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# The concept of resilience and its relationship with reliability in Vermont

## State Technical Assistance

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This technical brief discusses the concept of resilience and its current implementation in Vermont. It highlights uses of resilience by regulators and utilities in the state, but finds no agreed-upon definition, metrics, and general framework to ensure resilience in power system infrastructure, communities, and customers. We introduce a “reliability-to-resilience” approach that Vermont and other states could use to include resilience components by extending an existing reliability framework used for distribution system planning. “Reliability-to-resilience” could develop into a systematic approach to refine and enhance Vermont’s current reliability planning in order to include resilience-oriented planning in a more accessible and practical way. We offer this approach as a complement to the traditional resilience planning frameworks that we research and present in a different technical brief.

## Reliability and resilience: concept and definitions

The concept of power system resilience is relatively new, especially when compared to the concept of reliability. Reliability has been identified as a core attribute of the power system since early deployment of generation, transmission, and distribution systems. Reliability can be defined as “the ability to maintain the delivery of electric power to customers in the face of routine uncertainty in operating conditions” (Eto et al. 2020). Reliability metrics and frameworks depend on the power system domain:

- **Generation:** reliability at the generation level is typically split into resource adequacy (long term reliability) and operational reliability (short term or dynamic reliability). Resource adequacy tracks the likelihood that demand is larger than supply at any given time, while operational reliability tracks ancillary service needs for regulation, ramping, and stability, among others.
- **Transmission:** reliability analysis focuses on dynamic or transient issues. There are emerging efforts to consider transmission in resource adequacy, both due to its deliverability implications for generation as well as the adequacy contribution of transmission lines.
- **Distribution:** reliability at the distribution system level focuses on measuring the frequency and duration of service interruptions for customers, accounting for outages in supply from the bulk power system as well as outages in the distribution grid itself. Standard IEEE 1366-2022 codifies well-known reliability indices such as SAIDI, SAIFI, and CAIDI<sup>1</sup>, as well as the concept of major event days. Most large utilities use GIS-enabled systems, feeder data models, and AMI data to track

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<sup>1</sup> System Average Interruption Duration Index, System Average Interruption Frequency Index, Customer Average Interruption Duration Index, respectively.



interruptions, localize outages, and manage their recovery, while smaller utilities use call center data to identify, track, and restore interruptions.

There are multiple definitions of resilience, but most follow the basic definition in Presidential Policy Directive 21 of 2013: “the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents” (PPD, 2013). For example, the North American Transmission Forum (2022) define resilience as, “The ability of the system and its components (both equipment and human) to (1) prepare for, (2) anticipate, (3) absorb, (4) adapt to, and (5) recover from non-routine disruptions, including high impact-low frequency (HILF) events, in a reasonable amount of time”. In general, resilience appears focused on the preparedness of a system to withstand a large disruption and its ability to return to a normal state as quickly as possible.

The emerging definition of resilience in distribution systems has encompassed a wider range of entities for whom resilience is measured. While reliability indices focus largely on aggregates at the circuit, feeder, or utility levels, resilience is typically applied separately to individual customers, communities, power systems, and society. This expanded application requires new metrics, data, and modeling capabilities to track costs and benefits of resilience enhancement, as well as characterize the technical performance of resilience strategies.

The relationship between resilience and reliability is a subject of ongoing debate. On the one hand, efforts have been made to create a definition of resilience that is distinct and minimally overlapping with that of reliability. For example, Eto (2018) offers a useful comparison of both concepts that highlights key differences (Table 1). The table establishes that the types of events under the purviews of reliability and resilience are different, the former being shorter and routine interruptions, while the latter are HILF events. This difference then extends to the ways decisions to manage reliability and resilience are made, and the types of stakeholders involved in these decisions. The comparison highlights the lack of standard metrics for resilience in contrast with reliability, although it only focuses on distribution system metrics and not bulk power system metrics.

**Table 1. Comparing reliability and resilience for power systems across five dimensions (from Eto, 2018)**

Dimension	Reliability	Resilience
Common features/ characteristics	Routine, not unexpected, normally localized, shorter duration interruptions of electric service larger events will make it into the local headlines	Infrequent, often unexpected, widespread/long duration power interruptions, generally with significant corollary impacts. Always front page news, nationally
Metrics	Well-established, annualized (SAIDI, SAIFI, MAIFI), and often exclude “major events.” Not focused on non-electricity impacts.	Not standardized, event-based (number of customers affected; hours without electric service). Routinely include non-electricity impacts (e.g., costs to firms; health and safety impacts).
Actions to improve	1. Plan and prepare; 2. Manage and endure event(s); 3. Recover and restore; and 4. Assess, learn, and update plan.	No qualitative difference But generally larger in scope/cost (see below)

Entities involved in decision making	Electric utility and its regulator/oversight board, primarily	Electric utility and regulator. However, commonly and routinely in conjunction with parties that have responsibilities for other critical infrastructures, including local/regional/state/federal agencies/authorities, and communities/elected officials.
Factors affecting decision making	Actuarial records on frequency of exposure – widely understood risks: insurable. Well-understood/tested practices/approaches. Understood to be an expected cost of doing business. Emphasis of metrics and evaluation ex-post, focus on verification of performance given large number of reliability events	No actuarial basis to establish likelihood of occurrence – widely varying perceptions of risk/exposure: un-insurable. Limited opportunities to “test” strategies; emphasis on design standards. Large dollar amounts/extraordinary expenditures may require special approval/vote. Political judgements essential. Emphasis of metrics and evaluation ex-ante, given scarcity of resilience events and their changing nature

On the other hand, this table highlights differences between reliability and resilience characteristics. At the same time, it indicates that these are not necessarily categorical. For example, they share some of the same improvement strategies, which are instead distinguished by scope, scale, and expense. The notion of reliability and resilience as a continuum, or at least as complements, is discussed in several documents. For example, DOE’s Modern Distribution Grid report described reliability as an *objective* of the grid, while resilience is an *attribute*. In this context, enhancing the resilience of the system supports attaining reliability as an objective: there is a logical building block relationship. The Organization of MISO States (OMS) offers another example (Figure 1): the focus of reliability is on high frequency events of localized impacts, while resilience addresses impacts of events that are less common and have a geographically and/or temporally widespread impact. While this distinction is used in the table above to justify a difference, this OMS approach recognizes the gradient between both extremes. Even with this distinction, the idea of developing a resilience framework starting from an existing reliability framework is practical and possible.



Figure 1. Spectrum of reliability and resilience events. Source: Organization of MISO States 2019



## Understanding reliability and resilience through metrics

Definitions for the concepts of reliability and resilience are related to metrics used to quantify these concepts (Table 2). Reliability metrics generally track the duration, frequency, and magnitude of service disruptions at the bulk power system and distribution system levels. Resilience metrics are incipient and rather abundant, with a few examples of proposed metrics reported in Table 2<sup>2</sup>. In general, resilience metrics focus on duration and magnitude, perhaps neglecting frequency due to the infrequency of resilience events. In addition, resilience metrics may track specific types of customers – such as critical loads, military facilities, and customers with medical needs – as a way of ensuring that these loads are targeted in planning processes. Finally, some proposed resilience metrics focus on costs – to customers, the utility, and the economy/society, in distinction to the generally technical metrics used for reliability and also enabling a more widespread application of cost-benefit analysis. Broadly speaking, potential new resilience metrics provide corresponding information but in some cases are measured differently, as well as adapted to longer-duration and/or wider geographical scale power interruptions. In addition, economic metrics become much more important in assessing resilience investments because of their generally higher costs and more uncertain benefits relative to standard reliability measures.

**Table 2. Example metrics used or suggested for reliability and resilience in power systems**

	Distribution system	Bulk power system
<b>Reliability</b>	IEEE Standard 1366-2022 (feeder or utility-level metrics SAIDI, SAIFI, CAIDI; customer-level metrics: CEMI, CEMM, CELID)	Resource adequacy metrics such as loss of load events (LOLE), loss of load hours (LOLH), and expected unserved energy (EUE)
<b>Resilience</b>	Critical loads/services without power, customer-level metrics, cost of damages, time/cost of recovery, GDP loss, SAIDI/SAIFI/CAIDI with major event days included, asset performance during resilience events	

A general comparison suggests that resilience metrics are more customer-focused than reliability metrics and may allow for more targeted investments, strategies, and interventions. Resilience seems to balance the focus on customers, the utility, and the economy/society, in contrast to the focus of reliability on average indices for the bulk power and distribution systems. Even if, conceptually, resilience is focused on HILF events, proposed resilience metrics could be applied in a reliability planning context and probably produce more targeted and informed decisions. This comparison suggests that resilience could be an expansion of reliability, studying performance aspects of the power system that become more apparent and relevant with HILF events, but that are still present during regular operation.

<sup>2</sup> This brief is not focused on resilience metrics. They are only mentioned in general as they may reflect useful components of a definition of resilience.



## Reliability in Vermont's distribution system

Distribution system reliability metrics, reporting, and planning in Vermont are largely governed by Rule 4.900 on Electricity Outage Reporting, which was passed in November 2000. The rule provides clear definitions for relevant terms and metrics – including SAIDI, SAIFI, and CAIDI – and imposes recording and reporting requirements for transmission and distribution utilities in VT. Annual reporting requirements are explicitly outlined, requiring reliability indices since 2001, counts of interruptions and total customer-hours interrupted by source of interruption, and an assessment of reliability that includes identification of the worst-performing circuits and palliative measures. The rule informs several regulatory processes by Vermont utilities, including:

- Service Quality and Reliability Plans. These plans establish service quality performance metrics, and typically include other non-reliability aspects including customer service parameters, billing quality and accuracy, meter reading performance, customer satisfaction, and worker safety.
- Annual electricity outage reports, as described above, in direct compliance with Rule 4.900.
- Reliability and resilience plan. Some VT utilities file reliability and resilience plans (e.g. Vermont Electric Cooperative (VEC)), but these are largely included as-is in Integrated Resource Plans and hence are ultimately redundant with the latter.
- Memorandum of Understanding, Docket No. 7081. This MOU is largely focused on transmission planning as developed by VELCO, but has more general applications for transmission and distribution (T&D) planning. The MOU created the Vermont System Planning Commission (VSPC), the concept of reliability deficiency as a focus of the planning process, and puts forth the concept of non-transmission alternatives to avoid or defer transmission capital projects by leveraging supply-side or demand-side resources.
- Integrated Resource Plans. These plans include large portions of the most recent electricity outage report required by Rule 4.900. In addition, some IRPs develop threat, vulnerabilities, and risk analysis, outline their emergency response strategies, and report on existing reliability-management strategies. Some IRPs (e.g. VEC's from 2022) develop screening or prioritization methods to select T&D capital projects, using their reliability benefits as one criterion.
- General rate cases. General rate cases as well as multi-year regulation plans are largely financial in nature and do not propose, evaluate, or select specific capital projects related to reliability, although decisions in these ratemaking processes should be governed, in part, by reliability considerations.

Reliability planning in VT is largely carried out within the context of the IRP, with different criteria and approaches used for transmission/sub-transmission infrastructure (for utilities that own any) and distribution system infrastructure. Transmission and sub-transmission reliability projects largely follow MOU Docket 7081 guidelines, but do not report specific projects (perhaps because those are brought up and discussed with the VSPC). Distribution system reliability planning is less structured and standardized, but utility IRPs show efforts to identify capital projects, evaluate and prioritize them based on least-cost or cost-benefit analyses, as well as feasibility and impact, and implement them.



## Resilience in Vermont

Several organizations and reports in Vermont feature resilience as a desirable attribute or objective of its economy and power system. For example, the 2022 Comprehensive Energy Plan “balances the principles articulated in 30 V.S.A. § 202a of energy adequacy, reliability, security, and affordability, which are all essential for a vibrant, resilient, and robust economy,” and establishes that, “The electric grid must be optimized to ensure resilience and responsiveness, and to benefit all electric consumers” (VPSD, 2022). This section reports on the current use of the concept of resilience in different Vermont regulatory and planning processes.

### *Definitions codified in statute*

Vermont statute refers to resilience mostly in the context of conservation and climate change, with references to community, ecological, and infrastructure resilience (e.g. mostly in Titles 6, 10, and 24). Even in these cases, our research only found one formal definition of resilience in the statutes. However, this definition refers to childhood and family resilience and not to power system or infrastructure resilience.

### *Definitions used in IRP*

The VPSD guidance for Integrated Resource Plans characterizes resilience briefly and qualitatively, using language reflecting the above-mentioned Presidential Policy Directive and stipulating that resilience initiatives focus on “...low-probability, high-impact events, typically impacting large geographic areas, lasting more than 24 hours, and classified as ‘Major Events’ according to IEEE 1366” (VPSD 2023).

The 2024 IRP of investor-owned Green Mountain Power, the state’s largest electric utility, cites this definition and discusses resilience extensively, including metrics proposed by VPSD and specific projects it describes as resilience-enhancing (GMP 2024). VEC’s 2022 IRP discusses several distribution resilience initiatives, including undergrounding, relocation and/or hardening of overhead power lines, and the use of sensors and fault-finders (VEC 2022). Washington Electric Coop’s IRP mentions resilience and includes an analysis of how future extreme weather may affect its infrastructure, but does not discuss resilience analysis or investments *per se* (WEC 2024). Recent IRPs of Vermont’s small municipal utilities have not discussed resilience.

### *Definitions used in general rate cases and GMP’s MYRP*

GMP’s 2021 Multi-Year Regulation Plan highlights resiliency.<sup>3</sup> The utility frames it both as a strategic direction and as part of capital budgeting. With the exception of mentions to resiliency-focused projects, we did not find major references to resilience as part of the general rate cases.

### *Definitions used in other documents*

The 2022 Comprehensive Energy Plan recognizes that, in contrast to reliability, “Resilience (or resiliency), on the other hand, is more of a term of art, subject to a variety of proposed definitions, with an evolving landscape of potential metrics but without specific regulatory “teeth.”” The report cites several definitions

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<sup>3</sup> [Case Details | Vermont Public Utility Commission.](#)



of resilience by FERC, NERC, the U.S. DOE, and EPRI, but does not formalize a definition for planning purposes.

VEC's reliability and resilience section in their webpage states, "Resiliency is how quickly a utility recovers from a major event. The impact of resilience investments may not be realized until after a major outage event." In this definition, the subject of analysis is not electric service, but the utility as a whole. The definition also warns that resilience investments may only produce benefits under major outage events, not under routine interruptions.

## A "reliability-to-resilience" approach

The lack of precise definitions for distribution system resilience is not unique to Vermont. Numerous other jurisdictions have devoted considerable time and technical and regulatory effort to developing such metrics as well as comprehensive resilience frameworks, but for the most part this remains a work-in-progress. Our review of resilience planning approaches in other states reveals that considerable technical, financial, and regulatory effort has been needed – including time – to develop and implement resilience planning frameworks. The standard "top-down" approach entails designing and implementing not just metrics *per se*, but definitions, data requirements, models and other analytical tools, as well as decision-making mechanisms, including report requirements. For many utilities, especially smaller and less resourced ones, the prospects of this implementation are daunting.

This memo introduces the idea of "reliability-to-resilience," an approach focused on the idea of building a resilience-focused planning framework from existing reliability-focused activities within utilities. In contrast to the idea that reliability and resilience are distinct, the "reliability-to-resilience" approach builds on the notion mentioned earlier that performance metrics that would otherwise be categorized as reliability or resilience exist, to an extent, as a continuum. Extending existing reliability-oriented planning frameworks to include resilience metrics, data, methods, and outcomes would reasonably be a more efficient way for utilities to incorporate resilience aspects into their planning process and more practical for regulators that are already familiar with reliability planning.

A thought experiment may help illustrate how reliability and resilience can be closely related. Utilities treat outages due to animal damage to infrastructure as part of their reliability requirements. These events are reported as part of reliability metrics, and planning and maintenance includes strategies to deter or mitigate impacts of animals causing outages and interruptions. Imagine that, by chance, several dozen animals happen to damage infrastructure at the exact same time across a utility's service territory. While the underlying cause is treated as a reliability event, their joint – and admittedly improbable – occurrence would likely create for the utility what is typically referred to as a resilience event. In other words, this HILF event is the sum of multiple and simultaneous reliability events. Actual resilience events will likely include damage to non-electricity infrastructure and other emergency conditions that will affect restoration efforts. However, this thought experiment shows that reliability and resilience, in practice, may be conceptually closer than thought, given underlying metrics, strategies, and evaluation methods.

The following sections include a preliminary exploration of how current components of reliability planning in Vermont related to data and metrics, available strategies, and decision-making support may be leveraged to implement aspects of resilience-oriented planning. Note that our reviews suggest that traditional reliability planning practices will not cover all the requirements of comprehensive resilience-oriented planning. However, given the complementarities in many aspects of their definition, assessment, strategies,



and decision-making, developing a resilience planning framework that does not build off existing reliability frameworks may miss synergies that make the overall process faster, more predictable, and clearer.

Whether and how reliability planning in Vermont could be extended to include resilience elements should be part of the resilience proceeding. The preliminary notes below highlight some elements of reliability planning that we identified as potentially synergistic with resilience-oriented planning.

### *Data and metrics*

The use of historical data to capture the impacts of low frequency events has been deemed impractical since the historical record does not reflect a significant number of these types of events. However, the recently increased frequency and magnitude of natural hazards is offering more opportunities to verify the performance of certain resilience strategies that could complement the forward-looking weather forecasts that are used to simulate resilience events. Furthermore, maintaining detailed historical records of customer and utility performance during individual large historical events like storms and floods can be very valuable to develop scenarios for resilience valuation frameworks.

- Outage management systems and other record-keeping mechanisms used for reliability can be adapted to characterize high impact and low frequency events, especially if they leverage IEEE Standard 1782-2022 on “Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events”. Most VT utilities leverage outage management system data as part of their Rule 4.900 reporting, which requires them to identify and characterize outlier events.
- The incorporation of Major Event Days (MED) into calculations of performance metrics for duration and frequency can be used to internalize aspects of resilience in current reliability planning practices. Characterizing, modeling, simulating, and evaluating the impacts of MEDs in planning processes would yield a more resilient system, especially if failure rates and restoration processes are individually assessed. Minor refinements in how MEDs are defined to make them more directly linked to threats and hazards and less on performance<sup>4</sup> would improve their usefulness as a resilience tool and create better incentives for utilities to enhance resilience. For example, the New York Codes, Rules, and Regulations defines “major storms” as “any storm which causes service interruptions of at least ten percent of customers in an operating area, or if the interruptions last for 24 hours or more”<sup>5</sup>.
- Asset-level outage records can assist in developing better quantification of common-mode failures and failure rates under HILF events. These existing records would support the development of more rigorous fragility and vulnerability models to understand how distribution system assets respond to HILF events.
- Resilience metrics typically extend to include economic impacts of HILF events. Current reliability frameworks in Vermont already include service quality compensation in the Service Quality and Reliability Plans (SQRPs), which is an indirect measure of the economic costs of interruptions.

Duration and frequency statistics are already captured for reliability reporting and remain very useful for resilience. However, resilience events may require a refinement to capture the magnitude of the event,

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<sup>4</sup> MEDs are defined based on comparing a daily SAIDI against a historical average.

<sup>5</sup> See <https://govt.westlaw.com/nycrr/Document/I5059b0ddec1711dda432a117e6e0f345>



which has direct impacts on restoration efforts. Rule 4.900 is a good start for reliability and resilience metric reporting, and expansions for some types of resilience metrics should be relatively easily accommodated with existing underlying data and processes.

- High impact events conflate electric service interruptions due to direct damage to distribution system infrastructure and lack of power supply from the bulk power system. Resilience targeted to distribution systems may need to differentiate interruptions that arise from within the distribution system from interruptions that originate in the bulk power system.
- Utilities have experience calculating duration and frequency aggregates at the system or feeder levels. Existing or new smart meters could be leveraged to estimate duration and frequency aggregates at higher granularity, such as census block groups, service transformers, or customers.

### *Available strategies*

In many cases, the strategies and measures that utilities use to improve or maintain reliability as reported in their IRPs – vegetation management; SCADA, AMI, and circuit automation; outage management systems; weather forecasting; asset management, among others –also improve resilience, particularly when undertaken at larger scales. Conversely, strategies typically used to improve resilience – circuit relocation; circuit undergrounding; improved ground crew management; asset redundancy; proactive maintenance; acquisition of behind or in front of the meter backup power – all have reliability benefits.

- Utilities can expand on how these strategies improve performance for high impact events, either through preparedness/hardening of the system or through improvement in restoration time. The effect of these strategies should account for the widespread outages and interruptions that are typically the focus of resilience.
- The use of an integrated set of reliability and resilience strategies will simplify planning processes. Utilities will need to characterize how these strategies improve failure rates or restoration rates on both frequent and less frequent events. In addition to modeling these performance outcomes, Rule 4.900 reports from some utilities suggest that they have good information in their historical record for this characterization.

### *Decision-making support*

IRPs filed by Vermont utilities do not reflect extensive use of either cost-effectiveness or cost-benefit analyses, although there are mentions of these approaches employed as part of utility decision-making processes. The IRP workflow suggests utilities generally establish an overall T&D capital expenditure level and apply a screening process to select a combination of projects that enhance reliability (or resilience).

- This prioritization process is valuable and should be maintained if preceded by a new process that determines what is the socially desirable level of capital investment for a given year, or the required level of investment to achieve prescribed reliability and/or resilience performance.
- Several utilities report in their IRPs the use of quantitative methods for decision-making supported by system simulations. These can be great starting points to support quantitative resilience-oriented planning.





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