390	252
2029	1,406	255
2030	1,428	258
2031	1,456	264
2032	1,491	270

Appendix C – Detailed Projections for BC Hydro, Assuming Tier 1 DSM

CUMULATIVE ENERGY SAVINGS SINCE F2008

Projected Cumulative Energy Efficiency Savings (without losses)*.

Fiscal Year	GWh	MW
2013	2,290	423
2014	3,296	604
2015	4,283	776
2016	5,261	952
2017	6,215	1,125
2018	7,175	1,299
2019	8,093	1,465
2020	8,908	1,613
2021	9,659	1,749
2022	10,359	1,875
2023	10,923	1,977
2024	11,426	2,068
2025	11,895	2,153
2026	12,422	2,249
2027	12,883	2,332
2028	13,210	2,391
2029	13,451	2,435
2030	13,677	2,476
2031	13,902	2,517
2032	14,140	2,560

* The cumulative savings incorporate measure decay. The decay is based analysis done by Efficiency Vermont on February 28, 2012 for the Vermont Department of Public Service. By the end of year 5, incremental residential savings will have decayed by 41% and non-residential savings will have decayed 6%. By the end of year 10, savings will have decayed by 92% and 37% respectively.

Appendix C – Detailed Projections for BC Hydro, Assuming Tier 1 DSM

SALES FORECASTS (GWh, without Losses)

Fiscal Year	Without Energy Efficiency	With Energy Efficiency
2013	52,928	50,638
2014	55,417	52,121
2015	57,775	53,492
2016	59,783	54,522
2017	61,455	55,240
2018	62,948	55,773
2019	64,198	56,106
2020	65,328	56,420
2021	66,003	56,344
2022	66,739	56,380
2023	67,282	56,359
2024	68,018	56,592
2025	68,461	56,566
2026	67,957	55,535
2027	68,654	55,771
2028	69,479	56,269
2029	70,312	56,861
2030	71,380	57,703
2031	72,781	58,878
2032	74,549	60,409

Appendix C – Detailed Projections for BC Hydro, Assuming Tier 1 DSM

SPENDING PROJECTIONS

Fiscal Year	Budgets (Millions 2012$)		
	Residential	C&I	Total
2011	$28.88	$74.04	$102.92
2012	$30.34	$104.27	$134.61
2013	$94.58	$130.49	$225.07
2014	$116.68	$162.65	$279.33
2015	$122.27	$177.79	$300.07
2016	$128.46	$191.54	$320.00
2017	$133.90	$204.80	$338.69
2018	$139.57	$217.48	$357.05
2019	$145.36	$229.23	$374.60
2020	$151.72	$240.27	$391.99
2021	$157.09	$249.86	$406.95
2022	$162.89	$259.66	$422.55
2023	$168.93	$268.34	$437.27
2024	$175.76	$277.72	$453.48
2025	$181.66	$286.22	$467.89
2026	$188.03	$288.34	$476.36
2027	$194.51	$298.16	$492.67
2028	$201.06	$309.00	$510.07
2029	$207.68	$320.10	$527.79
2030	$214.13	$333.28	$547.41
2031	$220.86	$348.99	$569.85

APPENDIX D

List of Sources for Planned and Historic Energy Efficiency Data

Appendix D – DSM Data Sources

State / Province	Administrator	Data	Source
TX	Texas Statewide	2006 - 2009 Spending and Savings	"Table 3: Utility Funds Expended with Associated Demand and Energy Saving" from the EEUMOT Energy Efficiency Accomplishments Reports by Frontier Associates, http://www.texasefficiency.com/layout/inside.php?pgID=42&sn=Reports
TX	Texas Statewide	2010 Spending and Savings	Presentation by Electric Utility Marketing Managers of Texas on June 2, 2011 titled "2010 Program Results and 2011 Program Plans". Located at http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf
AR	Entergy Arkansas	2008 - 2010 Spending. 2010 Savings	Entergy Arkansas, Inc. "Energy Efficiency Program Portfolio Annual Report: 2010 Program Year (Docket No. 08-038-RP)". April 1, 2011. Page 8, Table 2.1
AR	Entergy Arkansas	2009 Savings	Entergy Arkansas, Inc. Energy Efficiency Quick Start Programs: 2009 Program Year Annual Report. April 1, 2010. Page 10, Table 3
AR	Entergy Arkansas	2008 Savings	Entergy Arkansas, Inc. Energy Efficiency Quick Start Programs: 2008 Program Year Annual Report. April 1, 2009. Page 8, Table 2
AR	Entergy Arkansas	2010 - 2013 Spending and Savings	Entergy Arkansas, Inc. "2011 - 2013 Energy Efficiency Program Plan (Docket No. 07-085-TF)". March 1, 2011. Page 3, Table1
VT	Efficiency Vermont	2001-2011 Spending and Savings	From EVT Annual Reports (2009 and 2010 savings are at generation and have a 88.7% factor applied to get to meter savings)
VT	Efficiency Vermont	2001 - 2008 Sales	EIA data for Vermont, excluding BED and Vermont Marble Industrial Sales.
VT	Efficiency Vermont	2010 Sales	Vermont Department of Public Service Memo of June 24, 2011 (Total State excluding BED)
VT	Efficiency Vermont	2012 - 2031 Spending and Savings	VEIC Excel workbook used for DRP reply comments to the PSB.

Appendix D – DSM Data Sources

State / Province	Administrator	Data	Source
CA	SDG&E	2005 Spending and Savings	Energy Efficiency Programs Annual Summary and Technical Appendix 2005 Results. San Diego Gas & Electric. 2006. Pages 1-182. 18 Jan. 2008 <http://sdge.com/regulatory/tariff/cpuc_openProceedings.shtml>
CA	SDG&E	2006 -2008, 2010 Savings	San Diego Gas and Electric. Monthly Portfolio Summary Reports for December 2006, 2007, 2008, 2009, and 2010. Table 1.7: Portfolio Impacts - Market Sector
CA	SDG&E	2009 Savings	California Public Utilities Commission. *Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period*. January 2011. Page 34
CA	SDG&E	2006 - 2010 Spending	San Diego Gas and Electric. Monthly Portfolio Summary Reports for December 2006, 2007, 2008, 2009, and 2010. Table 1.1: Monthly Summary Table
CA	SDG&E	2011 - 2018 Sales	Application of 0.87% average annual growth rate for 2011 - 2018 from "CED 2009 Staff Draft High Rate" Scenario. From: Gorin, Tom. Committee Workshop on 2010 - 2010 Peak Demand and Energy Forecasts, SDG&E Planning Area Forecast. June 26, 2009. http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-26_workshop/presentations/
CA	SDG&E	2011 - 2013 Savings	Public Utilities Commission of the State of California. "Decision 09-09-047: Approving 2010 to 2012 Energy Efficiency Portfolio and Budgets". September 24, 2009. Table 2, p 45 and 46
CA	SDG&E	2011 - 2012 Budgets	Public Utilities Commission of the State of California. "Decision 09-09-047: Approving 2010 to 2012 Energy Efficiency Portfolio and Budgets". September 24, 2009. Page 365
CA	SCE	2006 -2008, 2010 Savings	Southern California Edison. Monthly Portfolio Summary Reports for December 2006, 2007, 2008, 2009, and 2010. Table 1.7: Portfolio Impacts - Market Sector

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State / Province	Administrator	Data	Source
CA	SCE	2006 - 2010 Spending	Southern California Edison. Monthly Portfolio Summary Reports for December 2006, 2007, 2008, 2009, and 2010. Table 1.1: Monthly Summary Table
CA	SCE	2009 Savings	California Public Utilities Commission. *Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period*. January 2011. Page 34
CA	SCE	2005 Spending and Savings	2006 Energy Efficiency Annual Report. Southern California Edison. 2006. 1-242. 18 Jan. 2008 <http://www.sce.com/AboutSCE/Regulatory/eefilings/Annual_Reports/>. Pages 11-13, 145-237
CA	SCE	2004 Spending and Savings	2005 Energy Efficiency Annual Report. Southern California Edison. 2005. 1-222. 18 Jan. 2008 <http://www.sce.com/AboutSCE/Regulatory/eefilings/Annual_Reports/>. Pages 12, 131-222
CA	SCE	2011 - 2018 Sales	Application of 0.69% average annual growth rate for 2010 - 2018 from "CED 2009 Staff Draft High Rate" Scenario. From: Gorin, Tom. Committee Workshop on 2010 - 2010 Peak Demand and Energy Forecasts, SCE Planning Area Forecast. June 26, 2009. http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-26_workshop/presentations/
CA	SCE	2011 - 2013 Savings	Public Utilities Commission of the State of California. "Decision 09-09-047: Approving 2010 to 2012 Energy Efficiency Portfolio and Budgets". September 24, 2009. Table 2, p 45 and 46
CA	SCE	2011 - 2012 Budgets	Public Utilities Commission of the State of California. "Decision 09-09-047: Approving 2010 to 2012 Energy Efficiency Portfolio and Budgets". September 24, 2009. Page 365

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State / Province	Administrator	Data	Source
CA	PG&E	2006-2010 Spending and 2006-2008, 2010 Savings	Pacific Gas and Electric. Monthly Portfolio Summary Reports for December 2006, 2007, 2008, 2009, and 2010. Tables 1.1 and 1.7
CA	PG&E	2009 Savings	California Public Utilities Commission. *Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period*. January 2011. Page 34
CA	PG&E	2011 - 2013 Savings	Public Utilities Commission of the State of California. "Decision 09-09-047: Approving 2010 to 2012 Energy Efficiency Portfolio and Budgets". September 24, 2009. Table 2, p 45 and 46
CA	PG&E	2011 - 2012 Budgets	Public Utilities Commission of the State of California. "Decision 09-09-047: Approving 2010 to 2012 Energy Efficiency Portfolio and Budgets". September 24, 2009. Page 365
CA	PG&E	2011 - 2018 Sales	Application of 0.71% average annual growth rate for 2010 - 2018 from "CED 2009 Staff Draft High Rate" Scenario. From: Gorin, Tom. Committee Workshop on 2010 - 2010 Peak Demand and Energy Forecasts, PG&E Planning Area Forecast. June 26, 2009. http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-26_workshop/presentations/
NY	NYSERDA	2004-2006 Spending and Savings	NEW YORK ENERGY $MARTSM PROGRAM EVALUATION AND STATUS REPORTS, http://www.nyserda.org/Energy_Information/evaluation.asp
NY	NYSERDA	2007 Spending and Savings	Spending and Savings from: NEW YORK ENERGY $MARTSM PROGRAM QUARTERLY EVALUATION AND STATUS REPORT, September 2007, http://www.nyserda.org/Energy_Information/evaluation.asp
NY	NYSERDA	2008 Spending and Savings	New York Energy $mart. "New York's System Benefits Charge Programs Evaluation and Status Report: Year Ending December 31, 2008". March 2009.
NY	NYSERDA	2009 Spending and Savings	New York Energy $mart. "New York's System Benefits Charge Programs Evaluation and Status Report: Year Ending December 31, 2009". March 2010.

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State / Province	Administrator	Data	Source
NY	LIPA	2006 - 2008 Spending and Savings	LIPA Clean Energy Initiative Annual Reports for 2006 - 2008 from http://www.lipower.org/residential/efficiency/cei.html
NY	LIPA	2009 Spending and Savings	LIPA Efficiency Long Island. PY2009 Assessment, Volume I. Table 3 and Table 8.
NY	LIPA	2010 Spending and Savings	LIPA Efficiency Long Island 2010 Annual Report, Volume I. Table 1. Net Impacts: ELI & Renewable Portfolio Evaluated Impacts versus Goals
CT	Connecticut Statewide	2001 - 2010 Spending and Savings	From ECMB Annual Reports. http://www.dpuc.state.ct.us/Electric.nsf/cafda428495eb61485256e97005e054b/5abe828f8be75356852571390052 0270/$FILE/FINAL%20ECMB%202005%20Report.pdf
CT	Connecticut Statewide	2011 Spending and Savings	2011 Electric and Natural Gas Conservation and Load Management Plan (Docket No. 10-10-03 and 10-10-04). October 1, 2010. P
NJ	NJ Clean Energy	2001 - 2009 Spending and Savings	Reporting Excel File from http://www.njcleanenergy.com/main/public-reports-and-library/financial-reports/clean-energy-program-financial-reports
NJ	NJ Clean Energy	2010 Spending and Savings	New Jersey Board of Public Utilities. "New Jersey's Clean Energy Program Report: January 1, 2010 through December 31, 2010". Page 28
NJ	NJ Clean Energy	2011 Spending	New Jersey Clean Energy Program. "Monthly Report of Progress Toward Goals". April 2011. Page 21
ME	Efficiency Maine	2006 - 2010 Spending and Savings	Efficiency Main Annual Reports from http://www.efficiencymaine.com/documents-services/reports
RI	Narragansett Electric	2004 Spending and Savings	Revised 2004 DSM Year-End Report for The Narragansett Electric Company
RI	Narragansett Electric	2005 Spending and Savings	Revised 2005 DSM Year-End Report for The Narragansett Electric Company

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State / Province	Administrator	Data	Source
RI	Narragansett Electric	2006 Spending and Savings	National Grid Demand-Side Management Programs, Electric Operations 2006 Year-End Report
RI	Narragansett Electric	2007 Spending and Savings	National Grid Demand-Side Management Programs, Electric Operations 2007 Year-End Report
RI	Narragansett Electric	2008 Spending and Savings	National Grid Electric and Gas Demand-Side Management Programs, Electric Operations 2008 Year-End Report
RI	Narragansett Electric	2009 Spending and Savings	The Narragansett Electric Company d/b/a National Grid, 2009 DSM Year-End Report
RI	Narragansett Electric	2011 Plan	The Narragansett Electric Company (d/b/a National Grid). "Docket No. 4209 Revised Attachment 6 - Revised Text Table 1". December 6, 2010.
RI	Narragansett Electric	2012 - 2014 Savings Targets	Letter titled "RE: Energy Efficiency Savings Targets" from the Rhode Island Energy Efficiency and Resource management Council (EERMC) to the Rhode Island Public Utility Commission on September 1, 2010.
WI	Focus on Energy	2009-2010 Savings	Focus on Energy and Tetra Tech. "State of Wisconsin Public Service Commission of Wisconsin: Focus on Energy Evaluation Annual Report (2010)". April 11, 2011. Page 2-6, Table 2-5, Column "Annual kWh Saved -Verified Net"
WI	Focus on Energy	2010 Spending	Focus on Energy and Tetra Tech. "State of Wisconsin Public Service Commission of Wisconsin: Focus on Energy Evaluation Annual Report (2010)". April 11, 2011. Page 2-36, Table 2-28, Sum of columns "Incentives" and "Incremental Costs"
WI	Focus on Energy	2010 Spending	Focus on Energy and PA Consulting Group. "State of Wisconsin Public Service Commission of Wisconsin: Focus on Energy Evaluation Semiannual Report (Second Half of 2009)". April 23, 2010. Page 2-40, Table 2-23, Sum of columns "Incentives" and "Incremental Costs"
MA	Massachusetts Statewide	2002 Spending and Savings	Energy Efficiency Activities, A Report by the Division of Energy Resources, An Annual Report to the Great Court on the Status of Energy Efficiency Activities in Massachusetts, Summer 2004,Table 12.

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State / Province	Administrator	Data	Source
MA	Massachusetts Statewide	2003-2005 Spending and Savings	Massachusetts Saving Electricity: A Summary of the Performance of Electric Efficiency Programs Funded by Ratepayers Between 2003 and 2005 Executive Office of Energy and Environmental Affairs, Massachusetts Division of Energy Resources, 4/2/2007
MA	Massachusetts Statewide	2006-2009 Spending and Savings	Individual reports for Ngrid, NSTAR, WMECO, FG&E, and Cape Light
MA	Massachusetts Statewide	2010 Spending and Savings	Energy Efficiency Advisory Council." Efficiency as Our First Fuel: Strategic Investments in Massachusetts' Energy Future". 2010 Report to the Massachusetts Legislature. June 2011.
MA	Massachusetts Statewide	2011 - 2012 Spending and Savings	Commonwealth of Massachusetts Department of Public Utilities. Order for D.P.U. 09-116 through 09-120. January 28, 2010. Appendix A and C
MA	National Grid	2005 - 2009 Spending and Savings	National Grid Annual Energy Efficiency Reports before the Massachusetts Department of Public Utilities
MA	NSTAR Electric	2006 - 2009 Spending and Savings	NSTAR Electric Annual Energy Efficiency Reports before the Massachusetts Department of Public Utilities
MA	WMECo	2006 Spending	Western Massachusetts Electric Company. Information Request AG-01 in Docket No. DPU 07-111. January 17, 2008. Response to Q-AG1-007.
MA	WMECo	2007 Spending and Savings	Western Massachusetts Electric. "2007 Summary of Energy Efficiency Performance". February 2007. Appendix 3, Table 2: Reported, "Total PA Costs"
MA	WMECo	2008 Spending	The Commonwealth of Massachusetts Department of Public Utilities. Decision in D.P.U. 09-54. August 9, 2010. Appendix, Table 1
MA	WMECo	2009 Spending and Savings	Western Massachusetts Electric. "2009 Energy Efficiency Annual Report". August 2, 2010. Appendix 3, Table 2: Reported, "Total PA Costs"

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State / Province	Administrator	Data	Source
MA	WMECo	2006 and 2008 Savings	EAI Form 861 Data, File 3
MA	FG&E	2006 - 2009 Spending and Savings	Fitchburg Gas & Electric Annual Energy Efficiency Reports before the Massachusetts Department of Public Utilities
MA	FG&E	2005 - 2009 Spending and Savings	Cape Light Compact Annual Energy Efficiency Reports before the Massachusetts Department of Public Utilities
IA	Iowa Statewide	2001 - 2007 Spending and Savings	Energy Efficiency in Iowa's Electric and Natural Gas Sectors. January 1, 2009. http://www.state.ia.us/government/com/util/energy/energy_efficiency.html
IA	MidAmerican	2008 - 2010 Spending and Savings	MidAmerican Energy Company Annual Energy Efficiency Reports from http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
IA	IPL	2008 - 2010 Spending and Savings	Interstate Power and Light Annual Energy Efficiency Reports from http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
IA	MidAmerican	2008 - 2010 Spending and Savings	MidAmerican Energy Company Annual Energy Efficiency Reports from http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
NV	Nevada Power	2010 - 2012 Spending and Savings	Nevada Power Company. "Triennial Integrated Resource Plan for 2010 - 2029: Demand Side Plan - Exhibit A". Volume 7 of 26, Program Data Sheets (Page 2 to 432)
NV	Nevada Power	2006 - 2009 Spending and Savings	Nevada Power Company. "Triennial Integrated Resource Plan for 2010 - 2029: Demand Side Plan - Exhibit B". Volume 8 of 26, 2009 Annual Demand Side Management Update Reports (Page 2 to 171)

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State / Province	Administrator	Data	Source
NV	SPP	2004 - 2005 Spending and Savings	Sierra Pacific Power Company. "Integrated Resource Plan 2011 - 2030: Demand Side Plan 2011 - 2013". Volume 5 of 22, Page 38. Table DS-9
NV	SPP	2009 - 2013 Spending and Savings	Sierra Pacific Power Company. "Integrated Resource Plan 2011 - 2030: Demand Side Plan 2011 - 2013". Volume 5 of 22 Program Data Sheets (Pg 95 -382)
NV	SPP	2007 - 2008 Spending and Savings	Sierra Pacific Power Company. "Integrated Resource Plan 2011 - 2030: Demand Side Plan and Technical Appendix". Volume 6 of 22, 2010 Annual Demand Side Management Update Reports (Page 2 to 121)
NV	SPP	2006 Spending and Savings	Sierra Pacific Power Company. "Integrated Resource Plan 2008 - 2027: Volume V Demand Side Plan 2008 - 2010". Page 35 Table 10
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2008 - 2010 Sales	Emera Inc. 2010 Annual Financial Report. Page 19 "Year-to Date (YTD) Electric Sales Volumes"
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2010 Spending	Efficiency Nova Scotia Corporation. In the Matter of an Application to Approve Efficiency Nova Scotia Corporation's Electricity Demand Side Management (DSM) Plan for 2012. Figure 2.4 Page 9 February 28, 2011
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2010 Savings	Nova Scotia Power Inc. Nova Scotia's 2010 Electricity Demand Side Management Plan Evaluation Reports. February 28, 2011 Table 1-1, Page 2.
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2009 Savings	Nova Scotia Power Inc. Nova Scotia's 2009 Electricity Demand Side Management Plan Evaluation Reports. February 26, 2010. Table 1-1, Page 2.

Appendix D – DSM Data Sources

State / Province	Administrator	Data	Source
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2008 Savings	H. Gil Peach & Associates/Scan America. Savings Verification Study of Nova Scotia Power Incorporated 2008 Demand Side Management Programs. October 2009. Table 1, Page 7.
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2008 - 2009 Spending	Nova Scotia Utility and Review Board. Evidence of NSPI as Interim DSM Administrator: In the matter of an Application to Approve Nova Scotia's Electricity Demand Side Management Plan for 2011. February 26, 2010. Page 7, Figure 2.2
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2011 - 2032 Sales, Spending and Savings	Nova Scotia Utility and Review Board. NSPI 2009 Integrated Resource Plan Update Report: Appendix D. November 30, 2009.
Nova Scotia	Efficiency Nova Scotia / Nova Scotia Power	2011, 2013-2017 Spending and Savings	Evidence of ENSC as DSM Administrator, February 27, 2012
PA	Allegheny	2009 - 2012 Plan	West Penn Power Company d/b/a Allegheny Power. "Pennsylvania Act 129 Energy Efficiency and Conservation Plan (Docket No. M-2009-2093218)". June 30, 2009.
PA	Allegheny	PY 2009	West Penn Power Company d/b/a Allegheny Power. "Annual Report to the Pennsylvania Public Utility Commission for the period June 1, 2009 to May 31, 2010: Program Year 1, Annual Report". September 21, 2010.
PA	Duquesne	2009 - 2012 Plan	Duquesne Light Company. "Proposed Changes to Duquesne Light Company's EE&C Plans (Docket No. M-2009-2093217)". September 15, 2010.
PA	Duquesne	PY 2009	Duquesne Light Company. "Annual Report to the Pennsylvania Public Utility Commission for the period December 2009 to May 2010, Program Year 2009". September 15, 2010.

Appendix D – DSM Data Sources

State / Province	Administrator	Data	Source
PA	PECO	2009 - 2012 Plan	PECO Energy Company. "Revised PECO Energy Efficiency and Conservation Plan (Program Years 2009 - 2012)". Light Company. September 15, 2010.
PA	PECO	PY 2009	PECO Energy Company. "Annual Report to the Pennsylvania Public Utility Commission for the period December 2009 to May 2010, Program Year 2009". September 15, 2010.
PA	PPL	2009 - 2012 Plan	PPL Electric Utilities Corporation. "Revised Energy Efficiency and Conservation Plan (Docket No. M-2009-2093216)". September 15, 2010.
PA	PPL	PY 2009	PPL Electric Utilities. "Annual Report to the Pennsylvania Public Utility Commission for the period ending May 2010, Program Year 1". September 15, 2010.
PA	Met-Ed	2009 - 2012 Plan	Metropolitan Edison Company. "Revised Energy Efficiency and Conservation Plan (Docket No. M-2009-2092222)". September 21, 2009.
PA	Met-Ed	PY 2009	Metropolitan Edison Company. "Annual Report to the Pennsylvania Public Utility Commission for the period June 2009 to May 2010, Program Year 1". September 15, 2010.
PA	Penelec	2009 - 2012 Plan	Pennsylvania Electric Company. "Revised Energy Efficiency and Conservation Plan (Docket No. M-2009-2112956)". December 2, 2009.
PA	Penelec	PY 2009	Pennsylvania Electric Company. "Annual Report to the Pennsylvania Public Utility Commission for the period June 2009 to May 2010, Program Year 1". September 15, 2010.
PA	Penn Power	2009 - 2012 Plan	Pennsylvania Power Company. "Revised Energy Efficiency and Conservation Plan (Docket No. M-2009-2112956)". December 2, 2009.
PA	Penn Power	PY 2009	Pennsylvania Power Company. "Annual Report to the Pennsylvania Public Utility Commission for the period June 2009 to May 2010, Program Year 1". September 15, 2010.
HI	Hawaii Energy	2006 - 2008 Spending and Savings	Hawaii Energy Conservation and Efficiency Program. "Public Benefits Fee Administrator Annual Report - PY 2009, Executive Summary". December 15, 2010.

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State / Province	Administrator	Data	Source
HI	Hawaii Energy	2010 Plan	Hawaii Energy: Conservation and Efficiency Program. "Annual Plan Program Year 2010" Honolulu, HI: September 10, 2010.
HI	Hawaii Energy	2009 Spending and Savings	Hawaii Energy: Conservation and Efficiency Program. "Annual Report Program Year 2009". Honolulu, HI: September 10, 2010.
British Columbia	BC Hydro	2003 - 2007 Spending and Savings	BC Hydro Power Smart. "Report on Demand-Side Management Activities for the Twelve Months Ending March 31, 2007". September 2007. Page 8, Table 2; Page 9, Table 3.
British Columbia	BC Hydro	2008 - 2010 Spending	BC Hydro Power Smart. "Report on Demand-Side Management Activities for Fiscal 2010". Revised August 16, 2010. Page 8, Table 2.
British Columbia	BC Hydro	2008 Savings	BC Hydro Power Smart. "Report on Demand-Side Management Activities for the Twelve Months Ending March 31, 2008". October 2008. Page 9, Table 3
British Columbia	BC Hydro	2009 Savings	BC Hydro Power Smart. "Report on Demand-Side Management Activities for Fiscal 2009". September 11, 2009. Page 5, Table 1
British Columbia	BC Hydro	2010 Savings	BC Hydro Power Smart. "Report on Demand-Side Management Activities for Fiscal 2010". Revised August 16, 2010. Page 7, Table 1
British Columbia	BC Hydro	2004 - 2005 Sales	BCHydro PowerSmart, F2010 Demand Side Management Milestone Evaluation Summary Report, p.20
British Columbia	BC Hydro	2006 - 2010 Sales	Table A7.4 2010 BC Hydro, Reference Load Forecast Before DSM and Rate Impacts (Excluding the Impact of EVs and Overlap for Codes and Standards
Pacific Northwest	NWPCC	2010 - 2029 Sales	Northwest Power and Conservation Council. "Sixth Northwest Conservation and Electric Power Plan (Council Document 2010-09): Appendix C". February 2010.
Pacific Northwest	NWPCC	2010 - 2029 Spending and Savings	The Northwest Power and Conservation Council's "6th Plan Conservation Target Calculator" from http://www.nwcouncil.org/energy/powerplan/6/supplycurves/I937/default.htm

Appendix D – DSM Data Sources

State / Province	Administrator	Data	Source
Pacific Northwest	NWPCC	1991 - 2009 Spending, Savings, and Sales	Northwest Power and Conservation Council Excel summary of 2009 conservation achievements from http://www.nwcouncil.org/energy/rtf/consreport/2009/Default.asp
MD	Maryland Statewide	2007 - 2014 Savings	Maryland Energy Administration. Plan to Reduce Per Capita Electricity Consumption in Maryland by 15% by 2015. March 2010. Page 9.
British Columbia	Fortis BC	2005 -2010, 2012 - 2013 Spending, Savings, and Sales	FortisBC Inc. Responses to British Columbia Utility Commission ("BCUC") Interrogatory Request ("IR") 1. September 9, 2011.
British Columbia	Fortis BC	2005 -2010, 2012 - 2013 Spending, Savings, and Sales	FortisBC Inc.'s. Semi-Annual DSM Report for Year Ended December 31, 2011. March 30, 2012

BC HYDRO PIP PROGRAM

INCENTIVE COMPARISON OVER PAST YEAR REFLECTING SIMPLE PAYBACK IN SOME OF THE MORE POPULAR OPPORTUNITIES

Existing Configuration	Retrofit Configuration	Approx. Price Installed	Approx Annual Energy cost saved	Incentive 06/29/ 2011	*Payback time 06/29/ 2011	Incentive 01/12/2012	*Payback time 01/12/2012	Incentive 05/15/2012	*Payback time 05/15/2012
Par 20 55W Reflector	Par 20 LED 7W Reflector	$40.00	$21.12	$35.00	0.24	$30	0.47	$8	1.52
Par 30 55W Reflector	Par 30 LED 12W Reflector	$54.00	$18.92	$35.00	1.00	$30	1.27	$8	2.43
Par 38 75W Reflector	Par 38 LED 17W Reflector	$65.00	$25.52	$45.00	0.78	$35	1.18	$8	2.23
Incandescent A19 60W	A19 LED 12.5W	$37.00	$20.90	$35.00	0.10	$30	0.33	$8	1.39
Incandescent A19 40W	A19 LED 8W	$35.00	$14.08	$35.00	0.00	$30	0.36	$8	1.92
1000W Metal Halide	750W Pulse start Metal Halide	$425.00	$97.00	$250.00	1.31	$250	0.70	$125	1.20
T12HO refrigerator door	LED Refrigerated lighting /door	$300.00	$48.00	$285.00	0.31	$215	1.77	$0	6.25

* Based on 5000 hours per year at $.088/kwh

A Win-Win-Win for Municipal Street Lighting: Converting Two-Thirds of Vermont's Street Lights to LED by 2014

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Dan Mellinger, Vermont Energy Investment Corporation
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Dave Lahar, Vermont Electric Cooperative

ABSTRACT

Reducing energy costs and enhancing the nighttime environment with LED street lighting is by now well understood. However, few municipalities and utilities have successfully taken advantage of this opportunity to convert their street lighting operations to LEDs. Before a system-wide conversion of existing street lights can occur, a utility must obtain the large amount of required capital, identify appropriate LED street light equipment for their applications, consider changes in utility rate structures, and design effective methods for recovering costs. Using Vermont as a case study, this paper presents a partnership model among the statewide energy efficiency utility, the state's largest electric utilities, and several municipalities. The model was designed to overcome the challenges to widespread LED street light conversion. By 2014, more than two-thirds of Vermont's municipal street lights will be upgraded to LED technology. The conversion will: (1) provide municipalities with better nighttime street lighting and significant cost savings—at no additional capital expense to the municipalities, (2) deliver 8,000 MWh of cost-effective new savings to the energy efficiency utility, and (3) deliver financially attractive returns for Vermont's utilities. This win-win-win model is scalable and replicable, and is now being considered in Massachusetts and Rhode Island.

Introduction

The advent of LED technology for street lighting applications has brought about both new opportunities and a new understanding of street lighting systems. Although opportunities existed to improve the efficiency of street lighting applications, even prior to LED, few have pursued these opportunities in part because not enough decision-makers understand how to take advantage of them. Further, many decision-makers perceive that their own street lighting systems are already efficient. It is true that most existing street light systems do in fact use a relatively efficient light source in terms of the source efficacy, as shown in **Table 1.** However, the total efficiency of a street light system should consider both the efficacy of the light source as well as the optical efficiency of the luminaire. Many existing light fixtures emit only a fraction of the light actually produced by the source. Complicating matters further, lighting designers and decision-makers have historically not always understood control and distribution features of street lighting systems. However, LED manufacturers and vendors have used a system approach in selling LED technology, and have thereby expanded the efficiency opportunity that exists in street lighting applications. When the efficiency of the total street lighting *system* is considered,

with luminaire optical efficiency and control, LED technology has significant advantages over incumbent technologies. In fact, LED technology can offer savings of 50% to 75% or more. This fact has created a significant opportunity for utilities and their customers to reduce costs, improve efficiency, and enhance the nighttime environment.

Table 1. Efficacy of Various Street Lighting Technologies

Street Light Technology	Percent Market Share[1]	Typical Source Efficacy (lumens per Watt)	Typical Luminaire Efficiency	Typical Net Efficacy[2] (lumens per Watt)
High-pressure sodium	59%	70 – 150	45%	32 – 68
Low-pressure sodium	10%	68 – 177	25%	17 – 44
Mercury vapor	20%	34 – 58	30%	10 – 17
Metal halide	5%	61 – 85	35 – 40%	21 – 34
Compact fluorescent	2%	50 – 70	60%	30 – 42
Incandescent	4%	10 – 17	60%	6 – 10
Induction	0%	60 – 80	60 – 80%	36 – 64
HE ceramic MH	0%	95 – 120	60 – 80%	57 – 96
LED	0%	60 – 100	60 – 90%	36 – 90

Source: Clinton Climate Initiative, 2010

Approximately 44.9 million street lights are installed nationwide, using 52 TWh / year of electricity and representing 7% of all lighting energy use (Navigant, 2011). If all of these street lights were converted to LED technology, the estimated energy savings would be 17.2 TWh / year[3] (Navigant, 2010). Compared to the average electricity use of a home in the United States, the potential energy savings would provide enough electricity to power 1.5 million homes each year.[4] Although this is a large number, there are other lighting technologies such as LED A-type lamps that are commonly found in both commercial and residential applications, offering even greater potential energy savings (84.1 TWh / year) (Navigant, 2010). What makes LED street lighting so enticing is that the vast majority of street lighting systems is owned and controlled by a relatively small number of entities, the electric utilities. There are 3,269 electric utilities in the United States (APPA, 2010), a much smaller number that must be engaged, compared to the millions of entities that offer other types of lighting energy efficiency opportunities.

Interestingly, although the utilities own the street lighting, the costs of purchasing, installing, operating, and maintaining the street lighting are most often borne by the utilities' customers: municipalities, businesses, or even private individuals. This fact creates an interesting dynamic in which the utilities' customers stand to save from the LED technology, but the decision to move forward with LED street lighting and to offer it to customers lies with the electric utility. Street lighting opportunities—including the options, costs, and monthly charges

[1] Nationwide average.
[2] Excludes control and distribution of light.
[3] There is a discrepancy in the number of street lights between the Navigant 2010 *Energy Savings Estimates of Light Emitting Diodes in Niche Applications* report that estimates energy savings, and the Navigant 2011 *U.S. Lighting Market Characterization* report. Because the *U.S. Lighting Market Characterization* report is more recent and used a more accurate method, the energy savings estimates have been scaled back in a linear fashion, based on the number of street lights listed in the *U.S. Lighting Market Characterization* report.
[4] Assumes average electricity use per home of 11,496 kWh / year, according to data from the 2010 Energy Information Administration.

to customers—are governed by utility rate tariffs. Therein lies one of the most significant barriers to enabling and harnessing the LED street lighting opportunity: Before utility customers can move forward with LED street lighting, the utilities must offer the technology as an option through regulator-approved rate tariffs, a step that most utilities have not yet taken. Utilities' hesitancy in moving forward with LED street lighting rate tariffs is rooted in two areas: technical concerns and financial concerns.

Barriers to Moving Forward and Strategies to Overcome Them

Utility Perspective: Why Not Move Forward, Right Now?

Many utilities do not want to move forward with a technology that they believe to be unproven. Utilities tend to be very risk-averse, and they are likely to question whether "now" is the right time to switch to LEDs for street lighting considering the reliability uncertainties and future potential gains in efficacy. For example, if they move forward with LED, will they create a lost savings opportunity because the technology continues to become more efficient? If the technology is constantly changing, will replacement components be an issue in the future?

In addition to the technology perspective, utilities also have financial perspectives that cause them to hesitate to pursue this opportunity. First, the high initial cost of the technology and its cost-effectiveness have a direct impact on the lease rate they can offer to consumers. This fact also provides another reason to ask the "now" question, since the cost of LED technology continues to decline. Second, the high initial cost increases the amount of available capital required to fund the installation of LED street lighting, even if a rate is offered and the costs are recovered over the long term through the rate tariff. Third, utilities have to account for the unrecovered costs of existing street lights that would be removed from service before they have reached end of life and fully depreciated. The utility typically cannot afford to assume this cost, nor can the cost be factored into a rate tariff. Finally, some utilities might be concerned about the loss of revenue from an LED street lighting rate that is less than the rate of older technologies. Many other factors can affect the scope of utilities' financial concerns, including utility type (investor-owned utility, municipal-owned utility, or a co-operatively owned utility), rate structure, and regulatory oversight.

Key to Moving Forward: A Willing Utility

First and foremost, a *willing* utility that is truly looking for ways to say "yes" to LED technology is a necessary element to adoption of the technology for street lighting. Given the obstacles described above, an uncommitted utility will have no shortage of reasons to delay or forgo an investment in LED. Whether it is because the technology is unproven, the cost currently too high, the necessary capital not available, or the regulatory obstacle too great, the utility can always continue to find reasons to say "no." This cycle will stop only when a utility is forced to move forward by others such as a regulatory body, is pressured by industry peers already moving forward, or has found that the concerns and reasons for not moving forward are no longer valid. This consideration is an important point, since few utilities have a reason to say "yes" to LED technology at this time. At this relatively early stage in the adoption of LED street lighting,

efficiency program efforts are best spent with utilities that want to be leaders, are able to overcome their concerns with the technology, and ultimately show their peers and their customers that it can be done.

Addressing the Utility Technical Concerns

One of the key technical concerns that utilities have with LED technology is that the technology has not been fully vetted, tested, or proven. Indeed, viable LED products for street lighting have been in existence for only five to seven years. Given one of the key benefits and selling points of the technology is long lifetime (in some cases estimated at 20 years or more), utilities want to be sure that this long lifetime will be realized before they base customer rates on it. The problem is that the technology has not been in existence, much less installed, long enough to validate the manufacturers' claims about its lifetime without using predictive methods. This is a valid risk that utilities must consider.

Fortunately, there are several strategies to mitigate this risk. LED technology for street lighting applications is relatively new, but the components of an LED street lighting system and the science behind it are actually well understood. LEDs themselves have been around for decades. The electronics that drive LEDs are no different from many other electronic devices. What is new about LEDs for street lighting is that they are higher power devices than LEDs of the past, and they are being used in a new application where their performance truly matters. This new performance-driven application brings up many new concerns, but several resources in the industry can address them. There are well-regarded predictive methods that can be used to validate the claimed lifetime and performance of LED products. There is also a growing set of lighting standards that can be applied to help ensure the product performs as specified. There is research to support the long lifetime. In fact, there is no disagreement from the experts in the industry that LED street lighting has the ability to perform as promised. However, the challenge is to use the appropriate information and tools to ensure that the actual product delivers this performance. Utilities must tap into the best available knowledge, using the right standards, in the right way, to mitigate the risk of a product not living up to its manufacturer's claims. This can be done largely through a well-informed specification.

A template for this specification exists. Working with leading experts in the industry, the U.S. Department of Energy has developed a Model Specification for LED Roadway Luminaires, released in October 2011 (Municipal Solid-State Street Lighting Consortium, 2011). When used correctly, this specification drastically reduces the risk that an LED street light product will not realize its estimated lifetime and performance benefits. This specification is the key to mitigating many of the risks to utilities and other entities considering LED installations.

A second utility technical concern has to do with whether now is the right time to move forward with the technology given that LED performance is continuing to improve. If the technology is constantly changing, will replacement components be available in the future? This concern is also addressed through a specification. In fact, the more reputable manufacturers are making their street lighting luminaires "future-proof." That is, they have designed the LED components so that they can easily be upgraded with replaceable modules as the technology improves over time.

However, that is not the only concern with whether now is not the right time to move forward. The efficiency of LED technology continues to improve. The field of lighting controls for street lighting is largely undeveloped, but it holds great potential for additional energy savings in street lighting. Will energy savings be lost if the utility moves forward now? Or is it better to wait? This question is frequently asked about energy-efficient lighting. Each situation should be looked at individually, but most often the cost of waiting associated with increased energy and maintenance costs far outweighs the additional energy savings that might be gained by waiting and installing a newer technology later. This is partly due to the fact that the additional energy savings that result as the technology improves become incrementally smaller. For example, many LED street lights that will be installed using current technology will be 100 watts or less, compared to 200 watts or more for older technology, significantly reducing the "pool" of potential energy savings.

Regarding the concern about controls, this too is addressed through a specification. It is very important that LED street lights installed today are able to take advantage of the lighting control opportunities in the future. The DOE's Model Specification for LED Roadway Luminaires contains an optional clause that requires the luminaire / driver to be able to accept a control signal and dim for future control.

In addition to the key technical issues above, some utilities may be concerned with power quality (harmonics, for example), others may be concerned about the weight, or even temperature ratings. All of these concerns will eventually be addressed. The key will be to find solutions to each technical concern, so that utilities will attain a comfortable or acceptable level of risk in order to move forward.

Addressing the Utility Financial Concerns

A utility's financial concerns come from several places. The first concern has to do with the high current cost of the technology. With the cost of LED technology falling, does it make sense to lock in a rate at the current high cost, or should utilities wait until the cost comes down? A related concern has to do with cost-effectiveness. Some utilities have found that the high initial cost of the LED technology offsets all energy and maintenance savings in their rate tariff, resulting in a higher tariff rate compared to older technologies. If the tariff rate is higher than what it was with older technologies, then why would a customer want to convert to the newer technology?

Not all LED products are priced equally. In fact, more so than with any other lighting technology, the cost of LED street lighting luminaires varies widely, depending on light output. To reduce the cost, utilities must minimize the light output, while ensuring the lighting meets the intended design. This strategy of reducing light output cannot be stressed enough, but it can be challenging, given the conservative nature of street lighting design and the perceived safety risks.

Another strategy for reducing the luminaire cost is to select a luminaire manufacturer with competitive pricing. The cost of LED street light luminaries varies widely by manufacturer. Given that the cost of LED continues to decline, deciding when to lock in a price can be a challenging question. One solution is to revisit the rate tariff every few years, and adjust it. This might not be desirable by some utilities, because of the dynamic with regulators and utilities with rate cases. Another solution is to build a variable LED cost into the rate tariff—a cost that can be

adjusted downward without full regulatory approval. This solution was recently implemented by Progress Energy Carolinas, in their LED rate tariff.

A second utility financial concern has to do with the stranded, unrecovered costs of existing street lights that would be replaced with LED. If existing street lights are removed from service before their end of life, and before they have been fully depreciated, then the cost of the street light has not been fully recovered through the rates by the utility. Someone must pay this cost if the light is replaced with LED. This is where a utility's efficiency program or a state energy efficiency program can be extremely advantageous. Financial incentives can be offered to offset or reduce the stranded cost of the existing street lights. If a utility or state energy efficiency program does not exist, then this stranded cost must be factored into the rate tariff or billed to the customer, significantly reducing the cost-effectiveness of the upgrade.

A third utility financial concern is whether there is sufficient capital available to replace the street lights with LED. The costs of the product and installation are ultimately recovered through the street lighting rate tariff, but the utility must still provide the up-front capital to pay for the purchase and installation of the LED street lights. Utility capital is a complicated topic and is viewed differently by investor-owned, municipal, and cooperative utilities. Each utility will have different limitations on the capital available to it. To address these limitations, utilities can put a cap on the number of street lights they are able to install in each year. This cap can be filed with the rate tariff, and / or separately messaged to customers. This approach was successfully used by two utilities in Vermont.

Finally, some utilities might be concerned with the lost street lighting revenue if customers change to LED technology at lower rates. Street lighting revenue will likely decrease, but a utility's profit is just as likely to increase. Savings in fixed expenses—electricity and especially maintenance—can more than offset the loss of revenue. With a properly structured rate tariff, the customer can pay a lower rate, while the utility decreases its fixed expenses and increases its profit.

The Vermont Case Study

In Vermont, the barriers to moving forward with LED street lighting have been largely overcome. The state's three largest electric utilities, Green Mountain Power, Central Vermont Public Service, and Vermont Electric Cooperative, have filed rate tariffs for LED street lighting and received regulatory approval in 2011. The LED rate tariffs are financially attractive to the utility's customers, offering up to 25% in savings on utility bills. What's more, most municipalities and utility customers will be able to proceed with the LED conversion at no capital expense. All they have to do is simply proceed with the conversion, improve the nighttime environment, and begin saving up to 25% on municipal street lighting costs—in some cases much more. The barrier about stranded costs that result when existing street lights are replaced before they are fully depreciated will be eliminated by a financial incentive from the state's energy efficiency program, Efficiency Vermont. In turn, Efficiency Vermont will receive an expected 8,000 MWh of new cost-effective energy savings by 2014. It is also expected that by 2014, more than two-thirds of Vermont's municipal street lights will be converted to LED technology, representing approximately 18,000 street lights. Reaching this milestone required

more than two years of discussions and negotiations with the electric utilities, and perhaps most important, a willing utility partner looking to find a way forward.

Efficiency Vermont began discussions with the electric utilities about LED street lighting in 2009. A growing contingent of the utility customers (who are also Efficiency Vermont's customers) was increasingly frustrated by the lack of options to move forward with LED street lighting. Many had heard of successful installations in other parts of the country and wanted the opportunity to save energy and improve their street lighting for themselves. Initially, none of Vermont's utilities was ready to move forward. The technology was unproven, and it was too expensive. In late 2010, a breakthrough occurred. Green Mountain Power, one of the state's largest investor-owned utilities, signaled to Efficiency Vermont and the regulators that they wanted to try to move forward and develop an LED rate tariff. Their reasons for doing so were partly driven by their customers, and their own desire to be a "green" company. Their customers were becoming unhappy with the lack of options, and the utility's unwillingness to move forward. At the same time, the utility was looking for a suitable low-maintenance "white light" source for street lighting that customers were increasingly asking for, they had been unsatisfied with the higher maintenance required of alternative "white-light" sources such as metal-halide. Green Mountain Power saw this as an opportunity to offer value to their customers, improve their company's image, and find a suitable low-maintenance technology for their future street lighting needs, so long as the other technical and financial barriers could be overcome.

Interestingly, once one utility in a state paves a way forward with LED street lighting and shows that the barriers can be overcome, it becomes much harder for others to continue to say "no." Only a short time after Green Mountain Power had submitted an LED rate tariff to the state's regulatory agency, the second of the state's largest utilities, Central Vermont Public Service, had submitted a tariff of its own. A few months later Vermont Electric Cooperative, the third-largest utility in Vermont, filed its own tariff. This is why having a willing utility partner to pave the way and show that the barriers can be overcome is really a critical component of moving forward.

It is worth noting that in May 2011, Vermont's Legislature passed a law requiring Vermont utilities to offer an LED energy-efficient street light option to their customers through an LED rate tariff. However, the legislation ultimately had little impact. By the time it passed, Vermont utilities had already filed or were in process of filing their LED rate tariffs.

Overcoming Barriers

One of the biggest concerns from the Vermont utilities had been the stranded costs of the existing street lights. For all street lights that had not yet been depreciated, this stranded cost somehow had to be paid for, before a street light could be converted. From the utilities' perspective, they did not want to put a rate tariff out to customers that was not financially attractive and that required customers to pay stranded costs before conversion. In essence, it would only cause more problems and potential complaints. One solution might have been to limit conversions only to replacements of very old street lights that had been fully depreciated, but this was also problematic. Even within a single municipality, the level of depreciation of individual street lights varies widely. The utilities wanted a solution that would take advantage of economies of scale, and would allow them to proceed in a system-wide or municipality-wide

conversion. The breakthrough was made when it was determined that energy efficiency program funds could be used to offset or even completely pay for the stranded costs. The state's regulatory agency gave approval for the use of energy-efficiency program funds for that purpose. Second, the utilities had to look at a system-wide inventory of street lights and determine the average level of depreciation and remaining stranded costs. Across the entire system, the average stranded cost value was determined to be approximately $100 per fixture. This cost, on average, was at a level at which Efficiency Vermont could afford to pay it, through a financial incentive for the energy savings that would result. With the stranded cost barrier eliminated, customers were able to move forward without any capital cost.

A second concern of the utilities was the initial capital required to fund the purchase and installation of the LED street lights. Ideally, this cost needed to fit within the utility's capital budget and would not require any additional debt. How this capital is viewed and acquired depends on whether the utility is investor-owned, municipal-owned, or a cooperative. However, regardless of how this capital is viewed and obtained, the amount of available capital is generally limited. Further, a utility cannot afford to change all the street lights in its service territory all at once. To address this constraint, the utilities placed limits on the number of street lights they can replace in a given year. One utility, Central Vermont Public Service, wrote this limitation into their tariff itself. A first-come-first-served process determines which municipalities can move forward in any year, given the capital limitations.

A third concern of the utilities had been the high initial cost of the LED street lights. If this cost was too high, a financially attractive rate tariff would not be achievable. Fortunately, by the time the LED tariffs were written in 2010, a leading LED fixture manufacturer had introduced a very cost-competitive street light, specifically designed for the utility street lighting market. This fixture in most cases could be obtained for much less than $500. However, there was another critical component to reducing the cost of the LED street light that really enabled a financially attractive rate tariff. Because the cost of LED street lights varies according to lumen output, the utilities had to minimize the size and lumen output. It is important to recognize that a large proportion of the street lighting installed in the United States does not in fact meet the design standards established by the Illuminating Engineering Society of North America (IESNA). Rather, the street lighting is installed to provide what is estimated to be enough light, where there happens to be a utility pole. This offers significant opportunities to reduce and optimize the lumen output of the LED street light, so long as adequate and acceptable light is provided for the application. The utilities, Green Mountain Power in particular, pushed the envelope in the LED street light replacements they chose. To evaluate their choices, they installed many sizes of LED street lights and visibly and technically evaluated them to ensure they provided an acceptable amount of light and enhanced visibility. This approach resulted in LED replacement luminaires with surprisingly low lumen output. It effectively reduced the cost of the fixture, and significantly increased the energy and bill savings for customers. This approach worked for the large proportion of street lights that are not designed to IESNA standards. However, it should be recognized that this level of savings and minimization of lumen output might not be possible for street lighting designed to IESNA standards, as typically occurs with large highways, collector roads, and very urban environments. For these areas, a photometric analysis must be performed to determine the acceptable replacement.

Not all types of street lighting fixtures were addressed through the LED rate tariff. For example, the utility offers options for standard street lights (often called *cobraheads*), flood lights, and decorative options (often called *post-tops* or *acorns*). The vast majority of fixtures are cobraheads, and this is where LED technology is most advanced and most cost-effective. Because of this advancement in the technology and relative low cost, the LEDs are offered only as replacements of existing cobrahead fixtures, and not for flood or decorative luminaires. In the future, it is expected that LED options might be offered through a new rate tariff for flood or decorative luminaires.

Assess, Eliminate, and then Convert

Many of the street lights installed in Vermont and the United States were installed 20, 30, or even 50 years ago. They might have been installed for a purpose that no longer exists, or they might be significantly over- or undersized for current needs. In fact, it was determined that some street lights for which customers were receiving bills did not even exist. This is understandable, given the long period over which the lights were installed. Only in recent years has the street lighting system been electronically tracked and reported, using modern database systems or even a geographic information system (GIS). A desired outcome of all parties involved in the LED upgrades is to get an accurate inventory of the street lights installed in the system, and to correct any mistakes. Furthermore, the municipalities and Efficiency Vermont want to eliminate any unneeded street lights and those that no longer serve their intended purpose. This is the most effective way to increase the energy savings and bill savings from the upgrades. Some of the municipalities to use the program early on were able to eliminate over 30% of their street lights.

To facilitate the assessment of street lights before converting to LED, Efficiency Vermont required municipalities to sign a Memorandum of Agreement (MOA) to access the financial incentives for the program. This MOA requires the municipalities to assess their street lighting system before proceeding with an LED conversion. Efficiency Vermont developed a comprehensive guide and collection of technical resources to assist the municipalities in this process. The guide and resources go much beyond the technical process for evaluating the street lights, and provide guidance on such things as: (1) who should be involved, (2) what process should be used with the community, and (3) how best to obtain community support. Not all municipalities are interested in or successful at eliminating unnecessary lights, but many are successful and have eliminated 10% to 40% of their street lights, dramatically increasing energy savings and cost savings to the municipality, while also reducing light pollution.

A Partnership for Success

As of March 2012, 90 (out of 255) Vermont municipalities had signed MOAs with Efficiency Vermont and are in the process of identifying opportunities to remove unnecessary street lights and are exploring conversion. The utilities have developed systems for working with the municipalities that have signed the MOA, and are promoting the program to more of their municipal customers. Approximately 10 municipalities have already completed the conversion to LED. As more municipalities continue to sign on, the budget is being hit, and the limits to available capital are already being reached. The program is expected to continue to snowball and

reach the maximum amount of LED conversions by 2014, accounting for more than two-thirds of Vermont's municipal street lights. Discussions are under way on how to take the program beyond municipal street lights to those that are leased by businesses or private individuals.

The program is truly a win-win-win for all involved. This model could not have been achieved without a strong partnership among Efficiency Vermont, the electric utilities, and their municipal customers. Perhaps most important, none of this could have been achieved without willing utility partners—those who were looking for ways to say "yes" to LED technology, overcome their technical and financial concerns, mitigate their risks, and move forward to a new street lighting future. This partnership model is both replicable and scalable, and is sufficiently transparent to be considered in other jurisdictions and states.

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