2006 Vermont Transmission System 10 Year Long Range Plan Analysis

A Reliability-Based Electric System Upgrade Schedule for the Vermont Bulk Power Supply System

VOLUME 1: Body of report only

Volume 2, which includes the appendices, will be made available upon request

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This report has been redacted recognizing critical energy infrastructure information requirements. The full report is available upon written request.
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EXECUTIVE SUMMARY

This report presents an update of the previous 2001 VELCO long range planning study in a format designed to comply with the requirements of 30 V.S.A. section 218c(d). Regardless of statuary requirements, Highgate import contracts ending in 2016 and the operating license of the Vermont Yankee nuclear generator coming up for renewal in 2012, it is critical to re-assess Vermont transmission system reliability at this time with due consideration to the potential removal of these two important resources. It is too early to determine system reliability much beyond 2016 with any reasonable accuracy; the major source changes in Vermont and similar changes within New England could significantly alter system performance. Also, load forecasts and upgrade plans for the regions adjacent to Vermont (i.e., New York, New Hampshire and Massachusetts load areas) can affect Vermont electrical system performance, and the necessary information for these adjacent areas is not readily attainable for more than 10 years out.

Summer loads were studied in this analysis, since Vermont summer and winter load forecasts are presently quite close and transmission line ratings are significantly more limited during the summer. The most recent DPS forecast (released in August, 2002) suggests that the Vermont summer peak load will reach approximately 1,315 MW in year 2016. ISO-NE's April 2006 load forecast for Vermont correlates well with the DPS forecast. The ISO's forecasted load level has a 10% chance of being exceeded. The DPS forecast assumes that all existing DSM programs in Vermont have continued at current levels. The corresponding New England load was modeled at 31,200 MW, which was based upon the 2005 ISO-NE forecast and had a 50% chance of being exceeded.

In this study, two projects that were approved by ISO-NE were assumed in service: the Vermont Yankee (VY) generator uprate project that was completed in the spring of 2006 and the Monadnock Region Project that is scheduled for completion in 2009. The VY uprate increases the capacity of the unit by 20%. The Monadnock project installs system upgrades in eastern Vermont, southerwestern New Hampshire and north-central Massachusetts. They include a Coolidge 115 kV dynamic var device with a 150 MVAr dynamic range (installed in a VELCO substation in Cavendish, VT) and a 345/115 kV autotransformer at Fitzwilliam, New Hampshire, which will tap into the 345 kV line that goes from VY to Amherst, New Hampshire and the 115 kV line that goes from Bellows Falls, Vermont to Fitchburg, Massachusetts. In addition, a third project in its conceptual stage was assumed in service. That project is the dynamic var device proposed for the Stratton 46 kV substation. This study further assumed in service the Northwest Vermont Reliability Project (NRP), which is currently under construction with expected completion by end of 2007, as well as power factor correction capacitors on the lower voltage networks within Vermont.

Since both Highgate contracts and VY generation could cease by the year 2016, it is useful, and in fact critical, that we have an awareness of how these major source changes will affect system reliability upon their occurrence. Determining what upgrades would be made necessary by the absence of these two sources of power to Vermont helps determine their value to the transmission network. Therefore, in this Long Range Plan Analysis (LRPA), Highgate was studied at 200 MW and at 31 MW, i.e. feeding power only to the northern loop block load, and the VY generator was studied both in and out of service. These generation scenarios were studied under three regional power transfer conditions, recognizing that transfers can affect the performance of the Vermont transmission system.

This Long Range Plan Analysis consists of 6 stages of analyses as follows:

Stage 1) Analysis of the post–NRP system at 1,300 MW and documentation of all thermal and voltage reliability issues that resulted from that analysis. Upgrades to resolve these identified reliability issues were then proposed and incorporated into new analyses. Where more than one alternative to a reliability issue was identified, additional analyses were performed so that each alternative could be studied separately.

Stage 2) Analysis of the cases modified from stage one was completed and, again, thermal and voltage reliability issues were documented. Alternatives that were unsuccessful at maintaining acceptable reliability were eliminated, and alternatives that were relatively successful but needed additional upgrade elements were improved as necessary. During this stage of analysis, some reliability issues, such as transmission line and step-down transformer overloads, were left unresolved in order to allow stage three sensitivity analyses to remove the upgrades if possible.

Stage 3) The analysis involved taking eight remaining sets of upgrade alternatives and testing a few key, additional upgrade options to determine if the various remaining reliability concerns could be removed by any single, larger upgrade. During this stage of analysis, upgrade selections were made to resolve the reliability concerns that remained from stage two. In addition, sub-transmission through-flow issues were identified and analyzed to determine if all through-flow issues could be mitigated with post-contingency sectionalization.

Stage 4) In this analysis, the final lists of upgrade alternatives were modeled and analyzed. No additional Vermont high-voltage transmission system reliability concerns were identified. After this analysis was completed, brief winter load sensitivity analyses were conducted on some key winter peaking areas, after which additional upgrades were included to address any reliability concerns that were identified as a result of this study work.

Stage 5) This analysis involved reducing Vermont loads to 1,200 MW and 1,250 MW in order to determine the relative timing of the various elements of the final plan.

Stage 6) In this analysis, generation alternatives to the transmission upgrades identified in stage four were considered, and alternatives are proposed to those transmission upgrades that could be offset by non-transmission options.

The final transmission upgrade list follows on the next page. Whether Vermont Yankee is in service or not, the list of upgrades remains the same. The retirement of Vermont Yankee will have a negative impact on transmission system performance in Vermont as well as New York, New Hampshire and Massachussetts. However, the reliability concerns in Vermont observed with VY out of service were also observed with VY in service, although in the latter case they are less severe. Therefore, the upgrades needed with VY in service also address the concerns with VY out of service. Continuation of Highgate contracts will defer the need to reconductor the Rutland-Cold River 115 kV line, to rebuild the New Haven-Williston 115 kV line, and to install a second underground cable under the Causeway in the PV-20 line (between Plattsburgh, NY and Milton, VT) beyond 2016 based on current information and analysis. These are upgrades #22d, #23, and #20 on the following page. The usefulness of upgrade #20 assumes that this second cable will reduce the duration of the PV-20 outage to less than a day. It further assumes that other equipment outages along the PV-20 path can be addressed in less than a day as well. This assumption may be incorrect because the phase-shifting transformer at VELCO's Sand Bar substation or a submarine cable in Lake Champlain on the PV-20 path may require many days to many months to be repaired or replaced. If that is the case, continuation of Highgate contracts will defer, instead of the second underground Causeway cable, the need for a new 115 kV line between VELCO's Granite and Middlesex substations, a new 115 kV line between VELCO's East Avenue and Queen City (or Willsiton) substations, and the reconductoring of the Granite-Comerford 230 kV line.

This 10-year Long Range Plan Analysis will be revisited and updated no later than 2009. At that time, a new 10-year load forecast will be examined. In addition, it is anticipated that a new 2016 load forecast will be examined, to the extent additional data have modified the projected 2016 load significantly, and network topology both in and outside of Vermont has changed significantly. This ongoing Long Range Plan Analysis update process should provide useful information for the discussion of electric infrastructure needs within the state of Vermont.

The following is the final LRP transmission upgrade list:

1) One of the following 340 line back-up alternatives:

   (A VY – West Dummerston 115 kV line and a 115/46 kV step-down transformer at West Dummerston are included in all four alternatives)

   a) Coolidge – West Dummerston – VY 345 kV line
   b) Coolidge – West Dummerston – VY 115 kV line (built at 345 kV operated at 115 kV)
   c) Coolidge – Fitzwilliam (NH) 345 kV line
   d) Coolidge – Deerfield (NH) 345 kV line

2) 4-breaker VY 115 kV ring bus (not needed in Coolidge – VY 345 kV option)
3) Coolidge 115 kV dynamic var device (150 MVAr range) and two new 24.75 MVAr capacitor banks
4) Irasburg dynamic var device (minimum of 45 MVAr capacitive capability). 5-breaker 115 kV Irasburg ring bus
5) One of the following VY T4 auto back-up alternatives (dependant on choice in upgrade 1):

   a) West Dummerston 345/115 kV 448 MVA transformer (with upgrade 1a)
   b) 2^{nd} 448 MVA VY transformer (with upgrade 1b, 1c or 1d)

6) 2^{nd} Coolidge 345/115 kV 448 MVA transformer and a Coolidge 345 kV bus expansion to 6-breaker breaker-and-a-half substation
7) Replace the two existing Bennington 115/46 kV transformers with 75 MVA units
8) Ascutney 115 kV bus upgrade to a 9-breaker breaker-and-a-half substation with a 2^{nd} 115/46 kV 56 MVA transformer
9) Georgia 115 kV 6-breaker ring bus
10) Replace the two existing St. Albans 115/34.5 kV transformers with two 56 MVA units (move existing units to new Milton 115/34.5 kV station)
11) North Rutland 115 kV 4-breaker ring bus with 2^{nd} 115/46 kV 56 MVA transformer
12) 2^{nd} Queen City 115/34.5 kV 65 MVA transformer
13) Berlin 115 kV 4-breaker ring bus
14) Barre 115/34.5 kV 100 MVA transformer (retain the old unit and move it to new Berlin ring bus)
15) Hartford 115 kV 4-breaker ring bus with 2^{nd} 115/46 kV 56 MVA transformer
16) Middlebury 115 kV 4-breaker ring bus with 2^{nd} 115/46 kV 56 MVA transformer
17) Upgrade 115 kV bus conductor on Williston 115 kV ring bus
18) Add a new breaker adjacent to the 345 kV VY79-40 breaker at VY (for upgrade options 1b, 1c or 1d)
19) Stratton – West Dummerston 115 kV line and a 115/46 kV Stratton substation with a 56 MVA step-down transformer
20) 2^{nd} PV20 Causeway Cable [2 miles]
21) 16.2 MVAr of capacitance at Blissville 46 kV bus
22) Re-conduct the following transmission lines:

a) Cold River – Coolidge 115 kV line (18.2 miles of 1272 ACSR)

b) Barre – Berlin 115 kV line (5.6 miles of 1272 ACSR) (not needed with option 1d)

c) Florence – West Rutland 115 kV line (5.3 miles of 1272 ACSR)

d) Rutland – Cold River 115 kV line (5.6 miles of 1272 ACSR)

23) Re-build New Haven – Williston 115 kV line (20.6 miles of double-bundle 954 ACSR conductor potentially built with 345 kV construction but operated at 115 kV) (not needed with option 1b)

1.0 INTRODUCTION

The Vermont Long Range Plan Analysis is an effort that was last pursued in 2001. That plan provided useful insight into the future of the Vermont transmission system. Recognizing that the transmission system continues to evolve through time, this plan should ensure that proposed upgrades will remain useful beyond the study horizon, such that there is not a need to demolish recently installed or constructed infrastructure in order to incorporate reliability projects at higher load levels. This document will not only serve as the first 10-year transmission plan mandated by 30 V.S.A. section 218c(d), but it will also provide the necessary information so that demand-side management (DSM), distributed generation (DG), and larger scale generation options may be considered as upgrade alternatives as well.

The Northwest Vermont Reliability Project (NRP) is currently under construction. Studies performed in 2004 determined that the NRP will serve Vermont load reliably up to approximately 1,200 MW of load, assuming a long-term Highgate Converter outage as the major source outage; or 1,165 MW if instead the PV20 line is the assumed long-term outage. According to the DPS August 2002 forecast and the ISO-NE Capacity, Energy, Loads and Transmission (CELT) report 2005 90/10 forecast, the 1,165 MW Vermont load level is expected by year 2009.

With Highgate contracts ending in 2016 and Vermont Yankee eligible for retirement in 2012, this point in time is a pivotal one with regard to assessing Vermont transmission system reliability. At this time, it is too early to accurately determine system reliability much beyond the year 2016, since major source changes in Vermont and similar changes within New England could significantly alter system performance. Also, load forecasts and upgrade plans for the regions adjacent to Vermont (i.e., New Hampshire and Massachusetts load areas) can affect Vermont electrical system performance, and the necessary information for these adjacent areas is not readily attainable for more than 10 years out. The most recent DPS forecast (released in August, 2002) suggests that Vermont load will reach 1,313 MW in year 2016. This assumes that all existing DSM programs in Vermont continue at their current level of productivity, resulting in approximately 79 MW of load reduction from the original 2016 forecast of 1,392 MW. ISO-NE's April 2006 load forecast for Vermont correlates well with the DPS forecast. The ISO's forecasted load level has a 10% chance of being exceeded.

In this study, two projects that were approved by ISO-NE were assumed in service: the Vermont Yankee (VY) generator uprate project (which was completed in the spring of 2006) and the Monadnock Region Project that is scheduled for completion in 2009. The VY uprate increases the capacity of the unit by 20%. The Monadnock project installs system upgrades in eastern Vermont, southerwestern New Hampshire and north-central Massachusetts. They include a Coolidge 115 kV dynamic var device with a 150 MVAr dynamic range (installed in a VELCO substation in Cavendish, VT) and a 345/115 kV autotransformer at Fitzwilliam, New Hampshire, which will tap into the 345 kV line that goes from VY to Amherst, New Hampshire and the 115 kV line that goes from Bellows Falls, Vermont to Fitchburg, Massachusetts. In addition, a third project in its conceptual stage was assumed in service. That project is the dynamic var device proposed for the Stratton 46 kV substation. Finally, approximately 150 MVARs of power factor correction capacitors were assumed on the lower voltage networks (subtransmision and distribution) within Vermont.

Since both Highgate contracts and VY generation could cease by the year 2016, it is useful, and in fact critical, that we have an awareness of how these major source changes will affect system reliability upon their occurrence. Determining what upgrades are made necessary by the absence of these two sources of power to Vermont helps determine their value to the transmission network. In this Long Range Plan Analysis (LRPA), Highgate was studied at 200 MW and at 31 MW, i.e. feeding power only to the northern loop block load, and the VY generator was studied both in and out of service.

New England transfer conditions can have a fairly significant effect on Vermont system reliability, especially since Vermont is an importing transmission area. So, in this analysis west–east and east–west New England transfers are considered. The overall New England load studied, with losses included, was approximately 31,200 MW, which is only slightly higher than the 50/50 New England forecast for the year 2016 (from the ISO's 2005 forecast). The "50/50" forecast is a load value that has a 50 percent chance of being exceeded. A "90/10" forecast is the higher New England forecast that is normally used for planning purposes. Such a forecast has only a 10 percent chance of being exceeded. But to model a load flow case that reflects such a load would require system upgrades in other New England states that, as noted before, VELCO can not predetermine.

This Long Range Plan Analysis consists of six stages of analyses. First, the post–NRP system was analyzed at 1,300 MW, and all thermal and voltage reliability issues that resulted were documented. Upgrades to resolve these identified reliability issues were then proposed and incorporated into a new set of cases. Analysis of the new upgraded 1,300 MW cases was completed in stage two and, again, thermal and voltage reliability issues were documented. As a result of the stage two analyses, alternatives that were unsuccessful at maintaining acceptable reliability were eliminated, and alternatives that were relatively successful but needed additional upgrade elements to make them more complete were appended as necessary. During this stage of analysis, some reliability issues, such as line and step-down transformer overloads, were left unresolved in order to allow stage three sensitivity analyses to remove the upgrade needs where possible.

The third stage of analysis involved taking the remaining sets of upgrade alternatives and testing a few key additional upgrade options to determine if the various remaining reliability concerns could be removed by any single, larger upgrade. During this stage of analysis, upgrade selections were made to resolve the reliability concerns that remained from stage two and then brief winter load sensitivity analyses were performed on some key winter peaking areas, after which additional upgrades were included to address any reliability concerns that were identified as a result of this study work. In the fourth stage of analysis, the final lists of LRP upgrade alternatives were modeled and analyzed. No additional Vermont high-voltage transmission system reliability concerns were identified. The final LRP transmission upgrade list and related breaker one-lines indicating substation upgrade designs can be found in the Conclusion section of this report.

Stage five of the LRP analysis involved reducing Vermont loads to 1,200 MW and 1,250 MW in order to determine the relative timing of the various elements of the final upgrade plan. In stage six analyses, generation alternatives to the transmission upgrades identified in stage four were considered, and alternatives are proposed to those transmission upgrades that could be offset by non-transmission options (including potential load reduction through demand side management efforts and generation).

2.0 BASE CASE DEVELOPMENT

2.1 Load Forecasting: Vermont and the Rest of New England

Peak load analyses were performed consistent with VELCO study practice. Cases were developed using the most recent DPS forecast from August, 2002 and the ISO-NE CELT 2005 forecast. A summer peak extreme weather forecast (90/10 = 10% chance of being exceeded) was used for Vermont and a normal weather forecast (50/50 = 50% chance of being exceeded) was used for the rest of New England. A normal weather forecast was used for the rest of New England to ensure that extreme weather load growth outside of Vermont does not become the driver for any Vermont upgrade solution. Further, New England does not have sufficient installed generation in 2016 to support the 90/10 load forecast and maintain the power transfers at the interface limits.

In studies that look out shorter lengths of time, a 90/10 New England forecast is usually used for planning studies and proposed or planned upgrades for other regions are put in service to address reliability issues so that reliability problems in one region do not adversely affect another. Each Transmission Operator (i.e. National Grid and Northeast Utilities) also has the opportunity to redistribute its load to more accurately coincide with its own regional forecasts. However, a 10-year outlook is not yet a common length of time and, as a result, there are few proposed upgrade plans and/or load forecasts prepared for these other regions at 2016 extreme weather load levels. With that said, the most appropriate approach was to use a normal weather forecast for New England load outside of Vermont.

The DPS forecast from August of 2002 was broken into three load zones as follows:

1. Northwest Vermont: Chittenden, Franklin, and Grand Isle counties
2. Southern Vermont: Rutland and Bennington counties
3. Rest of Vermont: all other counties in Vermont

After using the DPS forecast to set the Vermont load to meet the year 2016 forecast, the resulting load distribution was reviewed by the sub-transmission utilities in Vermont. Several companies took the opportunity to redistribute their loads within each DPS load zone to more accurately reflect the forecast they maintain for their load in each respective area. The result was a final load forecast that met the DPS forecast for all three of its load zones and at the same time was distributed in a fashion that met the forecast of the Vermont sub-transmission utilities.

The resulting overall summer peak load levels studied were as follows; Vermont load was approximately 1,315 MW and New England load was about 31,200 MW (both values include system losses). Tables 2.1.1, 2.1.2, 2.1.3 and 2.1.4 show historic Vermont loads, future forecast loads (DPS August 2002 forecast with existing DSM programs taken into account), the ISO-NE CELT 2005 forecast for all of New England load and the ISO-NE forecast for Vermont loads from the 2006 CELT forecast, respectively. Note that the New England forecast (shown in table 2.1.3) does not go beyond 2014 and the ISO-NE Vermont forecast from the 2006 CELT (shown in table 2.1.4) does not go beyond 2015. Load growth was extrapolated from these forecasts to arrive at the values for later year totals.

Historic information was utilized to create figure 2.1.1. This figure presents on the same graph past Vermont summer peak load demands for the past 25 years (1980 to 2005), the 2002 DPS forecast and the 2006 ISO-NE forecast. The figure indicates that while the DPS and ISO-NE forecasts differ slightly in terms of the year where the predicted load level will occur (the ISO predicts faster load growth in Vermont over the short term), both forecasts predict roughly a 1,300 MW load level by the year 2016. Also, the trends suggested by the historic data indicate an expectation of approximately 20 MW of summer peak demand growth per year over the past quarter century. A decade's worth of load growth using this trend (200 MW) would also place Vermont's summer peak demand at approximately 1,300 MW by the year 2016.

The reason why VELCO used ISO-NE's 2005 CELT forecast instead of a later one for region wide load forecasts was availability and need; the analysis for this planning effort began in late summer 2005. The latest ISO-NE forecast available at the time was the 2005 CELT. The 2006 CELT forecast became available in April of 2006, which was too late for use in the creation of the cases for the analysis, but was useful for comparison of the Vermont state peak forecast to the DPS forecast used for this analysis. One last key item is noteworthy from the latest ISO-NE CELT forecast; the predicted New England regional summer peak load is predicted to grow at a faster rate than from last year's forecast. For example, the

2005 CELT forecast predicted a New England summer peak demand in 2014 of 32,050 MW with a 10% chance of being exceeded. The 2006 CELT report indicated the same 2014 year peak forecast to be 33,620 MW, or an increase of 1,570 MW.

Finally, table 2.1.5 and figure 2.1.2 were provided to better illustrate the geographic dispersion of estimated load growth in the 2016 cases. Based on the distribution of load among the substations modeled in the databases, and the limitations of the transmission network, the Vermont system was split into five zones to describe where load growth appeared. These five zones are shown graphically in figure 2.1.2, while table 2.1.5 provides the name of each zone, notes the base peak demand estimated from current peak demand levels, indicates how much load growth was modeled in the zone in the 2016 cases, and describes each load growth on a percentage basis (in terms of growth divided by the 2005 peak value).

Table 2.1.1 – Vermont Summer & Winter Peaks (1989 – 2005)

Year	Vermont Summer Peak (MW)	Year	Vermont Winter Peak (MW)
1989	804.7	1989/90	1000.6
1990	794.1	1990/91	941.6
1991	815.8	1991/92	957.1
1992	819.3	1992/93	974.1
1993	819	1993/94	972.3
1994	864.4	1994/95	956.8
1995	870.1	1995/96	964.1
1996	860.4	1996/97	960.6
1997	874.2	1997/98	960.1
1998	918.2	1998/99	994.5
1999	939.1	1999/00	1031.1
2000	931.6	2000/01	1016.3
2001	1003.6	2001/02	999.4
2002	1023	2002/03	1012.7
2003	1005	2003/04	1043
2004	970	2004/05	1086
2005	1073.5	2005/06	

Table 2.1.2 – DPS VT Summer Peak Forecast (with & without Existing DSM Programs)

Year	DPS 8-5-02 Forecast (MW)	Cumulative Estimated DSM Savings from Base DSM Programs (MW)	Vermont Peak Forecast Net DSM (MW)
2003	1044	5.5	1038.5
2004	1071	11.0	1060
2005	1090	16.7	1073.3
2006	1131	22.4	1108.6
2007	1158	28.1	1129.9
2008	1179	33.8	1145.2
2009	1203	39.5	1163.5
2010	1227	45.2	1181.8
2011	1253	50.9	1202.1
2012	1281	56.6	1224.4
2013	1302	62.1	1239.9
2014	1335	67.7	1267.3
2015	1361	73.3	1287.7
2016	**1392**	**78.9**	**1313.1**
2017	1426	84.5	1341.5
2018	1454	90.1	1363.9
2019	1480	95.7	1384.3
2020	1512	101.3	1410.7

Table 2.1.3 – New England Summer Peak Load Forecast (2005-2014)

New England Summer Peak Load Forecast for 2005-2014			
Loads beyond 2014 projected by VELCO Planning using the following growth percentages	**Year**	**New England 50/50 Load Normal Weather Forecast (MW)**	**New England 90/10 Load Extreme Weather Forecast (MW)**
		NE Load (MW)	NE Load (MW)
	2005	26355	27985
	2006	26970	28660
	2007	27350	29070
	2008	27750	29495
	2009	28145	29910
	2010	28565	30350
	2011	29050	30860
	2012	29500	31330
	2013	29845	31700
	2014	30180	32050
1.15%	**2015**	30527	32419
1.15%	**2016**	30878	32791
Probability of Exceeding Forecast	**~~>**	**50%**	**10%**

Table 2.1.4 – ISO-NE Summer Peak Load and Statewide Energy Forecast (2006-2015)

YEAR	VT Load Level (MW)	VT Energy Demand (GW-hrs)
2006	1105	6320
2007	1130	6390
2008	1155	6470
2009	1180	6540
2010	1200	6600
2011	1220	6645
2012	1240	6715
2013	1260	6790
2014	1275	6850
2015	1290	6910
2016	1305	6970
Probability of Exceeding Forecast	**10%**	

Figure 2.1.1: Vermont Historic and Forecast Summer Peak Loads (1980-2016)
(Historic loads from 1980 to 2005)

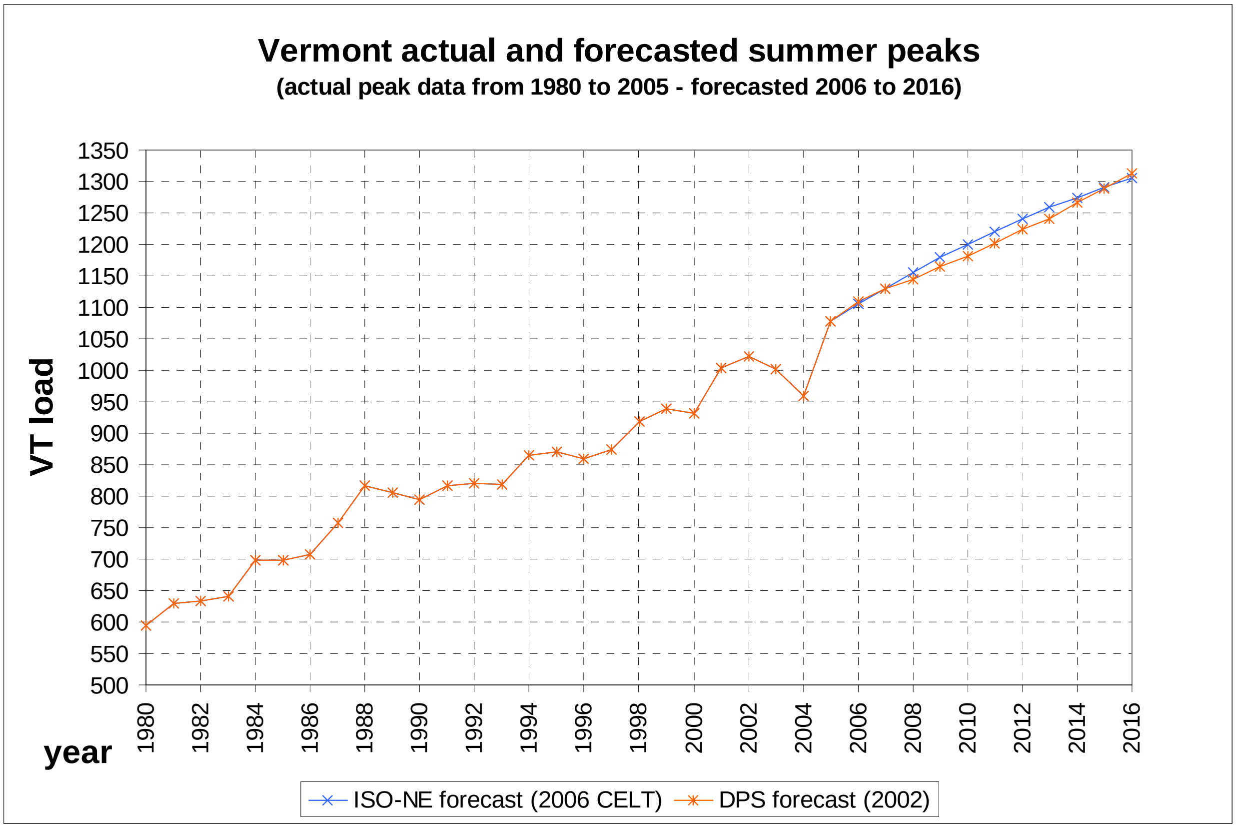

Table 2.1.5 – Vermont Zonal Load Growth Modeled in the Analysis

Load Zone	2005 Peak Demand	2016 Demand Increase	2016 Increase (%)
Northern	90	15	16.7%
Northwest	535	150	28.0%
Eastern	70	10	14.3%
Central	280	30	10.7%
Southern	140	20	14.3%

2.2 Network Model

The origin of the Long Range Planning cases is the 2004 ISO-NE area review analysis. Cases used in that analysis originated from the NPCC 2003 library of cases. The case that was used for the Long Range Planning study is a 2009 summer peak, extreme weather, New England load case. Vermont loads were grown to 1,315 MW as described in the Load Forecasting section of this report. New England loads were then grown to slightly greater than the 2016 50/50 New England load forecast. The Vermont detailed sub-transmission network was added to the cases, and new projects recently completed, or on the near-term horizon, were treated as is documented in Table 2.2.1. Those upgrades with the note "(I.3.9)" are already ISO-NE I.3.9 approved projects.

Table 2.2.1 – Network Model

Vermont Projects Included in Base Cases
Northwest Vermont Reliability Project (I.3.9)
VY Uprate to 667 MW net capability (I.3.9)
Stratton 46 kV +30 / -15 MVAr Synchronous Condenser
Tafts Corner 115/12.5 kV Transformer
Lamoille County Project
Relevant Outside Area Projects Included in Base Cases
Monadnock Region Reliability Project (I.3.9)
Y-138 Closed (I.3.9) (ME-NH 115 kV project)

Stratton 46 kV +30 / -15 MVAr Synchronous Condenser

The Bennington to Brattleboro 46 kV loop is an area that has a known and documented reliability deficiency. In preliminary preparation for this Long Range Plan, this area was examined and it has been confirmed that a +30 / -15 MVAr synchronous condenser at the Stratton 46 kV substation addresses these local area reliability concerns at present-day (year 2005) summer peak loads. As a result, this upgrade was included as a base upgrade in the Long Range Planning cases even though it is not yet an ISO-NE I.3.9 approved project. The +30 / -15 MVAr synchronous condenser was revisited at the end of the Long Range Planning transmission analysis to confirm that it was still a necessary upgrade at the 1,315 MW load level with any of the four final LRP upgrade alternatives in service, and it was still a necessary upgrade.

2.3 Power Factor Correction

Upon arriving at the completion of the load forecasting and network modeling portions of base case preparation, it was found that the Vermont system that resulted had poor pre-contingency voltage and low power factor in many areas. The appropriate approach to addressing these concerns is to improve the power factor of the load before analyzing load flow cases to determine transmission upgrade needs. VELCO transformer flows were examined and load areas that had pre-contingency low voltage issues were identified. Capacitor banks were added to improve the load power factor, as seen on the high side of the transformers, to at least 0.98 in accordance with VELCO power factor criteria. Table 2.3.1 shows a list of the year 2016 transformer flows in the initial Long Range Plan base case and corresponding MVAr deficiencies based on a power factor criteria of 0.98.

Table 2.3.1 – VELCO Transformer MVAr Deficiency Calculation in 1,315 MW Base Case

Stations	MW	MVAR	PF	Target pf	MVAR Deficiency
St Johnsbury	34.8	14.3	0.924953	0.98	7.23
Irasburg	10.3	3.5	0.946829	0.98	1.41
Newport	37.6	3.3	0.996171	0.98	none
Highgate CU	39.7	17.2	0.917584	0.98	9.14
Highgate VL	4.3	0.8	0.98313	0.98	none
St Albans	54.6	26.3	0.90093	0.98	15.21
E Fairfax	24.7	5.4	0.976926	0.98	0.38
S Hero	4.5	1.3	0.960714	0.98	0.39
Essex	77.8	27.9	0.941303	0.98	12.10
Taft Corner	35.1	7.2	0.979603	0.98	0.07
Queen City GMP	44.3	14.9	0.947824	0.98	5.90
Queen City BED	30.8	7.6	0.97088	0.98	1.35
East Ave	36.1	19.2	0.882894	0.98	11.87
Charlotte	9.2	1.5	0.986968	0.98	none
Shelburne	13.8	3.5	0.969311	0.98	0.70
N Ferrisburg	4.8	0.2	0.999133	0.98	none
Vergennes	11.3	4.7	0.923318	0.98	2.41
New Haven	6.2	2.2	0.942428	0.98	0.94
Middlebury	44.1	15.8	0.941403	0.98	6.85
Florence	30.6	3.4	0.993884	0.98	none
Blissville	22.4	2.1	0.995634	0.98	none
N Rutland	52.9	33.8	0.842676	0.98	23.06
Cold River	43.7	17.3	0.929791	0.98	8.43
Ascutney	49.7	5.7	0.993487	0.98	none
Windsor	31.6	4.8	0.988659	0.98	none
Hartford	21.3	6.5	0.956456	0.98	2.17
Chelsea	20.3	1.4	0.99763	0.98	none
Barre	34.9	-5.7	0.986924	0.98	none
Berlin	25.6	2.1	0.996652	0.98	none
Middlesex	23.7	0.3	0.99992	0.98	none
Moscow	16.6	-7	0.921426	0.98	-10.37
IBM	85.3	32.8	0.933374	0.98	15.48
Vernon Rd 46	36.9	5.4	0.989461	0.98	none
Vernon Rd 69	24.9	10	0.927962	0.98	4.94
Bennington 46	59.7	7	0.993196	0.98	None
Bennington 69	9.2	0.3	0.999469	0.98	None
Total	1113.3	297	0.966209	0.98	119.66

Once the additional capacitor banks were modeled, the pre-contingency voltages were again examined. Where voltages were still found to be unacceptably low, such as in the radial 69 kV system served by Bellows Falls, the radial 46 kV area out of Blissville, or the radial 34.5 kV system served from Comerford, additional capacitor banks were added to increase voltage. Table 2.3.2 is a complete list of the capacitor banks added to the case prior to the contingency analysis. Approximately 150 MVAr of new capacitors were added to the case. Two Lodge 5.4 MVAr capacitor banks were switched off. These capacitors are not needed for voltage support in the summer as evidenced by reactive power flow through the Moscow transformer from the 34.5 kV system up to the 115 kV system.

Table 2.3.2 – Sub-transmission Capacitor Banks Added to the 1,315 MW Base Case

BUS-NO	NAME	KV	ID	Actual Voltage (p.u.)	Total MVAr
87250	DORSET	46	x	0.963	1.6
87309	N RUT 46	46	x	0.9959	5.4
87314	GEN.EL.	46	x	0.9793	3.6
87357	MIDDLBRY	46	x	0.9839	7.2
87365	LALOR-D1	12.5	x	0.9866	5.4
87367	RUT GT-D	12.5	x	1.0436	3.6
87370	S.RUT-D1	12.5	x	1.0149	3.6
87371	S.RUT-D2	12.5	x	1.0242	10.8
87502	WDSVL TP	46	x	0.9909	5.4
87603	CAVDH 46	46	x	0.9645	1.6
87606	CHESTER	46	x	0.9561	1.6
87702	NORTH ST	46	x	0.9581	3.6
87753	N ELM ST	34.5	x	1.0164	5.4
87755	E ST ALB	34.5	x	1.0269	5.4
87813	GEORG TP	34.5	x	1.0124	5.4
87900	ST J CTR	34.5	x	0.9929	3.6
87906	LYNDN 34	34.5	x	0.9571	3.6
87952	S. ALBRG	46	x	0.9566	8.1
88005	PUTNEY	69	x	0.9325	1.6
88008	NORWICH	46	x	1.0023	5.4
88051	DORSET S	34.5	x	1.0083	5.4
88054	Q CTY 34	34.5	x	1.0136	5.4
88067	M BAY 34	34.5	x	1.0025	5.4
88071	VERGE 46	46	x	1.0042	2.7
88074	46Y1 TAP	34.5	x	1.0217	5.4
88100	EAVE	13.8	x	1.0215	5.4
88107	QCITY	13.8	x	1.0241	1.6
88115	PROV	13.8	x	1.0118	3.6
88118	UN	13.8	x	1.001	3.6
88349	IBMS/3-4	13.8	x	0.9958	5.4
88350	S/3-1	13.8	x	0.9945	10.8
97951	CU-HG-GI	46	x	1.0279	3.6
TOTAL					150.2

2.4 New England Power Transfer Conditions

Three New England system transfer conditions were assessed; an East-West, West-East and a Low transfer. The East-West transfer condition stresses from East to West within New England and from New England to New York. Interface flows under this stress condition are documented in Table 2.4.1. The West-East transfer condition stresses flows within New England from West to East and from New York to New England. Interface flows under this stress condition are documented in Table 2.4.2. The low transfer condition models lower East to West flows within New England and approximately 0 MW of power flow between New England and New York. Interface flows under this transfer condition are documented in Table 2.4.3. Note that the interface flows in the tables reflect transfers under all-lines-in conditions, but source outage cases, specifically Highgate out of service cases, differ somewhat. Case summaries with interface flows for each individual case can be found in Appendix B provided in volume

2 of the report. All of the cases are compared in a single table for each stage of the analysis at the end of Appendix B.

Table 2.4.1 – East-West Transfer Condition Interface Flows

Interface	MW	Interface	MW	Interface	MW
NB-NE	1005	MEYANK-SOUTH	730	MAINE – NH	1405
NNE-SCOBIE+394	2710	SEABROOK-SOUTH	1575	NORTH-SOUTH	2300
SANDY POND-SOU	2295	CMFD/MOORE-SOU	-90	SEMA/RI	1535
CT IMPORT	1475	SW-CONN IMPORT	1310	NORWALK-STAMFO	1060
BOSTON IMPORT	2210	NEMA/BOS IMPOR	2925	**NE EAST-WEST**	**2460**
PV20	125	**NY-NE**	**-1005**	NWVT AC import	570
TOTAL EAST	2320	CENTRAL EAST	1815		

Table 2.4.2 – West-East Transfer Condition Interface Flows

Interface	MW	Interface	MW	Interface	MW
NB-NE	1005	MEYANK-SOUTH	725	MAINE – NH	1175
NNE-SCOBIE+394	2440	SEABROOK-SOUTH	1620	NORTH-SOUTH	1480
SANDY POND-SOU	2290	CMFD/MOORE-SOU	-65	SEMA/RI	-390
CT IMPORT	510	SW-CONN IMPORT	1320	NORWALK-STAMFO	1050
BOSTON IMPORT	2850	NEMA/BOS IMPOR	3465	**NE EAST-WEST**	**-955**
PV20	120	**NY-NE**	**1040**	NWVT AC import	565
TOTAL EAST	4310	CENTRAL EAST	2200		

Table 2.4.3 – Low Transfer Condition Interface Flows

Interface	MW	Interface	MW	Interface	MW
NB-NE	1000	MEYANK-SOUTH	730	MAINE – NH	1175
NNE-SCOBIE+394	2480	SEABROOK-SOUTH	1565	NORTH-SOUTH	1865
SANDY POND-SOU	2235	CMFD/MOORE-SOU	-80	SEMA/RI	1225
CT IMPORT	1180	SW-CONN IMPORT	1310	NORWALK-STAMFO	1050
BOSTON IMPORT	2730	NEMA/BOS IMPOR	3405	**NE EAST-WEST**	**1175**
PV20	120	**NY-NE**	**0**	NWVT AC import	565
TOTAL EAST	3285	CENTRAL EAST	2000		

2.5 Vermont Transmission and Generation Resource Availability

2.5.1 Generation Resource Availability:

The Highgate Converter

The Highgate dc Converter terminal (200 MW), although not a generator, is the most critical resource in Vermont because of its location and its size relative to the load. This Converter ties Vermont to Canada at the northwest corner of the state allowing for the transfer of energy into Vermont. Three other dc terminals of the same design (Itaipu-Brazil, Rihand-India and Sylmar-California) have suffered catastrophic failures due to fire damage. Catastrophic failures are not necessary to cause significant outages. A wall bushing failure, which started outside the valve hall at the Nelson River 1,800 MW facility, caused an oil fire that contaminated valve components with soot and oil deposits. It took about 7 weeks working 24 hours a day to clean all valve components.

Although an HVDC terminal has no moving parts, it contains a very large number of parts that can and do fail due to such factors as human error, equipment damage, aging and the environment. The exposure is not simply the terminal itself. Highgate resembles a transmission line or a 50-mile generator lead stretching from Saint Césaire, Québec to Georgia, Vermont. It is in series with a 120 kV line in Québec, a converter transformer and a 115 kV line in Vermont. A failure of any of these facilities will cut off Highgate imports entirely. Outages north of Bedford, Québec may reduce Highgate to 20 MW due to voltage concerns.

In 1996, the Highgate Converter was out of service for over 300 hours due to a major ice storm, and again in 1997 the Converter was out for nearly 900 hours for transformer repairs. Outages of shorter duration have occurred several times since. For example, in 2002 Highgate was lost for 9 hours in mid-June after the Bedford to Highgate line tripped due to human error. The extended duration of this outage resulted from technicians encountering some difficulty re-closing one of the Highgate breakers. This type of outage, if it occurred on a peak load day, would place the Vermont transmission system in an unreliable operating situation. This information strongly supports using the ISO-NE reliability standards to analyze the system with Highgate unavailable (i.e. with a critical resource unavailable) prior to testing contingencies.

In addition, Highgate import contracts are also scheduled to come to an end in the year 2016. After that point, there is no certainty that power will be made available over the Highgate Converter. As a result, load flow cases were created with Highgate scheduled at 31 MW (i.e. feeding only a portion of the Northern Loop block load being supplied from the Vermont system). When contingencies are run against this subset of cases with all other transmission elements in service pre-contingency, it could be equated to studying the system with either Highgate contracts terminated or a Highgate long-term outage. But there is a subtle, yet important, difference between these two scenarios; if it is assumed that there is a long-term outage of Highgate, there need only be contingencies run against the system in that topology. <u>However, if Highgate contracts have ended, a long-term outage of some other major element in Vermont has to be applied with the Highgate Converter already reduced to 31 MW, before contingencies are tested</u>.

For the cases that have Highgate reduced to 31 MW, the assumption in this study is that Highgate contracts have ended. Therefore, long-term source outages will be applied to cases with Highgate reduced in the same manner as they are for cases with Highgate at 200 MW. These analyses were completed in this study in order to determine the effect a Highgate contract termination would have on Vermont system reliability, and thus assess the value of maintaining the contracts out beyond the year 2016. In the Methodology section of this report, stage one of the Long Range Plan is discussed in more detail and a full list of the cases created for analysis is presented.

Vermont Yankee Nuclear Generator

The Vermont Yankee nuclear generator was modeled at its uprate value of 667 MW. Its operating license will expire in the year 2012. After that time, there is no certainty that the unit will be in service because it has not been determined whether or not the license will be renewed. With this in mind, similar to the scenario with the Highgate Converter, the Vermont Yankee generator must be removed from service in a set of cases prior to any long-term outage being applied and contingencies tested. These analyses were completed in this study in order to determine the effect a Vermont Yankee retirement would have on system reliability. Again, in the Methodology section of this report, stage one of the Long Range Plan is discussed in more detail and a full list of the cases created for analysis is presented.

Vermont Hydro and Thermal Generation

There are limited generation reserves in Vermont for loss of the Highgate Converter or any critical transmission line. The Vermont hydro units, likely candidates for 10-minute reserves, cannot run if there is no water, as is more often than not the case during summer peak loads.

The next largest Vermont resource after Highgate is McNeil, which is a 51 MW wood burning generator in Burlington. This unit has been fairly reliable. Ryegate, which is a 20 MW wood burning plant in northeastern Vermont, has also been reliable. These two units make up approximately 40% of the small combustion units in Vermont and are assumed on line in this study. Ryegate was dispatched at 20 MW, while McNeil was dispatched at 51 MW in this analysis.

The other combustion units in Vermont have had very poor availability, and consequently are too unrealiable to be considered as available reserves. These smaller units (each 35 MW or less) are a selection of predominatly oil and diesel units. They can only run a limited number of hours yearly due to emissions requirements. They are showing signs of aging and they have not always run when called upon. Even if a percentage of these units were considered available to run, many cannot be brought on line within 30 minutes. Some of the units that have been called to run were unable to start, unable to come on line on time or have tripped shortly after starting. Others have been unavailable for extended periods due to ongoing major or minor failures. Since there is significant uncertainty as to whether these units will be available in the future, it seemed appropriate to not dispatch them in service as part of the Long Range Plan reliability study, and instead hold them in reserve for loss of McNeil.

Vermont Hydro was modeled at approximately 15 MW. Historically, this much hydro generation is about average at peak load levels in the summer when water supply is limited. Also Vermont tends to have a fairly flat peak, so it is not uncommon to find hydro generation lower than 15 MW during the hours around the peak when load is still very close to peaking. For example, during the 2002 summer peak week of August 12th – 16th, the average, peak load hour hydro was about 22 MW. However, during very high load, off peak hours hydro was as low as 5 MW. On August 16th Vermont load reached 1018 MW at 11 AM, but hydro generation was only 5.2 MW for this hour. The summer peak in 2002 was 1023 MW. Examples of past, and forecasted, hourly Vermont loads levels on summer peak days are shown in figure 4.6.2.

Table 2.5.1 – Generation Dispatch in Vermont

Hydro Units	Output (MW)		Thermal Units	Output (MW)
Fairfax	2.4		McNeil	51.0
Milton	3.5		Ryegate	20.0
Marshfield	4.9			
Silver Lake	2.2			
Glen	2.0			
Total	15.0		Total	71.0

2.5.2 Transmission Resource Availability:

Plattsburgh to Sandbar 115 kV (PV20) line

The Plattsburgh to Sandbar 115 kV (PV20) line has sections of cable that are under Lake Champlain (approximately 1.5 miles) as well as an underground section (approximately 2 miles) beneath the Causeway (The Causeway is a 1.2 mile raised roadway for Route 2 connecting Milton, VT with Grand Isle). It is possible that this line could suffer a long-term complete or partial outage due to failure of one or more of these cables. If an underground cable below the Causeway were damaged, the PV20 line would be completely out of service until the damaged section of cable was replaced with new cable, which has been estimated as a 26 to 31 day job assuming good weather conditions, contractor availabibility, and all required permits are obtained. If an underwater cable in Lake Champlain were damaged, the PV20 line would, at minimum, suffer a reduction in capacity. The full capacity of the line is 254 MVA, but if an underwater cable were lost a VELCO procedure exists to reconfigure the remaining cables so that the line could go back in service with a more limited capacity of 198 MVA. The line would remain at this limited capacity until the damaged cable could be replaced, or some other alternative solution was pursued.

In this study, both outage possibilities described in the paragraph above were considered. Going forward in this document, the first outage scenario (i.e. loss of an underground cable) is referred to as "PV20 out", and the second outage scenario (i.e. loss of an underwater cable) is referred to as "HalfPV20".

It is useful to note that the underground cables beneath the Causeway are 12 years old and the underwater cables (3-500 MCM and 3-1000 MCM cables) range from 35 to as much as 48 years old, with the 500 MCM cables being the oldest (circa 1958). Though this study assumes the HalfPV20 scenario could occur, it is important to recognize that the age of the underwater cables may play a role in the events that follow an initial underwater cable failure. Assuming that 198 MVA will be available assumes that the remaining cables, which will be just as old as the failed cable, can handle; 1.) the effects of the switching that would take place to reconfigure the cables, 2.) the initial post-contingency flow unbalance that would occur, and 3.) the increased power flow on the remaining cables after reconfiguration. This is a considerably significant set of assumptions and the HalfPV20 case results should be reviewed with these underlying assumptions in mind. If at any time these assumptions are determined to be too optimistic due to the age and health of the underwater cables, the existing HalfPV20 scenario would become invalid and any upgrade solutions that are needed in the PV20 out scenario would continue to be needed even if a redundant underground cable were to be installed in the Causeway, unless the underwater cables are upgraded as well.

Auto-Transformer Availability

The Coolidge 345/115 kV transformer is a large source for the 115 kV system in central Vermont. Recent 345 kV line upgrades in Vermont such as the Rutland Region Reliability Project and the Northwest Reliability Project (NRP) include back-up 345/115 transformers at each new 345 kV station (West Rutland and New Haven). This new approach has been undertaken by VELCO as a result of analyses that show that the Vermont system can be in an unreliable state for prolonged periods of time if one of these larger transformers should fail and be out long-term. This Long Range Planning analysis examines how the Vermont system performs, assuming a long-term outage of the Coolidge 345/115 kV transformer, to determine the extent of any potential reliability deficiency.

The VY 345/115 kV (T4) transformer is another 345/115 kV transformer that serves as a major source to the area it supplies. Without this transformer, the Keene to VY 115 kV line becomes a radial 115 kV source to Brattleboro from New Hampshire. The Monadnock Region Reliability study identified the long-term outage of this transformer as a reliability concern for load in southeast Vermont and southwest New Hampshire. The Long Range Planning analysis examines this long-term transformer outage in order to determine if any of the transmission upgrades proposed in this study address the concerns identified under T4 out conditions in the Monadnock study. If reliability issues continue to exist, a back-up unit will be the solution pursued.

The NRP includes two new 230/115 kV transformers at Granite. This approach has been taken for the same reason as that described above for New Haven and West Rutland 345 kV substations. Since the source from Comerford is one of Vermont's few high voltage sources, this Long Range Planning analysis examines the performance of the system with a long-term outage of one of these transformers, in essence, to confirm that one back-up transformer will continue to be sufficient as Vermont load grows.

Charlotte Area Underground Cables

As part of the NRP, a Queen City – New Haven 115 kV line is soon to be under construction. This new transmission line provides a second path between New Haven and Williston. During the studies that led to the NRP proposal, it was found that, under certain system conditions, separation of the northern and southern transmission areas in Vermont resulted in a reliability deficiency. To mitigate this reliability deficiency, this new line was proposed to parallel the New Haven – Williston 115 kV (K-43) line. However, since several portions of the new line will be underground, this Long Range Planning analysis considers the long-term outage of an underground cable section of the new line. An outage of the underground sections would remove the back-up to the K-43 line. This long-term outage was examined in order to determine what cable redundancy and switching capabilities the new underground cable sections between Queen City and New Haven should have in order to avoid having them become limiting contingencies in the future.

2.6 Base Case Development Summary

Below is a summary of the initial set of cases for the Long Range Planning analysis:

Table 2.6.1 – Long Range Planning Analysis Case Template

Long Range Planning Analysis Case Template

All as usual
Valid for 2009, 2012, and 2016 sets of cases

Cases	Highgate	VY	PV20	Coolidge auto	VY Auto	Granite Auto	Charlotte - North Ferrisburg 115 kV underground	
1	200	665	110-->249	IN	IN	IN	IN	
2	200	665	0	IN	IN	IN	IN	
3	200	665	70-->198	IN	IN	IN	IN	
4	200	665	110-->249	OUT	IN	IN	IN	
5	200	665	110-->249	IN	OUT	IN	IN	
6	200	665	110-->249	IN	IN	OUT	IN	
7	200	665	110-->249	IN	IN	IN	OUT	21 cases

VY Licence not renewed
Valid for 2012, and 2016 sets of cases

Cases	Highgate	VY	PV20	Coolidge auto	VY Auto	Granite Auto	Charlotte - North Ferrisburg 115 kV underground	
8	200	0	0	IN	IN	IN	IN	
9	200	0	70-->198	IN	IN	IN	IN	
10	200	0	110-->249	OUT	IN	IN	IN	
11	200	0	110-->249	IN	OUT	IN	IN	
12	200	0	110-->249	IN	IN	IN	IN	
13	200	0	110-->249	IN	IN	OUT	IN	
14	200	0	110-->249	IN	IN	IN	OUT	21 cases

Highgate dropped to 31 MW
Valid for 2016 sets of cases

Cases	Highgate	VY	PV20	Coolidge auto	VY Auto	Granite Auto	Charlotte - North Ferrisburg 115 kV underground	
15	31	665	110-->249	IN	IN	IN	IN	
16	31	665	0	IN	IN	IN	IN	
17	31	665	70-->198	IN	IN	IN	IN	
18	31	665	110-->249	OUT	IN	IN	IN	
19	31	665	110-->249	IN	OUT	IN	IN	
20	31	665	110-->249	IN	IN	OUT	IN	
21	31	665	110-->249	IN	IN	IN	OUT	21 cases

Highgate dropped to 31 MW and VY License not renewed
Valid for 2016 sets of cases

Cases	Highgate	VY	PV20	Coolidge auto	VY Auto	Granite Auto	Charlotte - North Ferrisburg 115 kV underground	
22	31	0	0	IN	IN	IN	IN	
23	31	0	70-->198	IN	IN	IN	IN	
24	31	0	110-->249	OUT	IN	IN	IN	
25	31	0	110-->249	IN	OUT	IN	IN	
26	31	0	110-->249	IN	IN	IN	IN	
27	31	0	110-->249	IN	IN	OUT	IN	
28	31	0	110-->249	IN	IN	IN	OUT	21 cases

84 Total

28 cases in low transfer

84 (28 * 3) cases total once E-W and W-E New England transfer conditions included.

Note: Red cases are All Lines In cases with no long-term outage (Various VY and Highgate scenarios are not considered long-term outages, but rather pre-existing system conditions).

Table 2.6.2 – Case Naming Convention

Case Label	Description
2016	Forecasted Year of 1315 MW cases
2014	Forecasted Year of 1260 MW cases
2011	Forecasted Year of 1200 MW cases
hg200	Highgate Converter at 200 MW
hg31	Highgate Converter at 31 MW
e-w	high NE-NY and East-West transfers
w-e	high NY-NE and West-East transfers
novyg or novy	Vermont Yankee generator assumed retired
cooltx	Coolidge 345/115 kV transformer out of service
grantx	One Granite 230/115 kV transformer out of service
t4	Vermont Yankee 345/115 kV T4 transformer out of service
ug	Underground cable between Charlotte and North Ferrisburgh out of service
pv20	Plattsburgh – Sandbar 115 kV line out (Causeway cable out of service)
halfpv20	Plattsburgh – Sandbar 115 kV line capacity limited to 198 MVA (Some underwater cables out of service)
Upgrade Options Examined in LRP Stage 2 Analysis	
A	Coolidge – VY 115 kV line
B	Coolidge – VY 115 kV line & VY T4 back-up
C	Coolidge – VY 115 kV line & Bennington – VY 115 kV line
D	2nd Coolidge – VY 345 kV line & West Dummerston – VY 115 kV
E	2nd Coolidge – VY 345 kV line & Bennington – VY 115 kV line
F	Fitzwilliam – Coolidge 345 kV line & VY T4 back-up & West Dummerston – VY 115 kV
G	Fitzwilliam – Coolidge 345 kV line & Bennington – VY 115 kV line
H	Deerfield – Coolidge 345 kV line & VY T4 back-up & West Dummerston – VY 115 kV
I	Deerfield – Coolidge 345 kV line & Bennington – VY 115 kV line
Final	Final set of Long Range Plan cases

3.0 METHODOLOGY

3.1 Summary of Facility Availability Methodology

Analysis was performed with a critical resource unavailable initially and loss of the next critical facility as required under NEPOOL criteria, which are consistent with those established by the Northeast Power Coordinating Council in the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems" and the "Bulk Power System Protection Criteria."

In addition, since it is possible that the Vermont Yankee generator could retire and/or Highgate contracts could end within the next ten year period, the following scenarios were studied as pre-existing system conditions upon which a long-term outage of a critical resource was applied and regular contingencies tested:

1.) Highgate Converter = 200 MW; VY generator = 667 MW
2.) Highgate Converter = 31 MW; VY generator = 667 MW
3.) Highgate Converter = 200 MW; VY generator = 0 MW
4.) Highgate Converter = 31 MW; VY generator = 0 MW

Transmission elements considered to be critical resources that could suffer long-term outages included high voltage transformers (345/115 kV and 230/115 kV units) and underground/underwater cable sections of critical 115 kV lines. The full list of long-term outages considered in this study follows:

1.) Plattsburgh – Sandbar 115 kV (PV20) line out of service (underground Causeway cables out)
2.) PV20 line limited to 198 MVA (one underwater cable out; line reconfiguration to maintain three phases in service)
3.) Coolidge 345/115 kV transformer out of service
4.) Vermont Yankee 345/115 kV transformer out of service
5.) Granite 230/115 kV transformer out of service
6.) Underground 115 kV cables between Charlotte and North Ferrisburgh out of service