UPDATE TO
ALTERNATIVES TO VELCO'S
NORTHWEST VERMONT RELIABILITY PROJECT

Prepared for VELCO

By

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July 2005

2005 Update of NRP Project Analysis:

Executive Summary

The Vermont Electric Power Company, Inc. ("VELCO") retained La Capra Associates ("La Capra") to develop and coordinate the study of a set of alternative resource configurations ("ARCs") against which to evaluate the merits of its proposed Northwest Vermont Reliability Project ("NRP" or "Project"). La Capra issued a report entitled *Alternatives to VELCO's Northwest Reliability Project* in May of 2003 ("Alternatives Report"), followed by a 2004 update ("2004 update"), which examined a broad set of theoretical alternatives to the NRP, ultimately concluding that the proposed NRP is the best means to address Northwest Vermont's reliability problems and meet near term incremental load requirements. In January 2005, the Vermont Public Service Board issued a Certificate of Public Good for the NRP, agreeing that "there is no cost-effective alternative to the proposed Project that is reasonably assured of timely implementation."

In the course of finalizing design and beginning the procurement process, VELCO has updated its estimates of NRP project costs and has asked La Capra to re-examine its comparison of the NRP with the theoretical ARCs. The fundamental conclusion of La Capra's updated analysis is the same as it was two years prior: neither the revised cost information nor any other factor that has changed in the intervening time alters the conclusion that *the NRP is the best and most viable means to address Northwest Vermont's reliability problems*.

La Capra's most recent economic analysis, performed during May through June 2005, tested the two most cost-effective ARCs considered in the previous analyses (ARC 4[1] and ARC 5[2]) against the NRP. The analysis was based on various revised assumptions, including cost increases and changes in the timing of the NRP and its theoretical alternatives, and the same methodology used to develop the Alternatives Report. As in each of the previous analyses, the following costs were estimated for each resource: (1) the option's capital costs, (2) the net variable costs to serve Vermont's load, and (3) the

[1] Consisting of combustion turbines, as well as a 200 MW combined cycle facility.
[2] Consisting of combustion turbines, along with the Maximum Achievable DSM program.

additional costs and benefits to society, including external environmental costs associated with air emissions from electric generating sources.

The estimated costs associated with implementing the NRP, relative to the costs of the theoretical alternatives, are higher in this updated analysis. Primary reasons for this change are a significant increase in VELCO's estimate of the capital cost of the NRP, and a significant increase in our forecast of New England capacity market prices (offsetting the carrying costs of new generating capacity in the ARCs). As shown in the table below, the estimated total societal costs associated with ARC 4 borne by Vermont ratepayers (i.e., adjusted for PTF cost treatment), are just under the societal costs of the NRP (less than 2% difference, or $22 million present value). The estimated total societal costs of ARC 5 are about 7% ($95 million present value) below the NRP. This advantage is due primarily to the assumed benefits of DSM other than wholesale power savings: particularly avoided distribution investments, though including other societal benefits (e.g., water and land usage) as well as a 10 percent risk adjustment discount to the estimated program costs.

Summary of Results
Estimated Present Value of Costs, 2008 - 2019
2005 present value ($ millions)[1]

	NRP	ARC 4	ARC 5
Total Costs			
Carrying Charges on Capital Expenditures	163	308	330
Net Cost to Serve Vermont Load[2]	1,284	1,038	1,113
Total Direct Costs	1,447	1,346	1,442
Societal Costs (net of Societal Benefits)[3]	-	(4)	(174)
Total Societal Costs (TSC)	**1,429**	**1,342**	**1,268**
TSC – Relative to NRP	-	(87)	(161)
Costs Borne by Vermont[4]			
Carrying Costs on Capital Expenditures	35	263	285
Net Cost to Serve Vermont Load[2]	1,284	1,038	1,113

Total Direct Costs	1,319	1,301	1,398
Societal Costs (net of Societal Benefits)[3]	-	(4)	(174)
Total Societal Costs (TSC)	**1,319**	**1,297**	**1,224**
TSC – Relative to NRP	-	(22)	(95)

[1] Annual discount rate is 10%.
[2]This includes costs such as fixed O&M, variable power supply costs, transmission losses, net of ICAP value. It does NOT include carrying charges, which are shown on the line item above, or emissions costs or DSM-related benefits, which are show in the line item below.
[3] Societal costs include emissions costs, as well as DSM-related benefits, such as avoided utility distribution upgrade costs, as well as a 10% discount to DSM program costs as a risk adjustment. Emissions costs for the ARCs are relative to emissions under the NRP case.
[4] Some portions of the capital expenditures of the NRP receive PTF cost treatment, i.e. are paid for by New England ratepayers as part of the Pool Transmission Facilities tariff rate. The costs shown here reflect only those costs estimated to be borne by Vermont.

While our analysis shows changes in the economics of the theoretical alternatives, it does nothing to dispel the critical concerns about the feasibility of implementing the ARCs and their robustness relative to the NRP that led the Public Service Board to reject them. In particular:

- Both alternatives to the NRP would require the construction of very substantial new generating capacity - including three 50 MW CT units, significant natural gas infrastructure improvements, and substantial electric system upgrades - in Northwest Vermont by 2008. While we believe that such a project is possible from a technical perspective, no such project is under active development today. An extraordinary effort and financial commitment would be required to implement such a project, and it appears questionable at best that the many steps (including sponsorship and financing of the generating capacity, regulatory approvals, and construction for the project and the gas and electric system upgrades) could be accomplished in this time frame.
- ARC 5 would require an unprecedented level of DSM investment and implementation in Vermont over the remainder of this decade, and would entail retail rate increases for the affected electric utilities.
- The NRP is at a relatively advanced stage of development. Its elements and their associated timing have been studied in substantial detail, approved, and VELCO has ordered several pieces of equipment with long lead times and completed scopes of work for several NRP elements. The alternatives to the NRP are not

nearly as advanced, and their respective scopes and costs are based on industry literature and planning studies. Similarly, finding sites for the substantial amounts of new generating capacity required in each of the alternatives (particularly in ARC 4) would be problematic.

- While the NRP is a very substantial project for Vermont, the ARCs would be much more capital-intensive to implement. Both ARCs require hundreds of millions of dollars more than the NRP in terms of capital that would need to be financed, requiring large capital raising efforts by the Vermont utilities. [3]

Finally, it is critical to note that the resource plans we have tested are not mutually exclusive. Implementing the NRP would not preclude Vermont from pursuing an aggressive DSM program like the Maximum DSM program featured in ARC 5, or from achieving the substantial DSM-related savings.

Based on the results of our updated economic analysis, and taking into account the practical implementation issues associated with the ARC 4 and ARC 5 alternatives, we conclude that the NRP remains the most robust and cost-effective way to ensure that Northwest Vermont has access to a reliable electricity supply.

[3] For comparison, the capital requirements of each of the ARCs would represent over 70% of the 2004 combined net utility plant of CVPS and GMP, the state's two largest utilities.

I. Introduction

A. Background

The Vermont Electric Power Company, Inc. ("VELCO") retained La Capra Associates ("La Capra") to develop and coordinate the study of a set of alternative resource options against which to evaluate the merits of its proposed Northwest Vermont Reliability Project ("NRP" or "Project"). The NRP is a coordinated set of eight transmission upgrades identified by VELCO as needed to provide reliable transmission service to meet existing and forecasted Vermont electric loads. In its analysis described in the May 2003 report *Alternatives to VELCO's Northwest Reliability Project* ("Alternatives Report"), La Capra examined a broad set of theoretical alternatives to the NRP. These alternatives include system expansion plans composed of transmission plant, utility-scale power plants, distributed generation ("DG") installations and demand-side management ("DSM") programs. The goal of this study was to explore the cost-effectiveness and robustness of potential alternative solutions to the reliability challenge facing Northwest Vermont. A similar analysis was performed in 2004 as part of rebuttal testimony submitted by La Capra in the Vermont Public Service Board ("Board") Docket No. 6860.

VELCO obtained approval from the Board for the NRP in January 2005, and has since moved ahead with final design and procurement of the NRP project elements. As part of this process, VELCO has updated its cost estimates and has asked La Capra to perform an updated analysis testing the NRP and leading alternative resource configurations ("ARCs") reflecting these more recent cost estimates, along with changes to the other primary input assumptions based on more recent information.

La Capra's most recent economic analysis, performed during May through June 2005, tested the two most cost effective ARCs considered in the previous analysis: ARC 4 (consisting of one 200 MW combined-cycle unit, one 25 MW simple-cycle combustion turbine ("CT") and three 50 MW CTs) and ARC 5 (consisting of three 50 MW CTs along with the Maximum Achievable Demand-Side Management ("DSM") program.

Based on the results of our updated economic analysis, and taking into account the practical implementation issues associated with the ARC 4 and ARC 5 alternatives, we conclude that the NRP remains the most robust and cost-effective way to ensure that Northwest Vermont has access to a reliable electricity supply.

The following sections of this report summarize the previous studies and the conclusions reached from them, and then summarize the updated analysis and its results.

B. May 2003 Alternatives Report

The La Capra study pre-screened commercially available generation technology options (both utility-scale and distributed generation) in its consideration of resource alternatives to the NRP. This information was combined with forecasted DSM peak demand and energy savings potential and program cost data prepared by Optimal Energy, Inc. ("OEI"), to develop five Alternative Resource Configurations ("ARCs") against which to test the merits of the NRP. Each ARC was an alternative set of resources designed to meet the same reliability and incremental load serving objectives for Northwest Vermont. All of the ARCs included the elements of the NRP that VELCO determined were non-displaceable.[4] The non-transmission components of the alternatives tested were as follows:

- ARC 1: 225 MW of simple-cycle combustion turbines ("CTs") and approximately 15 MW of distributed generation installations, all located in Northwest Vermont. [5]
- ARC 2: a 100 MW combined-cycle ("CC") unit and 150 MW of CTs.
- ARC 3: a 150 MW CC unit and 150 MW of CTs.
- ARC 4: a 200 MW CC unit and 150 MW of CTs.

[4] I.e, deemed necessary for voltage control and system stability whether or not additional supply- and demand-side alternatives are implemented in Northwest Vermont. See the May 2003 Alternatives Report for more detail.
[5] All megawatts listed here and throughout the report represent nameplate capacity.

- ARC 5: 150 MW of CTs, along with DSM contributions consistent with OEI's maximum achievable (or aggressive) DSM forecast. Specifically, ARC 5 included 74 MW of DSM-based peak demand savings in the Metro Zones by 2013.

The La Capra Alternatives report (presented in Board Docket 6860 as Exhibit MDM-2) compared the cost effectiveness of each of the five ARCs relative to each other and to the NRP. For each ARC and for the NRP, the analysis tracked for the 12-year period from 2005-2016:

1. The option's capital costs;
2. The net variable costs to serve Vermont's load; and,
3. The relative societal benefits, including emissions-related externality costs.

The results of this analysis are summarized below:

Table 1. Alternatives Report, Summary of Results

Estimated Present Value of Costs of Resource Alternatives, 2005 – 2016
2005 present value ($ millions)[1]

	NRP	ARC 1	ARC 2	ARC 3	ARC 4	ARC 5
Total Costs						
Carrying Charges	94.2	185.7	234.9	274.4	294.1	306.7
Net Cost to Serve Vermont Load[2]	1,178.1	1,130.3	1,068.8	1,023.4	981.5	1,067.6
Societal Costs (net of Societal Benefits)[3]	-	(5.1)	3.4	5.8	0.7	(167.9)
Total Societal Costs (TSC)	**1,272.3**	**1,310.9**	**1,307.1**	**1,303.6**	**1,276.3**	**1,206.4**
TSC Relative to the NRP		38.6	34.8	31.3	4.0	(65.9)
Costs Borne by VT Ratepayers[4]						
Carrying Costs	9.1	149.1	198.3	237.8	257.5	270.1
Net Cost to Serve Vermont Load[2]	1,178.1	1,130.3	1,068.8	1,023.4	981.5	1,067.6
Societal Costs (net of Societal Benefits)[3]	-	(5.1)	3.4	5.8	0.7	(167.9)
Total Societal Costs	**1,187.2**	**1,274.3**	**1,270.5**	**1,267.0**	**1,239.7**	**1,169.8**
TSC Relative to the NRP	-	87.1	83.3	79.8	52.5	(17.4)

[1] Annual discount rate is 10%.
[2]This includes costs such as fixed O&M, variable power supply costs, transmission losses, net of ICAP value. It does NOT include carrying charges, which are shown on the line item above, or emissions costs or DSM-related benefits, which are show in the line item below.
[3] Societal costs include emissions costs, as well as DSM-related benefits, such as avoided utility distribution upgrade costs.
[4] Some portions of the capital expenditures of the NRP receive PTF cost treatment, i.e. are paid for by New England ratepayers as part of the Pool Transmission Facilities tariff rate. The costs shown here reflect only those costs estimated to be borne by Vermont ratepayers.

The analysis showed that, under base case assumptions, the NRP required the lowest total present value carrying charges between 2005 and 2016 ($94.2 million), and ARC 5 the highest, $306.7 million.[6] The analysis also showed that the estimated total societal costs of ARC 4 were approximately equal to the NRP and that ARC 5 had the lowest estimated total societal costs of any of the alternatives. ARC 5's low total societal costs were due primarily to the assumed value of reductions in air emissions and assumed avoided distribution and sub-transmission upgrade costs produced by the DSM program savings, which largely offset the cost of the three combustion turbines added in 2005.

As shown in Table 1, the estimated total societal costs of the ARCs adjusted for PTF treatment[7] range from $87.1 million, or seven percent, higher than the expected total societal cost of the NRP (ARC 1) to approximately $17.4 million, or one and one-half percent, lower (ARC 5). While these differences are not trivial, La Capra's assessment concluded that there are sufficient uncertainties in the inputs to preclude the selection of the NRP or one of the ARCs solely on the basis of the expected value *pro-forma* economic analysis. As outlined in the Alternatives Report, examples of cost uncertainties include, amongst others:

- The cost and impact to expand the Vermont Gas system to supply natural gas to the bulk generation;
- The cost to integrate the bulk generation into the transmission grid; and,

[6] The relative cost of the ARCs and the NRP were also tested under a series of stress case scenarios. Generally, the NRP had lower societal costs than all ARCs except for ARC 5 under these stress cases. See the Alternatives Report for more detail.
[7] PTF cost treatment refers to the sharing of bulk transmission system costs across New England through the regional transmission network rate. The Alternatives Report contains a more detailed discussion of the PTF treatment of the NRP.

- The cost associated with dual-fuel capability or on-site liquid fuel storage if bulk generation is not solely natural gas-fired.

Nonetheless, to create a quantitative analysis, the Alternatives Report utilized assumptions for the above uncertainties, and such assumptions were conservatively low so as not to bias the results against non-transmission alternatives. The decision as to which project provides a more robust solution to the reliability problem, therefore, is dependent largely on professional judgments regarding both the relative cost and implementation uncertainties.

As discussed in more detail in the Alternatives Report, implementation uncertainties associated with the ARCs include:

- Financing sources and cost recovery for the large capital investments (i.e., several hundred million dollars) that would be needed to add the required new generating capacity and DSM resources;
- Availability of sites in Northwest Vermont for new bulk generation facilities, and feasibility of constructing such substantial new facilities quickly;
- Fuel infrastructure upgrades requirements associated with new bulk generation facilities;
- Uncertainty associated with the construction of transmission interconnections and upgrades to reliably incorporate bulk generation alternatives to the Vermont power grid; and,
- Challenges associated with implementing an aggressive DSM program required to achieve the savings assumed in ARC 5.

Given the uncertainties above, the Alternatives Report concluded that the projected difference in societal costs between ARC 5 and the NRP did not adequately justify the substantial expenditures required to implement the DSM program and to attempt construction of the generation and the transmission plant that would be needed to implement ARC 5. Based on the uncertainties presented above and the large capital expenditures associated with alternative resource plans, the Alternatives Report concluded that the NRP represented the most robust resource alternative. The NRP was recommended as the best means to address Northwest Vermont's reliability needs and to meet near term incremental load requirements.

C. July 2004 Rebuttal Testimony & Revised Analysis

In rebuttal testimony presented in Docket 6860 in July 2004, VELCO responded to various issues that were raised by other parties concerning the alternatives resource assessment prepared in May 2003. As part of the rebuttal testimony, the original La Capra analysis was updated and new results were presented to address some of these concerns ("rebuttal analysis"). In particular:

- The most recent schedule of timing of NRP element installation was modeled, including the assumption that the 345 kV lines would go into service in January 2006;
- A new resource alternative (ARC 6) was devised and tested, which included a fairly aggressive demand response program, in addition to three 50 MW combustion turbines, and a DSM program equivalent to 25% of the Maximum Achievable DSM program previously included in ARC 5;
- Revised fuel price assumptions, to reflect the fact that natural gas and crude oil prices had dramatically risen since the filing of the Alternatives Report in May 2003;
- A revised load forecast, based on the 2004 NEPOOL CELT report.

The rebuttal analysis was conducted using these revised input assumptions under base case, high, and low fuel price scenarios. It quantified the same set of costs as did the analysis in the Alternatives Report for the 12-year period 2006-2017. The analysis found that ARC 6 exhibited estimated total societal costs adjusted for PTF treatment that were between six and 12 percent greater than those of the NRP under base case and fuel price scenarios. The analysis also found that under the increased base case fuel prices ARC 5 was approximately 2 percent less expensive than the NRP considering total societal costs and adjusting for PTF treatment. Further, the rebuttal analysis considered the relative costs of ARC 4, ARC 5, and the NRP under high and low fuel scenarios and found that selecting the NRP effectively provides a hedge against potential high price fuel outcomes. The ultimate recommendation of the revised analysis was the same one presented in the original report: The proposed Northwest Vermont Reliability Project was the best means to address Northwest Vermont's reliability problems and to meet near term incremental load requirements.

Table 2 Summary of Rebuttal Results
Estimated Present Value Costs of NRP, ARC 5, ARC 6 Stress Cases, 2006 – 2017
2005 present value, $ millions
Costs Borne by Vermont Ratepayers

		Base Case	Stress 1 High Fuel Prices	Stress 2 Low Fuel Prices
NRP	Total Societal Costs (TSC)	1,300	1,534	1,242
ARC 5	Total Societal Costs (TSC)	1,271	1,554	1,144
	TSC Relative to NRP	(29)	20	(98)
ARC 6	Total Societal Costs (TSC)	1,381	1,735	1,353
	TSC Relative to NRP	81	201	111

II. Updated Testing of NRP and Alternatives

A. Introduction

Until all project requirements are met, permits granted, and equipment/construction contracts signed, the construction schedule and costs of the NRP are subject to uncertainty. Schedule and cost estimates are being updated as events become known. Since La Capra's original Alternatives Analysis and the 2004 update were conducted, a number of other significant factors affecting the cost-effectiveness of the NRP and its alternatives have changed. While the Board's approval of the NRP did not rely solely on the projected costs, VELCO asked La Capra to update its economic analysis to reflect current information for the major drivers. This updated analysis represents a full update and comparison of the leading resource options, as informed by the previous analyses.[8]

La Capra identified the following factors for consideration in this re-screening analysis, each of which is discussed in greater detail in later sections:

- Changes in the timing of the installation of the NRP elements.
- An increase in expected costs of the NRP elements;
- A change in turbine costs for utility-scale generation;
- A delay in the implementation of the Maximum Achievable DSM program, as represented in the original analysis by OEI;
- A further increase in the near-term cost of natural gas and crude oil;
- An increase in expected capacity market revenues for generators; and,
- Other changes in La Capra's wholesale market/production cost model.

B. Timing of NRP Elements

According to VELCO, changes from the July 2004 NRP construction schedule[9] have been required to comply with conditions of the Certificate of Public Good (CPG). Since the permit approval and post CPG processes have not yet been completed, the schedule may experience further changes.

The current schedule of construction completion dates and cost estimates can be found in Appendix 1. The major changes from the July 2004 schedule are listed below by category used in the original and this updated analysis of non-transmission alternatives.

- Potentially Displaceable Elements:
  - West Rutland to New Haven 345kV line: moves from end of 2005 to end of 2006.
  - Granite substation package of transmission elements moves from summer 2006 to end of 2006 and to end of 2007.
- Non Displaceable Elements:
  - Blissville PAR: moves from fall 2005 to fall 2006.

[8] Upon inspection of the results of the previous analyses, as well as consideration of the changes in the key variables in the updated analyses, we believe that the leading ARCs in the Alternatives analysis would remain the leading alternatives to the NRP based on current information.
[9] Submitted as rebuttal testimony by the Technical Panel

- Essex breaker: moves from spring of 2006 to fall of 2005.
- Williston breakers: moves from summer 2006 to spring 2007.

C. Change in Capital Costs for Utility-Scale Generation

In the May 2003 Alternative Report, capital costs for the combustion turbines and the combined cycle units that composed the ARCs were based on manufacturer cost estimates as reported in *Gas Turbine World Handbook 2003* (GTW). This publication provided estimates for equipment costs, along with a representative range (based on national data) of an additional 60 to 100 percent of the equipment costs for the additional non-equipment costs required to obtain a total project turnkey costs. La Capra utilized the low end of the range.

In August 2004, the ISO-New England sponsored testimony of John Reed[10] which provided detailed cost estimates for several types of combustion turbine units for installations in New England, including the aeroderivative type that would be suited for application in the ARCs. The Reed cost estimates are much higher than those used in the Alternatives Report. Some of the difference is attributable to equipment costs, particularly for the inclusion of SCR air emission control equipment and dual-fuel capability. The primary difference is attributable to non-equipment costs, which include engineering and construction, labor, owners' costs such as permitting, and contingency.

In this updated NRP analysis, the estimated capital costs for the 50 MW combustion turbine units included in ARCs 4 and 5 reflect the equipment estimates used in the Reed testimony, and the high end of the GTW range for non-equipment costs. Estimated capital costs associated with smaller combustion turbines were developed in a similar fashion. In total, the revised capital cost assumptions for the combustion turbines are substantially higher than in the Alternatives Report, but lower than the Reed estimates for similar units.

As discussed in the Alternatives report, there are significant challenges associated with finding one or more sites in Northwest Vermont to site the substantial amounts of new

[10] See FERC Docket ER03-563-030.

generating capacity that are assumed in ARC 4 and ARC 5. For the purpose of this updated analysis, it was assumed that the ARC generation would be located in the town of Georgia.

While system impact studies have not been conducted to fully identify the impacts of this new generation on the transmission system, initial assessments by VELCO indicate that electric system upgrades of approximately $100 million would be required to support the bulk generation (on the order of 350 MW) in ARC 4, and that most of this would also be required to accommodate the smaller amounts of generation in ARC 5. These estimates would translate to roughly $300/kW for ARC 4 and $600/kW for ARC 5. Given the preliminary nature of these estimates, and to recognize the possibility that some of the ARC generation might conceivably be sited at another location with lower incremental transmission upgrade costs, the La Capra update analysis assumes that ARC 5 and ARC 4 will each require capital costs of $200/kW for electric transmission system upgrades.

Finally, implementation of the ARC generation at Georgia would require upgrades to the delivery infrastructure of Vermont Gas Systems (VGS). Based on discussions between VELCO and VGS, we assumed that ARC 5 would require about $8 million of upgrades to the gas delivery system, and ARC 4 would require about $15 million. These estimates are somewhat lower than the assumptions used in the Alternatives Report, primarily because the latter report assumed that some of the ARC generation would be located at the Champlain substation and would require more lengthy upgrades to the VGS system.

For combined cycle costs, the updated analysis reflects the fact that the most recent version of Gas Turbine World Handbook indicates a small decline in turbine costs. It indicates that this slight decline in cost may be partially due to the general global economic downturn, as well as a result of inventory build-up due to plant cancellations and sales of existing assets.

The table below compares the installed cost assumptions for selected bulk generation components used in the Alternatives Report, versus those used in the current analysis.

Table 3: Comparison of Bulk Generation Cost Estimates

Bulk Generation	May 2003 Cost Estimate ($2005)	Updated Cost Estimate ($2005)
200 MW Combined Cycle	$128.0 million	$118.0 million
50 MW Combustion Turbine	$ 22.4 million	$ 30.8 million
25 MW Combustion Turbine	$ 11.8 million	$ 15.8 million
12.5 MW Combustion Turbine	$ 7.3 million	$ 9.2 million

Note: Costs associated with required upgrades to gas & electric transmission systems are estimated separately.

D. Increase in Expected Costs and Status Update of the NRP Elements

After Board approval of the NRP in January 2005, VELCO began the final redesign, as a result of CPG conditions, and procurement processes of certain NRP elements. The estimates received to date indicate a substantial cost increase over the past estimates: approximately 91 percent for the entire project of $229.5 million[11] when compared to the 2003 estimate of $120 million that was filed with the Public Service Board.[12] Such increase is due to a number of factors, including a lower valuation of the U.S. dollar, increased costs of raw materials, equipment, labor, fuel, and capital costs over the past few years. Additionally, there were alterations in the project scope, such as line and substation rerouting and undergrounding, due to the requirements of the CPG.

VELCO is in the process of redesigning the NRP elements consistent with the CPG conditions. Also remaining is the post certification approval process of these redesign efforts that the Public Service Board order dictates. For long lead time transmission elements, VELCO is placing orders to secure its position in the ordering queue in order to minimize slippage in the construction schedule. VELCO does not yet have all of the permits it requires from the Army Corps of Engineers and State of Vermont agencies, but is actively pursuing them.

[11] The total project capital cost of $229.5 million was provided to us by VELCO. We understand that this figure includes an allowance for element-specific contingencies which, in total, amount to approximately $30 million or about 15 percent.
[12] Since the Sandbar PAR was excluded from docket 6860, its costs have been excluded from these numbers.

E. Delay in Implementation of DSM Program

As in the Alternatives Report and the 2004 update, we assume the continuation of the existing Efficiency Vermont (EVT) and Burlington Electric Department (BED) DSM programs. We assume that under all resource scenarios (i.e., all ARCs and NRP) that future load reductions from DSM installations under these existing programs would be consistent with those forecasted by ISO-NE in the 2004 CELT report. In addition to these existing DSM programs (referred to in the Alternatives Report as "Base DSM"), ARC 5 also includes an additional DSM resource. This ARC 5 DSM resource represents the maximum contribution that an aggressive energy efficiency program targeted at this capacity constrained region (i.e., the "Inner Metro" and "Outer Metro" regions) could make to reduce summer peak loads during the next 10 years ("Max DSM"). This DSM resource estimate was a result of a study performed by Optimal Energy, Inc. (OEI). Realization of such a resource would require an unprecedented program effort to achieve the aggressive reductions in load forecasted by OEI.

As described in the May 2003 Alternatives Report, the Max DSM program would focus on key residential, commercial and industrial markets in Northwest Vermont. OEI estimated that the program would have resulted in a net reduction in Vermont load of 1.2 MW, beginning in 2003, with a cumulative reduction of 6.8 MW in 2004.[13] The program has yet to be launched, and such load reductions have not been realized. Therefore, the current analysis assumes a program launch in 2006, with 1.2 MW of load reduction being achieved in that year, and a cumulative reduction of 6.8 MW being achieved in 2007. As shown in Table 4, below, all subsequent load reductions are the same as described in the Alternatives Report, with a similar two-year delay.[14] No other program parameters have been changed for the purposes of the current analysis.

[13] For the estimated incremental load reductions achieved for the balance of the study period, please refer to Table 12 of the May 2003 Alternatives Report.

[14] Note the rebuttal analysis assumed a one-year delay in implementation of the DSM program vis-à-vis the assumptions in the May 2003 Alternatives Report.

Table 4: Cumulative ARC 5 DSM Benefits (MW) for Calendar Years 2005 - 2012
Comparison: Alternatives Report, Rebuttal Testimony and Updated Analysis

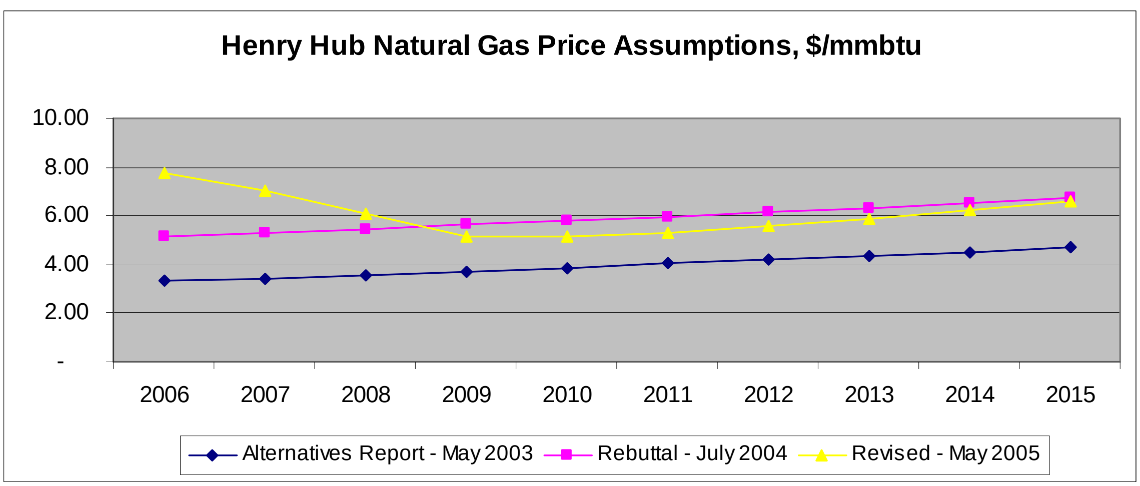
ARC 5	2005	2006	2007	2008	2009	2010	2011	2012
Alternatives Report	6.8	16.5	29.1	42.8	53.9	63.7	72.3	79.7
Rebuttal Testimony	1.2	6.8	16.5	29.1	42.8	53.9	63.7	72.3
Updated Analysis	-	1.2	6.8	16.5	29.1	42.8	53.9	63.7

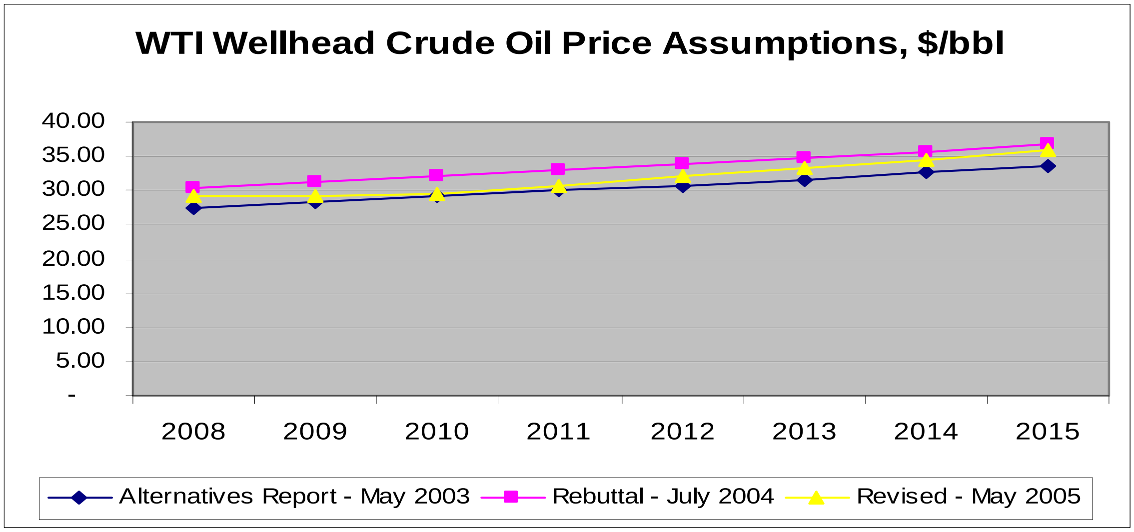
Note: DSM MWs include the benefits of avoided losses.

F. F. Increase in Fuel Prices

The prices of natural gas has increased dramatically since the filing of the May 2003 Alternatives Report. Natural gas price assumptions have increased approximately 40% relative to those used in the 2003 report. Crude oil price assumptions have also increased slightly. Short-term oil and gas price assumptions for this update are based on NYMEX future contract prices as of mid-May 2005. Long-term fuel price assumptions are based on the U.S. Energy Information Administration's ("EIA") 2005 Annual Energy Outlook; intermediate years reflect a blend. Coal price assumptions were also updated; they have a much smaller effect on projected New England electricity prices.

Figure 1: Comparison of Fuel Price Assumptions





G. Increased Capacity Market Price Forecast

Both ARC 4 and ARC 5 include significant amounts of bulk generation that would receive both energy and capacity revenues. Since the Alternatives Report and Rebuttal Report were prepared, ISO New England has developed a revised system of Locational Installed Capacity ("LICAP") which will feature a demand curve that relates the market price of capacity to the amount of capacity in the market, relative to objective capability ("OC").[15] Incorporating the parameters of the demand curve resulted in a significant increase in projected capacity market prices over the forecast period. This change has the effect of increasing the projected market revenues associated with the ARCs, thereby improving their projected cost-effectiveness relative to the NRP.

H. Other Changes

As in the previous analyses, the current analysis utilizes La Capra's Northeast Market Model to simulate energy price and market results. There have been a number of changes to the market model since the May 2003 report that better reflect the state of the current energy market. The results of the current analysis reflect these changes to the market model. The impact of these changes on the relative cost-effectiveness of the NRP and

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alternatives is relatively minor in comparison to the impact of the changes in the other factors described above. Briefly, these market model changes include:

- Emission allowance prices reflected in the model are currently greater than in the original analysis, reflecting the higher national and regional SO2 and NOX allowance prices.[16]
- The inclusion in the model of the Pataki emission limits[17], which as early 2005, impose more stringent NOx and SOx limits for generators located in New York state than the national limitations.
- Revised emissions rates for bulk generation, reflecting actual emissions rates of facilities in 2003.
- A revision to the bulk generation retirement methodology for thermal generating units in the region. The assumption used for the updated analysis is that coal units will retire when they reach 60 years of age and oil and natural gas units retire when they reach 45 years of age. Our previous assumption was that all units, regardless of fuel type, retired at their 50th year of service. The exception to this rule is in Ontario where we have assumed the retirement of all coal-fired capacity by December 31, 2007.
- Buildout of new renewables in the region is different than before and includes compliance with current understanding of targets associated with New York and New England Renewable Portfolio Standards (RPS); this represents a significant increase in renewable capacity.
- Refinements to the model representation of multi-fuel units.

These changes in input assumptions were then analyzed within the framework of the analysis previously performed to compare the relative costs and implementation risks of various non transmission alternatives to the NRP.

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[16] Note the increase in allowance prices is distinct from the calculation in externality costs, which are based on projected emissions and an estimated "societal cost" of those emissions.
[17] The "Pataki limits" refers to the New York Acid Deposition Reduction Program.

III. Alternatives Screening Process under the Updated Analysis

A. Selection of Alternative Resource Configuration for Testing

In determining what alternatives to test against the NRP in the current analysis, La Capra considered the following:

- The Alternatives Report showed that of ARCs 1 to 4 - the generation-based alternative - ARC 4 (featuring a 200 MW combined cycle unit) was the most cost effective. The increase in combustion turbine turnkey costs relative to combined cycle costs as previously described would increase the cost-effectiveness of ARC 4 relative to the other ARCs. Therefore, we did not test ARCs 1-3 in the updated analysis.
- ARC 5 was competitive with the NRP on a societal cost basis in both the original and rebuttal analysis. Given the changes in input assumptions detailed above, we believed that the economics of ARC 5 warranted consideration in this re-testing analysis.
- The rebuttal analysis demonstrated that ARC 6 (bulk generation, demand response, and some incremental DSM) was less cost-effective than ARC 5 on a societal cost basis, and therefore ARC 6 was not re-tested in the current analysis.

In summary, the current analysis focuses on ARC 4 and ARC 5, versus the NRP. However, the passage of time required that each of the three alternatives be reviewed to reflect current expectations about when the various generation and DSM-based alternatives could be implemented. As described in detail in the Alternatives Report, the original ARCs were constructed to meet the estimated need of Northwest Vermont in each year. Specifically, the forecasted peak demand of Northwest Vermont was compared to the load carrying capability of the existing generating resources as well as the transfer capability of the transmission facilities into Northwest Vermont to determine the annual incremental resource need, in MW, of the region. Then, the incremental load carrying capability of each potential ARC resource was estimated. The ARCs were constructed in such a manner that the total incremental load carrying capability of resources added would be sufficient to meet the expected need in each year.

B. Updated ARC 4

It was necessary to re-configure ARC 4 based on the current assumptions regarding peak load.[18] In addition, it should be noted that the ARC 4 in the Alternatives Report featured a 200 MW combined cycle facility assumed to be on-line by 2007. At that time, 2007 was considered the earliest feasible year for which it would be possible to physically site, construct, and make operational a facility of that size. Given the passage of approximately two years time since that analysis, we believe that it is no longer realistic to expect that this resource could be sited, constructed and made operational by 2007. Additionally, to be more realistic, the timeframe needs to include a reasonable amount of time for the regulatory review process. Consequently, the ARC 4 configuration for the current analysis assumes that the 200 MW combined cycle will be operational in 2010, the earliest we believe it is feasible for such a resource to come on-line[19]. A similar deferral was made to the operational date for the combustion turbines within ARC 4 and ARC 5. Table 5, below, provides details of the revised ARC 4 and ARC 5 configurations for the current analysis.

C. Updated ARC 5

ARC 5 was tested in both the Alternatives Report and the Rebuttal Analysis. For comparison purposes, the changes described are to the Alternatives Report. The Maximum Achievable DSM program as configured for the current analysis is adjusted to reflect the two-year delay in program start since the Alternatives Report. As discussed above, the program start is now assumed for 2006.

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[18] Recall that the load assumptions used in the Alternatives Report were based on a forecast prepared by the Vermont DPS; in the revised rebuttal analysis, load assumptions from the 2004 CELT report were used. Because ARC 4 was not tested in the rebuttal analysis, it was necessary to re-configure this ARC using need based on the 2004 CELT load.

[19] Assuming an 18 month regulatory permitting and development process, commencing immediately, and a simultaneous 36 month financing, construction and implementation process for gas pipeline, electric transmission upgrades and generation construction.

Table 5. Updated Alternative Resource Configuration Construction
2005 Update Analysis
Summer Coincident Peak Load Per 2004 CELT

ARC 4	2008	2009	2010	2011	2012
VT Critical Load Timing [1]	1,135.0				1,195.0
NW VT Peak Demand [2]	631.0	641.0	651.0	661.0	671.0
Cumulative DSM [3]					
Revised VT Critical Load Timing			1,101.3		
Adjusted NWVT Peak Demand	631.0	641.0	651.0	661.0	671.0
Need	**-130.8**	**-140.8**	**-150.8**	**-160.8**	**-170.8**
Bulk Gen. Added	3x50CT, 1x25CT		1x200CC		
Summer MW	140		200		
Bulk Gen. Inc. LCC	124.2		124.8		
Cumulative Increase in LCC	**124.2**	**124.2**	**249.0**	**249.0**	**249.0**

ARC 5	2008	2009	2010	2011	2012
VT Critical Load Timing [1]	1,135.0				1,195.0
NW VT Peak Demand [2]	631.0	641.0	651.0	661.0	671.0
Cumulative DSM [3]	16.5	29.1	42.8	53.9	63.7
Revised VT Critical Load Timing			1,101.3		
Adjusted NWVT Peak Demand	614.5	611.9	608.2	607.1	607.3
Need	**-114.3**	**-111.7**	**-108.0**	**-106.9**	**-107.1**
Bulk Gen. Added	3x50CT, 1x12.5CT				
Summer MW	130				
Bulk Gen. Inc. LCC	115.8				
Cumulative Increase in LCC	**115.8**	**115.8**	**115.8**	**115.8**	**115.8**

Notes:
[1] VT-wide native load levels without distribution and subtransmission losses corresponding to the critical loads presented by VELCO in its "Critical Loads Analysis"
[2] Northwest Vermont native load levels inclusive of distribution and sub-transmission losses.
[3] DSM MWs are adjusted to reflect the benefits of avoided losses.

D. Determining the Most Cost Effective ARCs

ARC 4 and ARC 5, as described above, were tested against the NRP (with revised timing elements) to understand which of the two ARCs was the most cost effective given the current set of assumptions. Recall that the following costs were analyzed for each resource: 1) the option's capital costs, (2) the net variable costs to serve Vermont's load, and (3) the additional costs and benefits to society, including external environmental costs associated with air emissions from electric generating sources. These costs were calculated, summed (the sum deemed "total societal costs,") and compared under base case conditions.[20]

The NRP and other alternative resource configurations entail different amounts of generating capacity, different wholesale market prices and, in the case of ARC 5 with the maximum DSM, different load requirements. La Capra used its proprietary market simulation model to simulate the effects of these factors on Vermont's total electricity costs and on the air emissions of the New England electricity system.[21] The analysis was performed for three sample years: 2008, 2010 and 2012, and costs were interpolated for all years in between. For each year and each resource configuration, the total societal costs were estimated using the following components:[22]

- Fixed costs and capacity value associated with each resource configuration, including assumptions regarding gas and electric interconnection costs;
- The net variable cost to supply the balance of Vermont's power needs;
- Power costs associated with serving transmission system losses;
- Emission-related externality costs; and,
- Estimated costs, with a 10 percent discount (risk adjustment), associated with incremental DSM implementation in ARC 5.

Costs were also extrapolated for the seven-year period from 2013-2019.[23] Results were then presented as the present value of total costs from the 12-year period, 2008-2019.[24]

[20] For the current analysis, La Capra did not test the resources under any stress case scenarios.
[21] See Appendix 8 of the Alternatives Report for more detail on the market simulation model used.
[22] See pages 63-66 of the Alternatives Report for a more detailed discussion of these cost categories.
[23] Vermont's power supply situation will change noticeably after 2012 as large power purchases from Vermont Yankee, Hydro-Quebec and VEPPI expire. Together, these purchases amount to several million MWh per year and provide almost half of Vermont's current and projected power needs. After 2011,

IV. Summary of Results

Table 6 Summary of Results
Estimated Present Value of Costs, 2008 - 2019
2005 present value ($ millions)[1]

	NRP	ARC 4	ARC 5
Total Costs			
Carrying Charges on Capital Expenditures	163	308	330
Net Cost to Serve Vermont Load[2]	1,284	1,038	1,113
Total Direct Costs	1,447	1,346	1,442
Societal Costs (net of Societal Benefits)[3]	-	(4)	(174)
Total Societal Costs (TSC)	**1,429**	**1,342**	**1,268**
TSC – Relative to NRP	-	(87)	(161)
Costs Borne by Vermont[4]			
Carrying Costs on Capital Expenditures	35	263	285
Net Cost to Serve Vermont Load[2]	1,284	1,038	1,113
Total Direct Costs	1,319	1,301	1,398
Societal Costs (net of Societal Benefits)[3]	-	(4)	(174)
Total Societal Costs (TSC)	**1,319**	**1,297**	**1,224**
TSC – Relative to NRP	-	(22)	(95)

[1] Annual discount rate is 10%.
[2]This includes costs such as fixed O&M, variable power supply costs, transmission losses, net of ICAP value. It does NOT include carrying charges, which are shown on the line item above, or emissions costs or DSM-related benefits, which are show in the line item below.
[3] Societal costs include emissions costs, as well as DSM-related benefits, such as avoided utility distribution upgrade costs, as well as a 10% discount to DSM program costs as a risk adjustment. Emissions costs for the ARCs are relative to emissions under the NRP case.
[4] Some portions of the capital expenditures of the NRP receive PTF cost treatment, i.e. are paid for by New England ratepayers as part of the Pool Transmission Facilities tariff rate. The costs shown here reflect only those costs estimated to be borne by Vermont.

Vermont's needs for new power sources will be much more substantial; the analysis attempted to capture this fact by considering the above costs during the period after 2012.
[24] The discount rate used is 10%, as in all analyses previously performed.

The results above show that the estimated total societal cost basis, including PTF cost treatment, associated with the NRP are similar to ARC 4, and about six percent more expensive than ARC 5.

Since the installation dates of generation in the ARCs have been delayed by the passage of time, it is also apparent within ARC 4 and ARC 5 results that Vermont would be exposed to increased levels of congestion pricing and hours of potential transmission deficiencies during 2007. VELCO plans to minimize these risks by constructing the 345 kV transmission line from New Haven to West Rutland and the Granite upgrades as soon as possible. VELCO analysis does not foresee any serious reliability deficiencies if these facilities are constructed in a timely manner. Delays, or the hypothetical use of ARC 4 or ARC 5 as an NRP replacement, would cause greater amounts of congestion pricing. Additionally, to preserve the reliability of the bulk power system, Vermont would either place greater reliance on under-voltage load shedding schemes or, alternatively, be required by ISO New England to procure temporary generation, which experience has shown to be quite costly.

V. Discussion and Conclusion

The La Capra alternatives analyses in Docket 6860 showed that in order to avoid the need for the NRP, substantial investments in local generating and DSM programs would be required. The estimated cost differential between the NRP and the ARCs (hypothetical alternative resource configurations) was not significant enough to choose the preferred resource plan based solely upon the projected costs. Professional judgment regarding non-cost, practical implementation issues is an important component of least cost planning, to ensure that the recommended solutions are viable ones. In the Alternatives Report, we concluded that considerations of the ultimate feasibility of implementing each of the alternatives, and likelihood of each alternative being implemented within the timeframe needed for reliable service, were more important than the small cost differentials shown in our analysis.

This report presents updated "base case" estimates of the costs associated with implementing the NRP and alternatives. This update indicates that the costs associated with implementing the NRP have increased somewhat, relative to the leading ARCs. The key question is whether these results change the final recommendation regarding the resource that is the most feasible, robust, and cost-effective in solving northwest Vermont's reliability needs. Several practical considerations, summarized below, raise serious doubts as to whether the hypothetical alternatives could be implemented, particularly in the time frame needed to ensure that northwest Vermont has a reliable electricity supply.

First, since the original La Capra analyses were conducted in 2003, VELCO has made progress on the NRP project. VELCO is in the process of redesigning certain NRP elements to meet CPG requirements, gaining final approval of such redesigns with the Board, ordering long lead time materials, and working through Army Corps of Engineers and state agency permit processes.

The ARCs examined in this updated analysis represent potential projects which are not actually under commercial development. Both alternatives to the NRP would require the construction of very substantial new generating capacity – including three 50 MW CT units, and substantial upgrades to the natural gas and electric transmission systems – in northwest Vermont by 2008. To our knowledge, none of the key steps in the project development process (e.g., financial sponsorship, studies of environmental impacts and transmission system impacts, petition for a CPG) that would be required to implement the ARCs has begun. Such efforts would face the same non-trivial hurdles identified by the Board in its 1/28/05 order, and it is possible that fatal flaws could emerge. In any case, significant time would be needed to bring the ARCs to commercial maturity and to ultimately implement them. This updated analysis assumes that substantial new CT capacity in Northwest Vermont could be brought online by 2008, and a new combined cycle facility by 2010. While we believe that these dates would be achievable from a technical perspective, for active generation projects, in the present circumstances it appears at best questionable that the many required commercial steps could be accomplished in this time frame.

Second, a fundamental assumption underlying the ARCs is that there is at least one sufficient suitable location in northwest Vermont at which the required generation could be sited. However, as discussed in the Alternatives Report, there are multiple problematic issues with the Georgia and Champlain sites, the most suitable locations for siting utility scale generation. Existing generator sites in northwest Vermont do not appear to provide viable locations for new generation on the scale that would be needed to implement ARC 4 or ARC 5.

Third, the costs to expand the Vermont Gas System ("VGS") to allow operation of such substantial new generation are uncertain, as detailed studies have not been performed. This is important because the ability of the ARCs to reliably supply electricity to northwest Vermont (and perhaps the feasibility of receiving the permits that would be required to implement the ARCs) would depend in part on a reliable supply of natural gas.[25] Similarly, the measures and costs required to integrate the new generating facilities assumed in ARC 4 and ARC 5 into Vermont's electric transmission system are uncertain, and could turn out differently than assumed in this updated analysis.

Fourth, pursuing the full potential of DSM to defer peak demand would require an unprecedented DSM program-one that seeks to capture all the appropriate northwest Vermont efficiency improvements that the OEI study identifies as available. Although the OEI study has estimated reasonably what an aggressive energy efficiency investment program could achieve, as the OEI report observes, a program that seeks to reduce peak demand this sharply over a limited period of time has not been attempted on such a large scale anywhere. This translates into the risk that load will continue to grow past critical levels, thereby exposing northwest Vermont to high congestion costs and an elevated risk of service interruptions.

Fifth, this updated analysis presents the estimated future costs associated with the NRP and alternatives primarily in terms of long-term present value. It is also important to note that the while the NRP is a very substantial project and capital commitment for Vermont,

[25]Note, however, that this is mitigated in part by the fact that we assume the combustion turbines to have dual-fuel capability. These units would be able to utilize oil or propane to some extent in case of disruption of natural gas supply. Note also the costs of these units reflect this dual-fuel capability, as discussed earlier in this report.

the ARCs would be much more capital-intensive to implement. Specifically, the estimated capital investment associated with the NRP is about $230 million. Taking into account the portions of the investment that would be shared across New England through regional network transmission tariffs, Vermont ratepayers would effectively be responsible for only a small portion of this amount. Alternatively, ARCs 4 and 5 would require capital investments of about $390 million and $410 million, respectively (including the portions of the NRP which are not avoidable). While these capital investments would reduce some other future expenditures (e.g., the purchased power and fuel savings that we have estimated in our analysis) that Vermont utilities would otherwise have to make - this commitment of capital would be extraordinary relative to the scale of Vermont's electric utilities and their existing asset base.[26] While some of the direct capital investment could presumably be avoided if the capacity were developed by a third-party and supported through a power purchase agreement by Vermont utilities, such a purchase would still represent a very substantial financial commitment by Vermont's utilities and ratepayers.

In summary, this updated analysis shows larger estimated societal cost differentials between the NRP and alternatives than the earlier La Capra analyses. At the same time, the numerous implementation issues and uncertainties associated with alternatives to the NRP have not been resolved. It is not clear that the alternatives studied here (i.e., ARCs 4 and 5) would ultimately be feasible, or if they could actually be developed in time to meet the reliability needs of northwest Vermont. In Docket 6860, the Board recognized these practical uncertainties associated with the alternatives to the NRP:

> "While ARC 5 has a lower expected total societal cost, building and completing three generating facilities in northwest Vermont in a timely manner is an unlikely proposition, especially in light of the fact that no one has come forward to propose building a single power generator in the area. The northwest Vermont region *today* faces a net need for additional

[26] The capital expenditures required by ARCs 4 and 5 are over 70% of the 2004 reported net utility plant of both GMP and CVPS, Vermont's two largest utilities.

reliable power. Relying on the highly uncertain proposition that three generating plants will be built in the inner and metro-area zones of northwest Vermont – as ARC 5 and ARC 6 each would require – is not a viable option, and would present unacceptable risks of power outages. We conclude that the most cost-effective alternative that will meet the need for service and that has a reasonable likelihood of implementation is the proposed Project." (Board order docket 6860, 1/28/05, p. 58)

Finally, it is critical to note that while our analysis projects ARC 5 (featuring the Maximum DSM program) to offer lower long-term costs than the NRP (featuring much less DSM), the two resources are not exclusive of each other. That is, implementing the NRP would not preclude Vermont from pursuing an aggressive DSM program.

Based on the results of our updated analysis, taking into account the practical implementation issues associated with the NRP and the alternatives, and considering that implementation of the NRP will not preclude an aggressive DSM program in the future, we conclude that the NRP remains the most robust, viable and cost-effective alternative to ensure that northwest Vermont has access to a reliable electricity supply.