Transmission System Integrated Resource Planning: Leveling the Playing Field

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ABSTRACT

The Vermont Electric Power Company (VELCO) is responsible for planning, developing, and maintaining Vermont's transmission system. Vermont's growing electric loads, particularly in Northwest Vermont, are straining existing capacity. VELCO has implemented an integrated distributed utility planning (IDUP) project to determine the optimal solution to ensure reliable supply of energy services. A proper IDUP must address traditional transmission capacity, along with distributed generation and energy efficiency. Particular attention to the timing of resource acquisition is critical, to match loads with capability, using a mix of appropriate resources.

VELCO's analysis raises substantial issues regarding electric system policy, especially related to cost-effectiveness, funding and equity. In VELCO's case, the most cost-effective societal solution is a mix of energy efficiency plus distributed generation. Energy efficiency, while substantial and important, was not sufficient in capacity and timing without some strategic contribution of distributed generation. While this solution provides the least societal, long-run cost, it is substantially more expensive to Vermont ratepayers than traditional supply. Under current Northeast Independent Systems Operator (ISO-NE) rules, Vermont's contribution to the transmission system capital cost is only five percent, with southern New England's greater loads covering the remainder of these costs. Vermonters, however, would likely bear the full cost burden of implementing any energy-efficiency initiatives and distributed generation (DG).

This paper will describe the IDUP process, analysis and results. It will address policy considerations currently under discussion in regulatory hearings. The pending resolution and issues surrounding the use and usefulness of the planning study will also be addressed.

Introduction

Through VELCO, Vermont's twenty-two electric utilities are represented as a single entity in the New England Power Pool (NEPOOL). VELCO's high voltage transmission system connects generating facilities with local distribution systems delivering electricity to Vermont's homes and businesses. Most of the system was constructed more than thirty years ago. Vermont's electric load is growing every year. Between 1999 and 2002, the summer peak increased by 9 percent, from 939 to 1023 megawatts (MW). The peak number is critical to providing reliable electricity because the system has to be built to handle the time of the highest use. Even with the active load-reducing programs that Vermont has in place, the summer peak continues to grow sharply. According to VELCO, because of continued growth in electricity usage, Vermont is reaching load levels at which the reliability of the system is in jeopardy. Vermont has a limited amount of in-state generation. Statewide, less than 50 percent of Vermont's summer peak demand was met by in-state generation. In Northwest Vermont, about 90 percent of the electricity is supplied by the transmission system during peak periods.

VELCO is regulated by both federal and state entities, and any proposed transmission upgrades must be approved by the Vermont Public Service Board (VT PSB). The purpose of VELCO's Northwest Reliability Project (NRP) is to ensure Vermont's transmission system continues to be reliable. According to Vermont law, prior to any significant transmission upgrade all feasible alternatives must be considered. As a result, VELCO engaged in an IDUP process to evaluate the opportunities for distributed generation and/or energy efficiency to provide the needed reliability levels at lower societal cost. In June 2003, VELCO filed for a permit to upgrade the high-voltage transmission system between Rutland and Burlington to meet existing and forecasted Vermont electric loads. Initial hearings on the NRP have concluded. More hearings will be conducted in summer 2004. A decision by the VT PSB is expected in Fall 2004.

The Need

Customer load in VELCO's service area has been growing at an average annual rate of 2.1% over the last decade, hitting a peak load of 1023 MW in the summer of 2002. The VT Department of Public Service (DPS) forecast (issued August 5 2002) that, absent additional efficiency or load control programs, load growth will continue to grow steadily (2.2% average) over the next twelve years, reaching 1250 MW by 2011.

NEPOOL and the Northeast Power Coordinating Council (NPCC) have developed standards for the planning and design of the bulk power system. The transmission planning standard, the "N-2 criterion," requires that the bulk power system be designed with sufficient capacity to serve loads after the loss of any critical system element and that within thirty minutes it be able to sustain the loss of the next most critical element. The resource adequacy planning criterion requires that the electric system be designed such that the probability of disconnecting non-interruptible customers is no more than, on average, once in ten years. Reliability studies performed by VELCO reveal that the power system serving Northwest Vermont does not currently meet the N-2 transmission planning standard (La Capra Associates 2003). In addition, in its 2002 Regional Transmission Expansion Plan, ISO-NE stated that: the Northwest Vermont area faces severe reliability problems due to weak interconnection with the bulk transmission system and a lack of generating resources and distributed resources in the region (ISO-NE, 2002). Given projected load growth, current generating unit forced outage rates, and known transmission constraints, the situation will deteriorate further unless remedial steps are taken.

The Northwest Reliability Project (NRP) is a combination of eight transmission upgrades identified by VELCO as needed to provide reliable transmission service to meet existing and forecast electric loads in Northwest Vermont. Major NRP elements include construction of and support for a new 115 KV line between New Haven and South Burlington, and construction of a new 345 KV line between West Rutland and New Haven. Many of the system support elements are intended to control voltage, ensure system reliability, or direct flows to prevent thermal overload, post contingency.

As part of the NRP, VELCO evaluated the potential of distributed generation and/or energy efficiency to cost-effectively defer or avoid any or all of the transmission upgrade components described above.

The adjusted load forecast for Northwest Vermont divides it into several sub-zones: Inner, Metro, Northwest and Northwest/Central. Demand-Side Management (DSM) resource contributions outside of the Inner and Metro zones would undoubtedly provide some benefit in easing Northwest Vermont's reliability constraints (La Capra Associates 2003). However, given that it was difficult to ascertain how much value the Northwest and Northwest/Central zones might offer to address the Inner and Metro zone reliability constraints, non-transmission resources from the Northwest and Northwest/Central were not included.

Potential Resources

VELCO conducted an IDUP analysis, pursuant to a Stipulation Agreement entered into between VELCO and the Vermont Department of Public Service (VT DPS) that considered the following resources (La Capra Associates 2003):

- The Northwest Reliability Project transmission upgrade as proposed by VELCO;
- Distributed generation;
- Energy efficiency; and
- Other potential transmission system upgrades.

Of note was the omission of consideration of demand response programs. It is recognized that demand response can also provide some potential cost-effective peak reductions.

Commercially-available generation options were pre-screened, generally eliminating those that are still in the developmental stages. Options assessed included: (1) Distributed generation – reciprocating engines, microturbines, industrial combustion turbines, and fuel cells; (2) Renewable Energy – wind turbines, biomass combustion, photovoltaics, solar thermal, and landfill gas; and (3) Bulk Generation – combined cycle, combustion turbines, coal-fired steam, nuclear, oil-or gas-fired steam, hydro, municipal solid waste, and internal combustion engines.

Energy-Efficiency Potential

The maximum achievable end-use energy-efficiency potential was assessed as a demand-side management strategy to reduce growing peak loads in each of the four northwestern Vermont load zones (Optimal Energy, Inc. 2003). The study examined the contribution that an aggressive energy-efficiency investment campaign targeted at this capacity constrained region could make during ten years (2003 to 2012) to reduce peak loads and thereby help defer or eliminate the need to build new transmission and/or generation capacity to serve this economically vital region of Vermont. The analysis considered impacts through 2014 of DSM programs that began in 2003 and ended in 2012.

The study targeted the Burlington area (comprising the Inner and Metro-Area zones) and its outer regions (comprising the Northwest and Northwest/Central zones). It estimated the summer peak load and annual energy reductions that could be achieved by highly aggressive DSM initiatives targeting key residential, commercial and industrial markets in these planning regions. These initiatives would extend and expand on programs Efficiency Vermont (EVT) is implementing statewide and in conjunction with the City of Burlington’s Electric Department (BED). While detailed program budgets were developed reflecting staffing needs, no specific solutions was proposed as to how such an ambitious effort would be undertaken in Vermont.

To achieve these aggressive load reduction goals, the study contemplated a large ambitious investment campaign over a decade, using the most aggressive proven market implementation strategies to acquire widespread participation in all market sectors. These included:

- Sustained marketing to consumers and equipment vendors, contractors, distributors and manufacturers;
- Generous financial incentives typically covering the full cost of discretionary retrofit measures and the full incremental cost for new construction/renovation and planned equipment replacement measures;
- Comprehensive technical and information services for market participants; and
- Complete customer service delivery.

All the technologies and market intervention strategies contemplated in the analysis have been effective in New England and elsewhere. It bears noting, however, that no utility, state, or program administrator has ever sustained such large energy-efficiency investment commitments for so long in so many markets simultaneously and actually achieved the relative magnitudes of savings projected over the next decade in this study.

The study estimated potential savings in three residential markets – retail products and appliances, retrofit applications and new construction for single- and multi-family buildings. It provided separate estimates for residential measures that alternately contributed comparatively high and low peak load kW savings. Efficiency measures with relatively high ratios of summer peak kW savings to total annual kWh savings were put into the "high peak savings" groups; those with low kW to kWh ratios were put into the "low peak savings" groups. All told, 70 different residential energy-efficiency measures – representing 36 different efficiency technologies and/or technology "bundles" – were analyzed in the six market segments (some measures were analyzed in more than one segment).

The study estimated potential savings in four commercial/industrial (C&I) markets – new construction, renovation, remodeling/planned replacement, and early retirement (discretionary retrofit). In the commercial and industrial ("C&I) sector, the analysis estimated savings for 54 distinct efficiency technologies or technology bundles for 11 building types in the four markets.[1] The combination of technology, building type and market resulted in 1,573 individual measures. These measures were a limited subset of a full measure list used in a similar study completed in 2003 for the Vermont Department of Public Service (Optimal Energy, Inc., 2003).

The VELCO analysis rejected consideration of numerous measures based on the following criteria:

- Measures that did not offer significant summer peak demand benefits;
- Emerging technologies that are not widely commercially available today; and
- Measures that are difficult to promote effectively without use of coordinated regional and/or national upstream approaches.

The analysis considered not only the energy savings each efficiency technology offered, but tracked the existing stock of equipment and projected market penetration rates over time, by market for each measure, to project savings annually for each year of the planning horizon. The analysis specifically sought to ensure that the estimates of potential peak demand savings were achievable at a high level (90% precision) of certainty. As a result, achievable market penetration rates used were significantly lower than ones that have been proven achievable in some markets,

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[1] The 11 building types were: agriculture, education, grocery, health, industrial, lodging, office, restaurant, retail, warehouse and other.

for some periods of time. However, as mentioned above, the overall depth of savings estimated would far exceed anything ever achieved if all savings, in all markets, over the full time period were captured.

Lastly, a key difference from the VT DPS statewide analysis is the geographic focus of VELCO's assessment, which separately analyzed achievable electricity savings potential for two distinct regions, each comprised of four load zones. The study estimated that the "Inner and Metro-Area" zones grouping contain approximately 22% of the state's residential customers, and 44% of its commercial and industrial electricity sales. The study estimated that the "Northwest-Northwest/Central" zones grouping contained approximately 54% of the state's residential customers and 44% of commercial and industrial ("C&I") electricity sales.

Overview of Analysis Results

Demand and energy savings impacts. Figure 1 presents the electric DSM achievable potential demand savings. These are expressed as cumulative annual savings through 2012 from initiatives targeted to the Inner and Metro-Area, and Northwest and Northwest/Central load zones. Projected outcomes are expressed in terms of summer peak demand (MW and % of 2012 forecast). All savings are expressed at the end-user meter.

Figure 1. Cumulative Annual Summer Peak Demand Savings (MW)

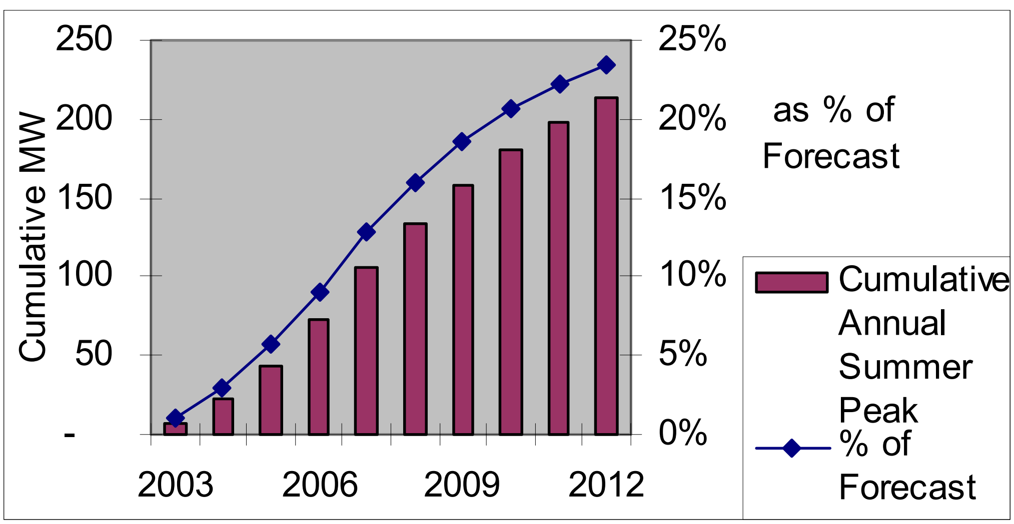
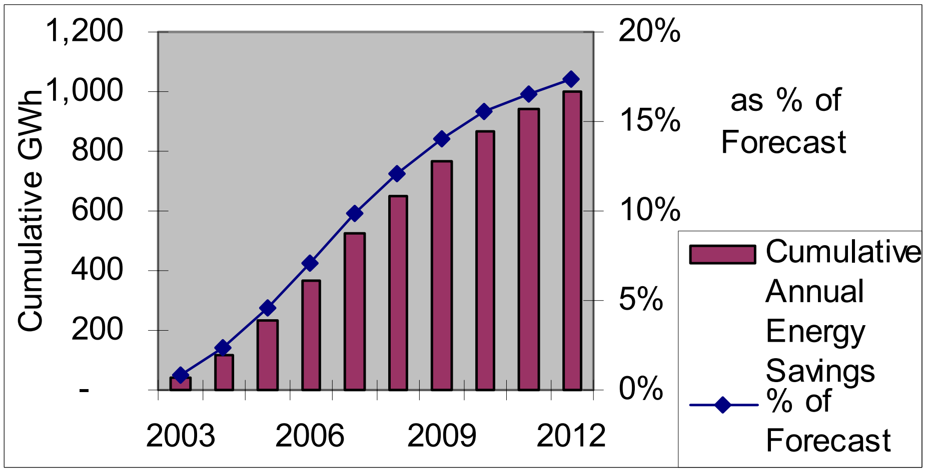


Figure 2 presents the electric DSM achievable potential energy savings expressed as cumulative annual savings (GWh and % of 2012 forecast).

Figure 2. Cumulative Annual Energy Savings (GWh)



For the first four years, from 2003 through 2006, the Inner and Metro-Area load zones accounted for a greater share of cumulative demand and energy savings. Thereafter, the Northwest and Northwest/Central load zones offer greater cumulative shares of targeted savings. By 2012, VELCO anticipates that total peak demand and energy potential savings will be 26% and 16% of forecast load in the Inner/Metro load zones and 22% and 18% in the Northwest and Northwest/Central load zones, respectively.

The C&I sectors provided the largest amount of 2012 cumulative annual demand savings, 79% of the total. In both the residential and C&I sectors, the retrofit market segment provided the majority of the 2012 cumulative annual demand savings, 68% and 60%, respectively. The three residential markets (retail, retrofit and new construction) were divided into two groups – a high peak savings group -and a low peak savings group.

Figure 2 presents the cumulative annual summer peak kW load reductions through 2012 by residential sub markets from the combined VELCO plus EVT and BED efforts in the Inner and Metro-Area and Northwest and Northwest/Central load zones.

Figure 2. 2012 Cumulative Annual Residential Sector Demand Savings - Percent

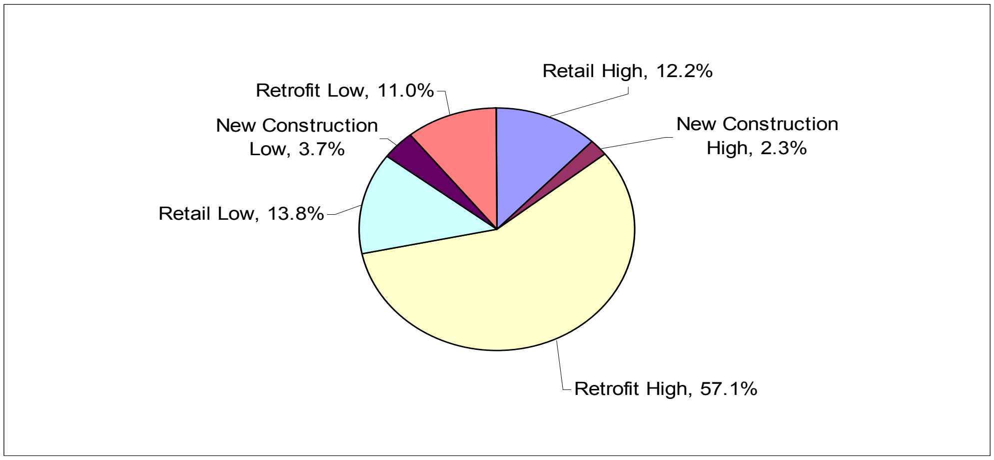
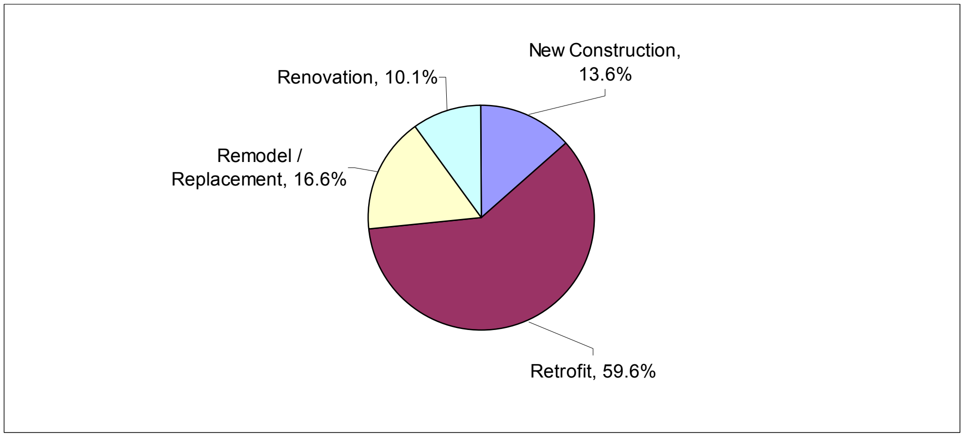


Figure 3 presents the same results for the four commercial and industrial markets analyzed.

Figure 3. 2012 Cumulative Annual Commercial and Industrial Sector Demand Savings - Percent of Sector Savings



Projected electricity savings were above and beyond what would occur naturally in the marketplace in the absence of future market intervention, and also broke out that portion projected to come from existing Vermont initiatives. These projected savings were subtracted from the VT DPS regional sales forecast to produce estimates of the resulting loads in each planning zone.

Regarding the VELCO study of maximum technically achievable potential:

- The 23% and 17% total VELCO summer peak demand and energy savings, respectively, were reasonable when compared to the 37% and 31% total Vermont maximum technically achievable potential statewide demand and energy savings, respectively, given the differences between the two analyses.
- The VELCO total demand and energy savings (23% and 17%, respectively), corresponded closely to that of the 2002 California study (The Energy Foundation and The Hewlett Foundation 2002) of technical potential savings scenario (25% and 19%, respectively).[2]

Economic impacts. Capture of the DSM achievable potential would require a budget of $569 million over ten years; a $479 million increase in the EVT and BED statewide investments projected over ten years at $90 million. All dollar figures were reported in 2003 present worth with future values discounted at 4% to reflect a long-term *real* societal discount rate. The targeted maximum achievable initiatives taken together resulted in present value net benefits to the Vermont economy of $589 million. This results from $1.2 *billion* in total benefits ($872M Utility, $335M additional non-utility societal) and $618 million in societal costs, for an overall benefit-cost ratio of 1.95.

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2 Vermont's per capita electricity consumption is considerably higher than that of California, 9400 vs. 7200 kWh per person, respectively. California has a relatively higher baseline level of energy consumption from which to pursue energy efficiency, in part due to very aggressive implementation and enforcement of its statewide energy codes.

Because of the substantial benefits from generation energy and capacity and distribution capacity avoided costs, the net cost to the transmission system for energy efficiency is negative (in other words, even if the transmission system avoided costs were zero, the efficiency would still be worthwhile). The analysis estimated transmission system savings from targeted energy efficiency were $-3,047/kW or $-107/kW-yr.

As a conservatism, the study did not count the value of risk-mitigating advantages of energy-efficiency resources recognized by the Vermont Public Service Board but did include the VT PSB recognized environmental externality values. These advantages include the ability to acquire resources in stages, and the tendency of efficiency savings to vary directly with hourly load fluctuations.

The primary barrier to capturing the vast economically achievable efficiency impacts is that it would require a large capital investment, and its benefits are diffuse, including distribution ($298 million), non-electric - fossil fuel and water ($258 million) and avoided generation ($208 million). No one source of benefits is large enough to cover the total cost of the energy-efficiency resources. Since these benefits would tend to accrue to different parties — distribution utilities, customers, generators, gas and oil suppliers and VELCO — concerted efforts on many parties would be required to mobilize this unprecedented level of sustained capital investment. VELCO's share of these total benefits is relatively small and by no means sufficient to support the acquisition of a major share of the economically deliverable transmission capacity in the load zones studied. Further compounding this capital barrier is the favorable capital cost treatment of the transmission upgrade based on current ISO-NE regional cost-sharing policy.

Integrated Resource Analysis

VELCO's permit application for the NRP included an assessment of five Alternative Resource Configurations (ARCs), against which to evaluate the merits of its proposed NRP (La Capra Associates 2003). This assessment concluded that a combination of efficiency and a combustion turbine provided the least cost plan. However, the total societal costs of the NRP were very similar to those of the efficiency/combustion turbine combination, making other issues important to consider. After consideration of these additional issues, VELCO concluded the NRP was the most robust solution to the reliability problem facing Northwest Vermont. The assessment focused on developing sets of alternative resources that might displace – or defer until loads that exceed the 1200 MW critical load level – the NRP elements intended to increase the ability of the transmission system to serve incremental loads in Northwest Vermont.

The assessment pre-screened commercially available generation technology options (both utility scale and distributed generation) and generally avoided those that were in the developmental stages and did not analyze load control. This information was combined with forecasted DSM peak demand and energy savings potential and cost data, to develop five ARCs. Each ARC was an alternative set of resources designed to meet the same reliability and incremental load serving requirements of the NRP. In addition to including certain transmission system upgrades, each ARC included non-transmission components. Four ARCs included different combinations of combustion turbines, combined cycle and distributed generation. ARC 5 included 120 MW of combustion turbines and 74 MW of DSM-based peak demand savings, reflecting DSM contributions consistent with the maximum achievable DSM forecast in the Inner and Metro zones only. While VELCO recognizes that DSM impacts in the Northwest and Northwest/Central zones would provide some reliability relief to the Northwestern VT power grid, it is not clear how much value they add. Therefore, as a conservatism, only the Inner and Metro zone DSM was included.

The assessment compared the relative cost effectiveness of each of the five ARCs to each other and to the NRP. For each ARC, the assessment tracked: (1) the option's carrying costs, (2) the net variable costs to serve Vermont's load, and (3) the relative societal benefits. Figure 3 sums and compares the five ARCs under base case conditions. Table 1 compares the present value costs of NRP resource alternatives.

Table 1. Present Value Costs of Resource Alternatives 2005-2016 NRP

2005 Present Value [1], $ millions	NRP	ARC 1	ARC 2	ARC 3	ARC 4	ARC 5
Carrying Charges	$ 94.2	$ 185.7	$ 234.9	$ 274.4	$ 294.1	$ 306.7
Net Variable Cost to Serve VT Load [2]	$1,178.1	$1,130.3	$1,068.8	$1,023.4	$ 981.5	$1,067.6
Societal Cost/Benefits relative to NRP [3]	-	($5.1)	$ 3.4	$ 5.8	$ 0.7	($167.9)
Total Societal Costs	$1,272.3	$1,310.9	$1,307.1	$1,303.6	$1,276.3	$1,206.4
Carrying Costs Adjusted for PTF Cost Treatment [4]	$ 9.1	$ 149.1	$ 198.3	$ 237.8	$ 257.5	$ 270.1
Total Societal Costs Adjusted for PTF Cost Treatment [4]	$1,187.2	$1,274.3	$1,271.1	$1,267.0	$1,239.7	$1,169.8

[1] Rate discount is 10%

[2] This includes variable portion of power supply costs, congestion costs and transmission losses

[3[For Arc 1 to 4 societal benefits is the monetized value of emissions. For ARC 5 societal benefits inlcudes the monetized value of emissions and avoided distribution costs

[4] About 90% of NRP costs will be recovered as PTF Through NEPOOl Transmission Tariff

Results

The LA Capra assessment analysis concluded that the NRP required the lowest total present capital outlay between 2005 and 2016 ($94.2 million), and ARC 5 (the maximum achievable DSM case) the highest, $306.7 million. However, ARC 5 has the lowest total societal costs of any of the alternatives. ARC 5's low total societal costs were due primarily to the avoided generation costs and the avoided distribution and sub-transmission system upgrade costs produced by the DSM savings, which largely offset the cost of the three combustion turbines added in 2005. Under a series of stress cases, ARC 5 had lower societal costs than did the NRP under all stress cases except the low load growth case.

The assessment further concluded that should high growth materialize, although not quantitatively captured, the physics of the power system would favor the NRP. On the other hand, should low load growth as represented in the Low Vermont Load Growth scenario, the need for the majority of the NRP elements and some generation to be installed and in service by summer 2005 is unchanged. In addition, pursuit of any alternatives results in higher societal costs.

Amongst the ARCs, the total societal costs ranged from 3% higher than the expected total societal costs of the NRP to approximately 9.5% lower. VELCO believes that, while these differences are not trivial, 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. It further concluded the decision as to which project provides a more robust solution to the reliability problem, therefore, was dependent largely on professional judgments regarding both the relative cost and implementation uncertainties.

VELCO maintains that DSM program implementation should not be difficult, however, the results are uncertain and the scale of the program is unprecedented. The DSM component does not, on its own, displace or defer any material part of the NRP. Moreover when one accounts for the ISO-NE pooled transmission funds (PTF) cost-sharing policy which the transmission project would receive, the societal costs between ARC 5 and the NRP close to within $10 to $20 million difference in total societal costs. Under ISO-NE regulations, all ratepayers throughout the region contribute to transmission system upgrades, resulting in Vermont's share of the NRP being only about 5% of the total cost. To date, ISO-NE has not established a similar cost-sharing mechanism for alternative resources. Given the uncertainties presented, VELCO believes this difference does not adequately justify the substantial expenditures required to implement the DSM program and construct the generation and the transmission plant for ARC 5.

The net cost of demand-side transmission capacity available from targeted energy-efficiency resources was negative. ARC 5, with DSM and distributed generation (DG) resources, proved to be the least-cost option with the benefits of the DSM portion more than offset the high cost of the combustion turbines. While the ARC 5 solution provided the least societal, long run cost, it was substantially more expensive to Vermont ratepayers than traditional supply. Under current Northeast Independent Systems Operator (ISO-NE) pooled transmission funding (PTF) rules, Vermont's contribution to the transmission system capital cost is only five percent, with southern New England's greater loads covering the remainder of these costs. Vermonters, however, would bear the full cost burden of implementing any energy-efficiency initiatives and DG. The preceding Table 1 shows the results of the PTF treatment. Proposing the installation of several DG resources would likely raise significant issues, particularly related to siting the units.

The assessment acknowledged that DSM resource contributions outside of the Inner and Metro zones valued in its study might prove useful to addressing Northwest Vermont's reliability constraints. However, given that it was difficult to ascertain how much value the Northwest and Northwest/Central zones might offer to address the Inner and Metro zones constraints, none was included, although it is clear that there would be some value. Therefore, only DSM resources from the Inner and Metro zones are included in ARC 5.

Policy Issues

VELCO's analysis raises substantial issues regarding electric system policy, especially related to cost-effectiveness, funding and equity. The VELCO analyses raise the following significant issues and barriers regarding the valuation of DSM resources:

- **ISO-NE PTF treatment is a barrier to least cost planning.** The current ISO-NE PTF treatment approach does not allow energy efficiency or distributed generation to be on an equal footing with traditional transmission supply solutions. This incongruity could drive decision making towards the least-expensive, capital costs rather than the lowest societal costs. Since regulators are first and foremost concerned with the public interest of their state, this poses significant dilemmas where the societally optimal solution may be the worst solution when drawing societies' boundaries at the state line. Such a skewing of values may drive decision makers to tend to overbuild traditional supply resources. In addition, the uncertainty about continuation of this PTF policy may actually encourage early construction of transmission solutions.
- **Timing is critical.** The likely needs must be identified as early as possible, and full integrated DUP engaged in as soon before the need as possible. In particular, the deployment of energy-efficiency resources must be done sufficiently in advance of the need to make a real difference. If energy efficiency resources are not deployed until the

need is imminent (i.e., within three to five years), then DSM is not likely to achieve savings fast enough to defer the need for other resource solutions over a substantial time period. However, overall DSM resource contributions could be substantial if these resources are deployed in advance.

- **Diversification of benefits and costs is a barrier to least cost solutions.** In today's environment where utilities are often not vertically integrated, the numerous benefits from efficiency or DG resources are often spread among numerous entities. For example, generation may accrue to one entity, transmission savings to another, and distribution to still another. Benefits are even further diversified when one considers natural gas, oil and water impacts from efficiency programs. The costs of efficiency or DG programs are typically borne by a single entity. In the case of Vermont, to pursue ARC 5, VELCO might bear the program costs for DSM, while they would accrue only the transmission benefits. Mechanisms to combine forces in a way that equity shares costs and benefits among many parties, while not instituting other barriers to effective planning and implementation, is crucial for non-traditional resources to be deployed in a least cost manner.
- **Ancillary load reductions may or may not be important.** More research is needed to better define the value of neighboring load reductions in improving the reliability within a constrained area. In this case, even with fairly rigorous estimates of DSM potential and program costs for the Northwest and Northwest/Central zones, VELCO was unable to determine the true least cost resource solution.

Conclusion

A number of lessons and research needs are apparent from the VELCO analysis. The significant value of ARC 5 – energy efficiency combined with combustion turbines – shows the importance of performing an integrated analysis looking at multiple resources to identify the long-term least-cost solution. To best perform this, a full integration with smaller chunks of resources may provide a more accurate solution (e.g., considering smaller portions of the full efficiency and distributed generation potential). Because the optimal solution may require multiple small resources, in different configurations and time trajectories, it is important not to screen out potential resources that, while not sufficient to defer any supply by themselves, could be important when combined with multiple other small resources.

In performing any least-cost analysis, it is important to consider all the costs and benefits, and to consider who pays and who gains. The significant diaspora of benefits among different parties can be a substantial barrier to implementation of the societally least-cost solution. In order to facilitate adoption of least-cost solutions, these equity issues must be addressed.

It is clear that energy efficiency offers substantial cost-effective resources to the transmission system. In addition, when accounting for non-transmission benefits, the cost of efficiency to the transmission system is *negative*. However, the timing and acquisition of efficiency and other resources is critical. Long-term planning must occur well ahead of the need for new resources in order to properly consider and take advantage of all potential cost-effective resources. If -- as is all too often the case – one waits until the need is critical and construction of transmission supply must begin, it is often too late to take advantage of other potentially cheaper resources that might have been worthwhile given more lead time.

Finally, we need to better understand how power flows and demand outside of constrained regions effect the need for new resources within these regions. This may open up additional resources that are not now considered as part of the potential resource solution.

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