GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #1

QUESTION:

Reference: Exhibit L.EGD.GEC.1, Page 17, Line 22 to Page 18 Line 4.

Preamble: Exhibit L.EGD.GEC.1 Page 17 Line 22 to Page 18 Line 4 states:

> *"These pipelines have operated at the current pressures throughout their lives, reaching back to the 1960's. The pipeline pressure does not appear to have prompted any actions by Enbridge and has only come into this case as a supplemental justification for facilities that Enbridge wants to build for other reasons. Enbridge has not provided any evidence of an actual problem with these operating pressures."*

In the Technical Conference Transcript, Day 1, Page 55 Line 25 to Page 56, Line 21, Mr. Thalassinos, Chief Engineer at EGD, states:

> *"So this project is absolutely necessary from a safety and reliability perspective. From a reliability perspective, as most recently as last week, we had some flooding on the Don Valley, on the Don River, which exposed a 50-metre section of our NPS 30 pipe, and we immediately downgraded that pressure down to 300 pounds to ensure that we're in a safe situation while we're assessing the risk. If this situation had occurred today or even this past winter, let alone 2015, we would be in a situation of losing tens of thousands of customers today. So, the issue of reliability is not a theoretical construct.*
>
> *As recently as last week, in the evidence [Exhibit A, Tab 3, Schedule 3, Paragraph 26 and Interrogatory Response A1.EGD.BOMA.12(c)] we've seen that we lowered the pressures on the Collingwood and Cornwall lines to 80% of their design pressures through the winter. And we regularly run internal inspection tools, which often, or sometimes, find issues that we need to take immediate action on to assess their safety and risk. And sometimes those assessments extend for lengthy periods of time that can extend through the winter. So I'm not sure how many close calls we need before, from a reliability perspective, we need to have more than a single feed on the NPS 30 now supplying that section of our network."*

Does Mr. Chernick believe that it is prudent for Enbridge to rely on a single feed, 40+ year old, high stress pipeline, without the capability to perform a repair during even mild winter conditions, for the supply of gas to downtown Toronto?

i. If no, what alternatives other than DSM or interruptible load arrangements would Mr. Chernick propose as a solution? Please explain the reasoning in detail.

ii. If yes, which of the following two alternatives would Mr. Chernick propose that Enbridge choose if forced to deal with an integrity issue requiring immediate attention during the heating season. Please explain the reasoning in detail.

a) Continue to operate the Don Valley pipeline above 30% SMYS, potentially risking a hazardous pipeline rupture, or;

b) Lower the pressure in the Don Valley line to below 30% SMYS to mitigate the safety hazard, but causing the potential loss of thousands of customers in downtown Toronto.

RESPONSE:

Mr. Chernick does not have a basis for agreeing that the conditions stated in the question apply to "these pipelines" generally or to "the Don Valley" specifically. The question does not define "high stress," establish that Enbridge cannot "perform a repair during even mild winter conditions, or that any single line is essential "for the supply of gas to downtown Toronto."

The transcript quoted in the question states that EGD reduced the pressure on the Don Valley line on May 29, but could not do so on June 12. Temperatures on June 12 were only slightly cooler than those on May 29, as shown in the following table, and had zero heating degree days, so the accuracy of the testimony is subject to question.

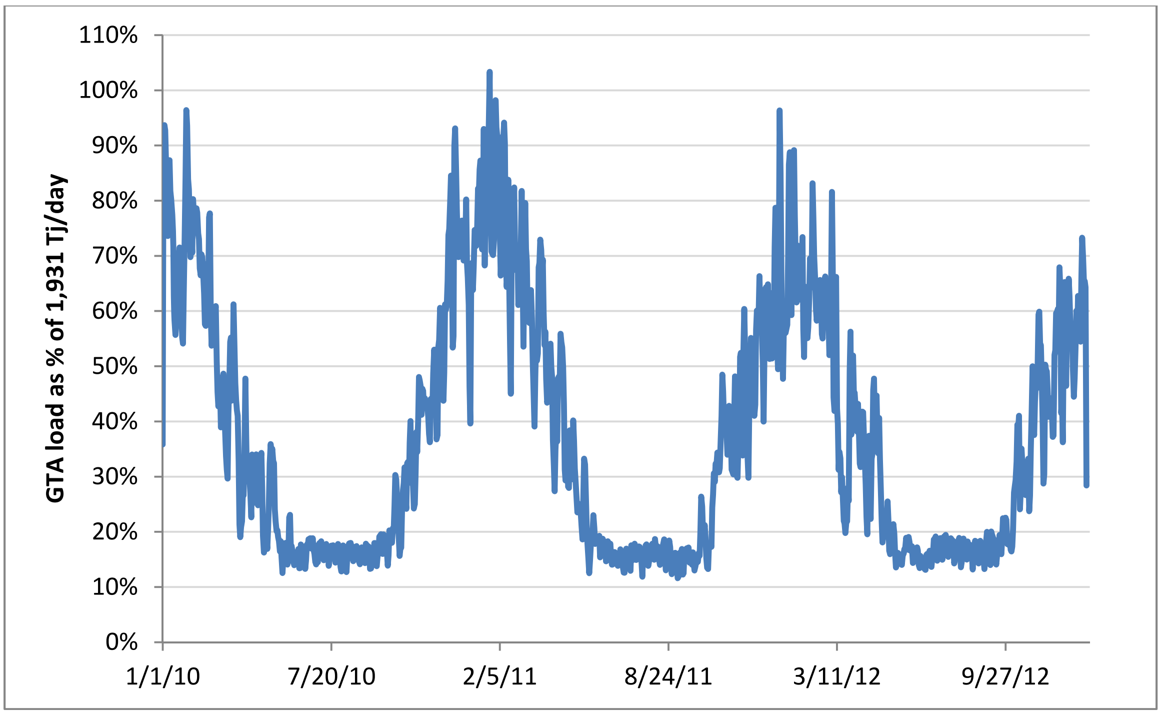
Date	Max Temp (°C)	Min Temp (°C)	Mean Temp (°C)	Cool Deg Days (°C)
5/29/2013	27.2	14.6	20.9	2.9
6/12/2013	23	13.9	18.5	0.5

The quote does not provide any information on mild winter conditions.

Mr. Chernick notes that EGD has found the existing pressure arrangements to be adequate until quite recently. Significantly, while EGD has decreased pressure on pipelines of unspecified vintage and pressure outside the GTA, it has presented no evidence that it has reduced pressure on the GTA pipelines in low-demand periods, other than for maintenance and contingencies. From Exhibit I.A1.EGD.BOMA.19i and Transcript June 14, 2013, p. 114, it appears that at 30% SMYS, the Don Valley line supply would be reduced by 165 Tj/day, or about 181 10^3m^3/hour. From Exhibit I.A1.EGD.BOMA.25, Attachment 1, it appears that the capacity at Victoria Square is at least 943 10^3m^3/hour. While it is not clear how much of that capacity supplies the GTA (since a small amount of gas moves north from Victoria Square, as indicated in Exhibit I.A1.EGD.BOMA.28), it appears that reducing the pressure on the Don Valley line would reduce capacity by about 19% if the load reduction is taken at Station B.

Since 2012 capacity is adequate for 2012 design-peak load, and assuming loads vary evenly over the GTA, we can then determine how often the GTA load exceeds 81% of the 2012 design peak, which Ex1.A1.EGD.APPrO.1e gives as 2,388 TJ/day, so 81% would be 1,931 TJ/day. In the period for which EGD provided load data (2010 through 2012), GTA daily load exceeded 1,931 TJ only once (on January 24, 2011), the four days with loads over 95% of that 1,931 TJ threshold were all in January, and the total of 19 days over 90% of the 1,931 TJ threshold were all between mid-December and mid-February, as shown in the following figure. The data are from EGD_IRR_ED_I.A4_ED.10_Attachment Hourly Flows_20130603.xlsx.

Daily GTA Load as a % of Load Deliverable at Don Valley 30% SMYS



Even with some load growth, it appears that EGD should be able to operate the Don Valley line at 30% SMYS for at least ten months out of the year, and perhaps all but one or two weeks in any given year, depending on the accuracy of forecasts for extreme weather and on the rate at which EGD can increase the pressure in the line. With added DSM or interruptible arrangements with PEC or a combination of the strategies suggested in the Resource Insight report, the occasions when the line would need to operate above 30% SMYS could be steadily reduced or eliminated.

Mr. Chernick does not have sufficient information to perform similar estimates for the NPS 26 line.

Mr. Chernick does not have enough information from EGD to respond to the sub-questions. Specifically, EGD has not provided the contingency plans that it has maintained for the hypothetical posed in question (a)(ii) in recent years. For example, the flooding on the Don Valley line occurred between Jonesville Station and Station B (Tr. July 12, 2013, p. 63), on a "single feed, 40+ year old" segment whose role in the supply of gas to downtown Toronto would not be changed by the construction of Segment B. Due to the flood damage, Enbridge reduced pressure on the Don Valley line from 450 psi to 300 psi, far lower than the 375 psi target with the GTA project (Tr. July 12, 2013, p. 56). Enbridge has not explained how it would deal with that situation at high-load periods, either historically, currently or in the future with or without Segment B.

GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #2

PREAMBLE:

Reference: Exhibit L.EGD. GEC.1, Page 28, Lines 10 to 12

Exhibit L.EGD.GEC.1, Page 28 Lines 10 to 12 states:

> *"The capacity of PEC is about 2.5% of Ontario's winter electric peak. In 10 most years, the Ontario electric system would have a higher capacity reserve on 11 the coldest winter day without PEC than on the peak winter day."*

IESO evidence dated June 28 2013 Page 3, within the report titled *Resource Adequacy: The Role of Gas-Fired Generators in Ontario's Supply Mix,* states:

> *"…Of the over 9900 MW of gas-fired generation in Ontario, approximately 2300 MW is situated in the greater Toronto area. In accordance with Ontario Regulation 496/07, all coal-fired generation will be retired by December 31, 2014, … While these shutdowns will not result in energy or capacity shortfalls, there will be more dependence on gas-fired generation to meet Ontario demand. Further, over the next decade, there are significant projects planned affecting Ontario's nuclear generators. With the expected shutdown and refurbishments of various nuclear generating units, the dependence on gas-fired generation to meet Ontario demand is expected to increase. The Toronto electricity zone*'s 6 peak demand for the summer of 2012 was 9344 MW. The installed capacity of generators in this zone is 8954 MW which represents a mix of natural gas and nuclear generators. Natural gas generators account for 2314 MW of the Toronto zone's installed capacity. With the upcoming anticipated nuclear refurbishment projects, there will be significantly increasing dependence on the natural gasfired generation within the Toronto zone to supply local demand…."*
>
> **The Toronto electricity zone is bounded by the municipalities of Oakville to the west, Woodbridge to the north and Pickering to the east, inclusive.*

IESO evidence dated June 28 2013 Page 4, within the report titled *Transmission Security: The Role of Portlands Energy Centre in Electric Reliability for the Downtown Toronto Core,* states:

> *"…Since PEC achieved commercial operation in 2009, it has played a vital role to secure the supply to downtown Toronto. Based on its location, it is not only needed to meet demand during peak demand days but also to allow maintenance outages of various local transmission elements to proceed…."*

QUESTION:

a) Does GEC agree that PEC may be dispatched based on the operational requirements of the Toronto electricity zone or the Downtown Toronto Core, and not necessarily based on the requirements of Ontario as a whole?

b) If no, please explain.

c) If yes, does GEC agree that PEC may be dispatched even though there is surplus capacity in Ontario outside the Toronto electricity zone?

RESPONSE:

a) Yes. Depending on transmission constraints, PEC may be dispatched out of merit order to meet some local load. This is most likely to occur in the summer.

Given the higher capacity of transmission and generation in the winter, and the lower load of Toronto in the winter, PEC is less likely to be needed on the winter peak for local load, and still less likely to be needed on the very cold days on which EGD might need to curtail PEC. According to Ontario Transmission System, IESO_REP_0265v22.0, November 23, 2012, import capacity into the Toronto zone is about 5,000 MW from the west and 1,000 MW from the north. The following table summarizes the load and generation in the Toronto electric zone on the electric peak hour for each of the days with more than 30 HDD since 2011, and computes the transmission flow into or out of the Toronto zone. The actual flow was out of the Toronto zone on 11 of the twelve days, with PEC on line, and would have been out of Toronto on five of the 12 days even if PEC had been shut down and no generation were available to be ramped up in the Toronto zone. Even without PEC, the Toronto zone would need to import under 800 MW, leaving some 4,200 MW to cover additional transmission and generation outages, beyond those that actually occurred.

		Toronto Zone At Electric Peak Hour (MW)					
Date	HDD	Load	Generation	PEC Output	GTA Gen Less PEC	GTA Import (export)	Import Without PEC
1/23/11	34.0	7,437	7,645	384	7,261	-208	176
1/23/13	33.4	7,854	8,389	639	7,750	-535	104
1/22/13	32.9	7,924	8,538	639	7,899	-614	25
1/31/11	32.5	7,771	8,911	593	8,318	-1,140	-547
2/17/13	32.0	6,674	7,696	639	7,057	-1,022	-383
1/3/12	32.0	7,713	7,502	583	6,919	211	794
1/24/13	31.4	7,814	8,402	639	7,763	-588	51
1/24/11	31.0	7,991	8,193	588	7,605	-202	386
2/8/11	30.8	7,799	8,300	513	7,787	-501	12
1/22/11	30.8	7,162	7,505	140	7,365	-343	-203
2/10/11	30.3	7,677	8,271	483	7,788	-594	-111
1/16/11	30.0	7,114	7,708	0	7,708	-594	-594

Hence, while PEC may be dispatched for economic reasons in the winter, it is not likely to be needed for reliability in Ontario or Toronto in the winter.

b) See part (a).

c) PEC may be dispatched even though there is surplus capacity in Ontario, due to economic dispatch, and under some high-load summer conditions, due to transmission constraints.

GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #3

PREAMBLE:

Reference: Exhibit L.EGD.GEC.1, Page 16, Lines 1 to 12.

Exhibit L.EGD.GEC.1, Page 16, Lines 1 to 12 states:

> *"First, it appears that most or all of the Company's projected purchases of U.S. gas could flow into the GTA even if just Parkway West and Segment A were constructed. Under those circumstances, Enbridge projects that the Parkway stations and Lisgar (where the U.S. gas would be delivered from Union and TCPL) would serve more than 2,040 103m3/hour (Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 2). In contrast, Victoria Square Station would provide 943 103m3/hour without any additional supplies to the Don Valley line (Exhibit 7 I.A1.Enbridge.BOMA.25 Attachment 1). Hence, so long as Enbridge purchases at least 30% of its peak-day supply for the GTA to be delivered from the TCPL facilities to Victoria Square Station, the portion of the Company's supply that flows from the U.S. can be taken entirely through the Parkway stations and Lisgar, without Segment B."*

Exhibit L.EGD.GEC.1, Page 7 Lines 11 to 14 states:

> "…the economics of accessing additional supplies of U.S. gas are not likely to be changed very much by plausible load reductions. Hence, I do not discuss those parts of the GTA Project."

QUESTION:

a) Please explain how the referenced 2,040 103m3/hr was calculated as being the sendout from Parkway and Lisgar with only Parkway West and Segment A, given that Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 2 shows the sendouts inclusive of both Segment A and Segment B.

b) For the 30% to be delivered at Victoria Square, please describe the upstream path and transportation requirements that Mr. Chernick expects Enbridge to utilize and comment on the availability of such path.

c) Mr. Chernick suggested to "purchase at least 30% of its peak-day supply for the GTA to be delivered from the TCPL facilities to Victoria Square Station". Please review Exhibit A, Tab 3, Schedule 5 and Exhibit E, Tab 1, Schedule 1. Please confirm that Mr. Chernick agrees that the economics would be less favourable and the customer bill impacts would be higher with this alternative. If Mr.Chernick cannot confirm, please explain why.

d) Please explain whether Mr. Chernick believes it is prudent for the Company to plan for 30% of the supply to come from a supply line that the supplier has stated may not have the currently utilized transport services available, or that the services currently being offered may only be available under different contractual conditions and at higher costs.

RESPONSE:

a) The original computation is explained generally on page 16 lines 3 to 6 and in footnote 8 of Exhibit L.EGD.GEC.1. More specifically, Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 2 shows the three lines running from Lisgar Gate Station carrying 553 10^3m^3/hr and the two lines running from Parkway Gate Station carrying 1,204 10^3m^3/hr, for a total of 1,757 10^3m^3/hr. In addition, the Bram West Interconnect is shown delivering 1,111 10^3m^3/hr through Albion Road Gate Station. Some of the gas from Bram West in Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 2 would flow along Segment B. Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 2 shows 282 10^3m^3/hr flowing through Buttonville Station, but it appears that some of the Segment B gas is bypassing Buttonville. The original estimate assumed that the bypass went through Jonesville XHP, resulting in a total of 827 10^3m^3/hr flowing from the west to the Don Valley, leaving 287 10^3m^3/hr from Bram West being used along Parkway North, and resulting in total deliveries of gas from the west of 1,757 + 287 = 2,144 10^3m^3/hr.

An alternative estimate of the Segment B flow would be the reduction in deliveries at Victoria Station from Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 1 to Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 2, which is 731 10^3m^3/hr, which would imply that 380 10^3m^3/hr from Bram West is delivered along the existing Parkway line. The sum of the Lisgar, Parkway and net Bram West flows without Segment B is 1,757 + 380 = 2,137 10^3m^3/hr.

For comparison, Exhibit I.A1.Enbridge.5 BOMA.25 Attachment 1 shows 2,139 10^3m^3/hr coming from Parkway and Lisgar without the proposed facilities.

b) Mr. Chernick assumes that EGD would use a portion of the TCPL capacity that it uses currently and plans to continue using after 2015 (Exhibit A.3.5 Table 1). In addition, construction of a line from Albion to Maple would allow EGD to bring western gas to Victoria Square over the TCPL line from Maple to Victoria Square, even if the TCPL line from Parkway to Maple is fully loaded. If EGD is concerned that TCPL or other transportation providers may withdraw facilities that EGD needs to maintain reliable service, it should oppose those actions before the NEB.

c) The question is not a complete sentence. As explained in Mr. Chernick's evidence, EGD is still planning to take considerable amounts of its supply from TCPL, as confirmed in Exhibit A, Tab 3, Schedule 5, Page 28, Table 1. Neither of the cited documents provides the economics of gas supply with Segment A and without Segment B.

d) The question appears to request that Mr. Chernick critique EGD's supply plan laid out in Exhibit A.3.5, Table 1; Exhibit JT1.10; or the like. Mr. Chernick has not conducted a review of the prudence of EGD's supply plan.

The question is quite vague regarding the nature of the concern that "the supplier has stated [that the supply line] may not have the currently utilized transport services available." It is not clear what sort of transport services would become unavailable under what circumstances. Again, if EGD is concerned that TCPL or other transportation providers may withdraw facilities that EGD needs to maintain reliable service, it should oppose those actions before the NEB. Exhibit A.3.5, Table 1 and Exhibit JT1.10 assume that EGD will change the tariffs under which it will take service to mitigate toll increases.

GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #4

PREAMBLE:

Reference: Exhibit L.EGD.GEC.1, Page 13 Line 3 to 8.

Exhibit L.EGD.GEC.1, Page 13 Line 3 to 8 states:

> *"The Board should require that the utilities integrate demand and supply options, including DSM and interruptible and curtailable rates and contracts, along with adding delivery facilities and local peaking supplies, to relieve that constraint. This process would effectively institute a form of local least-cost planning. A similar approach has been successful for dealing with local constraints on the electric system in Vermont and elsewhere."*

QUESTION:

a) Please define "successful" in terms of load reductions achieved, investment amounts, and time period from initiation of the plan to delivered load reductions.

b) Please provide examples for a local distribution company in the natural gas industry that achieved similar results.

c) Specifically compare the actual results in the examples to the forecast of Enerlife Consulting for both timing and load reductions achieved.

d) Please explain the difference between the electric industry and natural gas industry in regards to their abilities to track and monitor peak hour load.

RESPONSE:

a. By "successful," Mr. Chernick means that the efforts reduced load enough to defer transmission and/or distribution investments, at net costs lower than those of the deferred investments. For a review of targeted DSM, see *www.raponline.org/document/download/id/4765*

   For a summary of Con Edison's targeted DSM program, see

   - www.aceee.org/files/proceedings/2010/data/papers/2059.pdf
   - documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={11603D97-C6F2-44E0-8BA3-4FBE9B4186E7}

- switchboard.nrdc.org/blogs/lettenson/ConEdison%20Presentation%20%28April%202013%29.pdf.

b. In the time available Mr. Chernick has not attempted to perform a comprehensive search for such examples, and is not familiar with any from personal experience.

c. It is not clear what comparison is requested, but the question does not appear to refer to any analyses Mr. Chernick has performed. See the evidence of Energy Futures Group for examples of rapidly ramped DSM efforts in other jurisdictions.

d. Mr. Chernick is not familiar with EGD's practice in monitoring load. In general, both electric and gas utilities can monitor load on major system components on an hourly basis.

GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #5

PREAMBLE:

Reference: Exhibit L.EGD.GEC.2, Page 1, paragraph 4.

Exhibit L.EGD.GEC.2 GEC, Page 1, paragraph 4 states:

> "*Mr. Neme is also intimately familiar with Enbridge's current and past DSM efforts from serving on the current Ontario Technical Evaluation Committee (TEC), serving on all but one of Enbridge's annual DSM Audit Committees since they were first formed in 2000 (including the current audit committee charged with reviewing the Company's 2012 DSM savings), and having played a lead role in negotiating the settlement agreement between Enbridge Gas and stakeholder groups on Enbridge's 2012-2014 DSM plan.*"

QUESTION:

a) In the past decade, has GEC or any of its member groups made previous representations to the Company and/or the Ontario Energy Board regarding the use of DSM to defer or avoid capital investment to meet distribution system requirements?

b) In the past decade, has GEC or any of its member groups participated in OEB consultations and/or Generic Proceedings regarding the DSM framework, objectives of DSM and DSM Guidelines?

c) In the past decade, did GEC or any of its member groups raise the issue of integrated resource planning on any of those occasions?

RESPONSE:

a) Yes. See attached letter to the Board from 2012. In addition see extract from a case before the Board when Centra Gas proposed the addition of a pipeline into Orillia.

b) Yes.

c) Our understanding is that most of Enbridge's facilities applications in recent years have been to support new customer hook-ups, extending gas service to new subdivisions or large customers. In these situations, targeted DSM might have reduced load but not displaced facilities and any effect on equipment or pipe sizing would not have avoided significant investment. Both Union and Enbridge have noted that the GTA project is unprecedented in scale in recent years. As discussed in the affidavit materials filed in support of motions before the Board in the 2012-2014 DSM update hearing, GEC was unaware of the current GTA proposal before receiving the notice of application. GEC has always advocated for least cost planning, which by definition calls for an assessment by the utility of its avoidable supply side investments. Section 6.2 of the Board's DSM guidelines call for avoided costs "based on long-term estimates and include: avoided supply side costs, such as capital, operating and commodity costs." GEC had assumed that Enbridge would respect those guidelines and had not thought it necessary to advocate for the preservation of Board policy.

Green Energy Coalition

- Greenpeace Canada
- Nuclear Awareness Project
- Sierra Club of Canada
- World Wildlife Fund Canada

February 10, 2012

Rosemarie T Leclair
Chair, Ontario Energy Board
2300 Yonge St, 27th flor
Toronto, ON
M4P 1E4

RE: RRFE Consultation

Dear Ms Leclair,

Thank you for the invitation to consult on the OEB's renewed framework for regulation of the electricity distribution sector. Unfortunately no one from GEC is available on the 27th but we have had an opportunity to confer with Pollution Probe and we understand that they are raising concerns that we share including the lack of a specific commitment to least cost planning including demand side measures, the lack of a requirement for Local IRP to minimize distribution capital outlays, and the failure of the regulatory structure to provide suitable incentives for loss reduction.

We hope that the Board will be able to address these and related concerns in its forthcoming regulatory agenda.

Sincerely,

Kai Millyard

Kai Millyard
for the Green Energy Coalition

E.B.R.O. 483/484

BEFORE THE ONTARIO ENERGY BOARD;

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF an Application by Centra Gas Ontario Inc. for Orders approving rates to be charged for the sale, distribution, transmission and storage of gas.

Argument of the Environmental Coalition

November 8, 1993

Submitted by:
David Poch,
Solicitor for the
Environmental
Coalition

Argument of The Environmental Coalition EBRO-483/484

Introduction

The Environmental Coalition is comprised of Friends of the Earth, Greenpeace Canada and the Energy Action Project/Nuclear Awareness Project. These groups made up the steering committee of the Coalition of Environmental Groups for a Sustainable Energy Future (the CEG) which was active throughout the IRP process. A number of smaller groups who were part of the CEG had a primary interest in electricity and cross-fuel issues and, accordingly, are not part of the current coalition. The concern of the Coalition is the fostering of environmentally friendly activity by the LDCs and the discouragement of environmentally inappropriate activities.

The Coalition was very active throughout the ADR stage of these hearings and is a signatory to the settlement agreement (Exhibit M.1). As a result the Coalition was able to remain relatively inactive throughout the oral hearing stage. However, in addition to indicating our support for the resolution of issues proposed in Exhibit M.1, especially the DSM-related matters, we will make submissions on six matters that were discussed in the oral phase:

- economic feasibility criteria including the alternative of a surcharge payment mechanism;
- Centra's service line hook up policy;
- the 1994 capital projects budget and the utility's interpretation of EBO 134;
- a generic regulatory issue raised by the situation with the Orillia second feed;
- Centra's fireplace marketing budget; and,
- the proposed increase in the customer charge.

and the subsidy remains unsubstantiated from a societal perspective.

We submit that the budget for the unprofitable projects listed in exhibit J5.64 not be approved pending development of a surcharge proposal which eliminates cross-subsidy or their justification by way of a fuller analysis of societal costs.

Orillia

Regulatory implications of the Board's ruling to defer consideration of this issue

Given the Board's ruling that the capital costs forecast for the Orillia second feed will not be allowed into rate base at this time we recognize that it would be inappropriate to submit argument on the need or merits of the proposal. The Board, properly concerned with regulatory efficiency, has recognized that a discussion of alternatives amounts to a discussion of need, and that need will be discussed in the subsequent leave-to-construct hearing. The Board has acknowledged that we would be at liberty to argue for disallowance from rate base in whole or part in a subsequent rate case. However, we do wish to highlight the regulatory problem that the particular chronology has laid bare.

Centra forecasts a need date for the Orillia second feed of the winter of 94/95. It responds to our evidence on DSM alternatives, in part, by saying it is too late to achieve sufficient DSM to avoid a risk of a peak problem next winter. While we disagree with Centra about its forecast and the extent of the problem, and while we believe that it is still timely to attain adequate DSM and interruptible load as an alternative, we must acknowledge that there is some lead time required for DSM. The more time that elapses before the start of a leave-to-construct hearing, the stronger Centra's point becomes, and by then it may well be too late for DSM to serve as an adequate alternative. The fact that we could subsequently argue for rate base exclusion is small comfort. The pipe will be in the ground, Orillia will be a DSM lost opportunity, and the atmosphere will be polluted.

There is no requirement that a utility seek leave to construct prior to the rate hearing that will deal with rate base inclusion and sufficiently in advance of need to allow timely consideration of alternatives. We submit that a meaningful implementation of IRP requires such. We urge the Board to invite the utilities to follow such a protocol.

GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #6

PREAMBLE:

Reference: Exhibit L.EGD.GEC.2, Page 2, paragraph 1.

Exhibit L.EGD.GEC.2, Page 2, paragraph 1 states:

> "*That includes extensive experience with the integration of DSM into system planning which culminated last year in the publication of a report on North American experience with the use of energy efficiency to defer electric transmission and/or distribution system investments.*"

QUESTION:

a) Please provide the report.
b) Please list / describe any jurisdictions you are aware of that are currently using energy efficiency to defer gas distribution system investments.

RESPONSE:

A) See attached.
B) We have not conducted research to ascertain which jurisdictions have used energy efficiency to defer gas distribution system investments. It is worth noting that the electric study provided in response to part (A) of this interrogatory took many months to complete. However, from Mr. Grevatt's direct personal work experience, we can say that Vermont Gas has in the past used DSM to defer a gas distribution system investment.

Energy solutions for a changing world

US Experience with Efficiency As a Transmission and Distribution System Resource

Authors
Chris Neme, Energy Futures Group
Rich Sedano, Regulatory Assistance Project

February 2012

Acknowledgements

The authors would like to thank the following individuals who provided valuable feedback and suggestions on an initial draft of this report: Joshua Binus and Mike Weedall of the Bonneville Power Administration, Terry Black of The Project for Sustainable FERC Energy Policy, Dan Engel of The FSC Group, Toben Galvin of Navigant Consulting, Chris Gazze of the International Atomic Energy Agency (and former manager of Consolidated Edison's targeted demand-side management program), Chuck Goldman of Lawrence Berkeley National Laboratory, Jeremy Newberger of National Grid, Scudder Parker of the Vermont Energy Investment Corporation, Dan Peaco of La Capra Associates, and T.J. Poor of the Vermont Department of Public Service.

A number of other individuals also provided invaluable information, ideas, and perspective on the case studies we examined. They include most of the reviewers identified above as well as Dave Grimason of Grimason Associates (and formerly of Green Mountain Power), Larry Holmes of NV Energy, Ottie Nabors and Frank Brown of Bonneville Power Administration, Beth Nagusky of Environment Northeast, Rick Weijo of Portland General Electric, and Mike Wickenden of the Vermont Energy Investment Corporation and Efficiency Vermont. Their input was very much appreciated.

Though we could not have completed this report without the help of those identified above, it is important to note that some of the feedback we received was conflicting. In addition, in a few cases, we disagreed with and therefore elected not to make some specific changes suggested by one or more reviewers. We make these points to underscore that we, the authors, are ultimately solely responsible for the information presented and the conclusions drawn in the report.

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Executive Summary

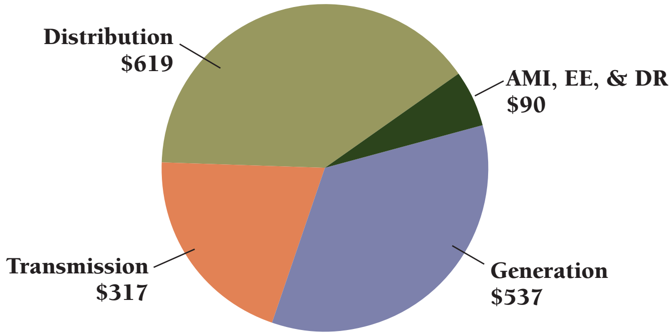
Improvements to electric efficiency in homes and business provide a variety of benefits to both the customers making the improvements and to the electric system as a whole. The most widely recognized are energy savings and system peak demand savings. A much less widely recognized or valued benefit is the potential to enhance the reliability of the transmission and distribution (T&D) system. This paper focuses on that potential, summarizing lessons learned from US initiatives in which geographically targeted efficiency programs have played a major role in electric utility funded efforts to defer T&D investments.

Importance of T&D Investments

The potential to defer T&D upgrades deserves much more serious consideration than it has received to date. The U.S. utility sector has invested on the order of $35 to $40 billion per year in the T&D system over the past decade and is forecast to invest nearly $50 billion per year over the next two decades. As Figure ES-1 shows, this represents approximately 60% of total forecast investments for the sector. Only 6% of the forecast capital investments are in advanced metering infrastructure (AMI), energy efficiency (EE) and demand response (DR). Not all forecast T&D investments will be deferrable. Some will be required to address time-related deterioration of equipment or other factors that are independent of load. However, a significant portion of T&D investment is likely to be associated with load growth. The potential benefits of deferring even a modest portion of such investments could be substantial.

Figure ES-1

US Power Sector Capital Investment Needs (2010 – 2030)
(in billions of 2009 dollars)



Passive Deferral vs. Active Deferral

Efficiency programs can defer T&D investments either passively or actively. We define "passive deferrals" as those that occur as a result of efficiency programs that were not undertaken primarily for the purpose of deferring T&D upgrades. For example, system-wide efficiency programs will reduce loads on virtually all major elements of the T&D system. As a result, at least some load growth-related investments in the T&D system will be deferred for at least some period of time. Indeed, Consolidated Edison (Con Ed) reduced its projected T&D capital expenditures by more than $1 billion after separately adjusting 10-year load forecasts for each of its 91 distribution networks and load areas in New York to reflect the expected impacts of system-wide efficiency programs.

In contrast, "active deferrals" are those that result from efficiency programs that are geographically-targeted for the express purpose of deferring the need for upgrades to specific elements of the T&D infrastructure. Though there are a number of notable exceptions, this concept has not yet been widely pursued due to a variety of inter-related factors:

- **Financial incentives –** utilities typically earn more from investing in "poles and wires" than from investing in efficiency and/or other alternatives;
- **Efficiency's multiple attributes/benefits –** because efficiency investments provide energy savings, peak capacity savings, reserve margin savings, and other benefits in addition to T&D reliability improvements, comparing them to "poles and wires" investments requires a holistic, systemic perspective that has not been universally adopted by utilities, their regulators, independent system operators (ISOs), or regional transmission operators (RTOs);
- **System planning is highly technical –** the technical specialization needed to do T&D planning fosters an environment biased to technical solutions;
- **System engineers distrust demand resources –** those charged with planning to meet reliability needs typically have limited interaction with efficiency program managers and limited direct experience with the performance of demand resources;

- **Risk aversion** – utilities are typically reluctant to try new approaches, particularly if they perceive any regulatory risk in doing so;
- **Socialization of transmission investment costs** – while the cost of transmission solutions are often socialized regionally, the cost of efficiency programs or other non-wires solutions that could meet the same reliability objectives are not; and
- **Responsibility for transmission planning is diffuse** – with state regulators, utilities, independent system operators or regional transmission operators and the Federal Energy Regulatory Commission all having roles, it is difficult for a new approach (i.e. non-wires solutions) to gain traction.

U.S. Experience with Active Deferrals of T&D Investments through Efficiency

Though far from widespread, a number of jurisdictions have tested and/or are in the process of testing the role that geographically-targeted efficiency programs could play in cost-effectively deferring T&D investments. This paper examines ten different initiatives or policies – four in the 1990s and six others that are much more recent and/or still underway. As summarized below, this experience provides valuable lessons to guide future policies for the successful deployment of energy efficiency as a T&D resource.

Pacific Gas and Electric's Delta Project (California, early 1990s)

The project aimed to defer the need for a new substation that would otherwise be required to serve a growing community of 25,000 homes and 3000 businesses in far eastern Contra Costa County. Several efficiency programs were quickly launched in the region to reduce peak loads, with more than 10% of homes receiving some major measures. The project did defer the need for the substation for at least two years, though at a higher cost than expected because some measures provided much lower peak savings than expected. While other measures provided greater savings than expected, the compressed timeframe for the project did not allow for switching of strategies early enough to keep average costs at more reasonable levels.

Portland General Electric's Downtown Portland Pilot (Oregon, early 1990s)

This project focused on several opportunities. In the case of individual buildings where load reductions were needed to defer transformer upgrades, the utility aggressively marketed existing system-wide efficiency programs to the building owners. For grid network objectives, where peak demand reductions of 10-20% for entire 10-15 block areas were needed, the utility contracted with energy service companies (ESCOs) to deliver savings. Results were mixed. For one building, savings were enough to defer and possibly permanently eliminate the need for a $250,000 upgrade. In another building an unexpected conversion from gas to electric cooling eliminated any opportunity to defer the upgrade. The ESCOs contracted to achieve savings in a grid area network succeeded in reducing peak load by more than the 20% required. However, the utility's distribution engineering staff decided to proceed with their construction project before the savings were documented.

BPA's Puget Sound Area Electric Reliability Plan (Washington, early 1990s)

The Bonneville Power Administration (BPA) and local utilities decided to address a transmission reliability concern through a strategy of adding voltage support to the existing transmission system (the most important part of the strategy) and more intensive deployment of energy efficiency programs (a complementary element). The project ended up delaying construction of a new cross-Cascade transmission line for more than a decade.

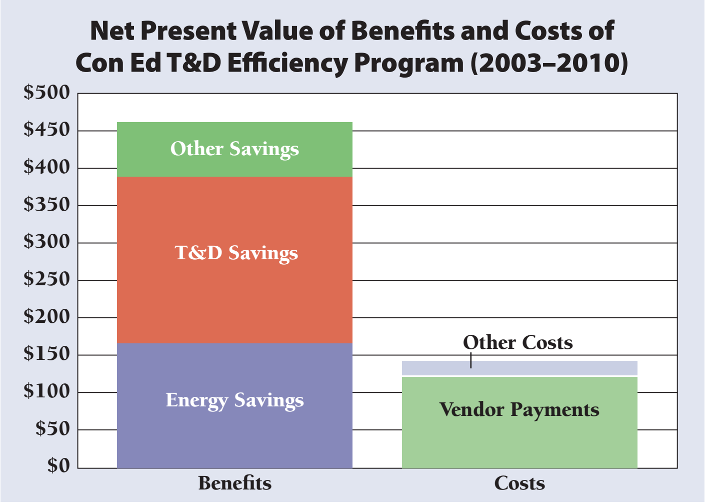
Green Mountain Power's Mad River Valley Project (Vermont, mid to late 1990s)

The project aimed to defer the need for a new distribution line in an area dominated by a large ski resort which had announced expansion plans that would add 15 MW of new load to the system. When it became clear that the resort may be required by Vermont regulations to bear most of the cost, negotiations between the utility, the resort and the state's rate-payer advocate led to an alternative plan in which the resort would better manage its load to ensure that total loads were within existing system tolerances and the utility would aggressively pursue efficiency improvements with its customers in the region. In the end, the project succeeded with the efficiency programs coming close to achieving overall savings goals.

Consolidated Edison (New York City, early 2000s to present)

In 2003, Con Ed launched a program to defer distribution system upgrades using a competitive bidding process to select the resources it would pursue. To date, only efficiency resources have been selected. To address reliability concerns, contracts for those resources include both significant upfront security and downstream liquidated damage provisions. All told, between 2003 and 2010, the Company employed geographically-targeted efficiency programs to defer upgrades in more than one third of its distribution networks. The resulting savings were very close to forecast needs and, as Figure ES-2 shows, provided more than $300 million in net benefits to ratepayers. In some cases, the efficiency investments not only deferred upgrades, but bought enough time to allow the utility to refine load forecasts to the point where it now believes that capacity extensions may never be needed.

Figure ES-2



Efficiency Vermont Geo-Targeted DSM (2007 to present)

Efficiency Vermont's performance goals were modified to include not only system wide savings targets, but also much more aggressive targets in selected geographic areas which the state's utilities had identified as candidates for deferring T&D investments. The initiative has had some success. Although peak demand savings in the targeted areas were at least 30% below targets, they were still three to five times greater than those achieved statewide (notable since the statewide savings were already the highest in the nation). The state's largest utility has observed that it has not had to schedule deployment of additional system upgrades in the targeted areas. The extent to which that is attributable to the geo-targeted efficiency programs, changes in economic conditions, other factors has not yet been determined.

NV Energy (Nevada, late 2000s)

NV Energy launched an efficiency initiative in and around Carson City in an effort to obviate the need to either run the locally situated but relatively expensive Fort Churchill generating station more frequently or construct a new transmission line and substation to bring less expensive power into the region. At the same time, the utility began re-conductoring the existing 120-kVA line to the region. An economic recession also hit at the same time, dampening growth. As a result, the Company has not had to revisit the need for either running the Fort Churchill station more often or adding new T&D capacity.

Central Maine Power (currently under development)

In 2010, the Maine regulators approved a settlement agreement that supported construction of most elements of a large transmission project, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched. In March 2011, Central Maine Power filed a plan for the Mid-Coast region that proposed using a competitive process to identify and acquire needed distributed resources. The plan suggested that efficiency resources were expected to be "highly competitive". A variety of issues regarding both the forecast capacity needs and the process for acquiring distributed resources were unresolved as this report was being finalized.

National Grid (Rhode Island, currently under development)

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that required utilities to file plans every three years. The plans must consider non-wires alternatives – including energy efficiency – whenever a T&D need is not based on an asset condition, would cost more than $1 million, would require no more than a 20% reduction in load to defer and would not require investment in a "wires solution" for at least three years. Based on these guidelines, in late 2011, National Grid proposed an initial pilot project to defer the upgrading of a substation through a combination of load management and energy efficiency.

Bonneville Power Authority (Washington, Oregon and Idaho, currently under consideration)

In 2002, the Bonneville Power Authority launched an initiative in which it committed to investigating options for deferring potential transmission reinforcement projects. A year later, it formed a Non-Wires Solutions Round Table of key stakeholder groups to provide input to its work. It then developed a formal process by which transmission alternatives – including efficiency – would be assessed. That process includes an initial screening to determine if a project is a possible candidate for a non-wires solution. The project qualifies if it is estimated to cost at least $5 million, it is driven by load growth and the need is at least eight years in the future. Bonneville is currently conducting detailed feasibility assessments of non-wires solutions to three projects – one each in Oregon, Washington and Idaho – that passed this initial screen. In each case, efficiency is part of a package of options being considered.

Lessons Learned

Our review of these efforts to use efficiency programs to defer T&D investments – alone or in concert with other resources – leads us to the following initial conclusions:

- **Geographically-targeted efficiency can defer T&D investments.** That appears to have been the case in New York City; Vermont's Mad River Valley; Portland, Oregon; and Contra Costa County, California.
- **Efficiency can be a cost-effective T&D resource.** There is less evidence regarding the cost-effectiveness of efficiency as an alternative to T&D investments. However, analysis of the most intensive and longest-standing effort – Con Ed's experience in New York City – concluded that T&D savings alone out-weighed the cost of efficiency. When all efficiency benefits are considered, the initiative had a three-to-one benefit-cost ratio.
- **Unexpected events can affect the benefits of efficiency.** In several of the cases analyzed, some or all of the T&D investment being considered for deferral ended up being constructed for reasons having nothing to do with the effectiveness of deployment of efficiency resources. However, forecasting uncertainty works in both directions. Indeed, in a couple of cases, efficiency investments bought enough time to enable a utility to conclude that – contrary to initial forecasts – a T&D upgrade may never be needed.
- **Sufficient lead time is critical.** It is necessary to allow for sufficient planning, for sufficient deployment of efficiency resources to meet needs (particularly for larger projects) and for refinement of efficiency strategies during the deployment process.
- **Smaller is easier.** The smaller the area being addressed, the easier it is to consider efficiency and other non-wires alternatives. It is easier to characterize the opportunity in small areas. Also, savings will need to be acquired from fewer customers. Both of those things mean shorter lead times will be required.
- **Distribution is easier than transmission.** Distribution deferral projects will be smaller in scope. They are also less technically complex, involve fewer parties, and do not involve ISOs/RTOs and associated regional cost allocation frameworks (i.e. cost socialization issues).
- **Cross-discipline communications is critical.** Collaboration between efficiency program managers and T&D planners is critical to considering deploying efficiency as an alternative to T&D investments. Both have much to learn from each other. Some level of trust must be developed between the two groups.
- **Efficiency should be integrated with other distributed resources.** Although efficiency programs can sometimes be sufficient to defer T&D investments, they will often need to be deployed in concert with demand response, distributed generation and other resources to enable deferment of T&D investments (particularly for larger projects).

Recommendations

The potential economic and other benefits of efficiency programs as a T&D resource are largely being ignored today. Some fundamental policy changes are required if that is to change:

- **Require least-cost T&D planning.** Experience in several jurisdictions suggest this is essential (though not sufficient) to beginning serious consideration of efficiency and other non-wires alternatives.
- **Require consideration of integrated solutions.** To ensure that potential synergies between efficiency and other non-wires alternatives are considered, any requirement for least cost-planning should make clear that all options, including different combinations of distributed resources, should be considered.
- **Institutionalize a long-term planning horizon.** The longer the lead time, the more likely it will be that efficiency and/or other distributed resources could cost-effectively defer T&D investments. At a minimum, T&D needs should be forecast at least 10 years into the future.
- **"Level the playing field" in payment for wires and non-wires alternatives.** Cost-allocation frameworks that socialize costs for transmission projects across a region but require all the cost of non-wires alternatives to be born locally create enormous disincentives to pursue least cost solutions.
- **Collect more data on efficiency's impacts.** In much of the country, relatively little data on the hourly and seasonal impacts of efficiency resources has been collected and made public over the past two decades. Better data should help address concerns of T&D system planners.
- **Start with pilot projects.** Pilots offer important, lower risk opportunities to bring together efficiency program and T&D planners.
- **Leverage "smart grid" investments.** Customer and end-use data collected through such systems may enable better assessments of the potential for efficiency to serve as a T&D resource.

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1. Introduction

Improvements to electric efficiency in homes and businesses provide a variety of benefits to both the customers making the improvements and the electric system as a whole.[1] The most widely recognized are annual energy savings and system peak demand savings. Most consumers are primarily interested in energy savings because they typically drive cost savings on electricity bills. Utilities and grid operators are often most interested in reductions in load at the time of system peak, which enable them to avoid purchasing expensive peak generating capacity. A much less commonly recognized or valued benefit of efficiency investments is the potential for cost-effectively deferring upgrades to transmission and distribution (T&D) systems.

This paper focuses on that potential. In particular, it summarizes US experience to date and lessons learned from initiatives in which geographically targeted efficiency programs have played a major role in electric utility funded efforts to defer transmission and/or distribution system investments. Although other demand resources such as demand response and distributed generation can also be considered viable alternatives to T&D investments and have occasionally been deployed for that purpose, this paper does not explore those options in any detail, except when they are deployed as part of a multi-pronged strategy in conjunction with geographically targeted efficiency programs.

Context – Historic and Future Investments in Transmission and Distribution

The potential to defer upgrades to T&D warrants much more serious consideration than it has historically been given. As Figure 1 shows, T&D investments by investor-owned utilities, which collectively account for approximately two thirds of electricity sales in the United States, have averaged about $26 billion annually over the past decade.

If public utilities are investing in T&D at the same rate, then total T&D investment nationally would be on the order of $40 billion per year. That level of investment is expected to continue, if not increase, in the future. Indeed, as Figure 2 illustrates, the Edison Electric Institute recently commissioned a study that concluded the US power sector, including both investor-owned and public utilities, will require over $1.5 trillion in capital investments

Figure 1[2]

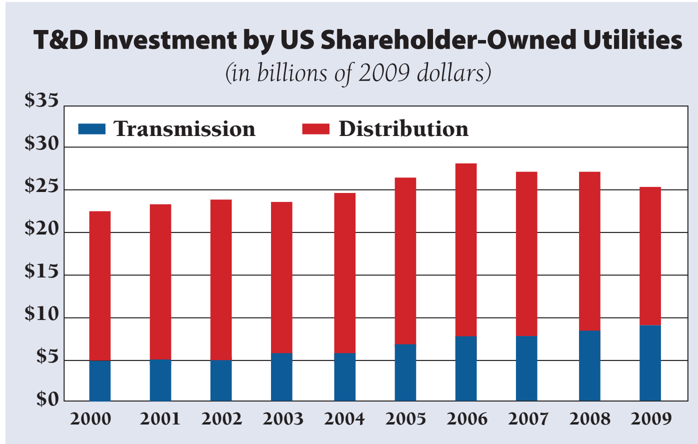
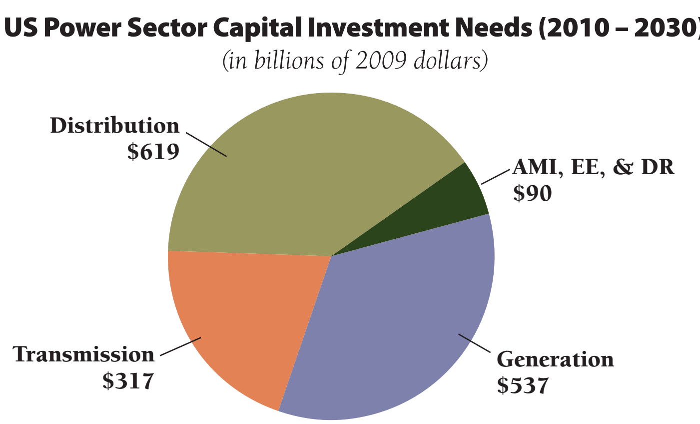


Figure 2[3]



1 There are also often a number of non-energy benefits (e.g., improved comfort, water and/or other resource savings, reduced operation and maintenance costs, increased productivity) that we do not address in this paper.

2 Personal communication with Steve Frauenheim, Edison Electric Institute (EEI), August 5, 2011. Data are from EEI's Statistical Yearbook of the Electric Power Industry 2009 Data, Table 9.1.

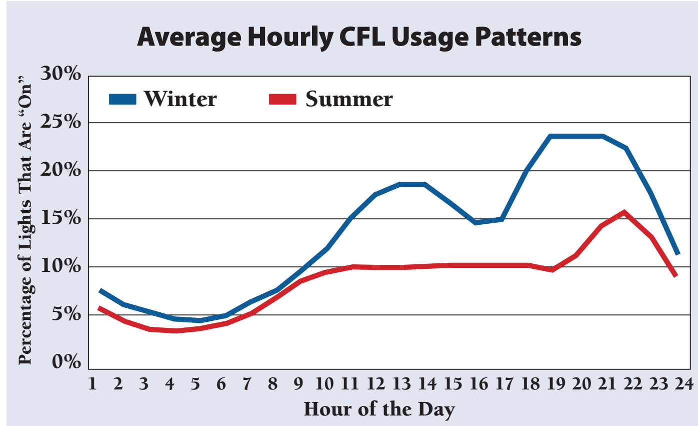
between 2010 and 2030 (2009 dollars), and that 40% of that investment – more than $600 billion (i.e., more than $30 billion/year) – will be in distribution system infrastructure and another 20% – more than $300 billion (i.e., more than $15 billion/year) – will be in transmission system infrastructure. Only about one third of the forecast investment is in new generation; another 6% is in advanced metering infrastructure, energy efficiency, and demand response.

"Passive Deferral" vs. "Active Deferral"

Deferrals of T&D investments can take two forms: passive deferral and active deferral. Passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs. For example, a statewide program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) will have the effect of lowering loads on every element of the T&D system every hour of the day. To be sure, the amount of load reduction from such a program will vary considerably depending on the season (more during winter than summer), hour of the day (e.g., more during the evening than the day), and the customer mix served (e.g., more for feeders, substations, etc. serving primarily residential customers). As Figure 3 shows, however, the load shape of residential lighting is such that – across a population of program participants – some reductions in energy use will occur every hour of the year. Some reductions thus will occur during every hour of peak demand for every element of the T&D system.

Passive deferral benefits are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs

Figure 3[4]



of energy and system peak capacity – are commonly used to assess whether efficiency programs are cost-effective (usually a regulatory requirement for funding approval). At the most general level, estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities' assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs typically have ranged from about $55 per kW-year to $120 per kW-year.[5] Avoided distribution costs typically account for 70% to 80% of those values (i.e., avoided distribution costs are typically two to four times greater than avoided transmission costs). Estimates for several utilities in California and the Pacific Northwest have ranged from $30 to $105 per kW-year, with an average of close to $50.[6] Again, avoided distribution costs are the larger

3 Chupka, Marc et al, (The Brattle Group). *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. The forecast presented here is for the report's base case scenario, including "realistically achievable potential" for energy efficiency and demand response. The report's 2006 costs were increased by 6.4% so that they could be presented in 2009 dollars (based on changes in the Consumer Price Index between 2006 and 2009).

4 Nexus Market Research, *Residential Lighting Markdown Impact Evaluation,* submitted to Markdown and Buydown Program Sponsors in Connecticut, Massachusetts, Rhode Island, and Vermont, January 20, 2009 (from Figures 5-1 and 5-2).

5 Most are in the range of $55 to $85 (Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2009 Report,* revised October 23, 2009, p. 6-66). Vermont's, however, is approximately $120 per kW-year for summer peak savings and $80 per kW-year for winter peak savings (personal communication with Erik Brown, Efficiency Vermont, December 23, 2011).

6 Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan, February 2010 (http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_E.pdf), p. E-14.

of the two components – on the order of twice as large as avoided transmission costs.[7] At the other extreme, in some jurisdictions it is conservatively assumed that no T&D investments can be avoided.[8]

Active deferral of T&D investments can occur when a conscious decision is made to invest in energy efficiency measures or programs – in targeted geographic locations – for the specific purpose of lowering loads on local T&D system elements. This concept has been actively pursued in relatively few jurisdictions to date. A variety of factors likely contribute to its limited testing for both transmission and distribution needs:

- **Economic incentives.** Utilities typically earn rates of return on capital investments. In many jurisdictions they do not make money on investments in efficiency.[9]

- **Efficiency's multiple attributes/benefits.** Efficiency resources provide a variety of benefits, including energy savings, peak capacity savings, environmental emission reductions, and T&D reliability improvements. Properly assessing whether efficiency could be a cost-effective alternative to T&D investments requires accounting for all of those benefits (e.g., although efficiency may not be cost-effective when considering just its T&D reliability benefits, it may be when considering all its benefits). That requires a holistic, systemic perspective that has not been universally adopted by utilities or their regulators, however, and is generally not a concern of ISOs/RTOs.

- **System planning is highly technical.** The technical specialization needed to do T&D planning fosters an environment biased to technical solutions. Put another way, utilities and ISOs/RTOs tend to be engineering oriented, with a propensity toward building capacity to meet growing consumer demand.

- **System engineers distrust of demand-side resources.** System engineers trust assets that they can control, like "poles and wires," and tend to be more skeptical or distrustful of investments on the customer side of the meter to reduce demand.

- **Risk aversion.** Related to the point above, utilities (like many other businesses) are often reluctant to try something different, particularly if they perceive any regulatory risk from doing so.

In general, the barriers to deployment of non-wires solutions to transmission needs are greater than those for distribution system needs. To begin with, transmission needs are typically more technically complex. In addition, the magnitude of the demand resources needed to defer them are larger and spread across much larger populations of customers. That can enhance system planners' fear of the ability of demand resources to meet reliability needs. It also typically means that longer lead times for consideration of non-wires solutions are necessary. Two additional factors are also critically important.

- **Socialization of transmission investments, but not non-wires alternatives.** The costs of transmission investments are often socialized regionally (i.e., across the entire grid), whereas the costs of efficiency programs or other non-wires solutions must typically be borne entirely by the local utility and its customers. This creates a classic "tragedy of the commons" in which it is less expensive for the local utility to choose what is often the most expensive option for a region.

7 Ibid. Figures E-5 (avoided transmission costs) and E-6 (avoided distribution costs) each provide eight separate examples. Only three of those examples are common, however: PG&E, Pacificorp and PGE. For those three utilities, avoided distribution cost estimates were roughly double avoided transmission cost estimates.

8 For example, see: Consumers Energy, *2012-2015 Amended Energy Optimization Plan*, submitted to the Michigan Public Service Commission, Case No. U-16670, August 1, 2011, p. 25.

9 A recent ACEEE study identified 18 states that had a mechanism that allowed investor-owned utilities to earn shareholder incentives for good performance in administering efficiency programs (Hayes, Sara et al, *Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency,* ACEEE Report Number U111, January 2011).

- **Diffusion of responsibility for transmission planning and decision-making.** State regulators, utilities, ISOs/RTOs, and ultimately FERC all have roles in transmission planning and approval of transmission investments. It is difficult for a new approach (i.e., non-wires solutions) to get traction when there is no one entity "in charge" that can require consideration of such approaches. It is unclear how the recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in their decisions, will change things.

Despite these barriers, aggressive geographically targeted energy efficiency programs have been implemented in several jurisdictions in an attempt to defer specific T&D projects. The purpose of this paper is to document the lessons learned from those efforts. Again, although there are a variety of potential non-wires alternatives that can be and have been deployed to defer T&D investments, the focus of this paper is only on those projects in which energy efficiency played or is playing a substantial role. It is also important to note that this paper documents the consideration of efficiency as a T&D resource as of late 2011. Several of the cases described below are still evolving, potentially in ways that could add significantly to information and ideas presented herein.

2. Active Deferral of T&D Investment – Selected Examples

A. Early History

The concept of using geographically targeted energy efficiency investments to cost-effectively defer T&D system upgrades is not a new one. One can find numerous papers on the concept in efficiency conference proceedings going back to at least the early 1990s. The Electric Power Research Institute (EPRI), a research organization serving the utility industry, began pursuing several projects to assess the potential for integrating demand-side management (DSM) into utility T&D planning during the same time period. Most important, several groundbreaking projects were undertaken in the 1990s to test the concept. What follows are brief descriptions of those projects.

Pacific Gas and Electric (California) – Delta Project

One of the most widely publicized of these early projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the Delta Project, which ran from July 1991 through March 1993. Its purpose was to determine whether the need for a new substation that would otherwise be required to serve a growing "bedroom community" of 25,000 homes and 3,000 businesses in far eastern Contra Costa County, California could be deferred through intensive efficiency investments. Peak demand in this area occurred on summer weekdays between 7 pm and 8 pm – much later than PG&E's system peak (typically between 3 pm and 5 pm). This later local peak was driven by the fact that 74% of the peak load was residential, with many of the residential customers being two-income families who had long commutes from the San Francisco and Oakland areas and turned on their air conditioners when arriving home to 100° F heat.[10]

As a result, the largest portion of the project's savings was projected to come from a residential retrofit program targeted to homes with central air conditioning (the vast majority of homes in the targeted area). Under the initial design, participating homes would receive free installation of low-cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets) during an initial site visit and would be scheduled for follow-up work with major measures such as duct sealing, air sealing, insulation, sun screening, and air conditioner tune-ups. More than 2,700 homes received such major measures. Later the program changed its focus to promoting early replacement of older, often over-sized and inefficient central air conditioners with new, efficient models. Other components of the Delta Project included commercial retrofits, a residential new construction program, and a small commercial new construction program.

Evaluations suggested that the project produced 2.3 MW of peak demand savings. The savings did come at a high cost – roughly $3,900 per kW. This can likely be attributed to a couple of key factors. First, the project had an extremely compressed timeframe. It was planned and launched within six months; the implementation phase was less than two years. A second related factor was that some of the efficiency strategies produced much lower levels of savings than initially estimated, whereas others produced more. Because of the compressed timeframe for the project, the switch in emphasis to the better performing program strategies could not occur early enough to keep total costs per kW at more reasonable levels. For example, the residential shell and duct repair efforts were initially projected to generate nearly 1.8 MW of peak demand savings, but in the end, produced only about 0.2 MW at a cost of over $16,000 per kW. In contrast, the early replacement residential central air conditioners produced 1.0 MW of peak savings – about 2.5 times the original forecast of about 0.4 MW – at a cost of about $900 per kW.

10 The Results Center, "Pacific Gas & Electric Model Energy Communities Program," Profile 81, 1994.

The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.[11] Although the project suggested that geographically targeted DSM could potentially defer T&D investments, no projects of this kind appear to have been pursued in California since.

Portland General Electric (Oregon) – Downtown Portland Pilot

In 1992, Portland General Electric (PGE) began planning the launch of a pilot initiative to assess the potential for using DSM to cost-effectively defer distribution system upgrades; implementation began in early 1993.[12] The pilot focused on several opportunities for deferring both transformer upgrades planned for large commercial buildings and grid network system upgrades planned for downtown Portland, Oregon. The projects were identified from a review of PGE's 5-year transmission and distribution plan. Although the PGE system was winter-peaking, downtown Portland was summer-peaking, so the focus would be on efficiency measures that reduced cooling and other summer peak loads. To be successful, deferrals would need to be achieved in one to three years, with the lead time varying by project. In each case, the value of deferring the capital improvements was estimated. The estimates varied by area, but averaged about $35 per kW-year.[13]

Two different strategies were pursued. In the case of the individual commercial buildings, where peak demand reductions of several hundred kW per building were needed to defer transformer upgrades, the utility relied on existing system-wide DSM programs, but target marketed the programs to the owners of the buildings of interest using sales staff that already had relationships with the building owner or property management firm. For the grid network system objectives, where peak reductions of 10% to 20% for entire 10- to 15-block areas were needed, the utility contracted with energy service companies (ESCOs) to deliver savings. The ESCO contracts had two-tier pricing structures designed to encourage comprehensive treatment of efficiency opportunities and deep levels of savings. The first tier addressed savings up to 20% of a building's electricity consumption. The second tier was a much higher price for savings beyond 20%.[14]

The results of the pilot were mixed. For example, savings in one of the targeted commercial buildings was nearly twice what was needed, deferring and possibly permanently eliminating the need for a $250,000 upgrade. Savings for another building, however, fell short of the amount of reduction needed to defer its transformer upgrade. While other options were being explored to bridge the gap, an unexpected conversion from gas to electric cooling of the building "eliminated any opportunity to defer the upgrade."[15] The results for the first grid area network targeted were also very instructive. Of the 100 accounts in the area, the largest 20 accounted for more than three quarters of the load. By ultimately treating 12 of those 20, the ESCOs contracted by PGE actually succeeded in reducing load through efficiency measures by nearly 25% in just one year. That was substantially more than the 20% estimated to be necessary to defer the need for a distribution system upgrade. The utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known, however, because they did not have sufficient confidence that the savings would be achieved and would be reliable and persistent. It is also worth noting that the utility's marketing staff who were managing the ESCO's work were not even made aware of the decision to proceed with the construction until after it had begun – a telling indication of the lack of communication and trust between those responsible for energy efficiency initiatives and those responsible for distribution system planning.[16]

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.[17]

11 Pacific Gas and Electric Company Market Department, *Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994*, July 1994.

12 Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.

13 Weijo, Richard O. and Linda Ecker (Portland General Electric), "Acquiring T&D Benefits from DSM: A Utility Case Study," Proceedings of 1994 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 2.

14 Ibid.

15 Ibid.

16 Ibid.

17 Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.

Bonneville Power Administration

In the early 1990s, the Puget Sound area received more than three quarters of peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. Bonneville Power Administration (BPA) studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.[18] The level of risk "violated transmission planning standards."[19]

The traditional option for addressing this reliability concern would have been to build additional high voltage transmission lines over the Cascades into the Puget Sound area. BPA and the local utilities chose instead, however, to pursue a lower cost path that included adding voltage support to the transmission system (e.g., "series capacitors to avoid building additional transmission corridors over the Cascades") and more intensive deployment of energy efficiency programs (focused on loads that would help avoid voltage collapse). The voltage support was by far the most important of these elements.[20] The project, known as the Puget Sound Area Electric Reliability Plan, ended up delaying construction of expensive new high voltage transmission lines for at least a decade.[21] Indeed, no new cross-Cascade transmission lines have been built to date.[22]

As discussed further below, BPA has not yet pursued an additional project to defer transmission system investments with efficiency programs.[23] It has, however, institutionalized a process for assessing whether non-transmission alternatives, including efficiency, would be preferable and, for the past decade or so, has initiated that process on several occasions (the most recent just getting started in the spring of 2011).

Green Mountain Power (Vermont) – Mad River Valley

In 1995, Green Mountain Power (GMP), Vermont's second largest investor-owned electric utility, launched an initiative – the first of its kind in the state – to defer the need for a new distribution line in the Mad River Valley – a region in the central part of the state made famous by the Sugarbush and Mad River ski resorts. The existing U-shaped 34.5-kV line serving the valley had a reliable capacity of 30 MW. Sugarbush, which was located at the base of the "U" (its weakest point) and was already the largest load on the line, had announced plans to add up to 15 MW of load associated with a new hotel, a new conference center, and additional snow-making equipment. The existing line could not accommodate that kind of increase. Studies suggested that a new parallel 34.5-kV line would need to be added at a cost of at least $5 million. Sugarbush initially requested that GMP

18 US Department of Energy, Bonneville Power Administration, Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light, Seattle City Light and Tacoma City Light, "Puget Sound Reinforcement Project: Planning for Peak Power Needs," Scoping report, Part A, Summary of Public Comments, July 1990.

19 Bonneville Power Administration Non-Construction Alternatives Roundtable, "Who Funds? Who Implements?" Subcommitee, "Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments," March 2004.

20 Indeed, although the plan included additional investments in efficiency, the additional capacitors, coupled with the addition of some local combustion turbines, were likely enough to defer the transmission lines even without the additional efficiency investments (personal communication with Frank Brown, BPA, 11/7/11).

21 Bonneville Power Authority, "Non-Wires Solutions Questions & Answers" fact sheet.

22 The system has been significantly altered over the past two decades as a result of substantial fuel-switching from electric heat to gas heat, the addition of significant wind generating capacity (much of it for sale to California), and other factors. At least until recently, BPA thus has had more "North-South issues" than "East-West issues" (personal communication with Frank Brown, BPA, 11/7/11). That may change in the future as utilities begin to rely more on wind generators east of the cascades (personal communication with Joshua Binus, BPA, 12/12/11).

23 In the mid to late 1990s, however, it did invest substantially in a demand response initiative in the San Juan islands to address reliability concerns after the newest of three underwater cables bringing power to the islands was accidentally severed. The initiative ran for five years and succeeded in keeping loads on the remaining cables at appropriate levels until a new cable was added.

pay for the new line. GMP was hesitant to do so, however, and Vermont's line extension rules were such that the utility and others could legitimately argue that much of the cost should be directly imposed on Sugarbush (and therefore less on other ratepayers).[24] Ensuing negotiations between GMP, Sugarbush, and the state's rate-payer advocate ultimately led to an alternative solution:

1. Sugarbush would ensure that load on the distribution line – *not just its load, but the total load of all customers* – would not exceed the safe 30 MW level;[25] and
2. GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region.[26]

To meet its end of the bargain, GMP filed and regulators approved the following four efficiency programs targeted to the Mad River Valley:

- Large commercial/industrial retrofit program (targeting the 10 largest customers in the valley);
- Small commercial/industrial retrofit program;
- Residential retrofit program, focusing particularly on homes with electric heat and hot water (promoting both fuel-switching and weatherization); and
- Residential new construction assessment fee program, which imposed a mandatory fee on all new homes being constructed in the valley to pay for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently.[27]

A couple of these programs were largely the same as programs GMP was offering to customers across its entire service territory, except that they were more aggressively marketed to Mad River Valley customers. In 1996, the year during which most of the project activity took place, GMP's efficiency program spending on the Mad River Valley represented about one quarter of its total DSM spending,[28] despite the fact that the area served represented no more than about 5% of its sales base.[29]

By the time the targeted efforts were concluded in early 1997, roughly half of the target populations had participated in the small commercial and industrial (C&I) retrofit and residential retrofit programs, and 7 of the 10 customers targeted by the large retrofit program had participated. Further, three of the four programs had achieved their savings goals. The large C&I retrofit program was the one exception, having achieved only about 20% of the forecasted savings (suggesting that the depth of savings achieved per participant was much lower than projected). Because that program represented less than one fifth of the total savings projected for the Mad River Valley project, however, the project as a whole came close to achieving its overall savings goal.

This project was initially touted as "the first of many" designed to address T&D constraints.[30] As discussed further below, it took more than a decade for that vision to begin to be realized. Nevertheless, it was an important stepping stone in the process of distributed utility planning in Vermont.

24 Cowart, Richard et al., "Distributed Resources and Electric System Reliability, Regulatory Assistance Project, September 2001. Available: http://www.raponline.org/document/download/id/682.

25 This was possible because Sugarbush was such a large portion of the load on the line. It subsequently installed a real-time meter to monitor the consumptions of its own operations and telemetry to monitor total load from all customers at the local substation. It used this information to manage its own operations, including the timing of its snow-making, to keep total loads on the substation below 30 MW. In addition to avoiding any costs associated with its responsibility for the need to upgrade the power line, Sugarbush also received a rate discount from GMP. (Ibid.)

26 Ibid.

27 Green Mountain Power Corporation, "Demand Side Management Program Filing," April 28, 1995 (Revised 5/5/95).

28 Green Mountain Power Corporation, "Demand Side Management Programs 1996 Annual Report," April 1, 1997.

29 Personal communication with Dave Grimason, former GMP efficiency program manager, November 7, 2011.

30 Green Mountain Power Corporation, "Demand Side Management Program Filing," April 28, 1995 (Revised 5/5/95), Executive Summary p. 2.

B. More Recent Developments

In the past several years, several additional efforts to defer T&D system investments have been undertaken. In a couple of additional jurisdictions, processes have been put in place to require that efficiency and other demand resources be considered as alternatives.

Consolidated Edison (New York City)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the United States in integrating end-use energy efficiency into T&D planning. That integration has occurred on two levels.

First, as part of the annual development of its 10-year "load relief plan" (in which it forecasts any shortfalls in transmission, sub-transmission, and area substation capacity and establishes plans for addressing those shortfalls), the Company now routinely estimates the effects of system-wide efficiency programs on the individual peak demands of each of its 91 distribution networks and load areas, adjusting for the geographic variability in the market penetration of different efficiency programs, the load profiles of different efficiency programs, and the load profiles (and peak periods) of each distribution network. The company recently estimated that "including demand-side management in the 10-year forecast reduced projected capital expenditures by more than $1 billion."[31]

Second, Con Ed routinely assesses whether additional, geographically targeted investments in demand resources could cost-effectively defer investments in its distribution system. More important, where analysis suggests such cost-effective deferrals are possible, the utility invests in, closely tracks, and carefully evaluates the impacts of those resources. When Con Ed assesses cost-effectiveness, it considers all the benefits of efficiency investments, not just the T&D benefits (i.e., it compares the net present value of energy savings, system peak capacity savings, and T&D deferral benefits to the costs of the efficiency programs).

This geographically targeted investment in efficiency began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. Given the density of its customer base, much of the company's system is underground, making upgrades expensive and disruptive. The Company thus began to assess whether it would be feasible and cost-effective to defer such upgrades through locally targeted end-use efficiency, distributed generation, fuel-switching, and other demand-side investments. At least initially, the focus was on projects "with need dates that were up to five years out and… required load relief that totaled less than 3% to 4% of the predicted network load."[32] A decision was made to proceed with geographically targeted demand resource investments, however, whenever it was determined that such investments were likely to be both feasible and cost-effective.

To maximize the financial benefits of relying on demand resources, Con Ed has chosen "not to hedge its bets by continuing the T&D planning and implementation process" in parallel with its pursuit of alternative demand resources. Instead, the Company has chosen to contract out the acquisition of demand resources to ESCOs and – to address reliability risks – to include in those contracts both "significant upfront security and downstream liquidated damage provisions," as well as rigorous measurement and verification requirements. Contract prices are established through a competitive bidding process, with the Company's analysis of the economics of deferment being used to establish the highest price it would be willing to pay for demand resources. Those threshold prices have varied from network to network. When the amount of demand resources bid at prices below the cost-effectiveness threshold were insufficient to defer T&D upgrades, supply-side improvements have been pursued instead.

In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine networks areas: five in midtown Manhattan, three in Brooklyn, and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten

31 Gazze, Chris and Madlen Massarlian, "Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions," in *Public Utilities Fortnightly,* August 2011, pp. 36-41.

32 Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum. "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction," in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

Island, and four in Westchester County. Although ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids to date have been solely for the installation of efficiency measures. There have been a couple of explorations of distributed generation, but they have not yet been shown to be cost-effective.[33] All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks.

This approach has had considerable, but not universal, success. As Figure 4 shows, in aggregate the level of peak load reduction for Phase 1, which ran through 2007, was approximately 40 MW – or 7 MW less than the contracted level. As a result, Con Ed collected considerable liquated damages from participating ESCOs. Load reductions in subsequent phases have been close to those contracted in aggregate. Those aggregate results mask some differences across network areas, however. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule, whereas reductions in areas whose loads were dominated by commercial customers with mid-day peaks have lagged behind goals. On the other hand, much of that commercial sector savings shortfall appears attributable to the recent economic recession, which also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.[34] As shown in Figure 5, even when there was a shortfall relative to the savings target for the largest of the T&D deferral projects Con Ed undertook in Phase 1 – the Astor Substation deferral project – the efficiency investments still produced substantial economic benefits ($28 million, or about $1,950 per kW of savings) that were very cost-effective (benefit-cost ratio of 3:1).[35]

This highlights an important benefit of efficiency programs – they are often load-following. Put another way,

Figure 5 [37]

Summary of Results for Astor Substation

Project: Build new substation to relieve five adjacent networks
Cost: $85 million (original estimate)
$145 million (as built)
Deferral: 2007 to 2009

Shortfall	2005	2006	2007	2008
Shortfall (Incremental)	0	2	9	8
Contracted (Cumulative)	0	4	13	21
Delivered (Cumulative)	1	4	8	14

RFP: Jun 2003
Contract: Sep 2004 – Jan 2005
Savings: $28 million (~ $1,950/kW)
TRC: 3.1
Note: Load growth was slower than forecast, offsetting under delivery

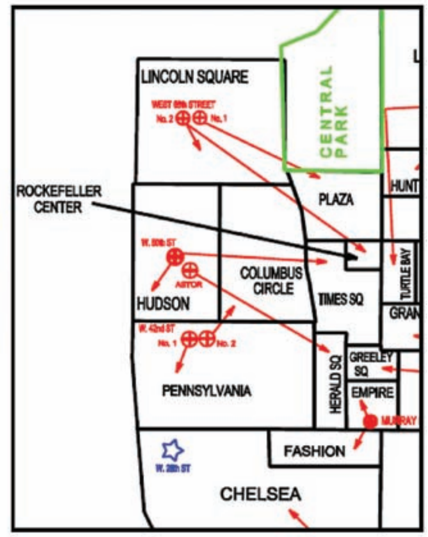
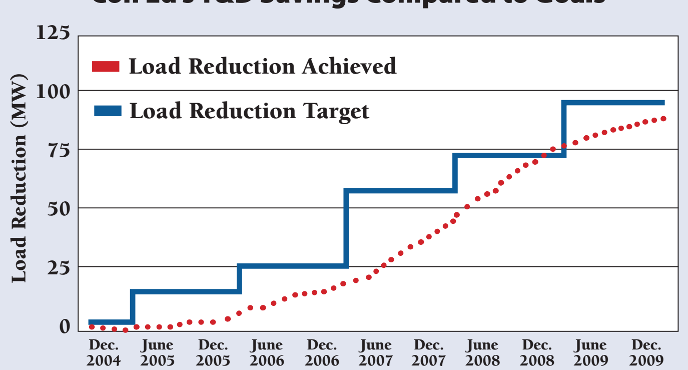


Figure 4 [36]



33 Although all types of demand resources have been considered, only energy efficiency has been pursued to date, because it is the only demand resource proven to be cost-effective (personal communication with Chris Gazze, February 2011).

34 Gazze, Mysholowsky, and Craft (2010).

35 Gazze, Chris (Con Ed) and Bruce Appelbaum (ICF), "Con Edison's Targeted DSM Program," presentation at ACEEE Summer Study on Energy Efficiency in Buildings, August 18, 2010, Pacific Grove, CA.

36 Graph reproduced from Gazze, Mysholowsky, Craft, and Appelbaum (2010) with permission from Con Ed.

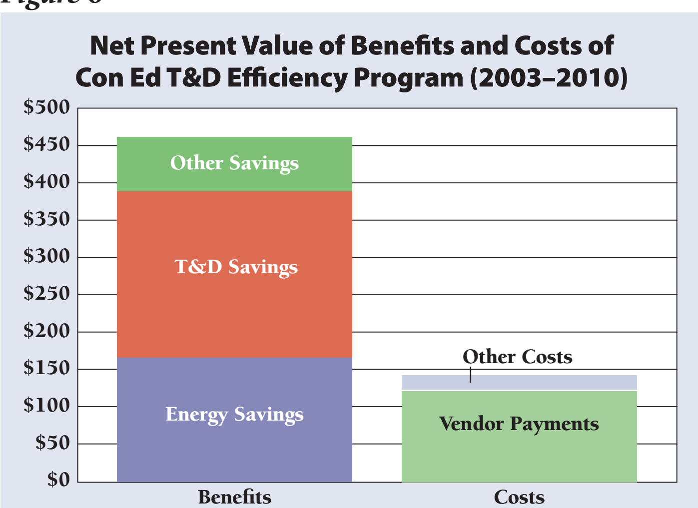
37 Graphic from Gazze and Appelbaum presentation, used with permission from Chris Gazze.

participation in efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly. In that sense, efficiency programs can help mitigate risk associated with forecast uncertainties. As Con Ed put it:

> *"…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."*[38]

As Figure 6 shows, in aggregate, Con Ed has saved more than $75 million when comparing the full costs of the efficiency programs to just the T&D costs that were avoided. When other efficiency benefits (e.g., energy savings and system peak capacity savings) are also considered, the efficiency investments have saved Con Ed and its customers more than $300 million.

Figure 6 [39]



Efficiency Vermont Geo-Targeted DSM

Shortly after the Mad River Valley project (see discussion earlier) was completed, negotiations began within the state to shift responsibility for efficiency program administration from the utilities to a dedicated "efficiency utility" – eventually to be named "Efficiency Vermont" – that would be selected through a competitive bidding process. The settlement agreement and subsequent September 1999 Public Service Board (the Board) order that created Efficiency Vermont made clear that, although Efficiency Vermont would be responsible for statewide efficiency programs, the utilities would still be responsible for funding and implementing any additional efficiency that could be justified as cost-effective alternatives to T&D system upgrades (although they could contract implementation to Efficiency Vermont). The Board also agreed to "initiate a collaborative process to establish guidelines for distributed utility planning."[40] That collaborative culminated in a set of guidelines approved by the Board in 2003,[41] as well as the creation of a number of "area specific collaboratives" in which opportunities for deferring specific T&D upgrades through non-wires alternatives would be explored. None of those discussions led to implementation of any such alternatives, however.

At roughly the same time (i.e., 2003), VELCO, the state's transmission utility, formally proposed a very controversial large project to upgrade transmission lines from West Rutland to South Burlington (known as the Northwest Reliability Project). As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. In all, five different combinations of alternatives were analyzed – four combinations of different kinds of local generation and a fifth combination of local generation and aggressive DSM. The analysis suggested that the four generation-only options were more expensive than the transmission line, but that the fifth option including DSM had a lower societal cost than the transmission line.[42] That option, however, would involve much larger capital expenditures than the transmission line. Further, whereas much of the cost of the transmission option would be socialized across the New England Power Pool (Vermont pays a very small share of the portion of costs that are socialized across the region), the cost of the alternative path would be borne entirely by Vermont ratepayers due

38 Gazze, Mysholowsky, and Craft (2010).

39 Cost and benefit data provided by Chris Gazze, February 11, 2011. Note that "other costs" includes program administration ($2.9 million), M&V ($9.2 million), and customer costs ($9.9 million).

40 State of Vermont, Public Service Board Order, Docket No. 5980, pp. 54-58.

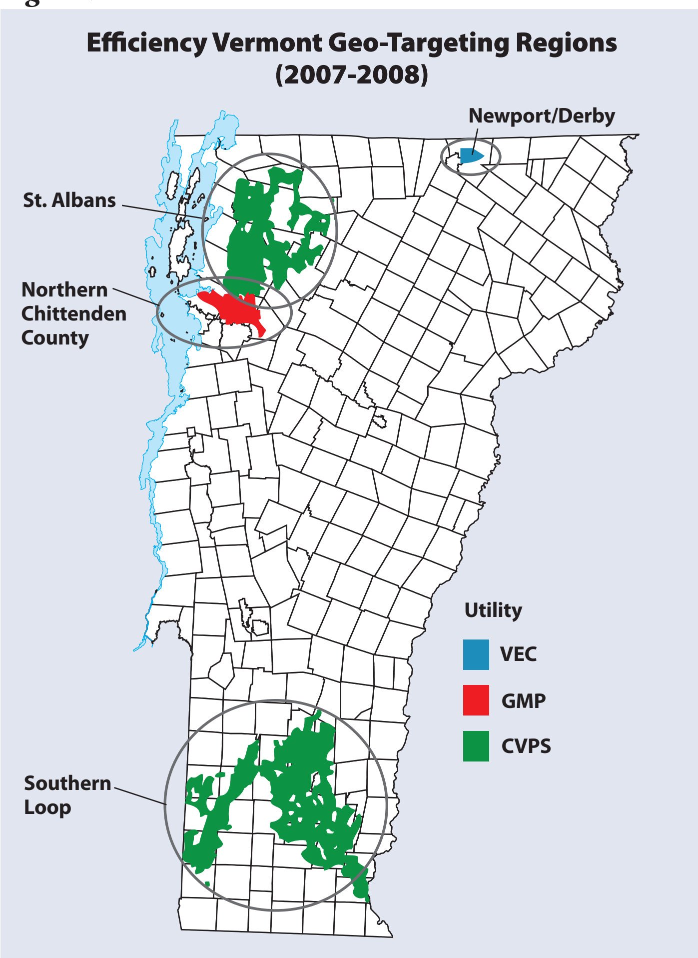
41 State of Vermont, Public Service Board Order, Docket No. 6290.

42 La Capra Associates, "Alternatives to VELCO's Northwest Reliability Project," January 29, 2003.

to New England ISO rules. Those concerns, coupled with VELCO's concerns that the level of DSM envisioned would be unprecedented, led the utility to argue in favor of the transmission option.[43] The Board ultimately approved VELCO's proposal in early 2005, but expressed concern and frustration with VELCO's planning process, namely that it did not consider alternatives, particularly efficiency, early enough in the process to make them truly viable options.[44]

The approval of the transmission line contributed to the passage later that year of legislation (Act 61) that eliminated the statutory spending cap for Efficiency Vermont, instructed the Board to determine the optimal level of efficiency spending, and made clear that cost-effectively deferring T&D upgrades should be one of the objectives the Board considers in establishing the budget. The Board subsequently increased Efficiency Vermont's budget by about $6.5 million (37%) in 2007 and $12.2 million (66%) in 2008 and ordered that all of the additional spending be focused on four geographically targeted areas: northern Chittenden County, Newport, St. Albans, and the "southern loop" (see Figure 7).[45] Those areas had been identified by the state's utilities as areas in which there may be potential for deferring significant T&D investment. Collectively, these efforts became known as Efficiency Vermont's "geo-targeting" initiative.[46]

Figure 7 [47]



As Table 1 shows, these areas were fairly diverse in terms of the density of population, the geographic area they cover, the relative importance of residential vs. commercial and industrial loads, and the number of large customers. Two of the areas were summer peaking, one was winter peaking, and one had similar summer and winter peaks. The peak loads in the area varied from 18 to 70 MW in 2007. Forecasted load growth without efficiency programs ranged from 1.7% to 4.3% per year. Collectively, the four areas contained 63,000 customers – or 18% of the state's customer base. A total of 167 were large users (greater than 500 MWh of annual consumption), 8,600 were other business customers (many of them quite small), and about 54,000 were residential customers.[48]

It is important to note that the investment in geo-targeting was viewed by the Board, utilities, and Efficiency Vermont as a "proof of concept" experiment. The selection of the targeted areas was rushed and probably not as well vetted as necessary to ensure deferral potential. Indeed, savings targets were not established from an analysis of how much was needed to defer the capital investments. Rather, they were set based on what was estimated to be achievable given available budget resources.

The original 18-month savings targets (from mid-2007 through the end of 2008) were 7.2 MW of summer peak savings (across the three areas with summer peaks) and 7.7

43 Ibid.

44 Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade", press release, January 28, 2005.

45 State of Vermont Public Service Board, Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008, 8/2/2006.

46 Efficiency Vermont Annual Plan, 2008-2009.

47 Efficiency Vermont Annual Plan, 2007-2008.

48 Massie, Jim, Nancy Wasserman, and Blair Hamilton, "Fast Capacity Reduction through Geographically Targeted, Aggressive Efficiency Investment: Early Results from a Vermont Experiment," in Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 194-205.

Table 1 [49]

Characteristics of Vermont Geographically Targeted Areas (2007-2008)

	Urban vs. Rural	Size of Area	C&I Sales %	Large C&I Customers	Peak Period	2007 Peak (MW)	Annual Load Growth w/o DSM	Projected Load Growth w/ Targeted DSM
N. Chittenden	Urban	Small	65%	72	Summer	64	4.3%	1.2%
Newport	Urban	Small	64%	15	Both	18	1.7%	-0.5%[50]
St. Albans	Urban	Moderate	64%	42	Summer	29	3.4%	-3.3%
Southern Loop	Rural	Large	48%	38	Winter	70	3.4%	-3.4%

MW of winter peak savings (across the two areas with winter peaks). These targets represented a 7- to 10-fold increase in the peak savings Efficiency Vermont had achieved in the same areas during the previous 18 months. It was estimated that peak demands would not only stop growing but would actually decline in three of the four areas. In the fourth area (Chittenden North), which had the fastest natural growth rate, load growth was projected to decline by about 75% (from 4.3% to 1.2% per year).

To meet these savings goals, Efficiency Vermont implemented a three-pronged strategy:

1. Intensive account management of large commercial and industrial customers (targeted to approximately 148 customers using more than 500 MWh/year) to identify opportunities for deep savings and to negotiate financial incentives (often greater than those offered in other parts of the state) designed to achieve those savings;
2. Launch of an aggressive small commercial/industrial program (targeting those using 40 to 500 MWh/year) in which high savings measures (primarily lighting measures, but also other cost-effective HVAC, refrigeration, and custom measures) designed to achieve an average of 15% savings per business are directly installed at no cost or very low cost to the customer; and
3. Aggressive local promotion of CFLs to residential and small business customers through both targeted marketing campaigns, community awareness campaigns, and the use of direct mail coupons.

All customers in the areas were also still eligible to participate in other statewide programs.

After the selection of the initial four targeted areas, a working group consisting of the state's largest utilities, Efficiency Vermont, and the Vermont Department of Public Service developed a set of criteria for future selections for geo-targeting:

- Areas experiencing high load growth;
- Areas with known concerns regarding the capacity of existing T&D infrastructure;
- Areas for which the minimum planning horizon for deferral was three years, with a preference for horizons of at least five years; and
- Areas for which there were "no other circumstances requiring immediate investment."[51]

Ultimately, decision-making on geo-targeting priorities was supposed to move to the Vermont System Planning Committee (VSPC), which VELCO was charged by the Board with initiating. Initially, "although the VSPC was formed and has been functioning, for all intents and purposes the selection process remained with the founding geotargeting utilities." This may have been because many parties still regarded geo-targeting as an experiment.[52] More recently, however, the VSPC has assumed the role it was intended to play and initiated a robust process to select targeted areas for future efforts.

Approximately one year into its delivery, one of the four initially targeted areas (Newport) was dropped from the geo-targeting program when the distribution utility determined

49 Massie et al and Navigant Consulting et al., "Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program," Final Report, Submitted to Vermont Department of Public Service, January 7, 2011, p. 103.

50 This is the forecasted growth in winter peak demand. The baseline peak demands for summer and winter were the same. Efficiency Vermont forecast that it could reduce summer peak by more than winter peak, however. That would make winter peak the more constraining variable.

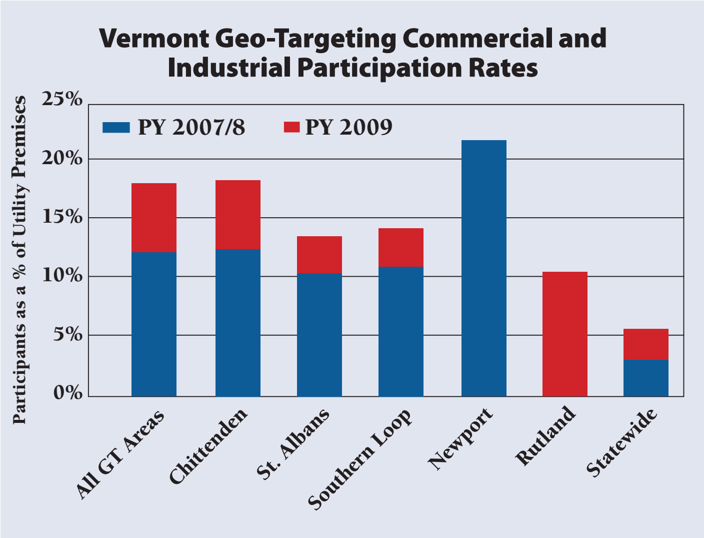
51 Navigant et al. (2011), p. 3.

52 Ibid.

that the substation whose rebuilding the program was intended to defer needed to be rebuilt for reasons other than load growth (i.e., "destabilization of the substation property due to river flooding").[53] Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

A recent evaluation of the geo-targeting program suggests that it has had some success, although not all results were as good as hoped or projected. To begin with, efficiency program participation was considerably higher in geo-targeted areas than in the rest of the state. For example, as Figure 8 shows, commercial and industrial customers in geo-targeted areas participated at a rate nearly four times as great as their counterparts in the rest of the state. For those areas that were in their third year of geo-targeted DSM in 2009, the participation rate multiplier (compared to the rest of the state) declined to 2 to 1. The multiplier for the newly added geo-targeted region (Rutland), however, was roughly the same 4 to 1 ratio experienced by the other regions in their first two years.[54] Savings per participant were also higher than in the statewide programs – 20% to 25% higher for commercial and industrial customers and 30% higher for residential customers. That increase appears to reflect success in achieving greater depth of lighting savings per participant rather than increased penetration of non-lighting efficiency measures.[55] The net result of those two factors was summer peak demand savings that were three to five times greater (depending on the region) in the first couple of years of the program than would have been achieved under the statewide programs.[56]

Figure 8 [57]



All told, over the 2007 to 2009 time period, the program achieved summer peak demand reductions in the targeted areas of 10 MW – about 70% of its goal. Winter peak demand savings were more problematic, with the program achieving only 4.1 MW of reductions, or only about 40% of its goal. Nevertheless, analysis of loads on individual feeders in geo-targeted areas suggests that geo-targeting program impacts "are detectable at the system level" and that the magnitude of savings observed at the utility system level was consistent with those estimated through evaluation of customer savings.[58]

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments has not yet been conducted. Central Vermont Public Service (the state's largest utility), however, has observed that it "has not been required to schedule the deployment of additional system upgrades in Rutland, St. Albans and Southern Loop areas." While it is difficult to know the extent to which that situation should be attributed to the geo-targeting of DSM, to changes in economic conditions (i.e., the recent economic recession), or to other factors, the Company has recommended to the Board that geo-targeting of DSM continue.[59]

Central Maine Power

In June of 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power (CMP) and a variety of other parties (including several public interest advocates) regarding a large transmission

53 Navigant et al. (2011), p. 26.

54 Navigant et al. (2011), pp. 85-87.

55 Navigant et al. (2011), pp. 89-91.

56 It is important to note that the statewide programs are already considered quite aggressive, achieving greater savings as a percent of sales than any state in the country in both 2007 (Eldridge, Maggie et al., *The 2009 State Energy Efficiency Scorecard*, ACEEE Report Number E097, October 2009) and 2008 (Molina, Maggie et al., *The 2010 State Energy Efficiency Scorecard*, ACEEE Report Number E107, October 2010).

57 Graphic courtesy of Navigant Consulting.

58 Navigant et al. (2011), p. 10.

59 Silver, Morris, Counsel for Central Vermont Public Service, letter to the Vermont Public Service Board regarding "EEU Demand Resources Plan – Track C, Geotargeting," January 18, 2011.

system upgrade project (the Maine Power Reliability Project) that the utility had proposed.[60] The settlement supported construction of most elements of the upgrade, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched.

As part of the settlement, CMP was required to conduct a needs assessment for the two regions and develop a proposal for using non-transmission alternatives in conjunction with one of the intervening parties – Grid Solar. In March 2011, CMP and Grid Solar filed a proposed plan for the Mid-Coast region. The plan looked at a couple of different scenarios, ultimately recommending an approach that would require 25 to 29 MW of distributed resources in the Camden-Rockland area and another 10 MW of distributed resources in the Boothbay region to fully obviate the need for a transmission upgrade. It also proposed to use an RFP process to identify and acquire the least cost mix of resources to meet this need. It further suggested the resources be acquired in phases, with the first RFP covering needs from 2012 through 2015 (10 MW in Camden-Rockland and 6 MW in Boothbay). Subsequent RFPs would be developed and issued "based on load growth in the Mid-coast area, on the performance of distributed resources under contract pursuant to prior RFP(s), and on changes to the physical electric transmission and distribution system circuits in the Mid-Coast area." [61]

Under the proposal, any distributed resource would be eligible to respond to the RFP, including:

- Existing back-up generators (the plan identified 45 generators with a combined capacity of 25 MW in the region);
- New generators that could be acquired to provide both back-up capability to customers as well as distributed resources for the pilot;
- Demand response resources (as much as 15 MW were estimated to be in the region);
- Targeted energy efficiency (the plan estimating maximum achievable potential in the Mid-Coast region to be 15 MW, but suggested that 10 MW of that amount was already captured in CMP's load forecast, leaving only 5 MW to potentially be acquired);
- Solar PV (the plan suggested that solar PV would not likely be competitive with other resources, but that it may be appropriate to set aside a portion of the RFP as a "solar carve out" to test the applicability of PV as a transmission resource); and
- Storage (which was also estimated to be too expensive for initial rounds of procurement).

The plan noted that Vermont's experience with geographically targeted efficiency programs suggested that efficiency resources would likely be "highly competitive with other distributed resources." It also suggested that the Efficiency Maine Trust, which is responsible for and funded to implement statewide efficiency programs, could bid enhancements to its efficiency initiatives in the target region in response to the RFP. The plan left unaddressed, however, the question of how baseline levels of savings (from which additional savings from a more aggressive set of geographically targeted efforts would presumably be measured) would be established. It was also not clear whether the plan anticipated the possibility of other efficiency resource providers bidding in response to the RFP. [62]

These issues have not yet been fully explored. In the summer of 2011 the Maine PUC held a Technical Conference on the plan. Among the topics discussed were the impacts of both the economic recession and new (more stringent) reliability standards issued by the North American Electric Reliability Council (NERC) on the forecast resource needs. CMP and Grid Solar are expected to examine these issues and file a new needs analysis and plan in late November 2011. A second Technical Conference is expected to follow in December 2011.[63]

NV Energy

In 2008 NV Energy faced a situation in a relatively rural portion of its service territory, east of Carson City, in which growth in demand was going to need to be met by either running the locally situated but relatively expensive Fort Churchill generating station more frequently or constructing a 30-mile, 345-kVA transmission line and new substation

60 Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

61 Central Maine Power and Grid Solar, Non-Transmission Alternative Pilot Plan and Smart Grid Proposal including Attachments 1-7, filed under Docket No. 2008-255 (Phase II), March 25, 2011.

62 Ibid.

63 Personal communication with Beth Nagursky, Environment Northeast, 11/16/11.

to bring less expensive power from the more efficient Tracy generating facility (situated further north, about 20 miles east of Reno) to the region. When the local county commission began expressing concerns about permitting construction of the substation, regulators instructed the Company to increase the intensity of its DSM efforts in the targeted region as an alternative to meeting the area's needs economically:

> *"…the concentration of DSM energy efficiency measures in Carson City, Dayton, Carson Valley and South Tahoe has the potential to reduce the run time required for the Ft. Churchill generation units. The increased marketing costs and increased incentives and subsequent reduction in program energy savings required to attain an increased participation in the smaller market area are estimated to be more than offset by reduced fuel costs. Sierra Pacific, d.b.a. NV Energy, will make a reasonable effort within the approved DSM budget and programs to concentrate DSM activities in this area…"* [64]

NV Energy pursued a variety of efforts to either focus its existing DSM programs more intensely on the Fort Churchill area and/or launch new initiatives. This included:[65]

- **Non-Profit Agency Grants.** NV Energy gave priority to projects in the impacted area and marketed the program accordingly. In the end, 12 of the 35 applications it received were from the targeted area.
- **Energy Education.** NV Energy concentrated its education events in the region, ultimately holding 19 in 2009 – up from just two the previous year.
- **Low Income Weatherization.** NV Energy asked its implementation contractor to make a special effort to solicit program participation in the targeted area. Participation in the targeted area increased from just eight homes in 2008 to 57 in 2009.
- **ENERGY STAR Lighting and Appliances.** NV Energy concentrated marketing and outreach events in the Fort Churchill area, leading to an increase in participation of nearly 20% (although estimated savings did not increase due to changes in assumptions regarding average run times of CFLs).
- **Second Refrigerator Collection and Recycling.** NV Energy increased marketing efforts in the targeted region, in part through a targeted door-to-door campaign that also included distribution of nearly 100,000 CFLs to more than 16,000 homes. This resulted in increased participation in the refrigerator recycling program of nearly 15% in the targeted region, as well as substantial lighting savings.
- **Energy Smart Schools.** NV Energy offered an "Energy Master Planning Service" to the Carson City and Douglas County School Districts, but both declined the service. The utility also launched a new initiative to distribute CFLs to school district employees.
- **Commercial Retrofit Incentive.** NV Energy renegotiated its contract with its program vendor to support increased marketing in the targeted area, increase financial incentives by 25% in the targeted area, and concentrate all direct install efforts in the target area. The result was a more than 260% increase in savings in the area.
- **Sure Bet Hotel Motel.** NV Energy increased marketing support and financial incentives for this program as well, but no increase in participation was realized.

Of these efforts, the second refrigerator collection and recycling program (primarily the CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.[66]

At the same time as these efficiency efforts were launched, NV Energy's transmission staff began re-conductoring the existing 120-kVA line to the region to increase its carrying capacity. The economic recession also hit at the same time, dampening growth. As a result, the Company has not had to revisit the need for either the additional power line and substation or increasing the run time of the Fort Churchill generating station. The project has also facilitated the beginnings of "rich conversations" between demand resource planners and transmission planners within the Company.[67]

64 Jarvis, Daniel et al., *Targeting Constrained Regions: A Case Study of the Fort Churchill Generating Area,* 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 178-189.

65 Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.

66 Ibid, and Jarvis et al.

67 Personal communication with Larry Holmes, NV Energy, 11/9/11.

3. Lessons Learned

Although the actual implementation of efficiency as an alternative to T&D investments has not yet been what one might call "widespread," there are enough examples in sufficiently diverse circumstances to draw initial conclusions.

Geographically Targeted Energy Efficiency Can Defer T&D Investments

A number of studies have suggested that aggressive, geographically targeted efficiency programs can meet T&D reliability objectives. More important, analyses of the actual deployment of efficiency as alternatives to T&D in several jurisdictions have concluded that supply-side investments were deferred for at least some period of time (e.g., Con Ed in New York City, Green Mountain Power's Mad River Valley Project in Vermont, PG&E's Delta Project in California, portions of PGE's project in downtown Portland, Oregon).

Efficiency Can Be a Cost-Effective T&D Resource

There is less evidence regarding the cost-effectiveness of efficiency as an alternative to T&D upgrades. However, analysis of the most intensive and long-standing effort to defer T&D investments with efficiency programs – Con Ed's experience in New York City – clearly concluded that the geographically targeted programs were very cost-effective. Indeed, the T&D benefits alone were greater than the costs of the programs. When other benefits (e.g., energy savings and system peak demand savings) are included in the analysis, the geographically targeted efficiency programs had a benefit-to-cost ratio of about 3 to 1.

The realization that energy efficiency provides a variety of electric system benefits is critically important, as that broad range of benefits can often render the pursuit of more intensive efficiency programs in localized areas a "no regrets" strategy – at least from a purely economic perspective. Indeed, even though a determination of whether the recent Efficiency Vermont geo-targeting program has deferred T&D system upgrades has not yet been definitively made, evaluation of the program suggests it has been cost-effective – with a benefit cost-ratio of about 2 to 1 (under the Total Resource Cost Test) – even if no T&D investments are deferred.[68]

This suggests that, in most cases, the most important concerns regarding the deployment of efficiency as a T&D resource will likely be efficiency savings forecast issues (i.e., particularly uncertainty about whether enough customers will install enough efficiency measures to actually avoid a reliability-driven investment) and possibly equity issues (i.e., concerns about customers in targeted areas getting greater access to and/or greater financial incentives from efficiency programs than those in other areas).

Stuff Happens! Unexpected Events Can Affect Benefits of Efficiency

It is worth noting that in several of the case studies examined for this report some or all of the T&D investment being considered for deferral ultimately ended up being constructed for reasons having nothing to do with the effectiveness of the deployment of efficiency resources. For example, part of PGE's project in Portland, Oregon (to defer a transformer upgrade for one commercial building) ended when the conversion from gas to electric cooling for the building added too much load to be offset by demand-side measures. More recently in Vermont, one of the original areas targeted for locally intensive DSM programs (Newport) was removed from the program when the existing substation became destabilized due to flooding, necessitating an immediate supply-side investment. In each of those cases, it could be concluded that the investments in efficiency programs ultimately provided either no T&D

68 Navigant et al. (2011), p. 100. Similar analyses for other case studies examined are not available.

benefit or very little benefit.

It is important to recognize that forecasting uncertainty works in both directions, however. In several of the examples discussed in this paper it appears as if efficiency investments not only permitted deferral of a T&D investment, but permanently eliminated the need for the investment. This happened either because the efficiency savings realized were greater than forecast (e.g., in one of the commercial buildings treated by PGE's program in Portland, Oregon) or because the efficiency investments bought enough time for more fundamental changes in demand to take hold (e.g., Con Ed's conclusion that $85 million in T&D investments that it otherwise would have made may now never be needed).

The bottom line is that there are a variety of risks associated with forecasting of T&D system needs that can affect the potential benefits of using efficiency to defer T&D system investments. These include:

- The reliability risk of under-forecasting demand growth;
- The economic risk of over-building the T&D system due to over-forecasting of demand growth; and
- Both the reliability risk (if it takes longer than expected) and the economic risk (if it ends up costing more)[69] of siting new poles and wires.

It could be argued that efficiency programs are more likely to mitigate than to exacerbate these risks. To begin with, many efficiency programs are "load-following." For example, efficiency programs designed to promote efficiency in the construction of new buildings will generally have lower participation and savings when construction slows (i.e., when savings are least needed) and higher participation and savings when construction accelerates (i.e., when savings are most needed). Similarly, efficiency programs often have a harder time convincing home-owners and businesses to participate – and therefore have a harder time meeting savings goals – during difficult economic times (i.e., when loads are not growing fast and therefore concerns about exceeding T&D system capacity are lower); they often have an easier time recruiting participants and exceeding savings goals during good economic times (i.e., when loads are naturally growing faster, imposing greater strains on T&D systems). Indeed, the reality that Efficiency Vermont launched its geo-targeting program just before the recent deep economic recession was probably a contributing factor to their failure to meet initial savings goals. On the other hand, as Central Vermont Public Service has implied, the recession is likely part of the reason the Company has not had to deploy additional system upgrades in its portion of the targeted areas.

Sufficient Lead Time is Critical

It usually takes time to generate enough savings from energy efficiency programs to defer T&D system upgrades. The programs must be planned, developed, and then marketed to consumers before any savings are realized. Reaching a large segment of the eligible market requires on-going marketing and business development efforts. Initial strategies may not be as successful as anticipated, so programs are more likely to be successful if there is time to refine them in response to market feedback. As discussed above, PG&E's Delta Project did not have that luxury and, as a result, ended up falling short of overall savings goals and spending more per unit of savings than originally planned. Even though a very cost-effective strategy was identified part of the way through the project, there was not enough time for it to gain enough traction to offset the less effective results of some of the initially pursued elements. Sufficient lead time may also better enable efficiency program managers to demonstrate to T&D system planners and engineers that efficiency strategies are affecting localized peak loads. Parts of PGE's downtown Portland project ultimately failed to defer T&D upgrades not because the efficiency savings were inadequate, but rather because T&D planners and engineers did not have sufficient confidence that the savings would be achieved and be reliable and persistent.

To be sure, the amount of lead time necessary to enable efficiency programs to defer T&D investments will vary

69 For example, in July 2005, about six months after its proposal to construct a major new transmission line and make other related improvements was approved by the Vermont Board of Public Utilities, VELCO filed with the Board a revised cost estimate that was nearly double the estimate it had made two to three years earlier and presented during the course of the hearing on the project. In order of importance, the increase was attributed to a high rate of inflation for the materials and services needed, regulatory conditions of the approval, and better (higher) estimates of the materials it would need (State of Vermont Public Service Board, Order on Remand RE: Reopening Proceedings, Docket 6860, 9/23/2005).

from project to project. In general, shorter lead times will be needed when the number of customers that must be served by efficiency programs in order to generate sufficient savings is small. One key to ensuring there is sufficient lead time is to conduct more systematic planning for meeting T&D needs, including long-term forecasting of potential needs, integrating the forecasting of such needs with forecasting of savings from system-wide efficiency initiatives, and including analysis of potential additional, localized efficiency programs in early stages of assessment of options for meeting T&D needs.

Smaller is Easier

In general, the smaller the area being addressed, the easier it is to consider efficiency and other non-wires alternatives to T&D investments. Smaller areas mean that efficiency savings need to be acquired from fewer customers. That in turn means that it is often easier to characterize the opportunity for efficiency investments accurately. It also means that shorter lead times will be needed. For example, deferring a transformer upgrade on a single large commercial building may not require much time if one need just convince a single owner of the building to make an efficiency investment. Alternatively, deferring distribution substations or transmission lines serving many thousands of customers will usually take longer unless there are just a few large customers who, if served by an efficiency program, could impact localized peak demands significantly.

Distribution is Easier than Transmission

Deferring distribution system investments is generally easier than deferring transmission investments because the non-wires solutions will generally be smaller in scope (see discussion above). In addition, distribution system planning is generally less technically complex, involves fewer parties, does not involve regional ISOs/RTOs, and does not involve regional cost-allocation frameworks that often bias investments in favor of "poles and wires" solutions.

Cross-Discipline Communication is Critical

This may seem self-evident, but it is critical nonetheless. T&D planners and engineers are often skeptical of the potential for end-use efficiency to reliably substitute for poles, wires, and other T&D "hardware." They worry that customers themselves are unreliable. Similarly, staff responsible for administration of programs that promote efficiency, load control, distributed generation, or other demand resources typically do not fully understand the complexities of the reliability issues faced by T&D system planners. Both need to better understand the needs and capabilities of the other.

It can take time to develop the relationships and confidence necessary for efficiency program implementers and their evaluated results and T&D system engineers to work together effectively. Those relationships and that trust must be developed, however, if efficiency programs are to be as successful as possible in deferring T&D investments.

Upper management can be very important in setting expectations that such communication and cross-discipline learning take place within a utility. It is much more difficult to institutionalize such communication when transmission planning has regional elements and implications that necessarily involve the ISO/RTO.

Integrate Efficiency with Other Distributed Resources

Although efficiency programs can sometimes be sufficient to defer T&D investments, other times they will not be. They can, however, be married with promotion of demand-response and distributed generation initiatives to meet the same objective.

4. Recommendations

Though several pilot projects in the past and some more substantial projects today appear to have demonstrated that efficiency programs can be a cost-effective T&D resource, such efforts remain uncommon. Put another way, the potential economic and other benefits of using geographically targeted efficiency programs as a T&D resource are largely being ignored today. Some fundamental policy changes are required if that is to change. In this concluding section of the paper we discuss the policies that should be explored if efficiency's potential is to be realized.

Require Least-Cost T&D Planning

As noted above, both economic incentives in many states and system planning culture have made "poles and wires" (or T&D hardware) the default solution to T&D-related reliability issues almost everywhere. Experience to date suggests that the only way that will change is if T&D planners are required by legislators or regulators to analyze alternatives and choose the least-cost option.[70]

Over the past decade, several jurisdictions have institutionalized such processes. Several notable examples are summarized below. There are certainly costs to such processes – both for the utilities doing the planning and for regulatory oversight. Feedback from several jurisdictions, however, suggests that the process evolves – as it is tested and refined – to one in which the burden on the utility is not only manageable but also much more than offset by cost savings. Once that point is reached and utilities are meeting a high standard in their work, the burden on regulators should be quite modest.

Rhode Island

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that requires utilities to submit system reliability procurement plans every three years. Guidelines detailing what to include in those plans were adopted more recently (see Appendix A). Those guidelines make clear that plans must consider non-wires alternatives – including energy efficiency, distributed generation, and demand response – whenever the T&D need:

- Is not based on an asset condition;
- Will likely cost more than $1 million to address;
- Would require no more than a 20% reduction in peak load to defer; and
- Would not require investment in a "wires solution" to begin for at least 36 months.

For such cases, the plans must include analysis of financial impacts, risks, the potential for synergistic benefits, and other aspects of both wires and non-wires alternatives.[71]

Vermont

Vermont has long imposed an integrated resource planning requirement on its utilities. However, the passage of Act 61 in 2005 – which reinforced those requirements by specifying minimum 10-year planning horizons, required the plans to be filed at least every three years, and required public meetings (in areas close to potential T&D upgrades) at which plans are presented (see Appendix B for legislative language) – has begun to make the process more rigorous. Indeed, VELCO and Efficiency Vermont are now working together to regularly reconcile and integrate

70 Note that this works only to the extent that states actually control the planning process. Although they do for distribution system investments, responsibility for transmission planning decisions is shared with regional ISOs/RTOs. That has lessened states ability to effectively impose least-cost planning requirements. Recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in planning decisions, may give states more influence in the future.

71 Rhode Island Standards for Least Cost Procurement and System Reliability Planning.

their respective forecasts of baseline demand and efficiency program savings.[72]

Bonneville Power Administration

Although not required by legislation or regulation, in 2002 BPA launched a Non-Wires Solutions (NWS) initiative in which it committed to investigating "least-cost solutions that may result in deferring potential transmission reinforcement projects."[73] A year later, BPA formed a Non-Wires Solutions Round Table composed of key stakeholder groups in the region to assist it in these endeavors.[74] It then developed a formal process by which non-wires solutions – including energy efficiency, demand response, load control, and distributed generation – would be routinely assessed. To begin with, transmission planners annually assess potential transmission needs over the next 10 to 15 years. That assessment is tied to the Western Electricity Coordinating Council's power flow and planning framework.[75] Once a transmission need is identified by BPA's Transmission Business Line, an initial "screening" is conducted to determine whether the project is a candidate for possible non-wires solutions. A project qualifies for an analysis of non-wires solutions if it meets three criteria:

1. The transmission project cost is estimated to be at least $5 million;
2. The project need is driven by load growth; and
3. The project need is at least eight years out.[76]

If these criteria are met, a high level economic assessment is conducted using a simplified spreadsheet template that has been developed specifically for this purpose. The analysis includes all of the potential benefits of non-wires solutions. Estimates of energy savings and capacity savings benefits are based on results of the Northwest Power Planning Council's integrated resource plans (conducted every five years). Avoided transmission costs are estimated for the specific project under consideration. If the analysis suggests both that there are sufficient non-wires resources to defer a project and that the deferral could be cost-effective, a detailed feasibility study is conducted. If that study confirms that the non-wires solution is indeed feasible, then the benefits, costs, and risks of both traditional transmission and non-wires solutions are compared to decide which strategies to pursue. This process is summarized in Figure 9. BPA went through this process on four different occasions between 2002 and 2006. In all of those cases a determination was made that the traditional transmission strategy was needed.

BPA recently reconvened its Non-Wires Round Table to consider new regional transmission needs in this same framework. Three potential non-wires projects are currently undergoing intensive analysis and discussion. Energy efficiency is an element of the non-wires solution being considered for both the I-5 corridor in Oregon and the Hooper Springs area in Idaho. Efficiency plays a more central role in a third potential project that has not yet been made public.[77]

72 This has not been without its challenges, because assumptions about such things as treatment of baseline efficiency conditions, the level of "naturally occurring" efficiency (related to free rider assumptions in efficiency savings forecasts), and other key issues are sometimes different or inconsistent (see Enterline, Shawn and Eric Fox, *Integrating Energy Efficiency into Utility Load Forecasts*, in Proceedings of the 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 86-96).

73 GDS Associates, "Process Evaluation of the Non-Wires Solution Initiative," prepared for BPA, June 8, 2007.

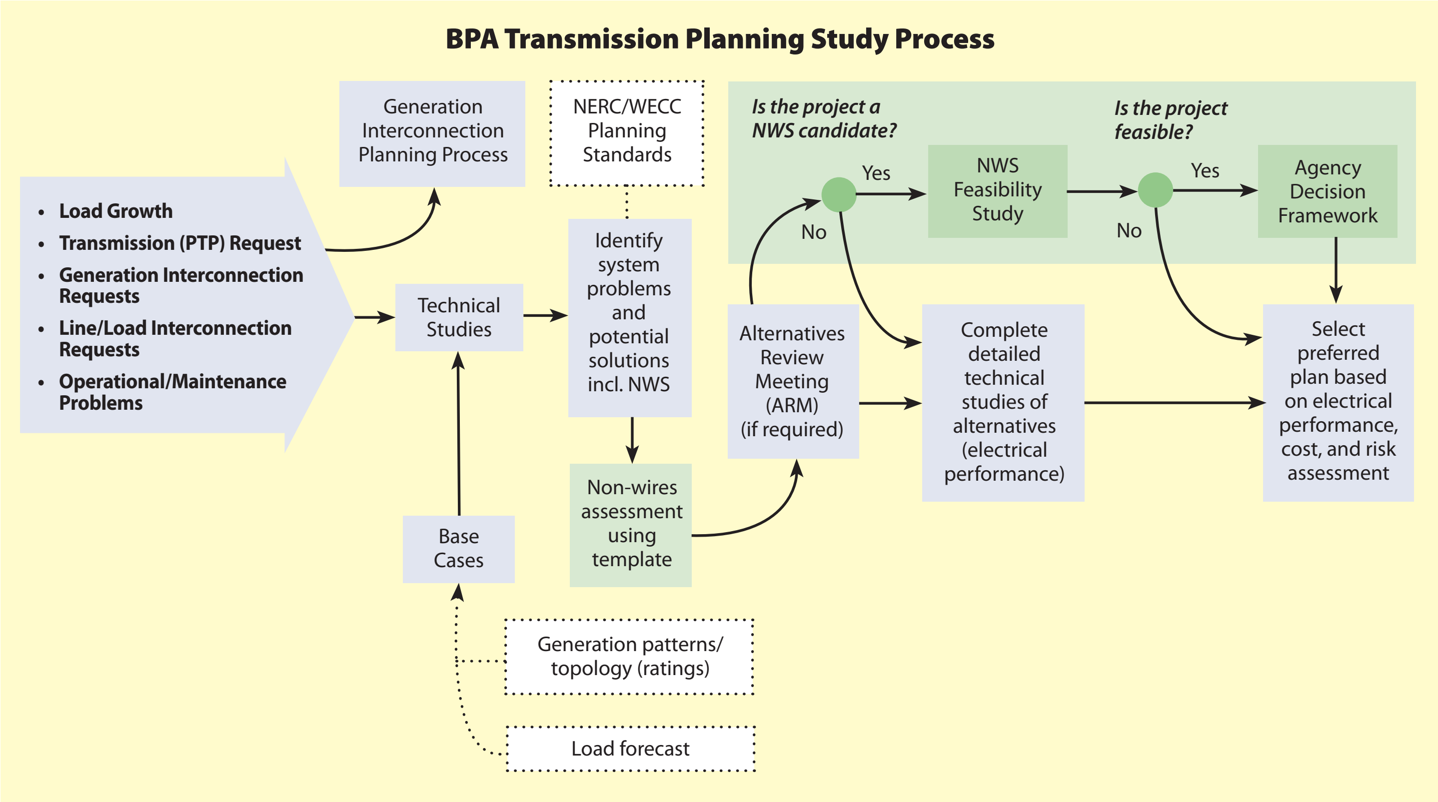
74 Although the Round Table has been organized to function collaboratively, its input is purely advisory. BPA makes all final decisions on how to address transmission needs.

75 Personal communication with Mike Weedall, Ottie Nabors, and Josh Binus, Bonneville Power Administration, 4/27/11.

76 Nabors, Ottie, "Non-Wires Alternatives Screening Process & Evaluation," presentation at the Non-Wires Round Table, April 15, 2011.

77 Personal communication with Mike Weedall, BPA, 12/23/11.

Figure 9 [78]



Require Consideration of Integrated Solutions

Efficiency is one of several types of distributed resources – demand response, load control, and distributed generation are other notable examples – that can help to cost-effectively defer T&D investments. Indeed, there may be important synergies in combining deployment of efficiency and other distributed resources (e.g., efficiency and demand response and potentially even distributed generation can often be "sold" to customers more effectively if sold together). Any requirement for least-cost planning thus should make clear that all options, including different combinations of distributed resources, should be considered.

The ability for states to require either least-cost planning or consideration of integrated solutions is clear with respect to distribution system planning, but more complicated for transmission planning because of transmission's regional implications and the involvement of regional ISOs/RTOs. Nevertheless, states have influenced transmission planning, and the recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in their planning decisions, may give them more clout in the future.

Institutionalize a Long-Term Planning Horizon

The longer the lead time, the more likely it will be that efficiency (or other distributed resources) could cost-effectively defer traditional T&D investments. This suggests it is critical that assessments of T&D needs are both long-term and conducted on a regular basis. As noted above, although they are all still refining their processes, all of the jurisdictions that are currently seriously considering non-wires alternatives to T&D investments are routinely forecasting T&D needs at least 10 years into the future. Con Ed develops a 10-year plan for T&D needs. Vermont requires an annual plan that looks out a minimum of 10 years. VELCO, Vermont's transmission utility, has chosen to forecast 20 years out. Similarly BPA looks at transmission needs 10 to 15 years into the future.

78 Graphic from Nabors, Ottie, "Non-Wires Alternatives Screening Process & Evaluation," presentation at the Non-Wires Round Table, April 15, 2011.

"Level the Playing Field" in Payment for Wires and Non-Wires Alternatives

One of the biggest barriers to serious consideration of efficiency (and other demand resources) as alternatives to T&D investments is the unequal treatment of the costs of wires and non-wires solutions. For example, nearly 90% of the nearly $290 million cost of VELCO's Northwest Reliability Project in Vermont has been deemed by the New England ISO to be eligible for Pooled Transmission Facility (PTF) treatment – or spread across the New England region.[79] Because Vermont represents a relatively small portion of the total regional power pool load, its ratepayers pay only about 5% of PTF costs. Its rate-payers thus will ultimately bear less than 20% of total project costs. The ISO does not give PTF treatment to non-wires solutions. As a result, if the state had pursued a non-wires solution to its transmission reliability needs, it would have borne 100% of the costs of the project.

Such policies represent enormous disincentives to pursue non-wires solutions – even if they are less expensive than traditional transmission investments. Unbalanced treatment of wires and non-wires solutions needs to be addressed if least-cost solutions are to be routinely and seriously considered.

Collect More Data on Efficiency's Impacts

In much of the country, relatively little end-use metered data on the hourly and seasonal impacts of efficiency resources has been collected and made public over the past two decades. As a result, many jurisdictions now rely on very old end-use metering studies when developing hourly load shapes for efficiency measures. Such load shapes are essential to estimating the impacts of efficiency resources on localized transmission or distribution system peaks (peak hours can vary considerably from one distribution element to another, even within the same utility service territory). Having more data of this kind should make it easier to address concerns of T&D system planners.

It is worth noting that the New England region may be ahead of much of the rest of the country in this regard, in part because the region's forward capacity market requires efficiency resource providers to use studies that are less than five years old to document achievement of the system peak demand savings that are bidding into the market. That requirement has resulted in a number of different end-use metering studies that have not only documented savings at the time of the regional system peak, but also at all other hours of the day. In many cases, the studies have been undertaken at the regional level – with all states sharing the cost – as a way to make them affordable.

Start with Pilot Projects

Virtually every jurisdiction that genuinely considered efficiency as a potential cost-effective alternative to T&D investments started with pilot projects. Much has been learned from those pilots. The pilots also offered important venues for facilitating the mutual education of system engineers and efficiency program managers. Experience to date suggests that a pilot project or two will not bridge the cultural chasms between these two groups. They can be important steps in that process, however.

Leverage "Smart Grid" Investments

A number of utilities have recently made or are about to make significant investments in advanced metering, customer feedback mechanisms, and other "smart grid" features. Customer and end-use data collected through such systems may enable better assessments of the potential for efficiency to serve as a T&D resource in general, and perhaps more important, in specific geographic areas.

79 ISO New England, "Summary of ISO-NE Reviewed TCA Applications under Schedule 12C of the Tariff" – Status as of 2/18/2011 (http://www.iso-ne.com/trans/pp_tca/status/tca_application_status.pdf)

Appendix A

Rhode Island Standards for Least Cost Procurement and System Reliability Planning – Excerpt on Distributed Resources in Relation to T&D Investment

Chapter 2 - System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into the Company's distribution planning process for the three years of implementation beginning January 1 of the following year.

B. Non-Wires Alternatives (NWA) may include but are not limited to:
   a. Least Cost Procurement energy efficiency baseline services
   b. Peak demand and geographically-focused supplemental energy efficiency strategies
   c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[80]
   d. Demand response
   e. Direct load control
   f. Energy storage
   g. Alternative tariff options

C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
   a. The need is not based on asset condition;
   b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
   c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
   d. Start of wires alternative is at least 36 months in the future; and
   A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:
   a. Ability to meet the identified system needs
   b. Anticipated reliability of the alternatives
   c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
   d. Potential for synergy savings based on alternatives that address multiple needs
   e. Operational complexity and flexibility
   f. Implementation issues
   g. Customer impacts
   h. Other relevant factors

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue

80 In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where an NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:
   a. Characterization of the need
      i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues
      ii. Identification and description of the T&D investment and how it would change as a result of the NWA
      iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
      iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions
   b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
   c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing
   d. Development of NWA investment scenario(s)
      i. Specific NWA characteristics
      ii. Development of an implementation plan, including ownership and contracting considerations or options
      iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule

G. Funding Plan
   The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:
      i. Capital funds that would otherwise be applied towards traditional wires based alternatives
      ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans
      iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved
      iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed
      v. Identification of significant customer contribution or third party investment that may be part of an NWA based on benefits that are expected to accrue to the specific customers or third parties
      vi. Any other funding that might be required and available to complete the NWA

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
   a. A summary of projects where NWA were considered;
   b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
   c. Implementation plan for the selected NWA projects;
   d. Funding plan for the selected NWA projects;
   e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
   f. Status of any previously selected and approved projects and pilots;
   g. Identification of any methodological or analytical tools to be developed in the year;
   h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

Appendix B

Excerpts from Vermont's Act 61

Sec. 8. Advocacy For Regional Electricity Reliability Policy

It shall be the policy of the state of Vermont, in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues, to support an efficient reliability policy, as follows:

(1) When cost recovery is sought through region-wide regulated rates or uplift tariffs for power system reliability improvements, all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding.

(2) A principal criterion for approving and selecting a solution should be whether it is the least-cost solution to a system need on a total cost basis.

(3) Ratepayers should not be required to pay for system upgrades in other states that do not meet these least-cost and resource-neutral standards.

(4) For reliability-related projects in Vermont, subject to the review of the public service board, regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis.

(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

Transmission and Distribution Planning

Sec. 9. 30 V.S.A. § 218c is amended to read:
§ 218C. Least Cost Integrated Planning

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives. The meetings shall be at separate locations within

the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4)(A) A transmission system plan shall be revised:
- (i) within nine months of a request to do so made by either the public service board or the department of public service; and
- (ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate.

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Other recent RAP publications on energy efficiency include the following:

Residential Efficiency Retrofits: A Roadmap for the Future

Roughly half of all efficiency and/or carbon emission reduction in North American and European buildings can be achieved through retrofit improvements to existing homes. In this publication, RAP offers a roadmap to help policymakers and practitioners design and implement a comprehensive residential retrofit strategy. We present eight principles for success based on two decades of international experience, designed to achieve the level of energy savings that will be needed to address the challenge of climate change.

The Executive Summary of this report is available separately in English and German at: http://raponline.org/document/download/id/4424.

The full report is available at: http://www.raponline.org/document/download/id/918

Prices and Policies: Carbon Caps and Efficiency Programmes for Europe's Low-Carbon Future

This paper was presented at the 2011 ECEEE Summer Study.

With the adoption of the Climate and Energy Package in 2008, European decision-makers created an integrated suite of policies to reduce carbon emissions, increase renewable energy production, and advance energy savings. As the EU ETS moves to carbon auctioning, decision-makers must continue to link carbon prices with other policy tools to meet Europe's adopted carbon and sustainable development goals. This paper demonstrates how energy efficiency (EE) policies can help meet ETS goals at lower cost, creating space to tighten carbon caps, and/or reduce the cost of protecting high-emitting industries and new Member States. Smart "complementary policies" can directly link ETS and EE strategies, especially by using auction revenue for EE programmes. Complementary policies are also needed to support low-carbon power markets, grid expansion, and renewable power investment across Europe.

The full paper is available at: http://www.raponline.org/document/download/id/931

Who Should Deliver Ratepayer Funded Energy Efficiency? A 2011 Update

This report describes policy options and approaches for administering ratepayer-funded electric energy efficiency programs in US states. It reviews how states have administered energy efficiency programs to learn what lessons their experience offers, and describes the most important factors states should consider with different administrative models. State legislators and utility regulators will find this report useful as they consider ways for energy efficiency administration to be more effective, both in states that are considering the question for the first time, and in more experienced states that are implementing significant increases in their savings goals. RAP's first version of this report was written in 2003.

The full report is available at: http://www.raponline.org/document/download/id/4707

Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements

While utilities and their regulators are familiar with the energy savings that energy efficiency measures can provide, they may not be aware of how these same measures also provide very valuable peak capacity benefits in the form of marginal reductions to line losses that are often overlooked in the program design and measure screening. This paper is the first of two that the Regulatory Assistance Project is publishing on the relationship between energy efficiency and avoiding line losses.

The full report is available at: http://www.raponline.org/document/download/id/4537

Achieving Energy Efficiency: A Global Best Practices Guide on Government Policies

This best practices guide provides a summary overview of the most effective policy mechanisms that regional, national, state or local governments at the executive, legislative or regulatory level can adopt to achieve significant energy efficiency in buildings, processes and equipment used in the residential, commercial, industrial, public and institutional sectors. By policy mechanism, we mean specific laws, regulations, processes and implementation strategies that foster the development and use of products and services which require less energy input to deliver the same or more productivity and output. Our focus is on how government policies can accelerate and increase efficiency investments to achieve additional savings. We do not address best practices in the design or delivery of efficiency programs that would flow from these policies. Nor do we address tariff structures or energy pricing and financing tools that can be employed to help end users invest in efficiency.

The full report is available at: http://www.raponline.org/document/download/id/4781

Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency

The Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency paper identifies varied, but complementary, government regulatory mechanisms utilized worldwide to mobilize the resources of energy providers to implement investments in energy. The paper identifies and describes twelve types of regulatory mechanisms that governments use effectively to: mobilize energy provider investments directly; facilitate investments in demand-side resources; or implement policies and programs that underpin important elements of successful investment programs. The paper also explains how each regulatory mechanism functions in different market settings to mobilize resources or enable effective programs, identifies key issues that ensure successful implementation, and then outlines an example of how at least one jurisdiction has achieved successful implementation of the mechanism.

The full report is available at: http://www.raponline.org/document/download/id/4872

Other documents on energy efficiency and other topics are available on The Regulatory Assistance Project website at:
www.raponline.org

Acronym Glossary

ACEEE American Council for an Energy Efficient Economy

AMI Advanced Metering Infrastructure

BPA Bonneville Power Administration

C & I Commercial and Industrial

CFLs Compact Fluorescent Light Bulbs

CMP Central Maine Power

Con Ed Consolidated Edison

DR Demand Response

DSM Demand-Side Management

EEI Edison Electric Institute

EPRI Electric Power Research Institute

ESCO Energy Service Company

FCM Forward Capacity Market

FERC Federal Energy Regulatory Commission

GMP Green Mountain Power

ISO Independent System Operator

NERC North American Electric Reliability Council

NWS Non-Wires Solutions

PGE Portland General Electric

PG&E Pacific Gas and Electric

PTF Pooled Transmission Facility

PTP Point-to-point

RTO Regional Transmission Organization

SPWG State Program Working Group

SRP System Reliability Procurement

T&D Transmission and Distribution

TRC Total Resource Cost

VELCO Vermont Electric Power Company

VSPC Vermont System Planning Committee

WECC Western Electricity Coordinating Council

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GREEN ENERGY COALITION RESPONSE TO

ENBRIDGE GAS DISTRIBUTION

INTERROGATORY #7

PREAMBLE:

Reference: Exhibit L.EGD.GEC.2, page 3, parargraph 5.

Exhibit L.EGD.GEC.2, page 3, paragraph 5 states:

> *"A number of different jurisdictions are now actively assessing whether system reliability needs can be met through geographically targeted DSM."*

QUESTION:

Please list the jurisdictions which GEC is aware of which are considering geographically targeted DSM to meet gas system reliability needs.

RESPONSE:

See response to EGD Interrogatory #6.

GREEN ENERGY COALITION RESPONSE TO

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INTERROGATORY #8

PREAMBLE:

Reference: Exhibit L.EGD.GEC.2, Page 4, paragraph 2.

Exhibit L.EGD.GEC.2, Page 4, paragraph 2 states:

> *"Unlike some other gas utilities, the Company has never even quantified the peak hour or peak day benefits of its efficiency programs."*

QUESTION:

a. Please provide a list of gas utilities which quantify peak hour or peak day benefits of energy efficiency programs.
b. Please provide any available information on those programs.

RESPONSE:

a. We have not done an extensive survey of gas utilities to identify their specific avoided costs, and in some cases it is difficult to obtain avoided cost data due to confidentiality concerns. However we provide the following as two examples of gas utilities that follow this practice:

   - Vermont Gas Systems: Mr. Grevatt is the former Manager of Vermont Gas' DSM programs and can speak from personal experience that the company's avoided costs reflect much higher values for Peak Day and Peak Period than for the rest of the year.

   - Puget Sound Energy: Please see the PowerPoint presentation describing Puget Sound's development of avoided costs: http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/c84fe7a57c3747f488257ab7007c92a4!OpenDocument

b. Please see Exh. M.GEC.CCC.1 and www.vermontgas.com for information on Vermont Gas programs and http://pse.com/Pages/default.aspx for information on Puget Sound's programs.

GREEN ENERGY COALITION RESPONSE TO

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INTERROGATORY #9

PREAMBLE:

Reference: Exhibit L.EGD.GEC.2, page 5, paragraph 3.

Exhibit L.EGD.GEC.2, page 5, paragraph 3 states:

> *"The same would be true of almost any imaginable expansion of the Company's DSM efforts – particularly if the expansion was specifically designed to defer pipeline investments."*

QUESTION:

Please provide references to programs of other gas utilities which are specifically designed to defer pipeline investments.

RESPONSE:

See response to EGD Interrogatory #6.

GREEN ENERGY COALITION RESPONSE TO

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INTERROGATORY #10

QUESTION:

Reference: Exhibit L.EGD.GEC.2, Page 7, Table 2.

Please confirm that Enbridge's apartment, commercial and industrial sectors are all achieving very respectable savings, comparable to the leading jurisdictions listed in Table 3, of just under 1% of sales.

RESPONSE:

Indeed, Enbridge's non-residential efficiency programs have achieved respectable savings as suggested. However, the point in question is not whether Enbridge's programs are performing respectably, but rather whether a more aggressive approach to planning and implementing efficiency programs in the GTA will lead to a less costly solution for ratepayers than the construction alternative as it has been proposed by Enbridge. In this context, with no disrespect to Enbridge's past non-residential achievements, it is simply insufficient for the Board to settle for less than all cost-effective energy efficiency.

GREEN ENERGY COALITION RESPONSE TO

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INTERROGATORY #11

QUESTION:

Exhibit L.EGD.GEC.2, Page 7, paragraph 1 states:

> *"One of the best indicators of how much additional savings could be acquired is the amount of savings other jurisdictions – particularly leading jurisdictions – are acquiring."*

Please list the criteria which define "leading jurisdictions".

RESPONSE:

In the cited sentence, the term "leading" refers to jurisdictions that are acquiring the greatest levels of energy savings. To enable comparability across jurisdictions, we focus on incremental annual savings as a percent of annual sales. That is a common metric for DSM success in the energy efficiency industry. Again, for comparative purposes, we focus on jurisdictions with substantial heating loads.

Note that we did not conduct a comprehensive assessment of gas DSM portfolios across the continent, so we have not necessarily identified all leading jurisdictions. Indeed, we may not have identified the jurisdictions with the greatest savings levels.

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INTERROGATORY #12

QUESTION:

Reference: Exhibit L.EGD.GEC.2, Table 3, Page 8.

a. Please confirm that the average savings of the leading jurisdictions across the timeframe provided in Table 3 is less than 1% of sales
b. Please confirm that in the leading jurisdictions provided across 6 years only one program achieved 1.5% savings as a percentage of sales and maintained that level of savings for 1 year.
c. For the jurisdictions cited please list the number of years that the utility has offered DSM programs.

RESPONSE:

a. No. First, it is not possible to compute the average savings across the full timeframe shown in Table 3 for all the utilities because we do not have data for all of the years covered for each utility. Second, the average for those years for which we do have data varies considerably, from 0.52% for Questar to 1.23% for Interstate Power and Light. In two other cases – Vermont Gas (0.99%) and Excel (0.97%) – the average is extremely close to 1%. Finally, the average across multiple years is not necessarily relevant to this proceeding nor the point of the references which were provided to demonstrate attainable ramp up rates. In some cases part of what the trajectory of savings shows is that utilities with savings levels at or lower than Enbridge's current level can and have ramped up to much higher levels relatively quickly.
b. Confirmed.
c. At least three of the five utilities we reference (Vermont Gas, Interstate Power and Light, and Xcel) have been offering DSM programs since the early 1990s (i.e. longer than Enbridge). We do not have precise information on the start date for National Grid, but know that it has been offering programs since at least 1997. It is our understanding that Questar began offering DSM programs in 2007.

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INTERROGATORY #13

QUESTION:

Reference: Exhibit L.EGD.GEC.2, Page 10, paragraph 2

Exhibit L.EGD.GEC.2, Page 10, paragraph 2 states:

> *"In summary, experience from leading jurisdictions suggests it is possible to achieve market penetrations of residential thermal envelop retrofits of 1% to 2% per year – an order of magnitude more than Enbridge's planned market penetration rate of roughly 0.1% for its combined efforts to retrofit both low income and non low income homes in 2013."*

a. Please provide the reports cited in footnotes 29 through 33.
b. Using the attached tables, please provide information on the "leading jurisdictions" referenced.

RESPONSE:

a. See attachments A to D.

b. See tables below. With respect to the second table, the publicly available data which we were able to access did not always specify whether each measure in the table was included in the program. The request for start and end dates was not explicitly addressed because the specific measures included in programs can vary over time. Thus, we have attempted to capture those measures that appear to have been included recently. Note also that several of the programs provide additional measures beyond those listed by EGD, including basement insulation, heating system controls, duct sealing, duct insulation, solar-assisted for gas water heaters, high efficiency clothes washers and dryers, etc

	Enbridge	Questar	Mass Save	Efficiency Maine	Vermont- State wide[1]
# residential customers (2012)	1,836,267	823,151 (2008)	2,205,729	592,828	265,732
# years gas DSM programs offered in Residential sector	17	7	at least 15[2]	approximately 10[3]	more than 20
Total residential savings achieved to date	352,410,278m3	Please see response to CCC #1 for an illustration of the retrofit savings achieved annually in these programs			
Average annual residential savings over the period	20,730,016 m3	Please see response to CCC #1 for an illustration of the retrofit savings achieved annually in these programs			
Previous whole home retrofit programs by other agencies	Federal EcoEnergy program with additional provincial incentive	Low Income weatherization programs have been in place since the 1970's			
Applicable standards re: furnace efficiency	Min AFUE – 90%	Most jurisdictions in the US follow federal standards as baseline, which are relevant for new construction and equipment replacement programs. However all programs that we are aware of that offer retrofit/early retirement programs for heating and DHW systems promote high efficiency equipment regardless of the baseline standards.			
Re: water heater efficiency	Min EF - 0. 67				
Minimum Building Code energy efficiency requirement: (EnerGuide rating or equivalent)	EnerGuide 80	New construction energy codes vary with jurisdiction, but are typically irrelevant when considering retrofit potential			
Current program(s)	Community Energy Retrofit (CER)	ThermWise Weatherization	MassSave Home Energy Savings Program	Efficiency Maine Home Energy Savings Program	Home Performance with Energy Star, Weatherization Assistance Program, Vermont Gas HomeBase Retrofit Program
Incentive / participant	Max $1500	Incentives have varied over time- current retrofit program incentives are shown per sq ft rebates for qualifying insulation measures, plus up to $450 for duct sealing, plus up to $850 for air sealing, plus $30 for tstat	75% of cost up to $2000 for insulation, plus no-cost air sealing, plus additional rebates for heating and hot water	$600 for insulation/air sealing + Financing up to $25,000 at 4.99%	LI WAP covers full cost, Home Performance Max $2600, Vt Gas 1/3 of measure cost plus 0%, 3 year financing
Program restrictions	CER participants must complete 2 deep savings measures and achieve 25% total savings to be eligible for the incentive	Authorized contractor required for some measures	Participating contractor required	Participating contractor, loan approval	Income restrictions for WAP, must achieve at least 10% air leakage reduction and address all health and safety to receive Efficiency Vermont incentives, 0.5 ccf/sq ft per year minimum usage for Vt Gas

[1] includes Vermont Gas, Home Performance with Energy Star, and WAP
[2] answer is provided for Massachusetts gas utilities generally
[3] We are not certain as to the exact date on which residential programs began, but believe it was soon after Efficiency Maine was established in 2002.

Measure	Questar		Mass Save		Efficiency Maine		Vermont Gas Systems	
	Offered		Offered		Offered		Offered	
	From:	To:	From:	To:	From:	To:	From:	To:
Space Heating								
HE Furnace	Y		Y		Y		Y	
Programmable Thermostat	Y		Y		Y		Y	
Attic Insulation	Y		Y		Y		Y	
Wall insulation	Y		Y		Y		Y	
Windows	Y		?		Y		N	
Reflector Panels	?		?		?		?	
Water Heating								
HE Water Heater	Y		Y		Y		Y	
Faucet Aerator	?		Y		Y		Y	
Low-flow Showerhead	?		Y		Y		Y	
Pipe Insulation	?		Y		Y		Y	
Drain Water Heat Recovery	?		?		?		Y	
Temperature Turn Down	?		?		?		Y	
Direct Vent Boilers	Y		Y		Y		Y	
Combination Units	?		?		Y		Y	
Tankless Water Heater	?		?		?		Y	

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INTERROGATORY #14

QUESTION:

Reference: Exhibit L.EGD.GEC.2, Page 12, Table 5.

a. Please confirm whether this table lists incremental or total achievable savings.
b. Please provide the sources, assumptions and calculations used to calculate the peak hour savings.

RESPONSE:

a. Table 5 shows incremental annual savings, where the term “incremental” refers to the fact that the savings are only the first year savings associated with the efficiency measures installed in that year. Consider a hypothetical example in which the utility caused one efficient boiler, with annual savings of 1000 m^3, to be installed in each of 2014, 2015 and 2016. In that example, the incremental annual savings in each year would be 1000 m^3. That is what we have depicted. In contrast, because the boiler has a long life and will therefore produce savings for many years, the cumulative annual savings would be 1000 m^3 in 2014, 2000 m^3 in 2015 and 3000 m^3 in 2016. We have not shown cumulative annual savings.

If the question refers to whether the savings are incremental to those that the Company would achieve with its own programs, the answer is that they are not incremental. They are the total annual savings that would be produced from each year’s total DSM activity. That is explained in the text preceding the table in which, for example, we note that the roughly 23,000 m^3 peak hour savings estimated for 2014 represent about a 9,000 m^3 increase over the roughly 14,000 m^3 we estimated for Enbridge’s forecast DSM efforts for that year.

b. The peak hour savings are calculated from our estimates of annual savings, using the ratios of peak savings to annual savings, by sector, calculated in Table 1 of our evidence. As noted in the footnote to Table 1, those ratios were computed by dividing the peak hour loads by sector provided by Enbridge in Exh. I.A4.EGD.ED.3 into the annual gas use by sector provided by Enbridge in Exh. JT2.36. The calculation was performed using 2013 values. However, the ratios remain relatively unchanged through 2025.

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INTERROGATORY #15

QUESTION:

Reference: Exhibit L.EGD.GEC.2, Page 11, par 1

> *"For comparison purposes, in its 2008 Update of natural gas efficiency potential in the Enbridge service territory, Marbek projected that after 10 years Enbridge could cost-effectively save 5.0% of its residential load under a $20 million annual DSM budget scenario, 5.7% under a $40 million annual DSM budget scenario and 7.5% under a scenario in which budgets were constrained only by whether the savings targeted were cost-effective."*

a. Please confirm that the Marbek Study residential potential cited is based on the list of measures on page 30 of the Marbek report.
b. Please confirm that only some of the measures would be considered as typical measures in a home retrofit program.
c. Please describe the cost effectiveness test which was used by the Marbek study.
d. Please provide the definition of that cost-effective test and its components as stated in the study report.
e. Does the cost-effective test used include all the utility's DSM program costs?
f. Does it include the cost of incentives provided to program participants?

RESPONSE:

a. "Exhibit 3.15 (the list of measures on page 30 of the Marbek study) presents the 2017 results by upgrade technology or measure…."[1]
b. While, almost all of the measures listed either are currently offered or have been offered through residential energy efficiency programs, it is accurate to say that only some of them would be considered typical measures in a home retrofit program. However, the number of measure types that are applicable to a retrofit program has little relevance to our testimony. Approximately three-quarters of the savings shown in the referenced table are associated with measures commonly installed through home retrofit programs.
c. The study states that its authors used the Total Resource Cost (TRC) test: "Cost effective for the purposes of this study means that a measure has a positive TRC."[2]
d. "The measure TRC calculates the net benefits that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual

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[1] Exhibit 1.A4.EGD.ED.14, Attachment, p28.
[2] Ibid, p6

energy, water, and equipment O&M costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity, and water supply costs, the life of the technology, and the selected discount rate which in this analysis has been set at 9.14%."[3]

e. "Salary and related overhead costs are not included…."[4] However estimates of fixed program costs such as "…advertisement, preparation of information and marketing materials, training workshops, contractor certfications, etc." were estimated by Enbridge personnel and included in the calculations. Given that in the $20M residential budget scenario Marbek estimated that it would cost the program only $0.42 per dollar of gross TRC benefits[5] – and that number presumably includes financial incentives which are not costs under the TRC – there should be ample room to include reasonable salary and overhead costs and remain cost effective.

f. Incentives have no impact on cost effectiveness using the TRC test as that test looks at capital costs regardless of who is responsible for paying them. However, incentive cost estimates were included as part of program budget estimates for the financially constrained scenarios.[6]

[3] Ibid, p4.
[4] Ibid, p26.
[5] Ibid, p32.
[6] Ibid, p26.

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INTERROGATORY #16

QUESTION:

Reference: Exhibit L.EGD.GEC.2, Page 13, par 2

"The principal difference between the expanded portfolio and the Company's current portfolio is that the Company would need to achieve much greater market penetrations of the measures it is currently promoting."

a. If DSM were used to defer capital investment required to meet growth and/or system reliability needs, what level of certainty would be required of the DSM results?
b. Would current practices regarding DSM evaluation and audit need to change? Please explain.
c. Please describe any additional provisions for certainty of DSM results which would be required.

RESPONSE:

a. The certainty of DSM results should be considered in the greater context of system planning, in which many, many assumptions are made. These models are designed to be resilient enough to accommodate some level of variability in the assumptions, and the certainty of DSM results relative to the certainty of the other assumptions should be sufficient to ensure that the reliance on DSM does not unreasonably increase the overall uncertainty of the models.
b. The basic structure of DSM evaluation and auditing in place in Ontario would not need to change. GEC has suggested for years that amount of impact evaluation being undertaken in the province was too low, and we would continue to support the need for some further increase in the level of evaluation activity. However, that would be the case irrespective of whether a GTA focused expansion of DSM took place. To the extent that programs in the GTA area were fundamentally different than other system-wide programs, there would likely be a need for some additional evaluation studies. To the extent that the programs in the GTA were largely expansions of existing programs, it may be appropriate and valuable in some cases to over-sample the GTA participants so that statistically significant results would be available for both Enbridge's entire service territory and the GTA portion of it.
c. No additional provisions would be required.

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INTERROGATORY #17

QUESTION:

Preamble:
Exhibit L.EGD.GEC.2, Page 13, paragraph 2 states:

"In general, that combination of strategies would lead to greater levels of DSM spending."

Additional Preamble:

Community Energy Retrofit (CER) is a new program introduced in 2012 by Enbridge for the Residential market. It is described in EB-2011-0295 DSM Plan submission to the Board. The 2012 results from the Community Energy Retrofit program show the following:

- o Total program cost - $817,000
- o Total annual m3 savings – 225,000
- o Average incentive cost/m3 - $3.63
- o Average TRC – 0.6

a) Please confirm that GEC was involved in the discussions leading to development of the CER program.
b) Please confirm that the terms of the program require that, in order to be eligible for the incentive, the participants: 1) implement at least 2 major measures, 2) achieve at least a 25% reduction in gas consumption.
c) Using the information from Table 5 on page 12 and the CER results above, please estimate the annual cost of incremental DSM from an accelerated home retrofit program in 2014, 2015, and 2016.

RESPONSE:

a) GEC was involved in discussions leading up to the commitment to implement a non-low income residential retrofit program, as well as discussions leading to the development of the shareholder incentive metrics that are attached to the utility's implementation of the program. GEC was not involved in discussions that may have led to the specific design of the program.

b) The program requires that each participant implement at least two major measures. It does not require that each participant achieve a 25% reduction in gas consumption.[1] There is a program

[1] EB-2012-0394, Exh B., Tab 1, Schedule 3.

performance metric that rewards the utility's shareholders if they meet certain participant goals so long as the *average* savings across all the participants is 25% of baseline space heating and water heating gas usage. Individual participants can have lower savings percentages.

c) First, we have not seen evidence in this proceeding to suggest that the data cited regarding CER performance in the question are accurate. Indeed, there appears at least one problem with the data. Specifically, \$3.63 appears to be the *total cost* per m^3 saved, not the *incentive cost* per m^3 saved. No more than half of the expenditures are likely to have been associated with incentive costs.[2] Second, we are not proposing that the CER program as initially designed and implemented in 2012 be the program that the Company would implement at a large scale. Finally, even if we were suggesting that the CER program design be the basis for an expanded effort, it would be completely inappropriate to take the results from what was essentially a pilot year, with fewer than three hundred participants and lots of initial start-up costs (and therefore high overhead costs per participant without any accounting for economies of scale), and suggest that the costs per unit of savings would then be applicable to a significantly expanded effort. Indeed, it is worth noting that the utility's own 2013 and 2014 DSM plan estimates that the program would have a benefit-cost ratio of greater than 1.1[3] – roughly double the 0.6 suggested in the question – even with a level of participation that is considerably lower than we have suggested in our evidence (the larger the participation, the greater the economies of scale).

[2] In its draft 2012 DSM Evaluation Report, the Company reported that the CER program had 271 participants in 2012. It also stated that the program "…offered qualifying customers \$150 towards the initial audit and up to \$1,100 in incentives."

[3] EB-2012-0394, Exh. B, Tab 2, Schedule 3.

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INTERROGATORY #18

QUESTION:

Exhibit L.EGD.GEC.2, Page 14, paragraph 1 states:

> *"However, given the cost-effectiveness of Enbridge's current DSM portfolio, we would be surprised if the net economic benefits of the significant DSM expansion we have suggested were not at least $1 billion over the next 12 years."*

a) Please clarify which cost-effectiveness test is referred to. Is it the Program Administrator test, the Ratepayer Impact test, or the Total Resource Cost test?
b) Please describe the cost and benefit components evaluated in the test used.
c) Does the test referred to compare the utility's DSM program costs with the deferred cost of capital investment?
d) Based on the cost effectiveness of the CER program shown in #14, please identify the impact on cost effectiveness.

RESPONSE:

Note that there was an error in this statement and that GEC is filing a correction. The statement should have read: "…at least $0.5 billion – not including any additional benefits from deferring capital expenditures associated with the proposed pipeline project – over the next 12 years."

a) The Total Resource Cost test.
b) The cost and benefit components are the same as those used in Enbridge's screening of its DSM programs. As the corrected statement above makes clear, the estimate of $0.5 billion in net benefits (i.e. the total benefits minus the total costs) excludes any benefits from deferring any capital investment associated with proposed pipeline project. Put another way, any such deferral benefits should be added to the at least $0.5 billion.
c) See response to "b" above.
d) Please see response to EGD Interrogatory #17, where CER program cost-effectiveness is addressed.