Vermont System Planning Committee

Ensuring full, fair and timely consideration of non-transmission alternatives to address Vermont electric system reliability challenges.

QUARTERLY MEETING
SEPTEMBER 14, 2011
9:30 A.M. – 4:00 P.M.
HOLIDAY INN
RUTLAND, VERMONT

Agenda

- Introductions; Approval of the minutes of the June 8 and 15, 2011, meetings
- Subcommittee reports
  - Energy Efficiency & Forecasting
    - Geographical targeting of energy efficiency: progress report and next steps
  - Transmission
    - In-depth discussion of 2012 Long-Range Transmission Plan update
- Old business:
  - Docket 7081 process reform
    - Action item: Recommendations of the ad hoc process reform group for modifications to the Docket 7081 Memorandum of Understanding
  - Feedback on June 15 VSPC meeting with ISO-New England
  - 2012 Long-Range Plan update progress report
- Regional update
  - FERC Order 1000 implications for transmission planning – Presentation by Karen O'Neill, VELCO General Counsel at 11 a.m.
  - Status of solutions to address issues identified in VT/NH Needs
  - Other regional issues
- Project updates

Energy Efficency & Forecasting Subcommittee Report

Geographical Targeting of Energy Efficiency – Progress Report

- PSB agrees VSPC should recommend areas for geotargeting (8/1/11 Demand Resource Plan order)
- PSB requests a proposed process and schedule for VSPC input (8/8/11 PSB memo)
- Schedule proposed by DPS/VSPC:
  - 8/30/11 Energy Efficiency & Forecasting Subcommittee meeting
  - 9/14/11 VSPC consideration of EE&F recommendations
  - 9/21/11 file recommendations or alternative schedule with PSB
- EE&F meeting postponed due to Hurricane Irene
  - Meeting to be rescheduled in September
  - Need special VSPC meeting by phone to consider recommendations

Recommendations of Ad Hoc Process Reform Group

Recap of status

- Recommendations of the Ad Hoc Process Reform Group approved at 6/8/11 VSPC meeting with direction for further work on two areas:
  - Consider using 20-year planning horizon (not changing to 10)
  - Clarify categories of projects.
- Next steps: circulate for final review a draft addressing the two open issues.
  - Proposed language to be considered at this meeting.
  - Establish action plan for petitioning PSB for approval of amendments.

¶5: Planning Horizon

5. The plan shall include a specific determination by VELCO as to whether the planning horizon should exceed the 10-year horizon established in 30 V.S.A. §218(c)(d). ~~In preparing the Plan, VELCO will use a 20-year planning horizon.~~ The Parties recognize that certainty of forecasts, details, and pertinent facts and circumstances decreases as a planning entity looks further out ~~over a 20-year horizon,~~ and that this decrease in certainty is particularly acute on the Subsystem where changes in load can have a more significant impact on the identification and resolution of Reliability Deficiencies. As a result, greater attention should be placed on Transmission projects within the first 10 years of the planning horizon and on large Transmission projects that are expected to be needed regardless of when they are needed within the planning horizon.

June draft

Proposed resolution: retain original language requiring 20-year analysis.
Rationale: Provides time for NTA development. Consistent with DU IRP horizon.

¶6: categorizes projects to identify those with greatest NTA potential

6.A. The plan shall establish two categories for deficiencies and criteria for categorization:

a. Projects for which need dates are imminent or have passed, and for which non-transmission alternatives are clearly impracticable and/or uneconomic.

b. All other projects

Revised draft

A. The Plan shall establish three general categories for deficiencies and criteria for categorization:

a. Long-range, large-scale needs (and groups of needs) with prospectively high potential for being met through non-transmission alternatives through early collaborative planning;

b. ~~Projects of significant impact representing s~~Short- to medium-term needs for which transmission solutions may have significant economic and/or environmental impacts, and which have at least moderate potential to be addressed through~~, where~~ non-transmission alternatives~~ may be viable~~; and

c. Small projects and those with need dates and/or characteristics that render non-transmission alternatives clearly impracticable or uneconomic.

June draft

¶51: Conforming paragraph 51 with 6

¶51: Red=June draft. Blue=revised draft.

…Following the filing of the Plan, the VSPC shall, for each identified reliability deficiency or group of deficiencies ~~as~~ categorized under Paragraph 6A.~~a and~~ b:

a. Develop a project-specific action plan that describes a~~n appropriate,~~ non-generic critical path from identification to resolution, including, but not limited to, dates for key milestones and coordination with anticipated regulatory and stakeholder processes;

b. Subject to the rights and obligations of the DUs and all other parties to this MOU, select areas for focused NTA consideration~~development~~ and draft specific plans for moving that development forward; and

c. Report progress in relation to the project action plan to the VSPC quarterly and to the Board and Department not less than annually. Where milestones have been modified, progress reports shall state in reasonable detail the reason for such modification.

Proposed next steps upon approval by VSPC

- VSPC acts on final edits.
- Communication with Docket 7081 not at VSPC to share the draft and action plan.
- VELCO petitions the Public Service Board
  - Requests approval of amendments
  - Represents support by all parties who have agreed
  - Requests expeditious approval.
- Questions: timing, who contacts non-participating parties, other?

FERC Order 1000

PRESENTATION BY

KAREN O'NEILL, VELCO GENERAL COUNSEL

Order 1000

- Planning requirements
- Cost allocation requirements
- Nonincumbent developer requirements
- Compliance

Planning Requirements

- Regional planning
  - Each transmission planning region must produce a plan reflecting solutions to meet regions needs stakeholders must have an opportunity to participate.

- Planning for public policy requirements
  - Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements (federal and state statutes and regulations), and to identify potential solutions.

Planning Requirements

- Interregional coordination
  - Each pair of neighboring transmission planning regions must:
    - Share information regarding needs and potential solutions.
    - Identify and jointly evaluate interregional transmission facilities.
  - No requirement to produce an interregional plan or build facilities.

Cost Allocation Requirements

- Regional cost allocation: Cost allocation method must satisfy six cost allocation principles.
- Neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that satisfies six similar principles.
- Participant funding of new facilities permitted but not allowed as the regional or interregional cost allocation method.

Cost Allocation Principles

- Costs allocated “roughly commensurate” with estimated benefits.
- Those who don’t benefit don’t have to pay.
- Benefit-to-cost thresholds must not exclude projects with significant benefits.
- No allocation of costs outside region unless region agrees.
- Cost allocation methods and identification of beneficiaries must be transparent.
- Different allocation methods could apply to different types of transmission facilities.

Cost Allocation

- Rule doesn't require one size fits all; each region to develop its own cost allocation method.
- If regions can't decide on a method, FERC will decide.
- No interconnection-wide cost allocation.

Nonincumbent Developer Requirements

- Rule promotes competition in regional transmission planning; requires a not unduly discriminatory regional process for transmission project submission, evaluation and selection.
- Removes any federal right of first refusal from Commission-approved tariffs and agreements with respect to new transmission facilities selected in regional transmission plan for purposes of cost allocation, with four limitations:
  - Doesn't apply to facilities not selected in plan for cost allocation.
  - Doesn't apply to facility upgrades like tower change outs.
  - Allows but doesn't require competitive bidding to solicit projects or developers.
  - Doesn't affect state or local laws or regulations, including authority over siting or permitting of transmission facilities.

Compliance

- Each transmission provider is required to make a compliance filing within 12 months of effective date of final rule.
- Compliance filings for interregional transmission coordination and cost allocation must be made within 18 months of the effective date.

2012 Long Range Plan

SEPTEMBER 14, 2011
VSPC MEETING

Outline

- Study plan
  - VT planning process
  - Overview of 2012 study plans
- Criteria and assumptions
  - Comparison between 2012 and 2009
  - Review of load forecast
- 2018 transmission results
  - Effects of VY retirement
  - Review of potential NTAs
- Next Steps
- Questions

Vermont Study History

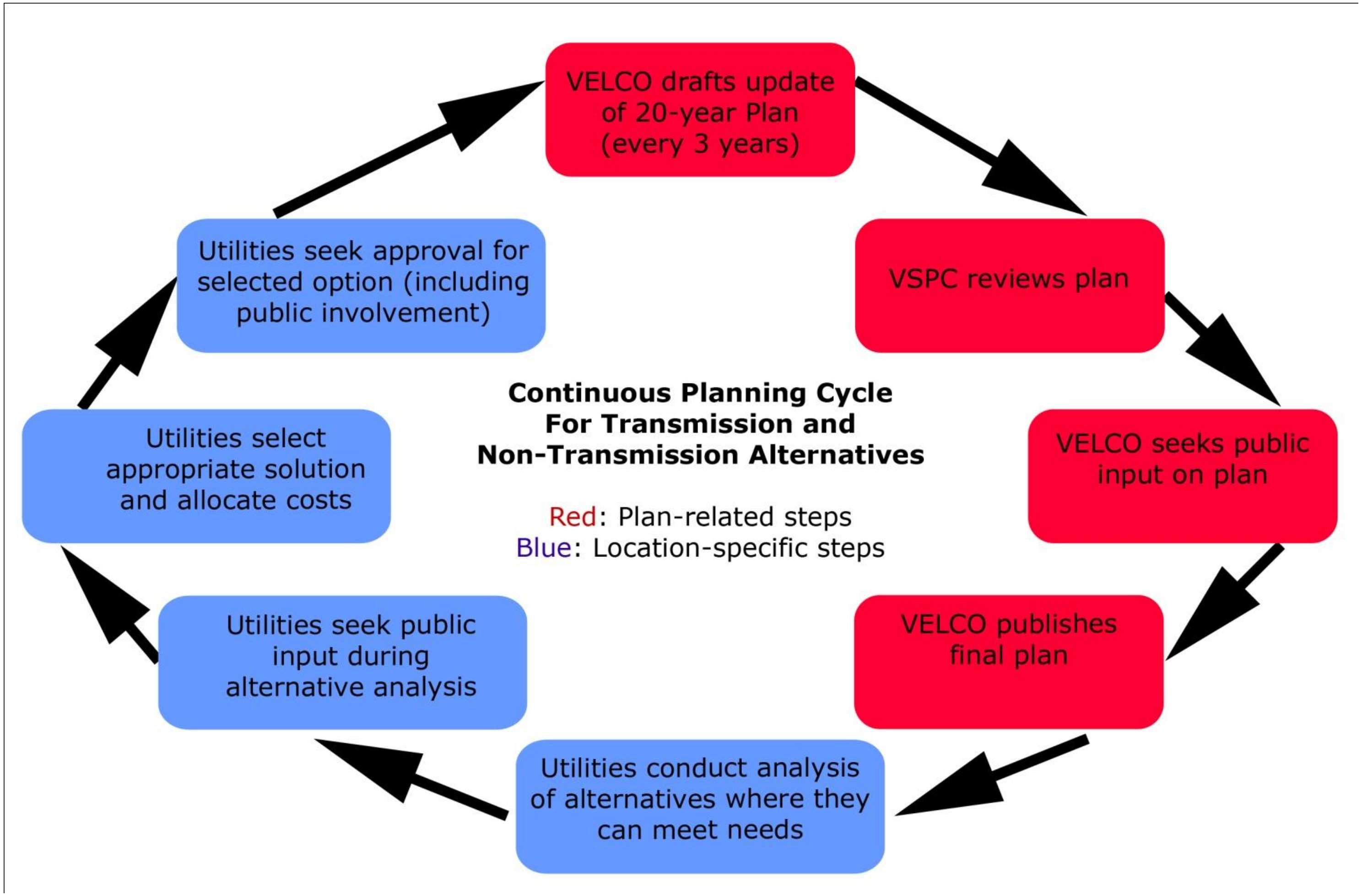
- Long range plan analysis completed in 2008 (Sept-Dec)
  - The analysis was the basis for the ISO-NE 10-yr needs assessment for Vermont
  - VSPC review in December and January
  - Public review from March to June
- Long range plan published in July 2009
- ISO-NE 10-yr Needs Assessment report published in February 2010
  - Under review by ISO-NE and the PAC since 2008
- ISO-NE 10-yr Solutions Assessment report completed in November 2009, but not published
- ISO-NE initiated the VT/NH 10-yr study in January 2010
  - The scope was submitted for review in May
  - Vermont and the PAC provided input to the scope

PAC = Planning Advisory Committee (Regional process)

Vermont Study History

- VELCO received permission to proceed with some of the upgrades identified in the 2008 analysis
  - Upgrades not affected by regional factors or future load growth
    - 115 kV capacitor banks at West Rutland
    - 345 kV shunt reactors at New Haven, Coolidge and Vernon
    - Substation reinforcements at Georgia, Ascutney and Bennington
- ISO-NE Needs Assessment report not yet final
  - Under review by the PAC since February 2011
- ISO-NE Solutions Assessment report is being prepared
  - The PAC accepted the proposed Vermont solutions in July 2011
  - Study to be completed by end of 2011
- Vermont long range plan analysis started in September
  - Completion planned for December 2011

High-level overview of VT Planning process



Plan development timeline

Date	Milestone
1/1/10 - 12/31/10	Develop load forecast with VSPC, particularly the DPS and EVT
5/2/11	Seek input from DUs on analysis required on sub-transmission system
9/14/11	VSPC input on scope
12/15/11	Issue draft for VSPC review
12/15/11-2/28/12	VSPC input period on the plan
3/1/12-3/31/12	Incorporate VSPC input
4/1/12	Issue public review draft
4/1/12-5/31/12	Public input period
4/15/12-4/30/12	Hold public meetings
6/1/12-6/30/12	Incorporate public input
7/1/12	Submit final plan to PSB

Overview of Public Outreach Plan

- Work plan
  - Identify targeted stakeholders
  - Develop plan for public meetings
  - Secure media coverage; possible use of PEG, VIT or web-based video
  - Develop website
  - Conduct public meetings
    - Two geographically diverse "open houses"
    - Public hearing in Montpelier
    - Presentation at meetings of groups as invited
  - Compile public input

Steps to be followed in developing the Long Range Plan

- ISO's VT/NH Needs Assessment and Solutions Assessment will be used as the bulk system analysis for years 1-10.
- VELCO will analyze the sub-transmission system and years 11-20 for the transmission system.
- VELCO requested that the DUs submit any relevant subsystem analyses early in the process.
- The Plan itself will be a non-CEII public document that is based on the underlying technical analysis.
- VELCO will update the load forecast by Oct 2011 as needed

Transmission Planning Criteria

- NERC planning standards
  - TPL-001 – No outages
  - TPL-002 – Outage of one element
  - TPL-003 – Outage of two or more elements
- ISO-NE planning standards
  - N-0, N-1, N-1-1
  - Stressed conditions
    - Extreme weather load (90/10)
    - Two significant resources unavailable
    - Maximize regional power transfers

NERC = North American Electric reliability Council

ISO-NE = Independent System Operator of the New England electric system

90/10 = 90% chance that the actual load will be at or lower than the forecast, 10% chance that it will exceed the forecast

Transmission Outages Examined

- Single element outages
  - Line, transformer, generator, Essex STATCOM, Highgate HVdc terminal
- Multi-element outages
  - DCT, breaker failure, Sandy Pond HVdc terminal
- First single element outage, then system adjustment, then another outage is tested
  - Long-term outages as the first outage
    - Highgate HVdc, Vermont Yankee (VY) generator, 230/115 kV transformer at Littleton, and 345/115 kV transformers at West Rutland, Coolidge, and Vernon
  - Short-term outages, i.e., overhead lines, as the first outage
    - K-54 Granite to Barre 115 kV
    - K-31 Coolidge to Ascutney 115 kV
    - K-186 Vernon to Chestnut Hill 115 kV
    - F-206 Comerford to Granite 230 kV line
    - 345 kV lines: 370 (New Haven to West Rutland), 350 (West Rutland to Coolidge), 340 (Coolidge to VY), and 3320 (Newfane to Vernon)

DCT = Double circuit tower outage that trips lines supported by the same poles
Breaker failures = outage that trips elements adjacent to a breaker

Transmission Performance Criteria

	Thermal criteria	Voltage criteria	
System event	For all facilities	For 115 kV facilities	For 230 kV and above
NERC Category A (All-lines-in)	At or below normal rating	At or above 0.95 pu and At or below 1.05 pu	At or above 0.98 pu and At or below 1.05 pu
Category B, C, & D (single or multi-element outages) N-1 and N-1-1	At or below LTE rating	At or above 0.95 pu and At or below 1.05 pu Delta V no greater than 10%	At or above 0.95 pu and At or below 1.05 pu Delta V no greater than 5%

Post-contingency voltages can exceed 1.05 pu if less than 1.1 pu and capacitor banks can be switched out of service near the high voltage location.

Thermal = That which is related to current flow
Normal rating = Nearly continuous current capacity of a piece of equipment, such as a line, a transformer
LTE rating = Long-term (4 to 12 hours) emergency current capacity of a piece of equipment
Voltage = That which is needed to allow current to flow. The higher the voltage, the lower the current for the same power level
pu = per unit voltage, which is the ratio of the calculated voltage over the nominal/operating voltage level, such as 115 kV, 46 kV
Delta V = change in voltage before and after an outage

Sub-Transmission Performance Screening Approach

System event	Thermal limit	Voltage limit
NERC Category A (All-lines-in)	At or below rating	At or above 0.95 pu and At or below 1.05 pu
NERC Category B (single-element outages) N-1	At or below rating	At or above 0.90 pu and At or below 1.05 pu Delta V no greater than 10%

- Will record system performance for single loss of a
  - Transmission facility
    - Also with a transmission facility already out of service
  - Step-down transformer (115 kV to a lower voltage)
    - Loss of load for radial transformers will be considered acceptable unless affected DUs state otherwise
  - Sub-transmission facility
    - Breaker to breaker and line-end open scenarios
- DUs will determine whether system concerns need to be resolved

Comparison with 2009 Analysis

2009 Analysis	2012 Analysis
Regional input: VELCO performs study with ISO-NE and other TOs	***Regional input:*** ISO-NE performs 10-yr study with VELCO and other TOs
Transfer assumptions: NY-NE flow: +/-1200 MW East-West flow: -1000 & 2400 MW	***Transfer assumptions:*** NY-NE flow: +/-1200 MW East-West flow: -1000 & 3500 MW
Load assumptions: 2018 forecast: 1275 MW 2028 forecast: 1425 MW Not adjusted - DSM forecast not complete	***Load assumptions:*** 2022 forecast: 1134 MW 2032 forecast: 1245 MW (estimated based on 2030 forecast of 1221 MW) Adjusted for DSM forecast
Demand Resource assumptions: None	***Demand Resource assumptions:*** ISO-NE 10-yr study: active & passive DR VELCO timing to include all VEIC EEF

NY-NE = New York-New England power transfer interface
ISO-NE = Independent System Operator in New England
TO = Transmission Owner
All-lines-in = no outages

Long-term outage = outage that is likely to exist for weeks at a time, such as outages of transformers, generators and cables

Short-term outage = outage that is likely to exist for a few hours, such as outages of overhead lines

Comparison with 2009 Analysis

2009 Analysis	2012 Analysis
Generation assumptions: All-lines-in: 88 MW With long-term facility out: 119 MW With short-term facility out: 150 MW	***Generation assumptions:*** All-lines-in: 55 MW With one facility out: 150 MW
PV-20 flow assumptions: 100 MW	***PV-20 flow assumptions:*** 0 MW
Generation outages: VY retired or in service Two resources out in VT: McNeil & Berlin Merrimack 2 out in all cases Sensitivities with AES Granite Ridge out and Merrimack 2 in	***Generation outages:*** VY retired or in service Two resources out in VT, NH and MA: AES Granite Ridge and Merrimack 2 AES and McNeil AES and Northfield 1&2

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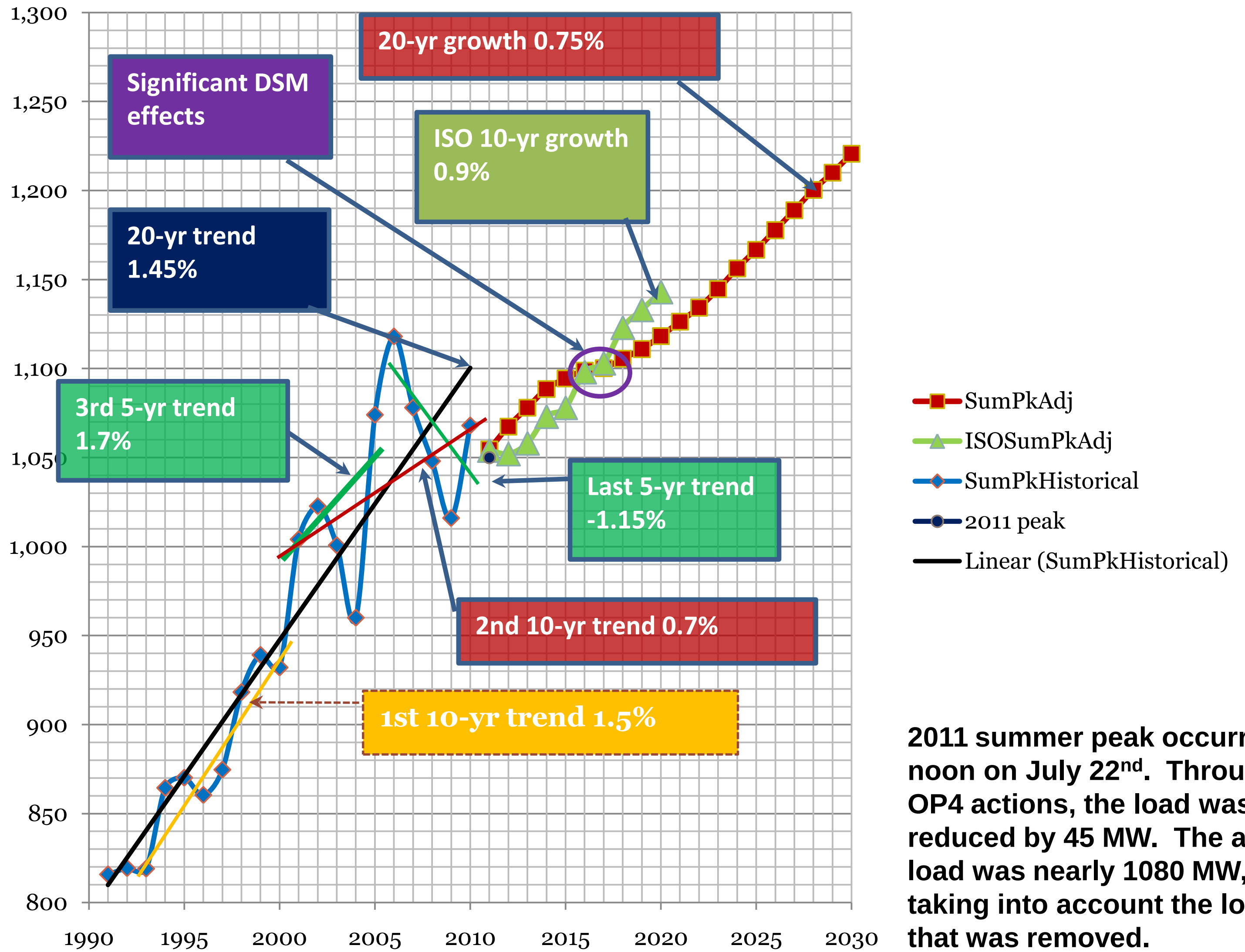
Limiting System Conditions

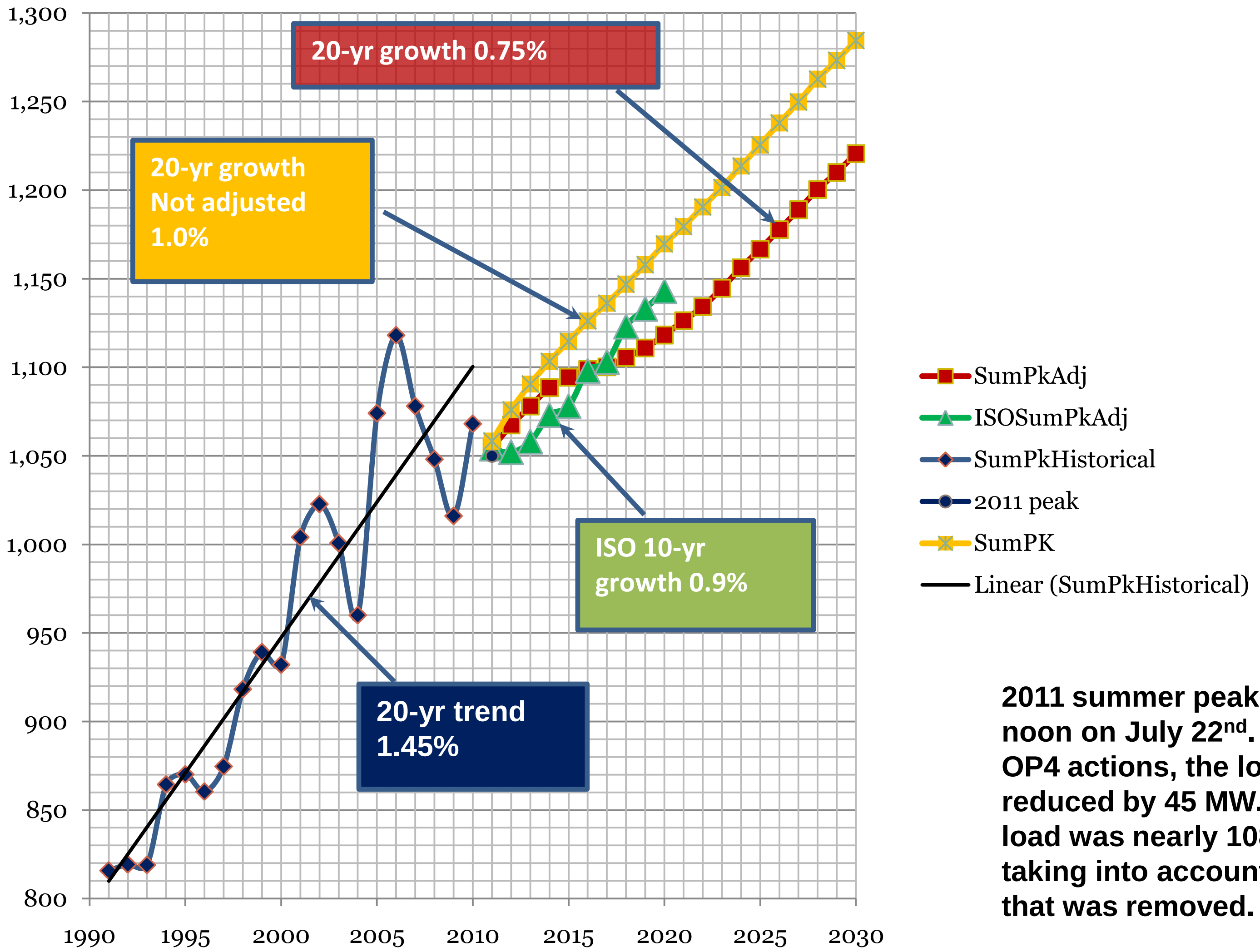
- West to East transfer conditions
  - Similar concerns as East to West but more severe
- Vermont Yankee in service
  - Similar concerns as VY out, but more severe for overloads
- McNeil out of service
  - AES + McNeil out more severe for VT
- Following N-1 (first contingencies)
  - Highgate
  - 370
  - 350
  - Coolidge autotransformer
  - F-206
  - K-31

Load Review



2011 summer peak occurred at noon on July 22nd. Through OP4 actions, the load was reduced by 45 MW. The actual load was nearly 1080 MW, taking into account the load that was removed.

Load Review



2011 summer peak occurred at noon on July 22nd. Through OP4 actions, the load was reduced by 45 MW. The actual load was nearly 1080 MW, taking into account the load that was removed.

Load Assumptions

- 90/10 loads in all cases tested
  - 2022 projected load – 1134 MW
  - 2030 projected load – 1221 MW
- Newport block load supplied from Vermont
- Load power factor constant at 0.97 in all cases
  - Assumes ongoing power factor correction on the distribution and sub-transmission systems
- NY load remained constant in all cases

Power factor = Measure of real power in relation to reactive power, which are perpendicular to each other.

Real power = Part of the electrical power that does the work, i.e. heat, lighting

Reactive power = Part of the electrical power needed for the system to function properly. By-product of alternating current.

Load Assumptions by Zone

Year	Vermont	New England	Montpelier	Morrisville	Johnson	StAlbans	Highgate	Newport	StJohnsbury
2012	1067	29330	105	34	15	67	40	34	31
2017	1100	31407	106	37	16	71	41	35	33
2022	1134	33338	106	41	17	75	42	36	35
2030	1221	36507	111	47	20	84	45	39	39

Year	Southern	Ascutney	Rutland	Central	Florence	Middlebury	BED	BurGMP	IBM
2012	126	82	101	68	23	38	69	174	60
2017	131	87	105	70	23	38	70	179	57
2022	136	92	109	72	23	39	71	184	54
2030	149	103	119	79	22	41	75	198	50

Next Steps

- Review VSPC comments on scope
- Perform analysis and consult DUs on results
- Present draft report at December meeting

ISO-NE VT/NH Solutions Assessment

SEPTEMBER 14, 2011
VSPC MEETING

Scope Definition and General Assumptions

Transmission Solution Assumptions:

- Circuit reconductoring assumes complete rebuild of the transmission lines (In consideration of the age of the line and design criteria associated with the wire size increase and associated structural loads).
- Each of the cases has been subject to a preliminary review for right of way needs. A preliminary assessment of the existing corridors was conducted such as review of existing right of way width.
- The alternative summary tables include the costs associated with the expansion or rebuild terminal stations to accommodate the new circuit.
- Substation design follows ISO PP9 Substation Bus Arrangement Guidelines except if noted otherwise.

Cost Estimate Assumptions

- Cost Estimates follow PP4, Attachment D, Project Cost Estimating Guidelines.
- All the solutions assume a timeline with a 2016 commissioning target date.
- All cost estimates are expressed in 2016 dollars. A yearly escalation rate of 5% was used.
- All estimates include 50% contingency (Planning stage).

Proposed solutions review

- Review of proposed solutions included consideration of factors such as operations and maintenance. A scorecard was established using for the following criteria:
  - Permitting
  - Constructability
  - System Performance
  - Longevity
  - Loss Saving
  - Operational Flexibility
  - Estimated Capital Investment

Northern Vermont Solutions

- Two 12.5 MVAr capacitor banks at Jay 115 kV
  - Needed at load levels below 2011 peak
  - Estimated to cost approximately $4M
- Solution Attributes
  - Common to all alternatives
  - Significantly less expensive than the other alternatives
  - No line upgrades required
  - Easier to permit
- ISO-NE NTA options
  - 55 MW at Moore 115 kV
  - Not a viable solution
    - Transmission is significantly less expensive, easier to implement and permit
    - Local area is constrained

Northwest Vermont Solutions

- Rebuild overloaded lines (Estimated to cost about $220M)
  - K-27 (Williston-Tafts Corner)
    - Needed at the projected 2017 load level based on ISO-NE forecast
  - K-43 (New Haven-Williston)
    - Needed at load levels just below the 2011 peak
  - K-30 (West Rutland-Middlebury)
    - Needed at load levels below the 2011 peak
- Other solutions considered
  - New Granite-Champlain 230 kV line
  - New W. Rutland-Champlain 345 kV line
  - New W. Rutland-Champlain 115 kV line

Northwest Vermont Solutions

- Solution Attributes
  - Significantly less costly than the other alternatives
  - Easier to permit
  - Performs adequately, but will require additional upgrades just beyond the 10-year period based on current forecast
  - Difficult to construct due to system outages
  - More losses compared to other alternatives
- ISO-NE NTA options
  - PV-20 flows increased above 70 MW (modeled at Sand Bar)
  - 15 MW at Tafts Corner and 35 MW at Williston
  - 55 MW at Essex

Northwest VT NTA–Possible Implementation Scenarios

- Resolve PV-20 restrictions
  - DUs obtain contract flow on PV-20 line
  - Market changes to schedule PV-20 flows
  - NY participants fund separation of NY DCT
  - Install an SPS to trip the PV-20 line
- Install generation in the Essex area
  - Possibly at Gorge (has I.3.9 approval)
- Implement hybrid solution comprised of generation, DSM and/or transmission

Central Vermont and Connecticut River Solutions

- Install 345 kV line from Coolidge to west Rutland and a 2nd 115 line in parallel with the K31 line (Estimated to cost about $260M)
  - Lines K-31 (Coolidge-Ascutney), K-32 (Coolidge-Cold River), and K-35 (Cold River-North Rutland) overload at load levels below the 2011 peak
  - Line K-37 (West Rutland-North Rutland) overloads at the projected 2017 load level based on ISO-NE forecast
- Other solutions considered
  - Same as above preferred option except that the Coolidge-West Rutland line is energized at 115 kV
  - Rebuild overloaded lines, install a 2nd autotransformer at Coolidge, install capacitor banks at Ascutney, and rebuild the Chelsea substation
  - Same as above option except that a 2nd K-31 line is added in place of the K-31 rebuild

Central Vermont and Connecticut River Solutions

- Solution Attributes
  - About the same cost as the other alternatives
    - 3.5% more expensive than the least expensive alternative, well within estimate contingency/accuracy
    - Cost estimate for least expensive alternative did not include generation must run costs to support construction outages
  - Much easier to construct compared to line rebuilds (system outages)
  - Significantly superior performance, particularly over the long term
  - Less losses compared to other alternatives

- ISO-NE NTA options
  - For Central VT
    - 10 MW at Cold River, 10 MW at West Rutland, and 70 MW at North Rutland
    - 90 MW at West Rutland
      - Would need a hybrid solution of generation, DSM and transmission
  - For Connecticut River
    - 10 MW at Coolidge, 35 MW at Ascutney Tap, and 125 MW at Ascutney
    - 170 MW at Ascutney Tap
    - Not a viable solution
      - This amount of generation would need a significant amount of transmission and fuel storage. The generation amount would need to be larger if generation is not installed in other sub-areas.

Next Planning Steps

- Implementation of 2008 solutions has been delayed by the regional study process
  - Reliability deficiencies are not new - timing advanced by PV-20 restriction
- ISO-NE to complete the Solutions study by end of September
  - Complete NH portion, optimize existing resources and take into account new resources from FCA #5
  - Publish the Solutions Assessment report by end of 2011
- Perform NTA screening as part of Long Range Plan
  - Document effects of PV-20 imports and generation as part of LRP
- Perform detailed NTA analysis for those projects that screen in (NTAs that are viable based on NTA screening)
  - Detailed NTA analysis to start 1st quarter 2012
- Seek ISO-NE I.3.9 approval of the upgrades
  - After the completion of the ISO-NE solutions study and the LRP
- File 248 permit for transmission reinforcements by end of 2012

Project Updates

TIMING OF PROJECT STEPS FOR ALL IDENTIFIED RELIABILITY PROJECTS – Updated 6/2010

Key on following page

CALENDAR QUARTERS

	Year Needed *	Load MW Needed	Completed	2010 1	2010 2	2010 3	2010 4	2011 1	2011 2	2011 3	2011 4	
Priority 1 : St. Johnsbury	pre 2009	400	T, N, SCI									Permitted
Priority 2 : Middlebury	pre 2009	700	T, N, SCI									Filed for 248.
Priority 3A : St. Albans	pre 2009	850	T, N, SCI									
												Expected to start Public Process in 2011
Priority 3B : Georgia substation	pre 2009	800			T	SCI						
					T		SCI					T complete. ISO approval process commenced.
Priority 3C : Georgia - St. Albans	pre 2018	1275	TBD									
Priority 4 : Rutland area	pre 2009	1000			T		N	SCI				
						T		N	SCI			
Priority 5 : Blissville - transformer	pre 2009	800	TBD**									
Priority 6 : Hartford - transformer	pre 2009	800							T	N	SCI	
Priority 7 : Ascutney substation	pre 2009	750				T	SCI					
					T		SCI					T complete. ISO approval process commenced.
Priority 8 : Newport capacitor	pre 2009	1000			T	SCI						
						T	SCI					T pending for coordination with VEC system reliability assessment.
Priority 8 : Queen City capacitor	pre 2009	<1120			T	SCI						Priority 8 under study. Operational procedure at Essex switch postpones need date for most of the capacitor banks. T analysis date pushed out to 2010 year end for completion of ISO study.
							T		SCI			
Priority 8 : West Rutland capacitor	pre 2009	<1120			T	SCI						
							T		SCI			
Priority 8 : Blissville capacitor	pre 2009	<1170			T	SCI						
							T		SCI			
Priority 9 : Ascutney capacitor	pre 2009	<1170			T	SCI						
							T		SCI			
Priority 10 : Bennington substation	pre 2009	500				T	SCI					
					T		SCI					T complete. ISO approval process commenced.
Priority 11 : reactors @ transmission voltage	pre 2009	400		T	SCI							
				T			SCI					T complete. ISO approval process to begin in July.

Priority 12 : Coolidge - Ascutney K-31 line	pre 2009	n/a		T	SCI	
					T	SCI: 12/31/12. Need to be determined by ISO regional study
Priority 13 : VY - Vernon Road Tap K-186 line	pre 2009	n/a		T SCI		
					T	SCI: 12/31/12. Need to be determined by ISO regional study
Priority 14 : Vernon	2010	1185	TBD			
					T	SCI: 12/31/12. Need to be determined by ISO regional study
Priority 15 : Ascutney - Ascutney Tap K-149 line	2013	1210		T	N SCI	
					T	SCI: 12/31/12. Need to be determined by ISO regional study
Priority 16 : Coolidge - Cold River K-32 line	2013	1210		T	N SCI	
					T	SCI: 12/31/12. Need to be determined by ISO regional study
Priority 17 : Ascutney - transformer	2013	1210			T N SCI	
Priority 18 : Coolidge - transformer	2016	1245	TBD			
					T	SCI: 12/31/12. Need to be determined by ISO regional study
Priority 19 : Barre	2018	1275	TBD			
Priority 20 : Chelsea	2018	1275	TBD			
Priority 21 : Plattsburgh - Essex	Note ***	n/a	TBD			

Note * : Based upon 2008 load forecast

Note**: See VSPC annual report for discussion of operational measures to address this deficiency prior to 2012 Plan update.

Note***: Timing may be 2016 or earlier depending upon other possible scenarios

Key:

Tan color: milestones in Project Priority List filed 2/2010

Yellow color: projects with changed milestones, 6/2010

N = Non-transmission alternative analysis (priorities with no "N" entry screened out of further NTA analysis in Long-Range Plan

S = Solution selection

C = Cost allocation

I = Implementation strategy

TBD = To Be Determined after the completion of the 2012 Long Range Transmission Plan

n/a = Not applicable

Future Meeting Dates

December 14 – Burlington

March 14, 2012 – Burlington*

June 13, 2012 - Montpelier

September 12, 2012 - Rutland

December 12, 2012 – Burlington

Note: change of location due to unavailability of VTC.