STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

Petitions of Vermont Electric Power Company, Inc. and Green Mountain Power Corporation for a Certificate of Public Good authorizing VELCo to construct the so-called Northwest Vermont Reliability Project, said project to include: (1) upgrades at 12 existing VELCo and GMP substations located in Charlotte, Essex, Hartford, New Haven, North Ferrisburg, Poultney, Shelburne, South Burlington, Vergennes, West Rutland, Williamstown, and Williston, Vermont; (2) the construction of a new 345 kV transmission line from West Rutland to New Haven; (3) the construction of a 115 kV transmission line to replace a 34.5 kV and 46 kV transmission line from New Haven to South Burlington; and (4) the reconductoring of a 115 kV transmission line from Williamstown, to Barre, Vermont	**Docket No. 6860**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

DECEMBER 17, 2003

Mr. Chernick's testimony describes numerous problems in VELCo's analysis of alternatives to the NRP, and in VELCo's past and present planning process. He describes the distributed resources that are likely to comprise much of a real least-cost solution to Northwest Vermont's reliability problems. He also explains that more recent forecasts of Vermont load predict slower peak load growth than anticipated in VELCo's planning for the NRP, allowing more time for non-transmission solutions to address reliability needs.

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EXHIBITS

I. Identification and Qualifications

Q1: Mr. Chernick, please state your name, occupation and business address.

A1: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts.

Q2: Summarize your professional education and experience.

A2: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit CLF PLC-1.

Q3: Have you testified previously in utility proceedings?

A3: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

Q4: Have you testified previously before the Vermont Public Board?

A4: Yes. I testified in the following cases:

- Docket No. 4936, on Millstone 3;
- Docket No. 5270 on DSM cost-benefit test, pre-approval, cost recovery, incentives, and related issues;

- Docket No. 5330, on the conflict between the HQ purchase and DSM;
- Docket No. 5491, on the need for HQ power and the costs of alternative purchases;
- Docket No. 5686, on the avoided costs and water-heater load-control programs of Central Vermont Public Service (CVPS);
- Docket No. 5724, on CVPS avoided costs;
- Docket No. 5835, on design of CVPS load-management rates;
- Docket No. 5980, on electric-industry restructuring and avoided costs;
- Docket No. 5983, on the prudence of Green Mountain Power's decisions regarding the HQ contract, avoided costs, and distributed utility planning;
- Docket No. 6018, on the prudence of CVPS's decisions regarding the HQ contract, avoided costs, and distributed utility planning;
- Docket No. 6107, on the prudence of GMP's decisions regarding the HQ contract and distributed utility planning;
- Dockets Nos. 6120 and 6460, on the prudence of CVPS's decisions regarding the HQ contract;
- Docket No. 6545, on the sale of the Vermont Yankee nuclear power plant to Entergy Nuclear Vermont Yankee;
- Docket No. 6596, on the prudence of Citizens Utilities's decisions regarding the HQ contract, including the role of transmission constraints in that decision and its consequences.

Q5: Have you been involved in other aspects of utility planning and regulation in Vermont?

A5: Yes. My other activities have included the following

- participation in the CVPS and Vermont Gas DSM collaboratives;

- preparation of testimony on the avoided costs of Green Mountain Power in Docket No. 5780, not presented due to settlement of the case;
- assisting the Department of Public Service (DPS or the Department) in the power-supply negotiations of the externalities investigation;
- providing consulting support to the Vermont Senate on stranded costs and Vermont Yankee economics;
- assisting the Burlington (Vermont) Electric Department on distributed utility planning;
- assisting the Department in the statewide collaborative on distributed utility planning, and in the Southern Loop and Stratton area-specific distributed utility planning collaboratives.

Q6: Are you the author of any publications on utility planning and ratemaking issues?

A6: Yes. I am the author of publications on rate design, cost allocation, cost recovery, cost-benefit analysis, and other ratemaking issues. Several of my recent papers and report deal with issues in electric and gas industry restructuring, including integrated resource planning and performance-based ratemaking. These are listed in my resume.

II. Introduction and Summary

Q7: On whose behalf are you testifying?

A7: My testimony is sponsored by the Conservation Law Foundation.

Q8: What is the purpose of your direct testimony?

A8: My testimony reviews aspects of the proposal of the Vermont Electric Power Company (VELCo) to construct the Northwest Reliability Project (NRP), the largest components of which would be a 345-kV transmission line from West Rutland to New Haven and a new 115-kV transmission line from New Haven to Queen City. Specifically, I examine whether distributed resources could cost-effectively defer or avoid elements of the NRP, and whether VELCo has adequately examined the potential for distributed resources to reduce its cost of providing service.

Q9: What do you mean by distributed resources?

A9: Following the practice of the Vermont Department of Public Service (DPS) and utilities in the Distributed Utility Planning Collaborative, I include the following in this category:

- investments to improve end-use energy efficiency;
- the practice of switching end uses from electricity to other fuels;
- controlling loads through interruptible contracts, direct load control, and similar mechanisms;
- small generating units attached to the distribution system either directly or on customer's side of the meter.

Q10: To what portions of VELCo's filing do you respond?

A10: While I respond to, or otherwise reference, other portions of VELCo's filing and discovery, my testimony deals primarily with

- The testimony of the VELCo System Planning Panel (VELCo Witnesses Cleveland Richards, Hantz A. Présumé, Dean L. LaForest and Richard Hinners) and Exhibit VELCo Planning–6, the Northwest Vermont Reliability Project Critical Load Milestone Study.
- The testimony of the Optimal Energy (OEI) panel (Velco Witnesses John Plunkett, Phil Mosenthal, and Chris Neme) and Exhibit VELCo OEI–1, Assessment of Economically Deliverable Transmission Capacity from

Targeted Energy-Efficiency Investments in the Inner and Metro–Area and Northwest and Northwest/Central Load Zones (the OEI Report).

- The testimony of VELCo Witness Mark Montalvo of La Capra Associates and his Exhibit VELCo MDM-2, Alternatives to VELCo's Northwest Vermont Reliability Project (the La Capra report).

Q11: What do you conclude?

A11: The evidence in this case strongly suggests that load reductions from distributed resources can delay, and potentially avoid, the need for at least major elements of the NRP, such as the 345-kV line from West Rutland to New Haven, while reducing societal costs.

VELCo has not properly considered the potential contribution from additional distributed resources to reduce the need for transmission capacity that it seeks to add with the proposed facilities. Additional load reductions would provide significant benefits to Vermont in terms of congestion costs, total costs of electricity supply, and reliability.

The alternatives to the New Haven–Queen City 115-kV line, which VELCo rejected on the assumption that future transmission expansions are inevitable, and that least-cost planning will not remove local constraints, should be re-examined. The Board should weigh the economic, aesthetic and other tradeoffs among the three alternatives VELCo has identified for the 115-kV line, without VELCo's arbitrary constraints.

The least-cost solution to the emerging supply problems in Northwest Vermont would include enhanced deployment of distributed resources and delay or avoid the major NRP components.

Vermont Electric exaggerates the urgency of the need for major improvements in the transmission situation in northwestern Vermont and obscures the feasibility of distributed solutions by insisting on immediately improving reliability performance to a level not achieved for twenty years and using a load forecast that exceeds the most recent forecast for Vermont produced by NEPOOL and the ISO. To the extent that the situation is anything close to the emergency VELCo portrays, that situation is largely due to VELCo's delay in addressing a problem that has been developing for decades.

Vermont Electric expresses great confidence that the cost of most elements of the NRP would be spread across all of New England, because they have been designated as pool-transmission facilities (PTF), and asserts that the costs of implementing Vermont distributed resources to avoid or defer the NRP must be recovered exclusively from Vermont. Neither outcome is assured. Both the Board and FERC have expressed a preference for treating distributed resources on the same basis as transmission.

NEPOOL and FERC may well change the allocation of transmission costs in the future in a manner that transfers much or all of the costs of the NRP back onto VELCo. In balancing the long-term societal benefits of DSM against the short-term possibility of shifting transmission-expansion costs to other New England ratepayers, the Board should consider the risk that the latter benefits may be ephemeral.

Q12: What are your recommendations to the Board?

A12: I recommend that the Board deny the Company's request for the 345-kV and 115-kV lines and direct VELCo and its owner utilities to pursue vigorously distributed resources and more-modest transmission options to ameliorate the current problems.

The Board should require that VELCo and the distribution utilities serving Northwest Vermont promptly start implementing distributed resources in

Northwest Vermont, to delay the need for the NRP. In addition, the Board should order VELCo to integrate least cost planning into its future transmission planning, and to coordinate its planning with the distributed-utility-planning efforts of the distribution utilities. The Board should require VELCo and the distribution utilities to demonstrate that their coordination will ensure that they identify and acquire any distributed resources that are justified by a combination of deferral of the NRP and other distribution (or sub-transmission) projects, even if for resources that would not be cost-effective for any individual project.

Finally, the Board should instruct VELCo to pursue cost-recovery at NEPOOL and FERC for the costs of the distributed resources in the least-cost solution in the same manner that NEPOOL has accepted for the NRP.

III. Statement of the Problem

A. VELCo's Transmission Problems

Q13: Please describe the transmission problems in Northwest Vermont that VELCo's NRP is intended to solve.

A13: Vermont Electric states that the Vermont system cannot meet the design and operating reliability criteria of NEPOOL that require sufficient transmission capacity to serve forecasted loads under representative contingencies identified in the criteria, and that apply after any one critical element is lost. According to VELCo, the most serious system double contingency is simultaneous loss of Highgate and the PV-20 line, at high load (Direct Testimony of Planning Panel at 4, 35). As a result, VELCo proposes to build the NRP to provide a fifth high-voltage line into Northwest Vermont.

Q14: How are these problems related to the August, 2003 Northeast blackout?

A14: I do not see any relationship. While VELCo states that the August 2003 blackout only reinforces the justification for the transmission upgrade (LaForest Testimony of 15 October, 2003), the blackout appears to have been caused by poor maintenance, poor communication, and inadequate provision for disconnecting control areas when one is failing. The blackout propagated easily across the well-integrated ISOs in Ontario and New York, and generally stopped at transmission constraints with PJM and New England. If anything, the blackout was a signal that more decentralized generation would be helpful to provide back-up service in the event of transmission or distribution failure (which is inevitable periodically) and to support local restart of generation after grid failures.

B. Timing of Need for the NRP

Q15: When does VELCo estimate that the major elements of the NRP would be required?

A15: According to VELCo, a set of substation improvements totaling about $45 million (including about $27 million to expand the Granite substation) are required immediately. In 2007, VELCo plans to add the New Haven–to–Queen City 115-kV line ($20 million), the West Rutland–New Haven 345-kV line ($29 million) and a second STATCOM at Granite ($10 million) (Exhibit VELCo MDM-2, Appendix I). While VELCo suggests that the projects may help avoid other problems, including regional voltage collapse, its major justification for the 2007 additions revolves around load growth in Northwest Vermont and the assertion that the 345-kV line is required when overall Vermont loads reach about 1,100 MW.

Q16: How long has Northwest Vermont been deficient in capacity?

A16: Vermont has been living with the supply situation in Northwest Vermont for several years. VELCo witness Tom Dunn testifies that "the existing system has deficiencies beginning at the 700 to 800 MW load level (summer peak load levels last experienced in the 1980s)" (Dunn Direct at 12). The method that the La Capra study uses to estimate a deficiency of 64 MW in 2002 (Exhibit VELCo MDM-2, Table 5) would have estimated a deficiency for Northwest Vermont going back to 1998, even with upgrades that have occurred since then. (VELCo response to DPS1-12).[1]

Q17: Is the need as urgent as VELCo suggests?

A17: No. VELCo describes the load and supply situation in Northwest Vermont as though the system were about to hit some sort of wall. VELCo's application is based on a goal of achieving reliability levels that VELCo and Northwest Vermont have lived without for many years. The Board can hardly expect to perform least-cost planning if utilities wait years beyond their professed need date to examine alternatives and request Board approval.

In recent years, VELCo has relied successfully on internal Vermont peaking units and temporary generators at the Sand Bar substation. VELCo has not demonstrated that such short-term procedures would be insufficient to provide interim relief while long-term distributed resources come on line.

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[1]Oddly enough, VELCo (response to CLF2-51a) also argues that these long-standing problems caught it by surprise. "The reliability deficiencies that the NRP seeks to address stem from the change in the Vermont load profile from a winter-peaking one to a dual-peaking one. That transformation took place very rapidly, and was not well-understood until after it had occurred."

Q18: What load and supply conditions does VELCo use to justify the NRP?

A18: In the studies sponsored by the Planning Panel, VELCo determines the year in which the system would be inadequate at the summer peak, if all of the following were true:

- the Highgate converter and the PV20 line (the two largest sources of supply to Northwest Vermont) were out of service,
- water conditions were adverse,[2]
- 1,000 MW happened to be flowing from New York to New England, and
- only 65 MW of generation is dispatched in Northwest Vermont (50 MW at McNeil and 15 MW of hydro), while the 70 MW of combustion turbines and diesels are "assumed held in reserve for loss of McNeil." (Planning Panel Direct at 19, 20; VELCo Exhibit Planning–6 at 5).

Q19: Are these conditions likely to occur at the same time?

A19: No. The double transmission contingency is unusual enough by itself. The Highgate converter has a forced outage rate of about 0.3%, and the PV20 line is probably more reliable still. Most summers do not have adverse water conditions, and the system is near peak on relatively few days in the summer. Large power flows from New York to New England are unusual, especially in the summer. In 2002, flows of 1,000 MW or more from New York to New England occurred for only ten hours, only one of those in the summer.[3] In 2003 (through November 30), flows of more than 1,000 MW occurred for 24 hours, of which two were on June 5 and the rest in January and March.

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[2]Exhibit VELCo Planning-6 says (at 5) "water supply is limited."

[3]There were only fifteen hours with flows exceeding 950 MW.

In sum, the frequency of the combination of all five events (1,000 MW flow from New York to New England, Highgate out of service, PV20 out of service, all in a high-load hour in a dry summer) is extremely rare. In the rare hour in which the system gets close to these conditions (e.g., Highgate out of service, high summer loads, and high flows from New York), reducing imports from New York, running the combustion turbines and diesels, and invoking interruptible contracts would give the system additional slack.

Those conditions might occur for a few hours a decade.

Q20: How much difference does the assumption about load flow from New York make in the timing of the need for the NRP?

A20: Without the stress of the large imports from New York, Exhibit VELCo Planning–6 shows the 345-kV line being needed at 1,145 MW, rather than 1,100 MW, and the second STATCOM at 1,170 MW, rather than 1,140 MW. (Exhibit VELCo Planning–6 , Table 3). Those higher loads occur one to three years later, depending on the load forecast.

Q21: Does the La Capra study use the same critical load-flow assumptions?

A21: The basic approach is similar. While the La Capra study does not provide a cite to the source of its transmission-capacity assumptions, the transfer capability of 384 MW appears to represent the capacity of the two remaining lines after the loss of Highgate and PV20.[4] La Capra assumes 116 MW of generation capacity out of the 356 MW in the region model, which is the capacity that would be available for all but one day in ten years, or roughly 3,649 days out of 3,650 (Exhibit VELCo MDM–2 at 25). The probability of so little generation being

[4]It is not clear whether La Capra adjusted these capacities downward to reflect the rare, adverse large New York–to–New England power flows.

available at the same time that the system is peaking is quite low. Again, occasional operation of interruptible contracts would help reduce risk in these rare circumstances.

C. Load Forecast Issues

Q22: How did VELCo forecast load growth in Vermont?

A22: Vermont Electric's application is based on a forecast prepared by the DPS in August 2002.

Q23: Have you seen a more recent forecast for Vermont loads?

A23: Yes. On October 29, 2003, NEPOOL and ISO-NE filed a zonal forecast through 2012.[5] I attach that document as Exhibit CLF PLC-2. The following table compares the DPS 2002 forecast with the current NEPOOL forecast for summer peak loads:

	DPS 2002	NEPOOL October 2003
2003	1,039	1,010
2004	1,060	1,040
2005	1,073	1,040
2006	1,109	1,060
2007	1,130	1,080
2008	1,145	1,090
2009	1,164	1,110
2010	1,182	1,120
2011	1,202	1,140
2012	1,224	1,160

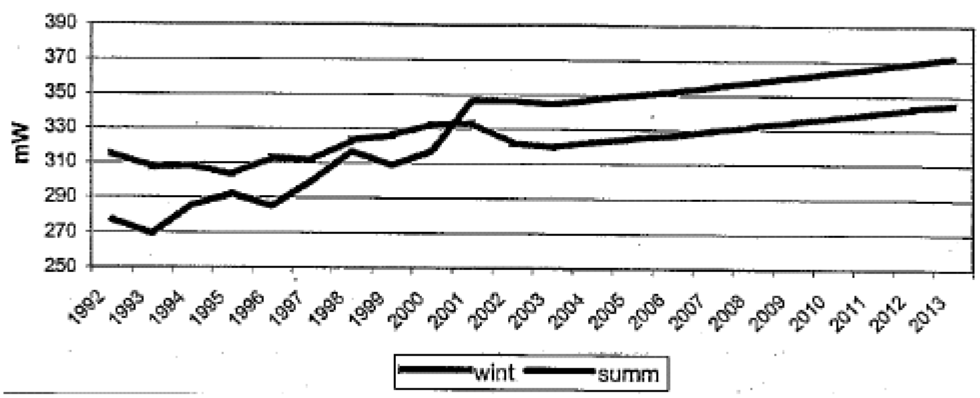
[5]Response to Commission's Questions Regarding Transmission Cost Allocation Proposal for New England, New England Power Pool and ISO New England Inc., FERC Docket Nos. ER03-1141-_____, EL03-222-_____, October 29, 2003, Response 9, at 14 (Filed in this docket as VELCo's Response to DPS2-24).

The loads that the Department expected to be reached in 2007–2009 are now expected three years later.[6]

Q24: Are you aware of any other forecasts of slower summer peak growth in Vermont?

A24: Yes. The IRP filed by Green Mountain Power in August 2003 forecasts summer peak load growth of 0.8%, about a quarter of the historical load growth, as shown below. (The IRP is attached as Exhibit CLF PLC-3). The summer load started 40 MW below the winter load in 1992, and exceeded the winter load by 2002, growing about 80 MW in ten years. In the next ten years, Green Mountain Power forecasts only about 20 MW of growth.[7]

Peak Hour Load by Season (Source: Green Mountain Power 2003 IRP)



Green Mountain Power load is a significant fraction of load in Northwest Vermont.

Q25: What is the significance of slower load growth?

[6]In comparing the load forecasts, I assume that the definitions of "Vermont" are similar. Also, the NEPOOL forecast includes losses to the generation level, while La Capra says that the Department's forecast was for load at the customer meter; assuming that is true, the NEPOOL forecast should be adjusted down by roughly 10% to be consistent with the Department's forecast. The VELCo critical load levels used by La Capra are at the customer level.

[7]"2003 Integrated Resource Plan," Green Mountain Power, August 14, 2003, at 25–27.

A25: The NEPOOL forecast suggests that the need date for the expensive NRP lines is more likely 2010, or 2011, for service reliability equivalent to that in the VELCo application. This gives more time for development of a least-cost plan and deployment of distributed resources.

D. Adequacy of Distributed Resources to Defer the NRP

Q26: Would distributed resources be able to displace significant portions of the NRP?

A26: It certainly appears so. By 2010, the DSM plan La Capra assumes in its study (Exhibit VELCo MDM–2) would reduce Northwest Vermont load by 73 MW, which would be equivalent to about 130 MW load reduction for Vermont as a whole.[8] The following table computes the equivalent statewide load for the 2002 Department forecast and the DSM identified by La Capra:

	DPS 2002 Forecast	NW VT DSM	State Load Equivalent	Net Effective Load
2003	1,038.5			1,060
2004	1,060.0			1,070
2005	1,073.3	2	3	1,092
2006	1,108.6	9	16	1,091
2007	1,129.9	22	39	1,077
2008	1,145.2	38	69	1,060
2009	1,163.5	58	103	951
2010	1,081.8	73	131	1,047
2011	1,202.1	87	156	1,048
2012	1,224.4	99	176	1,033

[8]Northwest Vermont is about 56% of Vermont load. For the purposes of timing the need for the NRP, one MW of load reduction in Northwest Vermont is equivalent to 1.8 MW of lower statewide forecast.

The net load peaks in 2005, and then falls, consistently staying below

- the 1,100 MW level that VELCo has identified as the "critical load" at which the 345-kV line would be needed;
- the 1,140 MW level that VELCo has identified as critical for the second STATCOM,
- the 2007 load levels at which VELCo was planning to add those NRP components.

Q27: How would the lower, updated load forecast affect the adequacy of the NRP?

A27: With the current NEPOOL load forecast for Vermont, the VELCo DSM program would have even more dramatic effects on the need for the NRP:

	NEPOOL 2003 Forecast	NW VT DSM	State Load Equivalent	Net Effective Load
2003	1010			1,010
2004	1040	2	3	1,037
2005	1040	2	3	1,037
2006	1060	9	16	1,044
2007	1080	22	39	1,041
2008	1090	38	69	1,021
2009	1110	58	103	1,007
2010	1120	73	131	989
2011	1140	87	156	984
2012	1160	99	176	984

The net effective loads peak in 2006, barely above the VELCo load forecast for 2003, and decline to under 1,000 MW by 2010.

Q28: Do these comparisons reflect the maximum potential for distributed resources in reducing the NRP ?

A28: No. The DSM program included in the portfolio that the La Capra designates as Alternative Resource Configuration 5, or ARC5 (Exhibit VELCo MDM-2, at 83), considers only targeted DSM programs for the Inner and Metro zones from the DSM study performed by Optimal Energy (VELCo Response to CLF1-17, 1-47).[9] (The important discovery responses I cite are included as Exhibit CLF PLC-4). Optimal Energy's conservative estimate of the effects of aggressive DSM initiatives for *all* zones (Inner and Metro zones and Northwest and Northwest/Central zones) results in much higher peak-load reductions, as I discuss below in Section V.A.

In addition, the comparisons above do not reflect any distributed generation or load management.

IV. Vermont Electric Company's Planning Process

Q29: Has VELCo acted in a reasonable and timely manner to determine the least-cost solution for the transmission problems that have developed over the past decades?

A29: No. VELCo took no specific actions, with its owner utilities, to evaluate, plan and implement a least-cost approach that includes use of distributed-resource planning. VELCo has not prepared an integrated resource plan, or participated actively in the Distributed Utility Planning efforts, or developed any alternative least-cost planning process. Instead, VELCo looked only at incremental steps to optimize the existing transmission infrastructure, such as the Essex FACTS, and then pursued transmission-only approaches, such as the Northern Loop

[9]The La Capra Study adds line losses of at least 6.25% to the OEI savings, so the figures in Exhibit VELCo MDM-2 are a bit higher than in Exhibit VELCo OEI-1.

(VELCo response to DPS1-12b). Only when the Department demanded that VELCo perform an alternatives analysis in 2002 did VELCo perform a last-minute, inadequate, alternative analysis. However, by this time, VELCo appears to have been firmly committed to the NRP transmission solution. As I describe throughout this testimony, the La Capra analysis does not reflect a serious effort to identify a least-cost alternative.

Q30: How should VELCo and its owner utilities have responded to anticipated constraints on the transmission system?

A30: The utilities should have approached this major investment as an opportunity for least cost planning. They should have started much earlier to seek distributed resources (as well as transmission alternatives) that would avoid or defer the NRP transmission additions at a lower net cost. They should have included load management and distributed generation, as well as DSM.

The utilities also should have integrated the planning and alternatives analysis for the NRP with the area-specific distributed-utility-planning efforts in Northwest Vermont. Under their Memorandum of Understanding with the Department in Docket 5980, each distribution utility committed to engage in least-cost transmission-and-distribution planning and to implement such plans effectively. The utilities were to identify areas where strategic DSM and distributed generation could delay or avoid transmission investments. The first group of those analyses is underway, and could be contributing to the solution of the Northwest Vermont reliability problems.

For example, if the Milton-area DUP collaboratives identified particular distributed resources whose contribution to avoiding the distribution and sub-transmission upgrades in the Milton area did not quite justify their deployment, those resources may still be cost-effective when their contribution to deferring the NRP is added in. If the DUP collaborative does not recognize the benefits for deferring the NRP, and VELCo does not recognize the benefits for resolving the Milton problems, the distributed resources might never be implemented, even though they could have been part of a cost-effective plan to defer both the NRP and distribution investments. Indeed, the distributed resources that are cost-effective even without credit for deferring targeted T&D investments might well be implemented *after* the T&D investments that they could have deferred have already been built.

In addition, Green Mountain Power should be conducting a DUP analysis for reconductoring its 34.5-kV line from Queen City to Charlotte, if that project is really expected to be required by 2006 (VELCo Response to DPS1-6). Load reductions that defer that upgrade would also contribute to deferring NRP components.

Vermont Electric's response to discovery on its failure to coordinate with the DUP collaboratives indicates no understanding of integrated planning, and acknowledges that its analysis "did not incorporate any specific distributed resources that may be proposed as part of the Area-Specific Collaboratives between the distribution utilities and the DPS" (VELCo response to CLF2-38, 2-39).

Q31: Vermont Electric asserts, "VELCo is not allowed to participate in the Area-Specific Collaboratives because VELCo does not supply any load" (VELCo response to CLF2-39). Do you agree?

A31: That is not my recollection of the situation, as a consultant to the Department in the negotiations that led to the Area-Specific Collaboratives (ASCs) and in the Stratton and Southern Loop ASCs. Other entities that "do not supply any load" in the sense that distribution utilities do (such as the Stratton Corporation) were formal participants in the specific ASCs. Further, Green Mountain Power's 2003 Integrated Resource Plan reports that "VELCo, GMP and other area utilities are currently involved in a 34.5-kV to 115 k…transmission-upgrade ASC study…" (Exhibit CLF PLC-3 at 38), so Green Mountain Power appears to believe that VELCo can and is participating in an ASC.

Q32: What is the effect of VELCo's delay in seeking a least-cost solution to the supply concerns in Northwest Vermont?

A32: The delay leaves less time for the analysis and deployment of distributed resources. VELCo now argues that it lacks the time to implement what *could* have been the least-cost option, because DSM can no longer be deployed rapidly enough, and that the NRP is now the only feasible solution (except perhaps for the second STATCOM).

As a matter of fact, any solution to the problems identified in Northwest Vermont—transmission, distributed resources, central generation, or a mix—will take many years to implement, and there still appears to be time to implement a solution with lower total cost than the NRP. More importantly, the effect of VELCo's behavior is to reduce the Board's options, by playing chicken with reliability.

Q33: Does the La Capra study consider distributed-resource alternatives to the two transmission-line upgrades proposed as part of the NRP?

A33: No. The La Capra study treats the substation improvements and the 115-kV line upgrade from New Haven to Queen City as unavoidable, since loads are already above the levels at which VELCo has declared those facilities to be required. The study also treats the 345-kV line as unavoidable, although that decision appears to have been based on the authors' misconception that VELCo had declared the 345-kV line to be required in 2005, rather than the 2007 date that VELCo has actually adopted.

Q34: Has VELCo adequately explored alternatives to the 115-kV line upgrade from New Haven to Queen City?

A34: No. As I noted above, VELCo dismissed the feasibility of non-transmission alternatives to the 115-kV upgrade, based on the timing problem VELCo has created. This line was included in each ARC portfolio in the La Capra study. Independent of the La Capra study, VELCo has considered at least two transmission alternatives, as follows:

- Reconductoring of the existing Green Mountain Power 34.5-kV line that occupies the right-of-way that the proposed 115-kV line would use along most of its length from New Haven to the Burlington area (Response to DPS 1-10, 2-56).
- Constructing a second 115-kV line along the current 115-kV corridor from New Haven to Williston (Response to DPS 1-6, 2-56).

Vermont Electric cites multiple reasons for rejecting each of these alternatives, including tradeoffs in aesthetics and right-of-way issues. I would expect that, if these tradeoffs were the important considerations, VELCo would express its opinion, but put the choice among the alternatives before the Board. VELCo also argues that its 115-kV proposal would receive cost-sharing from the rest of New England's ratepayers, while the 34.5-kV reconductoring option would not. But the decisive points in VELCo's rejection of the alternatives appear to be the following two issues related to planning:

- Vermont Electric declares both alternatives to be "inconsistent with VELCo's long range plan" (Response to DPS 1-6 and 1-10). Specifically, VELCo intends to build the 115-kV line from New Haven to Queen City, and not build the additional 115-kV line from New Haven to Williston, because it has plans for a 345-kV line on the New Haven–Williston corridor in 2016 or 2017, when VELCo anticipates Vermont load reaching 1,400 MW. To further this plan, it needs the space in the New Haven–Williston corridor and wants the new 115-kV line from New Haven to Queen City so that the existing New Haven–Williston 115-kV line can be removed while the New Haven–Williston 345-kV line is built. (Ibid.)

- Each of these alternatives would leave unsolved local load-related transmission or distribution problems: the need for an "another VELCo source into Burlington" (Response to DPS1-10a), and the need to reconductor the GMP line from Queen City to Charlotte in 2006 to accommodate expected load growth (Response to DPS1-6(c)).[10]

Vermont Electric's reasoning about the first point is circular: VELCo rejects least-cost planning for its current project, because it has already decided to build, rather than avoid, a future project, without conducting least-cost planning on the future project or the combination of the two projects, and without seeking Board approval of the later project. VELCo declares that it need not perform least-cost planning for the New Haven–to–Queen City 115-kV line because it does not intend to perform least-cost planning for the New Haven–to–Williston 345-kV line. This really turns least-cost planning on its head and assumes that the Board will act as though it had already approved a transmission project scheduled for 2016–2017. VELCo effectively asserts the right to do what

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[10]The VELCo response to DPS1-10a references the "EPRO East Chittenden County Phase II study" in Attachment DPS1-VELCo-6c, but that attachment finds that the Digital Injection project would satisfy the need for increased VELCo supply. It is thus unclear what analysis VELCo believes supports the need for the New Haven to Queen City 115kV line.

it wants now, so that it will be prepared to do what it wants later. VELCo's treatment of the New Haven–Williston 345-kV expansion in 2016 as unavoidable is one glaring example of a broader problem: VELCo's failure to commit to the use of distributed resources to delay post-NRP additions, as I discuss below.

Similarly, VELCo's arguments about local needs demonstrates its failure to take least-cost planning seriously. VELCo should have recognized that the load reductions that could defer the later portions of the NRP could also defer the need for those local projects within Northwest Vermont.

Q35: Has VELCo adequately considered the benefit of delaying decisions to commit to the NRP?

A35: No. Each year of delay avoids the annual carrying costs associated with the NRP investment. Deferring $100 million of the NRP investment (assuming about $20 million is non-deferrable) in the NRP by one year would reduce the present value of transmission revenue requirements by at least $10 million. VELCo considers deferral value only for the $10.3 million second STATCOM, at $2.3 million annually.

In addition to the time value of money, the value of delay includes the benefit of additional information about load and supply, and changing technology. For example,

- As New England load and capacity come back into balance around the end of this decade, new central generation may be developed in Northwest Vermont, reducing the need for transmission upgrades.
- Additional transmission technologies may be commercialized, changing the nature and cost of the least-cost transmission alternative.

- Small distributed generation units (microturbines, Stirling, fuel cell, photovoltaics or other technologies) may become economic and widely accepted, leading to reductions in load.

Delay in committing capital can be extremely valuable in avoiding decisions that turn out to be sub-optimal, such as building for load that never materializes.

Q36: Has VELCo identified and implemented changes in its planning process to avoid a repeat of the problems with its current application?

A36: No. In response to a request to "state if, when, and how VELCo has changed its procedures to ensure that decisions about resource deployment, including DSM, can take place in time to allow the implementation of the least-cost alternative for future projects," VELCo suggests that someone else will take responsibility for least-cost planning:

> In New England, the Regional Transmission Expansion Plan (RTEP) process is in place and operating to identify locations in New England where system reliability is in jeopardy of not meeting regional criteria, such as northwest Vermont and southwest Connecticut. This process through regularly held meetings of the Transmission Expansion Advisory Committee (TEAC), open to all, highlights critical problems through detailed presentations by ISO-NE personnel and others. All market participants, including generators, load response aggregators, suppliers, merchant transmission builders, DSM providers, etc. are effectively invited to propose solutions to the problems presented.

VELCo response to CLF2-51 (d).

Vermont Electric also suggests that someone else should have performed the least-cost planning for the NRP:

> A VELCo RFP [for NRP alternatives] would be duplicative of the NEPOOL/ISO Regional Transmission Expansion Plan process, which is essentially an open invitation to any entity to propose and implement market-based solutions to any of the deficiencies identified in the plan. The NRP was discussed in RTEP01 and was formally made a part of RTEP02. No party has approached VELCo, and to VELCo's knowledge, no party has approached ISO-NE, with proposals that address the reliability issues to which the NRP is directed.

VELCo response to CLF2-27k.

Vermont Electric does not identify the entity that would assemble the least-cost plan that VELCo has been unwilling to develop, or utilize the VELCo and NEPOOL tariff financing and engineering staff, or incorporate the Board's values for externalities and risk mitigation.

Q37: Does VELCo expect that the NRP would resolve the transmission constraints in Northwest Vermont for the foreseeable future, so that there will be no more important projects to do least-cost planning for?

A37: No. With the forecast VELCo uses in this docket, VELCo projects that transmission reliability in Northwest Vermont would fall below NEPOOL's reliability criteria in 2012. Under VELCo's own assumptions, the NRP resolves Northwest Vermont's reliability need for about four years. VELCo expects to meet that need by upgrading the New Haven–to–Williston line to 345-kV. VELCo's reluctance to consider any alternative to the 115-kV line upgrade from New Haven to Queen City appears to be motivated primarily by the desire to facilitate the construction of the New Haven–Williston 345-kV line.

Q38: Has VELCo committed to prudent least-cost planning to delay the New Haven–Williston 345-kV line?

A38: No. Despite its experience with the NRP, where VELCo claims that it is too late to implement least-cost distributed resources to defer the transmission alternatives, VELCo apparently intends to repeat that pattern with the New Haven–Williston line. VELCo states that it "has not developed proposals to extend the life of the project" because such decisions "would require the involvement of several parties in addition to the ones presently involved in the NRP docket" (VELCo Response to CLF1-11). VELCo attempts to excuse its failure to engage in least-cost planning by asserting that it should be undertaken by the ISO in the RTEP process, with "all market participants," while simultaneously complaining that VELCo cannot effectively coordinate least-cost planning of its own facilities with its owners and Efficiency Vermont.

On these flimsy grounds, VELCo has renounced any serious effort to use distributed resources to defer additional transmission upgrades. VELCo's approach appears to consist of the following steps:

- Do nothing about least-cost planning for anticipated transmission additions for which construction start is not imminent;
- Wait until the transmission system falls close to or below VELCo's standards;
- Tell the Board that it is too late to gather information on distributed generation, expand DSM programs, or solicit resources, since decisions about ordering equipment and starting construction must be made immediately;
- Do nothing about least-cost planning for anticipated future transmission additions that do not require near-term construction, and repeat the cycle indefinitely.

Q39: Has VELCo taken steps to create the institutional framework for implementing a least-cost alternative to a future transmission addition?

A39: No. In discovery, VELCo states that "It…remains unclear, whether and how VELCo could manage or implement a non-transmission-based solution." (VELCo response to CLF2-27k).

VELCo asserts that it is currently "prohibited from participating in implementing generation, DSM, and load management programs," because "To participate in DSM or load management programs, VELCo would probably first have to amend its Articles of Incorporation. To participate in any of the activities, VELCo would probably first have to amend its tariffs" (VELCo response to CLF2-59). While the tariff amendment might seem to be a trivial barrier, the limits of the VELCo tariff is one of VELCo's justifications for neglecting distributed resources: "VELCo made the decision to mobilize the resources and institutions that had the known capability of addressing the problem, i.e., the transmission planning staffs at VELCo and NEPOOL and the financing capabilities made possible by the VELCo and NEPOOL transmission tariffs" (VELCo response to CLF2-27k). VELCo does not appear to have taken any steps to amend its Articles of Incorporation or its tariffs, suggesting that VELCo has no interest in pursuing distributed resources.

Q40: How do you recommend that the Board respond to VELCo's position on least-cost planning and acquisition of least-cost resources?

A40: The Board should reject VELCo's behavior and clearly establish that it will not tolerate non-compliance with the Board's rules and state law requiring the planning and acquisition of least-cost resources. Accepting and rewarding VELCo's imprudence in this case, and VELCo's announced intention to continue its imprudence, would set a disturbing precedent and signal the distribution utilities that they also need not comply with Vermont law and Board rules when those are inconvenient.

V. Potential for Distributed Resources

Q41: Did VELCo adequately analyze distributed resources in its Application?

A41: No. VELCo (and its consultant La Capra) did not adequately evaluate DSM or distributed generation, ignored load management and demand response programs, and failed to coordinate the NRP analysis with the distribution companies' Distributed Utility Planning efforts.

A. Energy Efficiency and Fuel Switching

Q42: Did Optimal Energy's analysis for VELCo include all the DSM potential identified by the Department study "Electric and Economic Impacts Of Maximum Achievable Statewide Efficiency Savings 2003-2012," also performed by Optimal Energy?

A42: No. Optimal Energy's study for VELCo was significantly more conservative in estimating savings than its statewide study for the Department (Exhibit CLF PLC-5). For example, Optimal Energy's study in this proceeding excluded two whole categories of efficiency savings from the Department's statewide study: emerging technologies and measures that depend on regional or national upstream efforts. While more caution must be applied in projecting the timing of deployment for particular technology and regional cooperation for the short term than for a longer-term study, some efficiency-technology improvements and some regional efforts are likely over the next five to ten years, the relevant period for the later parts of the NRP under various load forecasts.

Also, unlike its study for the Department, Optimal Energy's study for VELCo does not provide a best estimate of achievable savings, which may be high or low. Rather, it produces a very cautious, conservative estimate of achievable savings. By design, the estimate in Exhibit VELCo OEI-1 is very likely to be too low. To achieve this conservative estimate, OEI "reduced and slowed the measure penetration rates projected over time in the Department's statewide analysis (Exhibit VELCo OEI-1 at 12, VELCo Response to DPS1-87).

Q43: Does the La Capra study include all the savings identified in Optimal Energy's analysis of Northwest Vermont's DSM potential?

A43: No. Optimal Energy estimated savings for four parts of Northwest Vermont: Inner Metro, Outer Metro, Northwest (which includes the Northwest South, Northwest East and Northwest North in Appendix 2-1 to Exhibit VELCo MDM-2) and Northwest-Central. La Capra included in its portfolio ARC-5 only the savings Optimal Energy identified for the Metro zones.

Mr. Montalvo acknowledges that "an exclusive DSM option was not analyzed" (VELCo response to CLF2-5(b)). Mr. Plunkett agrees that the VELCo alternatives "analysis did not include all potential efficiency technologies that could be deployed in the inner and metro zones" and "did not include DSM resource options, including demand-response, load management, etc." The only alternative considered by VELCo that includes DSM, ARC 5, "does not include the economically achievable savings from efficiency in areas adjacent to the inner/metro load zones" (VELCo Response to CLF1-61).

Q44: What was La Capra's rationale for excluding the savings from the Northwest and Northwest-Central areas?

A44: Mr. Montalvo explains that Optimal Energy's conservative estimates of the potential load reductions in the Northwest and Northwest-Central zones were not included in his analysis of alternatives because they were not necessary to defer the small portion of NRP resources that he defined as deferrable (VELCo response to CLF1-17; CLF2-40).[11]

Q45: Does the La Capra study consider the option of deferring all the elements of the NRP?

A45: No. The La Capra study, by design, is an exercise in trivializing DSM's role in deferring the transmission investments.

La Capra compared the costs of DSM only to the costs of the second STATCOM at the Granite substation. The study treated the substation improvements and the 115-kV transmission line from West Haven to Queen City as unavoidable because VELCo has declared them to already be needed.

La Capra's justification for treating the 345-kV line as unavoidable is more obscure and ultimately arbitrary. The study acknowledges that "a drop-off in demand growth could allow the construction of the West Rutland–New Haven 345-kV line to be delayed for a few years," but declares that "we are of the view that the line will be needed and that the risk (and costs) of not having the line in service in a timely manner far outweigh the three or four years of avoided carrying charges" (Exhibit MDM-2 at 6). La Capra goes so far as to assert that "Given the magnitude of the need in 2005 and the ramp up schedule of the 'Max Achievable' DSM savings, either the West Rutland–New Haven 345-kV line or the 120 MW of CTs as proposed for the ARCs above should be installed in

[11]Mr. Montalvo also states that "DSM-based load reductions in the Northwest/Central zone will not have a material impact on the load serving capability of the transmission system into Northwest Vermont during the summer on-peak" (VELCo response to CLF2-41a). It is not clear whether he means something by "material" here that is different from his responses to CLF1-17 and CLF2-40.

2005" (Exhibit MDM-2 at 57), even though VELCo has declared the 345-kV line to be needed (and scheduled it for construction) in 2007, *not* 2005.

Mr. Dunn observes that "Mr. Montalvo's analysis demonstrates that the DSM investment in ARC 5 does little to avoid the investments in the major components of the NRP. According to La Capra's analysis, the $270 million investment in energy efficiency only defers the need for the second phase of the Granite STATCOM by eight years, saving approximately $8 million in carrying costs" (Dunn Direct Testimony at 20). Mr. Dunn fails to note that Mr. Montalvo *intentionally* designed ARC 5 to defer only the second phase of the Granite STATCOM, and ignored the possibility of deferring any other NRP investments.

Q46: How does the total DSM potential in Northwest Vermont identified by Optimal Energy differ from that used by La Capra?

A46: The following table shows Optimal Energy's estimates of summer peak reduction for the four zones modeled by Optimal Energy. Following La Capra's assumption, I have lagged the Optimal Energy's savings by one year, reflecting the passage of time since Optimal Energy's analysis was conducted.

Year of Savings		Optimal Energy					La Capra	
		Metro		*Outer NW*				
OEI	La Capra	Inner	Outer	NW	NW Central	Total	Identified[a]	Used[b]
2004	2005	1.1	0.1	0.6	0.8	2.6	1.8	1.2
2005	2006	5.7	0.7	2.7	3.6	12.7	9.1	6.4
2006	2007	13.9	1.5	6.2	8.1	29.7	21.6	15.4
2007	2008	24.5	2.6	11.3	14.9	53.3	38.4	27.1
2008	2009	36	3.8	17.9	23.4	81.1	57.7	39.8
2009	2010	45	4.7	23.7	30.9	104.3	73.4	49.7
2010	2011	52.9	5.4	28.8	37.8	124.9	87.1	58.3
2011	2012	59.1	6.2	33.3	43.6	142.2	98.6	65.3
2012	2013	63.9	6.6	36.8	47.7	155.0	107.3	70.5
2013	2014	67.4	6.8	39.2	51.2	164.6	113.4	74.2

[a]Exhibit MDM-2, Table 12.
[b]Exhibit MDM-2, Table 18, ARC 5 suggests slightly greater savings, including line losses.

None of VELCo's alternative portfolios includes all of La Capra's identified achievable DSM, let alone Optimal Energy's total. VELCo's study of alternatives simply fails to include the full DSM savings that VELCo's own consultants conclude are achievable.

Q47: Optimal Energy's study concludes that the net cost of transmission capacity from demand management programs is negative. Can you explain the meaning and significance of this conclusion?

A47: Yes. At page five of their direct testimony, the OEI panel (Messrs. Plunkett, Mosenthal, and Neme) says that the benefits of the DSM in avoided generation and distribution costs would exceed the costs of the DSM, so the targeted transmission benefits would have no net cost, and indeed would be accompanied by reduced total social costs. From an economic perspective, Vermont should implement the DSM that Optimal Energy identifies, *regardless* of its effect on the NRP.

The benefits of DSM represent an example of joint production, which is really quite common. In joint-production systems, the concept of negative net costs for one product is not uncommon. For example, if the cost of keeping sheep in one's pasture is more than covered by the revenue from their wool, their benefits in keeping the grass cut and fertilized have negative net costs. Negative net costs of deferral of targeted transmission or distribution investments are common for DSM.

Q48: Is there any reason to believe that Vermont is close to exhausting the achievable savings form energy efficiency programs?

A48: No. The 2002 Department report to the Board on the Energy Efficiency Utility found substantial potential for increased efficiency savings. The Department's Report states,

> This analysis shows that, if it wanted to, Vermont could more than offset all projected electricity sales growth with efficiency investment. By 2007, five years of full investment in these all-out efforts would yield 979.4 GWh/year in cumulative annual electricity savings. This would represent 15.2% of forecast statewide sales. Over ten years, savings would reach 2175.1 GWh/year, by then reducing statewide sales by 30.9%. Peak demand savings would reach 449.3 MW (summer) and 436.5 MW (winter) at the customer meter….
>
> The analysis likewise demonstrates that there is significant potential remaining beyond the captured by EEU programs for Vermont's electric utilities to exploit through targeted efficiency investment to defer distribution and transmission capacity investment.

DPS Report and Recommendations to the VPSB Relating to Vermont's Energy Efficiency Utility, May 29, 2002, Attachment 1 at 1–2 and 4.

The report and its Attachment 1, Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings, 2003–2012, Results and Analysis Summary (Plunkett, Mosenthal, and Neme, May 2002) are attached as Exhibit CLF PLC-5.

The Department's analysis also projects societal benefits and costs associated with maximum achievable electricity savings. The programs for residential, commercial, and industrial initiatives would produce net present-value savings of $496.6 million.

Q49: Does the available funding of Efficiency Vermont limit the achievement of C&LM savings?

A49: Yes. The maximum ratepayer funding of the Energy Efficiency Utility permitted by authorizing state legislation is $17.5 million. In 2002, Efficiency Vermont invested $16.8 million dollars in energy efficiency measures. The Board reduced the EEU budget for 2003 to $14 million, even while acknowledging that "the potential to achieve cost-effective energy efficiency savings in the state is not close to being met" (Order of 12/30/02, Investigation into DPS Request to Reduce Amount Collected Via Energy Efficiency Charge, Docket No. 6777, at 19).

The Department concluded in its May 2002 Report to the Board on the EEU that "it is clear that the economically achievable potential far exceeds any level of savings that could be secured by the activity of Efficiency Vermont" at current budget levels. (Exhibit CLF PLC-5 at 4).

With additional funding, Efficiency Vermont could increase savings through existing programs, or additional efforts could be implemented by the EEU or other parties. For example, savings can often be increased by expanding program eligibility to more customers; by including additional efficiency technologies and higher efficiency levels; and by intensifying marketing and incentives to increase participation and improving delivery services, so that participation is easier for customers.

Q50: Could Vermont effectively target its current efficiency programs geographically to focus on Northwest Vermont's priority reliability problems?

A50: Yes. The Board has required distribution utilities to target distributed resources as alternatives to new distribution capacity. This practice focuses on much smaller areas than all of Northwest Vermont, which comprises over half of Vermont load.

B. Load Management

Q51: Could load management help relieve the reliability problems in Northwest Vermont?

A51: Yes. Load management is particularly well suited to addressing reliability problems associated with relatively short periods in which high loads coincide with outages on the transmission system. For some of the problems discussed by VELCo, reducing loads for a few hours a few times during the year would be helpful in improving reliability.

Q52: How did VELCo reflect load management in its analyses of alternatives to the NRP?

A52: VELCo did not consider any pricing or metering options to entice peak load shaving. (VELCo Response to CLF1-37, CLF2-61). Load control and demand-response programs can provide significant load relief (in the form of decreased lighting, slightly higher thermostat settings, and the like) for short peak periods, especially if those measures are only necessary when a critical transmission element has failed at times of high load. On August 16, 2003, for example, the New York ISO's demand-response programs reduced loads in upstate New York (excluding New York City and Long Island) by about 2.5% to 3% of summer peak, in addition to the older load-control programs of the various utilities. This response was probably suppressed by the fact that the event occurred on Saturday, two days after the Northeast Blackout, and after a long load-control event on August 15. A load reduction of 3% in forecast Northwest Vermont summer peak would be about 18 MW.[12]

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[12]New York Independent System Operator, Inc. Semi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation FERC Docket No. ER-3001-00, Attachment I—NYISO 2003 Demand Response Programs.

C. Distributed Generation

Q53: Has VELCo adequately investigated the opportunities for distributed generation in Northwest Vermont to reduce the need for transmission expansion?

A53: No. VELCo, BED, and GMP have not undertaken any broad or rigorous effort to determine the potential for distributed generation in their service territories.

La Capra's examination of distributed generation in its alternatives study (Exhibit VELCo MRM-2) is interesting, but has many serious shortcomings.

First, La Capra's computation of net distributed-generation costs (as summarized in Exhibit VELCo MDM-2, Table 13) appears to run distributed generation more than can be justified, given the assumed market energy price and thermal benefits of CHP. Forcing these resources to run at a loss increases the cost of the distributed generation option.

Second, La Capra gives no credit for any benefits of distributed generation to the host facility for back-up generation that can maintain service (and/or power quality) despite problems from the generation system to the customer's transformer and service drop.

Third, as I noted above, La Capra assumes high outage contingencies (equivalent to the outages that would occur one day in ten years) in addition to the transmission and load contingencies. Thus, La Capra requires 120 MW of new generation to provide 107 MW of incremental load-carrying capacity.[13]

Fourth, La Capra assumes that distributed generation will follow the host facility's load shape, without any ability to dispatch to meet local or regional

[13]Of course, the transmission equipment in the NRP is also subject to periodic failure.

supply needs. (Exhibit VELCo MDM-2 at 50). This restriction understates the benefit of distributed generation in deferring the NRP investments.

Fifth, La Capra credits distributed generation with distribution losses of only about 2%, even though La Capra elsewhere assumes losses of 6% and the Department has estimated statewide average marginal energy distribution losses of 14% to 20% for various rating periods.

But most importantly, La Capra's treatment and dismissal of DG relies on speculation about the potential for distributed generation, rather than the result of any solicitation of interest from customers or developers. VELCo did not survey or identify customers to determine their interest in distributed generation. (VELCo response to NH2-16). VELCo and the utilities that serve Northwest Vermont did not solicit proposals for distributed-generation resources to address the reliability problems. (VELCo response to CLF2-27k; BED response to NH2-17). As La Capra admits, "a coordinated effort to identify promising [distributed-generation] loads and install the schemes that are economic…has, to date, not been attempted." (Exhibit VELCo MDM–2 at 81). VELCo also does not appear to have worked with the electric utilities and Vermont Gas Systems (the fuel supplier for most attractive distributed generation options) to identify potential distributed-generation resources.

Vermont Electric appears to have treated the inquiries from University of Vermont and the Town of Highgate regarding generation opportunities as potential integration issues, but not as part of an integrated least-cost alternative to the NRP or portions of it. (Attachment to VELCo response to CLF2-3a).[14] For example, VELCo told UVM's consultant, with regard to UVM's proposed

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[14]Correspondence with other potentially promising developers of generation in Northwest Vermont was provided under confidentiality restrictions, so I cannot discuss them here.

15-MW plant that "any generation at UVM was helpful but the amount about which they were talking would not cause any deferral of part of the NRP" (email from Miller to Parker, August 8, 2003).[15] Since 15 MW would be an average of 1.25 years of load growth for Northwest Vermont and 1.5 years of Metro load growth, that VELCo assertion appears to be a policy statement (that VELCo will not defer the NRP) rather than a conclusion about the feasibility of deferring additions. Even the La Capra alternatives study acknowledges that 15 MW of distributed generation (which is all that La Capra imagines is viable in all of Northwest Vermont) would defer the second STATCOM, which is the only NRP component La Capra considers deferrable under any circumstances.

The IBM plant in Essex is the largest electric customer in Northwest Vermont, and seems likely to have gas access, land, transmission connections, heating load, and reliability needs conducive to an efficient and cost-effective distributed-generation installation. VELCo acknowledges that generation at IBM could "be very beneficial in that the majority of the electrical load in the Burlington area is served from VELCo's Essex substation," but admits that it has not discussed that option with IBM. (VELCo response to CLF2-3). Green Mountain Power refuses to disclose publicly whether it has communicated with IBM regarding the siting of new generation.[16]

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[15]The Highgate proposal, for 50 to 250 MW, would be central, rather than distributed generation, but would also provide a backup for the contingency of an outage of the Highgate converter.

[16]Green Mountain Power may view distributed generation at IBM as a competitive threat rather than as a potentially cost-effective solution to reliability problems in Northwest Vermont. The Green Mountain Power 2003 IRP notes that "GMP's single largest load risk remains the possibility of a dramatic reduction in energy use by its largest customer, IBM." (Exhibit CLF PLC-3 at 82).

With some support payments for their contribution to resolving transmission problems, customers like IBM may find a range of generation options attractive, including fuel cells where high power quality is essential. Even solar photovoltaic systems may be interesting to some customers; since solar generation is highest on the sunny summer days when Northwest Vermont's peak load occurs, it is technically a good match for this problem.

VI. Least-Cost Alternatives

Q54: Please explain the basic economic test for determining whether targeted distributed resources are preferable to constructing additional transmission facilities, such as VELCo's NRP project.

A54: The appropriate test, which has been used in Vermont since the Order in Docket No. 5270, is the societal test, which compares the present value of the societal costs (capital, operating, fuel, and environmental effects) of the various options. In Docket No. 5270, the Board also selected a 10% risk credit for energy efficiency compared to supply.[17]

As I understand 30 VSA §248(b), the Board can permit transmission projects only if they are the least cost among all the options, including demand management and power supply. That point is also made by VELCo and the

[17] This credit remains appropriate, since DSM avoids lumpy commitments to expensive new resources (such as the NRP), reduces Vermont's exposure to volatility in market prices due to swings in natural gas prices, load-and-supply balance, and other factors affecting generation in New England and beyond.

Vermont distribution utilities in the Vermont Strawman proposal for cost allocation of network upgrade costs, attached as Exhibit CLF PLC-6.[18]

Q55: Has the principle of least-cost planning been applied to the planning of electric delivery facilities in Vermont?

A55: Yes. This is precisely the point of the Distributed Utility Planning Guidelines, the Memoranda of Understanding, and the Board Orders in Docket No. 5980 and Docket No. 6290. Specifically, the creation of the Energy Efficiency Utility, with its budget for funding core programs, does not eliminate the utilities' obligation to identify and implement the optimal investment strategy, determined under the societal test, even if this means increasing investments in energy efficiency well beyond the core programs.

Q56: What are the resource benefits of energy conservation and load-management resources?

A56: Resource benefits consist of avoided electricity costs. Electricity benefits consist of avoided energy generation, generating capacity, distribution capacity, and transmission capacity. Non-electric benefits are avoided natural-gas, oil, and water use. In addition, while this effect is not included in the La Capra analyses, load reductions in Vermont (or anywhere else in New England) will reduce regional market prices. Based on historical experience, every dollar of energy savings from reduced consumption will produce about a dollar of reduced costs to regional consumers, all else equal.

Q57: Does VELCo's NRP proposal represent the least-cost resource option identified in VELCo's own studies?

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[18] New England System Improvement Cost Allocation, January 16, 2003 (Response to DPS2-21; Supplemental Response to NH2-15(b)&(c) and DPS2-21).

A57: No. VELCo admits that ARC 5 has expected total societal costs 9.5% lower that the NRP (Exhibit VELCo MDM-2 at 4, Response to CLF1-8).[19] Even assuming than the NRP costs are spread over all of New England through PTF treatment and that the costs borne by other states are not considered societal costs, ARC 5 is still nearly $20 million less expensive than the NRP.

Q58: Do you agree with La Capra (Exhibit VELCo MDM-2 at 78) that "On an expected value basis using pro-forma cost assumptions, the proposed Northwest Reliability Project and the Alternate Resource Configurations studied are effectively equal?"

A58: No. A 5% cost difference is not "effectively equal," and the benefits of regional socialization may well be illusory, as I explain below in Section VII.[20]

Q59: Is ARC 5 the least-cost alternative to the NRP?

A59: Probably not. While ARC 5 would entail the least cost of the alternatives La Capra chose to analyze, additional portfolios—particularly those combining Optimal Energy's full DSM estimate with more aggressive use of distributed-generation and load-management resources—would likely be less expensive still.

Q60: Can distributed resources defer *all* the components included in the NRP, and at a lower cost than the NRP?

A60: Probably not. We do not have reliable estimates of the potential for load management or distributed generation to defer the NRP, so any answer must be

[19]The La Capra report shows a difference of about $66 million, which I compute to be about 5%.

[20]VELCo cites this language about "effectively equal" in its response to CLF1-8, but does not explain how these different values can be considered equal.

somewhat tentative. I expect that Optimal Energy is correct that DSM could not "—by itself—provide the same amount of transmission capacity with the same timing as the NRP" but that "DSM can provide a cost-effective substitute for a portion of the transmission capacity provided by the NRP" (VELCo Response to CLF1-61). The least-cost portfolio will likely include some elements of the NRP, and some non-transmission alternatives. The question is how much of the NRP can be deferred: only the second STATCOM as assumed in the La Capra report, or the more expensive West Rutland–New Haven 345-kV line.

As I show above in Section III.C, the West Rutland–New Haven 345-kV line and the second STATCOM can be deferred well beyond 2012 by the load reductions that Optimal Energy identified as cost-effective and achievable in the Metro and Northwest areas, with either the Department's 2002 baseline forecast or NEPOOL's updated 2003 forecast. Those load reductions would be even more clearly adequate if the computation started with the NEPOOL forecast discounted for line losses to the customer meter, to be consistent with the Department's forecast and the VELCo critical-load study. In addition, any load reductions in the Northwest-Central area (which Optimal Energy finds are substantial) would further reduce the need for transmission upgrades.[21]

[21] I do not have data on the relationship between statewide loads of the broader region that comprises the Northwest and Northwest-Central region, as I do for the narrower definition of the Northwest (including the Metro areas), so I cannot perform the same quantitative analysis of the effects of distributed resources in that larger area.

VII. Regional Sharing of Transmission and Distributed-Resource Costs

Q61: How is the regional sharing of transmission-related costs relevant to the evaluation of the NRP and its alternatives?

A61: Vermont Electric expects that the bulk of the NRP costs will be socialized across New England but assumes that distributed resources would not eligible for cost sharing.

Q62: Vermont Electric states that NEPOOL's approval of PTF treatment for the transmission expansion is a substantial benefit for Vermont ratepayers, and that this approval could be lost if VELCo does not construct the entire upgrade by 2007. Do you agree?

A62: No, for five reasons. First, I am not convinced that the cost socialization will continue within NEPOOL. Both FERC and NEPOOL are actively considering different cost allocation principles.[22]

Second, if transmission-cost socialization does turn out to be durable, it is not clear that NEPOOL will withdraw the PTF designation (and hence favorable rate treatment) for the NRP were VELCo to use distributed resources to defer portions of the upgrade. Punishing a participant for using non-transmission options to defer transmission investment seems inconsistent with FERC's desire to put all resources on the same cost-recovery basis.

Third, it is not clear that Vermont would be better off accepting regional cost socialization of NRP and other transmission, but not least-cost solutions. Vermont may be worse off paying for 5% of a broad category of New England

[22]Vermont Electric's assumption that it will continue to be able to transfer the bulk of NRP costs to ratepayers in other states is reminiscent of the assurances by the Vermont utilities that they would be able to resell any unneeded Hydro Québec entitlements at or above cost.

transmission upgrades rather than 100% of its own least-cost solutions. The 2002 RTEP identifies a total of $2.0437 billion of regional investments.[23]

Fourth, even if Vermont ends up paying only 5% of the direct costs of the PTF portion of the NRP and future transmission (for so long as FERC tolerates that arrangement), it must pay for 100% of the power supply delivered over those lines, and 100% of the costs of distribution to delivery the power to customers. Again, the cost sharing for transmission, typically the smallest part of utility supply costs, should not lure the Board into accepting higher distribution and generation costs.

Fifth, if the NRP does receive special cost recovery, the alternatives may qualify for the same cost recovery as NRP.

Q63: Is the socialization of regional transmission cost certain to continue?

A63: No. In Docket Nos. ER02-2330-001 et al., FERC indicated that it regards the socialization of costs related to relieving zonal transmission constraints to be extraordinary, limited, and temporary. VELCo acknowledges in discovery that PTF funding for the NRP could be affected by the rulings in this FERC docket. (VELCo response to DPS2-20).

The FERC decision first indicates that combining high locational marginal prices (LMP) in Southwest Connecticut (the area under discussion in the Order) with local assignment of the costs of relieving the Southwest Connecticut constraints may be inequitable:

[23]VELCo Response to DPS2-24. The response also notes, "In addition there are 17 RTEP02 projects that do not have cost estimates and the document contains many disclaimers noting the preliminary nature of the cost estimates for a number of projects."

> We are sympathetic…regarding the effects of LMP on Connecticut consumers. As a matter of equity, it would be reasonable to adopt measures that could moderate the financial impact of LMP on Connecticut consumers without blunting LMP price signals. One measure would be to reduce congestion by building a defined set of transmission upgrades into Southwest Connecticut, identified at the start of the implementation of LMP, and to assign *a portion of the upgrade costs* to other New England customers. Such a mechanism could allow the economic benefits of LMP to be shared more widely through a defined and limited assignment of transmission upgrade costs that would moderate the increase in LMP prices in Connecticut. [See note quoted below] To aid in the transition to LMP, we encourage ISO-NE to work with New England market participants to identify and construct a *defined set of transmission upgrades* into Southwest Connecticut, and we commit to allowing the costs of such upgrades that are placed in service within 5 years from the date of this order to be spread among customers throughout New England. We note this is consistent with our ruling infra that the costs of demand response will also be spread system-wide.

New England Power Pool and ISO New England Docket Nos. ER02-2330-001 et al., December 20, 2002, at 13 (emphasis added).

Thus, FERC seems have offered socialization of only some of the southwest Connecticut upgrade costs, and only for a limited period of time, motivated by a concern over excessive burdens of locational pricing of both energy and transmission. The energy constraints in Northwest Vermont are much less severe than those in southwest Connecticut.

The footnote to the paragraph I quoted above further illuminates FERC's thinking:

> Indeed, the Commission approved a similar mechanism for the customers in Northeastern Massachusetts as part of a compromise package to implement LMP. Specifically, NEPOOL proposed to socialize for an interim period the costs of a series of transmission upgrades into the Northeastern Massachusetts (NEMA) area, which the Commission has approved in a February 15, 2002 order. These upgrades are expansions not related to generation interconnection in NEMA that will be in service by June 30, 2004. These transmission upgrades would moderate the price increases that LMP would bring to customers in the NEMA area. See 98 FERC 61,173 at pp. 49–62 (2002). At the time that the Commission approved the mechanism, the Commission noted that congestion costs in New England were socialized, and thus, relieving congestion through the NEMA upgrades would benefit all participants.

Id., note 14 at page 13.

The approval that FERC refers to in the previous passage allowed the socialization of the NEMA upgrades only for a transition period, during which the "upgrades would benefit all participants." That is, until locational marginal pricing (LMP) is in place:

> Whatever mechanism is selected for New England now, that mechanism will be superseded once a standard market design is applied to the future Northeastern RTO. Thus, for this interim period until that market design is put into place, the Commission will accept NEPOOL's distinction between PTF and non-PTF facilities as a default cost allocation method for upgrades. The Commission recognizes that this mechanism does not send price signals that would encourage the siting of new generation in congested areas. For this interim period until the development of a standard market design for the Northeast, however, all congestion costs will be socialized in any case: the financial incentive to site new generation in congested areas will not become meaningful until the imposition of LMP begins to allocate the costs of congestion to the parties who cause it. Thus, LMP and an appropriate default cost allocation method go hand in hand to use market forces to relieve congestion, and since we are currently in an interim period until LMP can be fully developed for New England, it makes sense also to accept NEPOOL's proposed PTF/non-PTF distinction solely for that same interim period. LMP has not yet been implemented, and congestion costs continue to be socialized. Under these circumstances, in order to bring closure to this contentious issue, the Commission will allow socialization of quick fix and NEMA costs during this interim period.

ISO New England, Inc., Docket No. EL00-62-032 et al., February 15 2002, at 17.

Since LMP has been in effect for nine months, a large part of FERC's rationale for temporarily socializing costs has already disappeared.

Q64: Does VELCo consider the socialization of transmission costs to be guaranteed or permanent?

A64: No. VELCo does not assume that the project will remain eligible for PTF treatment after 2007 (VELCo response to CLF2-1, DPS2-19, DPS1-15).

Q65: Has FERC indicated an intention to treat distributed resources consistently with transmission in planning and cost recovery?

A65: Yes. In it's SMD NOPR (at ¶¶ 347, 348), FERC lays out its intentions regarding regional planning, including the following points:

> The planning process should leave open the question of how and by whom those needs should be met, without favoring one solution (whether it is transmission, generation or demand response) over another.…to the extent the entity sought to roll-in the costs of the facilities, the rate treatment should be reviewed through the planning process.

> When the planning process determines that additional resources are needed to serve the regional market…parties may respond with proposals to expand the grid, add generation (including distributed generation), or implement demand response.

Q66: Has the Board previously taken a position with regard to regional cost-recovery for non-transmission solutions to transmission problems?

A66: Yes. In joint comments with the Department, the Board criticized the ISO's proposal for cost recovery:

It does not provide for parity among resources. Thus, it is in conflict with the Commission's stated goals. A "resource parity" standard would test all alternatives against a least cost solution. This is consistent with several state statutes, such as Vermont's statutory requirement that any transmission or generation resource sited in the state be cost effective. 30 V.S.A § 248(b) states in relevant part,

> Before the public service board issues a certificate of public good…, it shall find that the purchase, investment, or construction:…(2) is required to meet the need for present and future demand for service which could not otherwise be provided in a more cost effective manner through energy conservation programs and measures and energy-efficiency and load management measures.…

The Commission needs to declare that the Petition is deficient in this area. The Commission should require Petitioners to cure this deficiency by applying a "resource parity" standard, as consistent with the SMD NOPR. Under this standard, a regional planning process would treat *all* potential solutions (transmission, generation, demand response, and distributed generation) for reliability or economic upgrades on an equal basis. This would allow *any* potential solution, not just a transmission solution, to receive rolled-in cost treatment.[24] This standard is consistent with the NOPR's guidance that "the planning process should leave open the question of how and by whom those needs should be met, without favoring one solution (whether it is transmission, generation or demand response) over another." The "resource parity" standard is also consistent with the Commission's goal of market-based participant funding for a sub-set of network upgrades and expansions, while preserving the option of socialized treatment for those facilities that provide region-wide reliability benefits and thus may be eligible for rolled-in funding.

Motion to Intervene and Protest of the Vermont Department of Public Service and the Vermont Public Service Board, FERC Docket No. RT02-3-000, November 8 2002 , p.26, 27 (original emphasis).

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[24]This treatment was put into practice in New England in response to a request for proposals for 80 MW of peak shaving. This served as a solution for what has been identified by ISO-NE a

Q67: Have VELCo and the Vermont distribution utilities requested that NEPOOL or FERC allow transmission providers to recover the costs of generation and distributed resources that take the place of transmission system upgrades?

A67: Yes. In their "Vermont Strawman" proposal, the Vermont utilities advocate that both generation and load management (which the Strawman document defines to include demand-side resources generally, including demand response and energy efficiency) should be eligible for cost recovery through the regional transmission tariff. (Exhibit CLF PLC-6).

Q68: Has VELCo requested that NEPOOL or FERC approve socialized regional cost recovery for non-transmission solutions?

A68: No. VELCo has not made such a request. The only expenditures for which VELCo requested PTF treatment were transmission costs. VELCo appears to have made no effort to get pool-wide funding for the least-cost solution, consistent with Vermont law.

To the contrary, it appears that VELCo representatives actually were working hard to convince NEPOOL that no lower-cost, non-transmission solution existed. Mr. Weiss, VELCo's counsel, wrote in a memorandum to the NEPOOL committee that

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reliability problem in Southwest Connecticut. In that situation, the costs of the demand response program rolled into uplift for the region. [Original footnote.]

> VELCo commissioned an extensive study to compare the NRP project to various generation and load-response programs. The study concluded that there is no lower cost, non-transmission solution. But you will not have to take our word, alone, on this. The construction/siting approval process for the project has not yet commenced, but when it does get underway, we will have to prove the validity of that conclusion to the satisfaction of the Vermont Public Service Board, which is, I believe, as demanding as any commission in the country in its insistence that a proponent of a transmission project demonstrate that conservation, generation and load-response solutions are not lower in cost.

VELCo response to CLF1-1, memorandum to NEPOOL Participants Committee Members from Thomas Weiss, March 27, 2003.

This statement apparently refers to the La Capra study, which did not include any load-response resources, considered alternatives for only one $10 million component (the second STATCOM) of the $120 million NRP project, and found that there *is* a "lower-cost, non-transmission" alternative to that component. From the tone of the memorandum, it appears that NEPOOL was more interested in lower-cost, non-transmission solutions than VELCo was.

Q69: How should the Board respond to VELCo's arguments about the asymmetrical socialization of transmission and least-cost solutions?

A69: I recommend that the Board continue to use the societal cost test, without adjustment for preferential socialization of transmission. The Board should view the prospect of long-term socialization of the costs of the NRP to be uncertain, and the prospect that NEPOOL will continue to deny equal treatment to alternatives as unlikely and undesirable.

I also recommend that the Board instruct VELCo and its affected owner utilities to immediately request NEPOOL approval of cost recovery for measures that cost-effectively defer the NRP investments (or any part thereof), and if NEPOOL denies such approval, to promptly appeal to FERC.

Q70: What are your recommendations to the Board?

A70: I recommend that the Board deny the Company's request for the 345-kV and 115-kV lines and the STATCOMs at the Granite substation. The Board should direct VELCo and its owner utilities to pursue vigorously distributed resources and more-modest transmission options to ameliorate the current problems.

The Board should require that VELCo and the distribution utilities serving Northwest Vermont promptly to start implementing distributed resources in Northwest Vermont to delay the need for the NRP. In addition, the Board should order VELCo to integrate least-cost planning into its future transmission planning, and to coordinate its planning with the distributed-utility-planning efforts of the distribution utilities. The Board should require VELCo and the distribution utilities to demonstrate that their coordination will ensure that they identify and acquire any distributed resources that are justified by a combination of deferral of the NRP and other distribution (or sub-transmission) projects, even if for resources that would not be cost-effective for any individual project.

Finally, the Board should instruct VELCo to pursue cost-recovery at NEPOOL and FERC for the costs of the distributed resources in the least-cost solution in the same manner that NEPOOL has accepted for the NRP.

Q71: Does this conclude your testimony?

A71: Yes.