3 Reliability Issues and Solutions

3.1 Reliability issues identified

Figure 3-1 summarizes the transmission reliability issues identified as part of the 2009 planning process. These areas represent locations that require future transmission related upgrades or alternatives, such as local generation or energy efficiency, to meet the reliability standards. The following table provides a brief description of each deficiency and its causes.

Figure 3-1. Identified transmission reliablity issues.

Deficiency number	Name	Causes of Deficiency	Deficiencies
1	**Georgia/ St Albans**	* Loss of transmission line * Loss of E. Fairfax transformer * Loss of one or both St Albans transformer	Low voltage, voltage instability, voltage collapse, thermal overloads
2	**Middlebury**	* Loss of Middlebury transformer or breaker failure	Low voltage, voltage collapse
3	**Blissville**	* Loss of Blissville transformer	Low voltage, voltage collapse, thermal overload
4	**Hartford/ Chelsea**	* Loss of Hartford transformer or breaker failure	Low voltage, voltage collapse
5	**North Rutland**	* Loss of the North Rutland or Cold River transformers	Low voltage, voltage collapse, thermal overload
6	**Ascutney**	* Loss of Ascutney transformer	Low voltage, voltage collapse, thermal overload
7	**Bennington**	* Bennington breaker failure	Low voltage, voltage collapse
8	**Blissville/ Ascutney**	* Various scenarios involving loss of transmission lines	Low voltage
9	**West Rutland/ Coolidge**	* Light to moderate load levels	High voltage
10	**St. Johnsbury**	* Loss of St Johnsbury transformer, aggravated when Highgate converter or Littleton autotransfomer is out of service * Loss of transmission line	Low voltage, voltage collapse
11	**Vernon**	* Loss of Fitzwilliam transformer	Thermal overload
12	**Coolidge/ Ascutney**	* Transmission line out of service	Thermal overload
13	**Ascutney-Ascutney Tap**	* New England power flows and New Hampshire load	Thermal overload
14	**Vernon**	* VY autotransfomer out of service	Thermal overload
15	**Coolidge/ Cold River**	* Loss of transmission line	Low voltage, voltage collapse, thermal overload
16	**Coolidge**	* Loss of Coolidge transformer	Low voltage, voltage collapse, thermal overload
17	**Loop Flow**	* Increase in load and transmission outages. Note deficiency can be handled by operations at the subtransmission level	Thermal overload

Deficiency number	Name	Causes of Deficiency	Deficiencies
18	**Sub-transmission Voltage**	* Load level and loss of transmission lines/transformers. Note deficiency can be handled at the subtransmission level.	Low voltage
19	**Barre**	* Load level, loss of transformer	Low voltage, voltage collapse, thermal overload
20	**Vermont Yankee**	* VY removed from system. Note overloads occur in southwestern New Hampshire. Solution will need to be addressed at the regional/ISO-NE level.	Low voltage, voltage collapse, thermal overload
21	**Plattsburgh-Essex**	* Highgate converter removed and loss of transmission lines	Low voltage, voltage collapse, thermal overload
22	**Highgate**	* Highgate converter out of service and loss of transmission lines	Low voltage, voltage collapse, thermal overload
23	**2028**	* Year 2028 load levels, Highgate out of service, loss of transmission lines	Low voltage, voltage collapse, thermal overload

The range of reliability performance issues documented in the 2009 technical analysis center on these causes:

- Heavy use of transmission facility may overload the equipment beyond its rating.
- A poorly supplied area may suffer **voltage** far below or above acceptable levels.
- **Voltage instability** may occur in areas with weak transmission networks.
- In the extreme, very low voltage can lead to a **voltage collapse**, where the transmission system becomes unstable and sections automatically disconnect, potentially leading to widespread **blackout**.

These transmission system phenomena are examples of unacceptable system performance that must be resolved. The plan describes proposed transmission reinforcements to address these unacceptable transmission performance issues.

On the subtransmission system, several potential reliability issues were also identified. The reliability of the subtransmission system can be improved by reinforcements made on the transmission system system and vice versa; therefore, many of the subtransmission issues may be resolved by implementation of transmission solutions, and subtransmission fixes may sometimes resolve transmission system issues. The table in Figure 3-2 shows the reliability issues that would remain unresolved after implementation of the proposed transmission solutions shown in Figure 3-4. The table shows which part of the electric system is causing the reliability issue, i.e., transmission, subtransmission, or the failure of a transformer within a substation. The reliability impact of the equipment failure (or “contingency”) is shown as either causing high or low voltage, or as a **thermal** issue in which equipment exceeds its rated temperature.

The table illustrates that there are five general subtransmission areas with potential reliability issues including Ascutney, Chelsea, Montpelier, Rutland, and St. Albans. At the subtransmission level there can be more flexibility concerning the reliability level to which the system is designed when compared to the transmission system because the subtransmission system is not currently subject to mandatory federal reliability standards. For example, it may be acceptable in the area to incur an infrequent power outage rather than to invest in infrastructure to eliminate the power outage risk. The affected utilities will determine what, if any, projects are required to address the potential reliability issues on the subtransmission system. The affected utilities have not yet submitted these evaluations.

Figure 3-2. Subtransmission potential reliability issues grouped by location (assuming proposed transmission projects are completed).

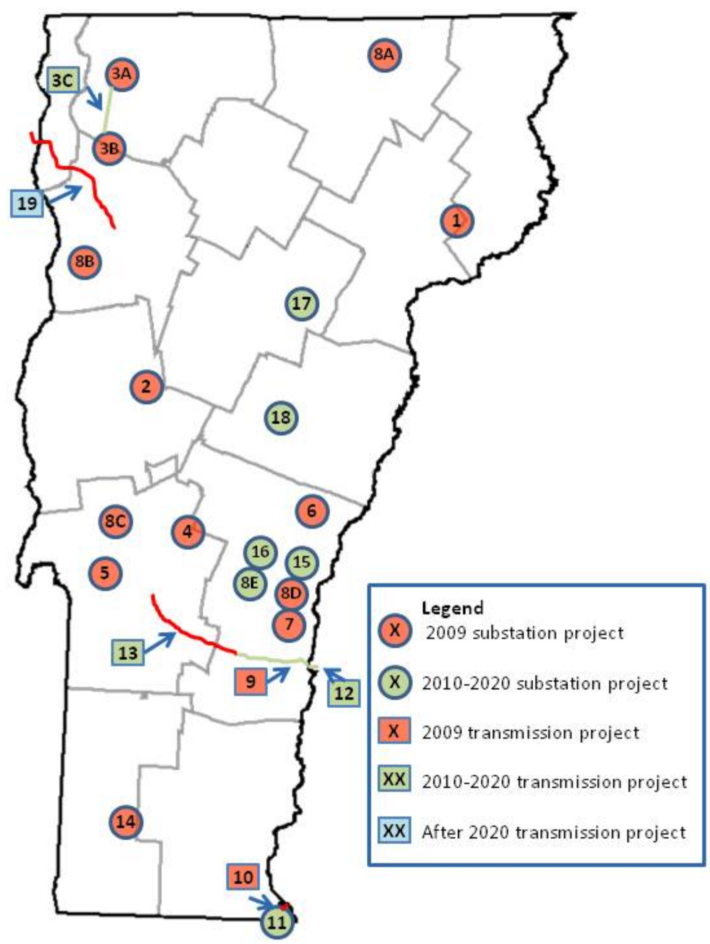
Location	Year Needed	"90/10" Load Forecast for Year	Contingency	Issue	VELCO Criteria Violations	Affected DUs	Lead DU
Ascutney	2009	1141 MW	Subtransmission	Voltage	Low voltage & voltage collapse	CVPS	CVPS
Ascutney	2010	1155 MW	Transfomer	Thermal	Ascutney-Lafayette	CVPS	CVPS
Ascutney	2009	1141 MW	Transfomer	Thermal	North Springfield-Riverside	CVPS	CVPS
Ascutney	2009	1141 MW	Transfomer	Voltage	Ascutney	CVPS	CVPS
Ascutney	2009	1141 MW	Transmission	Voltage	Ascutney	CVPS, GMP, Ludlow	CVPS
Ascutney/ Cold River	2009	1141 MW	Transmission	Thermal	Wallingford-Cavendish	CVPS, Ludlow	CVPS
Chelsea	2009	1141 MW	Transmission	Voltage	Chelsea	CVPS, WEC	CVPS
Chelsea/ Hartford	2013	1185 MW	Subtransmission	Voltage	Chelsea-Hartford	CVPS, GMP, WEC	CVPS
Montpelier	2009	1141 MW	Subtransmission	Thermal	Berlin to Mountain View Tap to Montpelier	GMP, WEC	GMP
Montpelier	2009	1141 MW	Transfomer	Thermal	Berlin-Mnt View-Montpelier	GMP, WEC	GMP
Montpelier	2016	1215 MW	Transmission	Thermal	Berlin-Mountain View Tap-Montpelier	GMP, WEC	GMP
Rutland	2009	1141 MW	Subtransmission	Thermal	North Rutland to East Rutland to South Rutland	CVPS	CVPS
Rutland	2009	1141 MW	Transfomer	Thermal	North Rutland-South Rutland	CVPS	CVPS
Rutland/ Cold River	2009	1141 MW	Subtransmission	Voltage	Rutland-Cold River	CVPS	CVPS
St Albans	2009	1141 MW	Subtransmission	Thermal	Fairfax Falls to Milton	CVPS	CVPS
St Albans	2009	1141 MW	Subtransmission	Thermal	North St Albans to Nat Carbide	CVPS	CVPS

CVPS = Central Vermont Public Service, GMP = Green Mountain Power, WEC = Washington Electric Co-op

3.2 Proposed Transmission Solutions

Addressing transmission reliability deficiencies fall into two broad categories of transmission-related solutions: substation upgrades and transmission line reinforcements. Substation upgrades typically involve adding a transformer, the reconstruction of the substation to a redundant design such as a **ring bus** or **breaker-and-a-half**, and/or the installation of **capacitor**s and **reactor**s to improve system performance. Generally, substation projects have minimal impact on surrounding communities because substations are typically built on properties that are acres in size. The other category of reinforcement is transmission line-related. Transmission lines are sometimes rebuilt to increase their electricity carrying capacity. Transmission line rebuilds typically involve the replacement of existing poles (or towers) and wire within existing rights of way. Certain reliability issues require construction of entirely new high-voltage transmission lines, and may impact multiple surrounding communities.

Figure 3-3. Proposed transmission related project locations.



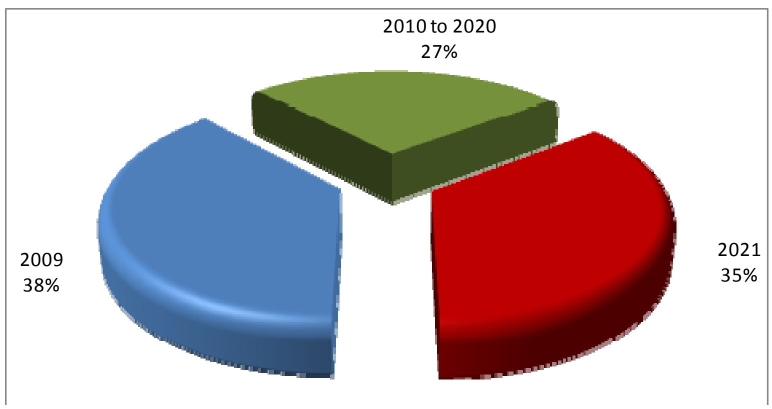
Planners have identified 25 potential transmission solutions in 22 locations where new transmission-related infrastructure upgrades would enable Vermont to comply with the transmission planning standards. The numbers on the map in Figure 3-3 are keys to the locations, type and timing of the proposed reinforcements shown in Figure 3-4.

Of the 25 projects identified, six involve transmission lines; the rest are substation related. Of the six transmission projects, two of the projects are new lines, the others propose rebuilding existing lines to a higher capacity. The two new transmission lines are projects 3B and 19 in northwestern Vermont. Project 3B is a proposed new transmission line that is needed before 2018. This 115-kV line would run from Georgia to St. Albans at a distance of about 10 miles. Project 19 is a 230-kV line that would run from Plattsburg to Essex at a distance of about 30 miles. In the “base plan,” the timing of project 19 is scheduled for 2021 but may be needed by 2016. Project 19 may be undertaken sooner for reliability reasons or to facilitate access to renewable resources in New York State. Many of the listed projects are needed in 2009, based on existing loads and applicable reliability criteria. Most projects, however, will take several years to obtain the required approvals and to construct. The projects are therefore prioritized to help provide a sense of the order in which an application may need to be filed with the Board, the number of hours the criteria violation would exist, or the year in which the criteria violation occurs. All transmission reliability standards, however, must be met so the prioritization should not be interpreted as indicating discretion on whether or not to address the problem.

Figure 3-5 provides more details about the transmission solutions. Planners were required to project the year need each solution will be needed. Given the uncertainties associated with predicting future electric demand, planners also identified at what Vermont load level the projects become necessary. The load levels allow decision-makers and the public to evaluate these reliability issues in terms that can adjust to potential changes in the load forecast over time. Cost estimates in year 2008 dollars are illustrated and the figure indicates whether the project is a substation or transmission line modification. The deficiencies addressed by each individual project are listed. The description of the deficiency is available in Figure 3-1 according to the deficiency number listed. A brief description of the reinforcement, the distribution utilities that are impacted, and the local distribution utilities that will take the lead on coordinating the project are also provided in Figure 3-5.

The total cost for the proposed transmission projects is estimated in the range of $512 million to $902 million at today's costs (year 2008 dollars). As shown in Figure 3-4, many projects are needed as soon as practically possible (indicated by year 2009 projects), which represent 38 percent of the proposed dollar investment total. One single project (number 19), represents another 35 percent of the proposed total investment, but that project is currently identified as being needed in 2021 or sooner as already discussed. The remaining projects represent 27 percent of the proposed investment and are scattered between years 2010 and 2020.

Figure 3-4. Percentage of proposed investment by year(s).



Note that most 2009 projects will take years to implement, however the 2009 year does indicate they are needed as soon as practically possible.

Figure 3-5. Proposed transmission project details (the cost estimates are in year 2008 millions of dollars).

Priority number	Name	Year of Need	Load MW Needed	Low Cost	High Cost	Project Type	Defi-ciencies	Project	Affected DUs	Lead DU
1	**St. Johnsbury**	2009	400	$ 22	$ 22	Substation	10	Construct new ring substation at or near Lyndonville substation, install capacitor banks	CVPS, LED for station. CVPS, LED & VEC for capacitor banks	LED
2	**Middlebury**	2009	700	$ 10	$ 20	Substation	2	Install 2nd 115/46 kV transformer, rebuild to ring station	CVPS	CVPS
3A	**St Albans**	2009	900	$ 25	$ 50	Substation	1	Construct new ring station with two 115/34.5 kV transformers	CVPS, VEC	CVPS
3B	**Georgia**	2009	1100	$ 20	$ 40	Substation	1	Rebuild to ring station	All Vermont Dus	CVPS
3C	**Georgia-St. Albans**	2018	1275	$ 15	$ 30	Transmission	1	Construct new Georgia to St Albans 115 kV transmission line, under 10 miles. ***Needed before 2018.***	All Vermont Dus	VEC
4	**S Rutland**	2009	1000	$ 15	$ 30	Substation	5	Construct new substation with a 115/46 kV transformer	CVPS	CVPS
5	**Blissville**	2009	800	$ 15	$ 30	Substation	3	Install 2nd 115/46 kV transformer, rebuild to ring station, install capacitor banks	CVPS	CVPS
6	**Hartford**	2009	1000	$ 15	$ 30	Substation	4	Install 2nd 115/46 kV transformer, rebuild to ring station	CVPS, GMP	CVPS
7	**Ascutney**	2009	<1170	$ 14	$ 28	Substation	6	Rebuild to breaker-and-a-half station	All Vermont DUs, NU, NGRID	CVPS
8A	**Newport**	2009	1000	$ 1	$ 2	Substation	10	Install capacitor banks	All Vermont DUs	VEC
8B	**Queen City**	2009	<1170	$ 2	$ 4	Substation	8	Install capacitor bank	All Vermont DUs and NGRID	GMP
8C	**W Rutland**	2009	<1170	$ 6	$ 12	Substation	8, 9	Install capacitor banks and shunt reactors	All Vermont DUs and NGRID	CVPS
8D	**Ascutney**	2009	<1170	$ 2	$ 4	Substation	6	Add capacitor banks	All Vermont DUs, NU, NGRID	CVPS
8E	**Coolidge Reactor**	2011	1200	$ 4	$ 8	Substation	9	Install shunt reactor	All Vermont DUs, NU, NGRID, NY	CVPS

Priority number	Name	Year of Need	Load MW Needed	Low Cost	High Cost	Project Type	Defi-ciencies	Project	Affected DUs	Lead DU
9	**Coolidge-Ascutney**	2009	N/A	$ 25	$ 50	Transmission	12	Rebuild transmission line to higher rating, under 15 miles	All Vermont DUs, NU, NGRID	GMP
10	**Yankee to Vernon Rd**	2009	<1170	$ 5	$ 10	Transmission	11	Rebuild line for higher rating, under 10 miles	All Vermont DUs, NU, NGRID	CVPS
11	**Vernon**	2010	1185	$ 15	$ 30	Substation	14	Install 2nd 345/115 kV transformer	All Vermont DUs, NU, NGRID	CVPS
12	**Ascutney-Ascutney Tap**	2013	1210	$ 5	$ 10	Transmission	13	Rebuild transmission line to higher rating, under 10 miles	All Vermont DUs, NU, NGRID	CVPS
13	**Coolidge-Cold River**	2013	1210	$ 35	$ 70	Transmission	15	Rebuild transmission line to higher rating, under 20 miles	All Vermont DUs, NY	CVPS
14	**Bennington**	2009	<1170	$ 10	$ 20	Substation	7	Rebuild to ring substation, install capacitor banks	All Vermont DUs, NGRID	CVPS
15	**Ascutney Transformer**	2013	1210	$ 6	$ 12	Substation	6	Install 2nd 115/46kV transformer	CVPS, Ludlow for station	CVPS
16	**Coolidge Transformer**	2016	1245	$ 20	$ 40	Substation	16	Install 2nd 345/115 kV transformer	All Vermont DUs, NU, NGRID, NY	CVPS
17	**Barre**	2018	1275	$ 10	$ 20	Substation	19	Install 2nd 115/34.5 kV transformer and rebuild to ring station. ***2018 assumes there will be an upgrade to the 34.5 kV system***	GMP, WEC	GMP
18	**Chelsea**	2018	1275	$ 15	$ 30	Substation	4	Install 2nd 115/46 kV transformer, rebuild to ring station	CVPS, WEC	CVPS
19	**Plattsburgh-Essex**	2021	N/A	$ 200	$ 300	Transmission	21, 22, 23	Construct new Plattsburgh to Essex 230 kV transmission line, parallel with existing 115 kV lines, under 30 miles, ***NOTE: timing may be 2016 or earlier depending on other possible scenarios***	All Vermont DUs	GMP
	TOTAL			*$ 512*	*$ 902*					

* R&J = Readsboro and Jacksonville

Figure 3-5 identifies the year of need, based on the load forecast, for the potential transmission solution to each identified reliability deficiency and concern. Figure 3-6 below shows the estimated year when each reinforcement may be in service. These dates consider the severity of need, the ability to mobilize resources to act, and the ability to construct multiple reinforcements simultaneously. The dates are estimates that will likely be revised as the planning process continues.

Figure 3-6 Estimated In-Service Year for Potential Reinforcements

Location	*Load MW Needed*	*Priority*	*Estimated In-service Year*
St. Johnsbury	400	1	2012
Middlebury	700	2	2013
St. Albans	900	3A	2013
Georgia	1100	3B	2012
Georgia-St. Albans	1275	3C	2015
South Rutland	1000	4	2013
Blissville	800	5	2014
Hartford	1000	6	2015
Ascutney	< 1170	7	2012
Ascutney	< 1170	8A	2012
Newport	1000	8B	2015
Queen City	< 1170	8C	2013
West Rutland	< 1170	8D	2012
Coolidge-Ascutney 115 kV K-31 line	VT load generally not relevant	9	2013
VY to Vernon Road 115 kV K-186 line	< 1170 NH and Brattleboro load mostly	10	2014
Vernon	1185	11	2013
Ascutney-Ascutney Tap 115kV K-149 line	1210	12	2013
Coolidge-Cold River 115 kV K-32 line	1210	13	2013
Bennington	1170	14	2014
Ascutney	1210	15	2013
Coolidge	1245	16 for trans-former	2016
Barre	1275	17	2018
Chelsea	1275	18	2018
Plattsburgh to Essex	N.A.	19	2021 or earlier

3.3 Non-Transmission Alternatives (NTA)

For each proposed transmission project, planners performed a PSB-approved method of initial screening to determine whether or not an alternative can postpone a transmission solution. The results of the analyses are summarized in Figure 3-7, indicating proposed transmission projects 3B, 11, 12, 14, 15, 16, 17, and 18 require further study of alternatives to transmission. The lead distribution utility will be responsible for analyzing the alternatives to transmission using the process established in Docket 7081. For these projects, there is a possibility some or all of the proposed transmission solutions can be avoided or delayed with alternatives such as installing new generation to serve load or implementing additional energy efficiency to reduce demand.

Not all projects are good candidates to solve a reliability deficiency using an alternative to transmission. Examples of where non-transmission alternatives are not technically feasible are where deficiencies are caused primarily by power flowing for the New England region or other states, or it is not practical to use an alternative to achieve the required high level of demand reduction immediately. These were the two main reasons for the screening outcomes in Figure 3-7. Project 1 has already undergone a more detailed NTA assessment, the results of which can be found at the http://www.vermontspc.com/ website in the Lyndonville project details.

Figure 3-7. Screening for the potential to meet needs through alternatives to transmission. Rows colored in green are projects with NTA possibilities.

Priority number	Name	Year Needed	NTA
1	St. Johnsbury	2009	NO
2	Middlebury	2009	NO
3A	St Albans	2009	NO
3B	Georgia	2009	NO
3C	Georgia-St. Albans	2018	YES
4	S Rutland	2009	NO
5	Blissville	2009	NO
6	Hartford	2009	NO
7	Ascutney (substation)	2009	NO
8A	Newport (capacitors)	2009	NO
8B	Queen City (capacitors)	2009	NO
8C	W Rutland (capacitors/reactor)	2009	NO
8D	Ascutney (capacitors)	2009	NO
8E	Coolidge Reactor	2011	NO
9	Coolidge-Ascutney	2009	NO
10	Yankee to Vernon Rd	2009	NO
11	Vernon	2010	NO
12	Ascutney-Ascutney Tap	2013	YES
13	Coolidge-Cold River	2013	YES
14	Bennington	2009	NO
15	Ascutney (transformer)	2013	YES
16	Coolidge (transformer)	2016	YES
17	Barre	2018	YES
18	Chelsea	2018	YES
19	Plattsburgh-Essex	2021	YES

For those reinforcements where the use of non-transmission alternatives (generation and/or demand reduction) may defer the need for transmission investment, figure 3-8 indicates the rough magnitude of the alternatives that could potentially defer the transmission reinforcements five to ten years. These are preliminary screening estimates, and will require more detailed examination later in the planning process based on the use of specific non-transmission alternatives. Given uncertainties in how alternatives may be used to address any given reliability issue, the table presents a range of values.

Figure 3-8. Rough magnitude for potential NTAs

Priority number	Name	Year Needed	Rough NTA magnitude
3C	Georgia-St. Albans	2018	20 to 50 MW
12	Ascutney-Ascutney Tap	2013	20 to 50 MW
13	Coolidge-Cold River	2013	50 to 100 MW
15	Ascutney Transformer	2013	15 to 30 MW
16	Coolidge Transformer	2016	30 to 60 MW
17	Barre	2018	20 to 40 MW
18	Chelsea	2018	15 to 30 MW
19	Plattsburgh-Essex	2021	100 to 250 MW

To be effective, the non-transmission alternatives must:

- **Be located in the deficiency area and in the "right" location.** For example, a generator may need to be two to ten times larger than the overload it is meant to correct, depending on the specific details of the network, because power flow from the generator leaves via all transmission elements, not just on the overloaded line or transformer. Also, typically the farther a single non-transmission resource is from the deficiency, the less its effectiveness. Therefore, an effective alternative will likely have to be larger the farther it is removed electrically from the problem.

- **Be present and in-service when the problem occurs.** The most significant challenge to deploying non-transmission alternatives is the need to be "on-line" when needed. A generator must be "on-line" and load in a demand response program must be "off line" when the transmission system deficiency arises for these resources to be effective alternatives to transmission reinforcement. In addition, the variations in system voltage, frequency and power flow experienced during the events or outages that cause the deficiency can cause protective devices to automatically disconnect local generation from the transmission system to avoid potential damage. This cannot occur if the generation is to be an alternative to a transmission reinforcement.

Some non-transmission alternatives may be effective for more than one deficiency. For example, a demand response program, or generator deployed on a subtransmission network may help address a deficiency that involves loss of the transformer connecting the subtransmission network to the transmission system, or loss of local portions of the transmission system.

Vermont distribution utilities are responsible for integrating consideration of non-transmission alternatives into the analysis of solutions to reliability deficiencies related to transmission facilities. The affected distribution utilities will supply the human and financial resources and information necessary to conduct or oversee the detailed analyses, including identification of alternatives, with respect to the reliability deficiencies identified in the plan. The affected utilities must identify a lead distribution utility that is responsible for ensuring that detailed non-transmission alternatives analyses are completed in a timely manner.

Each solution – transmission or non-transmission – face potential obstacles to implementation. At this stage of the planning process, those obstacles are unknown for any specific reinforcement described in this plan, or any potential alternative. One challenge in implementing solutions is land availability and land use. Most infrastructure requires space. Some substation reinforcements may require additional land adjacent to existing substations. New line reinforcements may be constructed within existing rights of way or may require expanded rights of way. A new generator may require land to construct the facility or a substation to connect it to the transmission network. Resources—physical, human and financial—present additional challenges to any solutions.