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Electric distribution resilience and reliability

Definitions, metrics, planning, and regulation

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This brief argues that existing utility frameworks inappropriately conflate reliability and resilience by using statistical, impact-based criteria—such as "Major Event Days" definition—which focus on the resulting power interruptions rather than their underlying causes. To resolve this, we propose a foundational boundary: reliability should be evaluated based on operations under "normal" weather conditions, while resilience must specifically address a utility's capacity to withstand and recover from "extreme" weather events. Subsequently, we recommend that these extreme weather events be defined not through relative meteorological statistics, but through absolute numerical thresholds tied to the specific physical vulnerabilities and operating envelopes of an individual utility's infrastructure.

Standard reliability averages are inadequate to effectively measure and regulate this weather-based resilience, as they obscure the localized and high-impact nature of severe weather outages. Instead, we propose a suite of four specialized metric categories: local extreme weather thresholds, grid vulnerability measures (such as fragility curves), utility emergency response performance, and granular, customer-centric service interruption metrics that account for the growing role of distributed energy resources (DER). Ultimately, this brief advocates for a proactive, risk-based planning approach. This requires utilities to explicitly separate the uncertainty of extreme weather from the measured performance of their resilience upgrades, managing total risk through a coordinated strategy of infrastructure hardening, DER integration, and rapid emergency restoration.

Introduction

From September 2024 through February 2026, Berkeley Lab and collaborators at the University of Texas, Austin advised the Vermont Department of Public Service in its electricity resilience planning efforts. This included participation in the Vermont Public Utilities Commission "Resilience Proceeding" (hereafter "Proceeding"). LBNL/UT's work focused on developing a resilience planning framework and a methodology for electric resilience benefit-cost analysis in Vermont.

Electricity system resilience has been a subject of considerable discussion and research, and its regulation is in the early stages. As was discussed during the Proceeding, the concept has generated considerable confusion, in part due to an absence of specificity regarding the precipitating events that warrant an examination of distribution system resilience. Thus, this brief will focus solely on electric distribution system resilience with respect to extreme weather, which has been the focus of the Proceeding itself and a recurrent driver of resilience frameworks elsewhere.

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This technical brief addresses aspects of and contributes to several topics that arose during the Proceeding:

- Exploring the boundary between distribution system reliability and resilience focusing in distinguishing the types of precipitating weather events that each concept addresses
- Why "all in" reliability metrics that include major event days are insufficient and inadequate as resilience metrics
- An approach to establish "major events" that supports resilience planning and regulation
- An approach to define metrics for resilience analysis based on an objective definition of the types of events, threats, and consequences that resilience addresses, as opposed to reliability
- Considerations for risk-based planning and uncertainty management that were generally overlooked during the Proceeding
- Practical regulatory implementation aspects for resilience in utility planning that were not given due consideration during the Proceeding

Distribution system reliability and resilience

While the appropriate definition of "resilience" has been widely debated, it has frequently been emphasized that it is fundamentally different from reliability. However, it is important to note that, paradoxically, there is no precise, standard definition of electric distribution *reliability.* For example, the IEEE Standards Association offers ten definitions of "reliability" (for systems, technologies, etc.) but not of "electric distribution [or transmission] reliability."[1] In the present context, however, electric distribution reliability is generally understood to refer to continuity of service under "normal" weather conditions – although this also lacks a standard definition.

IEEE implicitly characterizes the boundaries of reliability in the development of its standard indices. Its 1366 Guide defines a "Major Event" as "…an event that exceeds reasonable design and/or operational limits of the electric power system." [2] Although not necessarily weather-related, the only specific examples it provides are hurricanes and ice storms - "catastrophic large-scale events…that have a "low probability of occurring" but "result in unusually sizable daily SAIDI values." These events upwardly skew a utility's SAIDI and SAIFI statistics, and thus obscure reliability performance under normal conditions, that is, in the absence of such events.

Because it found "…difficulties…creating a uniform list of major events,,,", IEEE developed a technique for excluding severe weather and other Major Events from consideration when measuring distribution utility reliability performance through standard reliability indices. IEEE 1366 further states, "A Major Event Day (MED) is a day in which the daily system SAIDI exceeds a threshold value, T_{MED}", which is calculated using a specific mathematical formula drawing on historical reliability information (known as the "Beta method"). Instead of excluding power interruptions based on the characteristics of *precipitating* events (which are exogenous to utility decision-making), the MED statistical approach excludes outliers in the resulting power interruption events themselves (which are driven by both exogenous weather and endogenous utility decisions).

[1] IEEE Standards Dictionary, 7th Edition, 2000.
[2] IEEE Standards Association. 2021. *IEEE Guide for Electric Power Distribution Reliability Indices* (IEEE Std 1366-2022, revision of IEEE Std 1366-2012). Developed by the Transmission and Distribution Committee, IEEE Power and Energy Society. Approved September 21.

IEEE acknowledges the shortcomings of its approach, and advises individual jurisdictions to develop their own.[3] Vermont and other jurisdictions have done this by defining "Major Storms" and excluding them from the calculation of distribution reliability indices in utilities' "Service Quality and Reliability Plans (SQRPs)." In the following list, stipulations ii. and iii. apply to all utilities; stipulation i. applies to Green Mountain Power (GMP), Vermont Electric Cooperative (VEC), and a few others.[4] Note that the Vermont definition of major storm remains focused on tracking the power interruption impacts of the storm, rather than the specific characteristics of the precipitating event.

> "Major Storms: Calculation of all SAIFI and CAIDI indices shall be net of outages caused by major storms. A major storm is defined as a severe event that satisfies all three of the following criteria: i. Extensive mechanical damage to the utility infrastructure has occurred; ii. More than 10% of the customers in a service territory are out of service due to the storm or the storm's effects; and, iii. At least 1 % of the customers in the service territory are out of service for at least 24 hours."

IEEE states that the purpose of its MED criterion "...is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events." This also essentially describes the motivation for Vermont's Major Storm exclusion, which is applied to distribution utility management and operations aimed at maintaining acceptable standards of electric service reliability, and to the regulation of same.

In this paradigm, "normal" weather could be defined as that which does not include phenomena resulting in Major Event Days or Major Storms, and "extreme" or "severe" weather as that which does – whether involving wind, precipitation, ice, or temperature. And with respect to weather specifically, reliability would be characterized in terms of the management and operation of distribution utilities under these normal conditions. In turn, "extreme" or "severe" weather might be characterized as phenomena that *do* result in power interruptions meeting the MED or, in the case of Vermont, Major Storm thresholds. Weather-related resilience would then have to do with planning and operations dealing with these precipitating conditions.

The IEEE standard indicates that the purpose of its Beta method is "…to allow major events to be studied separately from daily operation." For Vermont, the idea just mentioned is promising but not readily implementable using the Major Storm criterion, for the following reasons.

A Vermont criterion or threshold distinguishing resilience from reliability needs to provide a benchmark enabling the state to address extreme weather risks in a proactive way. In the IEEE framework, weather

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[3] From IEEE Standard 1366-2012 text: "While significant study was undertaken to develop objective methods for identifying and processing catastrophic events (in order to eliminate the noted effect on the reliability trend), the methods that were developed, in order to be universally applied, caused for many utilities, catastrophic events to occur far too often to accept as being reasonable. In addition, the elimination of catastrophic events from the calculation of the major event threshold cause, in some utilities, a rather large increase of days identified as MEDs in the following five years. *It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities since no objective method has been devised that can be universally applied to achieve acceptable results*" (emphasis added).

[4] Ann Bishop, Vermont Public Utilities Commission, Vermont Dept. of Public Service Resilience Proceeding Measurement Workshop #1, July 14, 2025.

catastrophes and their electricity service impacts are low probability. But in Vermont and other states/locations, their probability (and actual occurrence) has increased to the point that they are major public policy and regulatory concerns. That is, while the weather events themselves cannot be prevented or mitigated, reducing their *impacts* has been raised as a regulatory and utility planning *goal.* In other words, these impacts have become "endogenous" to regulation and planning. The identification of "major events" in Vermont therefore needs to facilitate decisions by utilities aimed at this goal, as well as support oversight by the Department and Commission.

From this perspective, there are several practical problems with the Major Storm criterion. It was reported during the Proceeding that severe power interruptions are occurring that do not meet it. In addition, Major Storms cluster together a wide range of exogenous and endogenous phenomena, which may include non-weather and non-resilience events. For example, flooding could cause minor grid issues but prevent crew access to impacted sites, therefore extending restoration times. However, for the purposes of decision support, the fundamental problem is that Vermont's Major Storm criterion is itself defined in terms of impacts – that is, *effects*. Instead, the boundary between reliability and resilience should be defined in terms of *causes* – in this particular context, having to do with weather.

The IEEE 1366 standard ambiguously refers to both severe weather events and their distribution system impacts as "catastrophic," but this is a colloquial and undefined term. There is no single objective definition of "extreme" or "severe" weather in meteorology or climate analysis. In non-IEEE documents, these terms are defined in terms of distributions of meteorological variables – e. g., 90th percentiles of wind speed or precipitation. Use of relative thresholds based solely on climate/weather statistics may not be adequate in a decision context, since it does not *per se* connect events with their electricity impacts. A simple example illustrates this: the 90th percentile precipitation event in a very dry climate zone is very unlikely to drive any type of flooding.

More generally, we posit that electric distribution infrastructure – and infrastructure in general - is sensitive to *absolute* and not *relative* levels of severe weather. Thus, thresholds for severe weather events should be identified in terms of utility *vulnerability* to these events*.* Utilities should then "rate" their distribution infrastructure with respect to its capacity to continue operating, or to rapidly recover from outages, when subject to specific categories of weather extremes. A few common examples include wind-load ratings for utility poles, manufacturer ratings for other equipment, as well as utilities' own knowledge and experience. A way of describing this assessment is that each Vermont utility would identify its own "operating envelope" regarding weather extremes, defined in terms of specific numerical thresholds for the variables noted above: gradient winds, icing, wet snow, and heavy rain – these would define utility-by-utility major events. This is in fact the approach taken by the National Weather Service (NWS) in issuing weather advisories or warnings. For Vermont, the NWS has numerical thresholds for gradient wind, ice, wet snow, and precipitation. Numerical definitions of severe weather thresholds were also used for these variables in a 2021 study for Vermont Electric Power Company, for variables quantifying gradient winds, icing, wet snow, and heavy rain.[5] These were chosen on the basis of vulnerability, as discussed above.[6]

The 2021 study focused on extreme weather impacts on the Vermont Electric Cooperative specifically, and the threshold values may have reflected that utility's particular weather vulnerabilities. Going forward, it

[5] Northview Weather, LLC. 2021. *Extreme Weather and Climate Change in Vermont: Implications for VEC's Asset and Storm Planning*. Report prepared for Vermont Electric Power Company, August 9.
[6] Jay Shafer, Ph.D., personal communication, January 2026.

would be necessary for individual Vermont utilities to determine their own thresholds for the weather variables relevant to their service territories, or even more spatially granular definitions for utilities whose infrastructure is affected by specific weather events or weather-driven hazards (e.g. flooding).

We propose the following definitions:

- ***A "major event" for a utility is an occurrence of extreme – i.e., threshold-exceeding - weather within its service territory.***

- ***"Extreme weather resilience" is an electric distribution utility's capacity to avoid or mitigate increases in the frequency or severity of power interruptions resulting from extreme weather events,*** where "severity" encompasses both the number of customers affected and the duration of interruptions.

It is important to highlight that these definitions conceive resilience as a characteristic or property of an entire *utility* as opposed to just the infrastructure. Infrastructure engineering measures (e.g., preemptive storm hardening, grid redundancy, and switching capability), preventative and proactive maintenance (e.g. vegetation management), and emergency response activities (e.g. rapid restoration of power when interruptions occur) all contribute to resilience.

We also note that with these definitions, what is "major" may be, in part, a function of a utility's inherent resilience, with the implication that weather-related thresholds may need to evolve over time. That is, enhancing resilience will decrease vulnerability and may require an increase of numerical weather sensitivity thresholds to reflect this fact. However, redefining weather thresholds too frequently would not allow to monitor the performance of resilience strategies deployed by the utility. We would recommend that the Department use individual utilities' vulnerability assessments (as described above) to establish weather-informed benchmarks for "major events" that would be in place for a period of time – e. g, 5-10 years. These would provide the basis for utility resilience planning and implementation, and Department assessment of these efforts, during that period. As the utility becomes more resilient, the original "major events" would not stress the utility infrastructure and response the same way it did before resilience interventions were deployed. It follows that the Department and individual utilities would then potentially re-assess these benchmarks to decide if they should be changed in order to further increase or maintain resilience.

We can also now state clearly that a "resilience measure" is one that meets either of these conditions:

- *an investment (such as storm hardening) or operational or maintenance procedure (such as enhanced vegetation management) intended specifically to improve the ability of the utility to withstand events by reducing infrastructure vulnerability to extreme weather – that is, to avoid interruptions.*
- *The resilience-related component or aspect of a project with multiple benefits or*
- *a change in utility emergency preparedness/operations planning/capability or in a customer's facilities that is addressed specifically to improve restoration of service after an interruption triggered by extreme weather conditions – that is, to mitigate interruptions (reduce duration and/or scope) if they occur.*

Finally, we can now also define "normal" weather as "meteorological conditions in the absence of extreme weather events", with the understanding that this requires specifying appropriate levels of spatial and topographical granularity. These "normal" conditions would be the realm of reliability metrics and procedures. Note that the definition of extreme weather event proposed earlier will be inconsistent with the MED definition as stated in IEEE 1366. These definitions clearly distinguish, and pinpoint the relationships between, the planning, operational, and regulatory domains of distribution reliability with respect to weather and extreme weather resilience, respectively. Reliability concerns performance and strategies responsive to normal weather conditions, while resilience concerns performance and strategies responsive to extreme weather conditions.

We note that because reliability deals with non-weather threats too – animals, vegetation, car wrecks, etc. – resilience does not completely subsume it here. Therefore, any weather-related reliability enhancing measure *may* increase resilience, depending on the details; in contrast, resilience measures aimed at preventing power interruptions (but not necessarily all emergency response measures) are likely to increase weather-related reliability.[7]

We are aware that the approach we have just described would affect both VT Rule 4.900 and the utility Service Quality and Reliability Plans with respect to reliability alone. In particular, any electricity service disruptions caused by weather that was not "extreme" by the above definition would be included in utility SAIDIs, etc. This might be a larger change, but it is arguably a direct implication of VT's policy and regulatory positions on climate change and resilience.[8]

Metrics for resilience analysis

As noted above in regard to IEEE 1366 and Vermont's Major Storm exclusion, distribution reliability metrics are based on the concept of removing outliers in order to estimate a central tendency – that is, average performance of a utility. This is believed to be driven by feeder characteristics and hence – all else being equal – assumed to remain stable over time absent interventions. These metrics are also intended to gauge overall – that is, utility service territory-wide - performance.

The usefulness of this approach in a resilience context should be considered in terms of decision-support. A central theme of the Proceeding is that in Vermont, while distribution reliability targets are generally being met, increasing impacts of extreme weather are resulting in some customers of some utilities experiencing power interruptions that are long-duration, frequent, or both. For GMP and apparently several others, this is occurring in geographically delimited areas – "hot spots" or worst-performing zones – that are rural and relatively isolated. In other words, these impacts are heterogeneous both spatially and in terms of which customers are affected – specifically, up to a point, they have been *localized.*

Standard reliability metrics' focus on average systemwide performance is inappropriate both for quantifying these impacts and for assessing measures to prevent or minimize them. In addition to the localized nature of the impacts, the assumptions underlying reliability metrics do not apply to analyzing

[7] By contrast, operations-oriented resilience measures may not – for example, improved emergency-response tactics that would not come into play in the absence of extreme weather events.
[8] In this context, we would recommend that power outages caused by tree impacts be re-classified as storm-related when they are in fact due to extreme weather.

events that have (relatively) low likelihood and high impact and are not represented well in a central tendency – they are by definition exceptions (even if they are becoming more common).

Another consideration is the emerging role of distributed energy resources (DER) in Vermont. As was illustrated during the review of Green Mountain Power's Zero Outages Initiative, the distinction between electric power outages and customer electricity service interruptions is becoming increasingly important. From a decision-support perspective, thorough quantification of resilience and utility actions to improve it requires distinguishing causes from effects, as discussed above, and systematically characterizing utility resilience-related actions and their consequences. This implies the need for measurements to

- characterize precipitating events
- track grid vulnerability to impacts of those events
- estimate outcomes of infrastructure and other measures to reduce vulnerability
- assess utility restoration actions when power interruptions occur
- understand customer electricity service and how both extreme events and resilience affect it.

As was discussed during the Proceeding, over the past several decades many proposals have been made for electricity resilience metrics, but none have been generally accepted as industry standards analogous to reliability metrics. For this reason, a number of jurisdictions are using "all-in" reliability metrics - standard metrics but calculated without excluding major storms/events - as a default for resilience assessment. However, metrics such as all-in SAIDI do not address the requirements listed above. Instead, the above considerations imply that four types of metrics are needed:

- Numerical thresholds identifying the occurrence of extreme weather events, as discussed in the previous section
  - These would be at a level of spatial/geographical/topographical granularity sufficient to accurately measure the interfaces between events and distribution infrastructure
- Measures of grid vulnerability to severe weather events
  - An example is "fragility curves," which relate (in this application) the probability of asset failure as a function of the precipitating weather event. [9] However, we note that the degree of vulnerability is also a function of grid characteristics such as redundancy and switching capability, which may enable continued operation even with some instances of asset failure.
- Measures of utility emergency response performance
  - These gauge how effectively a utility can restore power following interruptions caused by severe weather. They are important because the Proceeding highlighted the potential trade-offs between preventive measures such as storm hardening, on the one hand, and rapid recovery, on the other.
- Metrics for electricity service interruptions

[9] These are discussed in: EPRI Climate Resilience and Adaptation Initiative (Climate READi) Technical Reports, April 2025: *Asset Vulnerability and Response Assessment Guidance*, and *Fragility Curves for Quantifying Physical Climate Risk in the Electric Power Sector.*

- Some customers may exploit DER when power from the grid is interrupted. In part for this reason, actual service interruption metrics should focus on the customer experience. [10] The Department is interested in requiring more granular metrics – such as circuit-or feeder-level CMI, CELID, CEMI[11] – to accurately quantify the specific types of service interruptions described above. In contrast to standard metrics, these newer metrics focus on impacts resulting from precipitating events "in the tails" of distributions, not around their means. Ultimately, actual *customer*-level metrics may be available for utilities with advanced metering deployment that can track individual customer interruptions.

The next section discusses how these metrics could facilitate utility resilience planning and oversight of same by the Department.

Resilience planning and regulation

The frequency and severity of future extreme weather events cannot be precisely predicted. Therefore, the degree to which their magnitudes will exceed historical norms and require new resilience measures to address is uncertain. In addition, with the present state of knowledge, possible uncertainty in the outcomes of resilience-enhancing measures even *conditional* on weather must be recognized. This refers to estimating *ex ante* how well specific resilience measures will perform in practice when subject to the extreme weather stresses they were designed for.

For these reasons, improving distribution resilience is a matter of *reducing risks* posed to utilities and electricity users. There are several components to these risks and their mitigation. First, the likelihood of the extreme events themselves. Second, the vulnerability of the distribution grid to the events.[12] Third, the extent to which DER reduces customers' exposure to grid power interruptions when they do occur.

We can summarize the *ex-ante* relationships among these factors based on the standard definition of risk. For grid-dependent customers,

Risk (electric service interruption) =
Likelihood of extreme weather event X vulnerability of grid to weather-caused power interruptions.

For customers with DER, the risk of a service interruption will depend on both their equipment and the duration of the interruption – e. g., if it exceeds battery life. In that case, how long they are without power will again depend on the utility. [13] Also, the above expression refers only to the occurrence, not the duration, of service interruptions. When they do occur, duration will be primarily a function of utility response and restoration actions.

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[10] In addition, some grid asset failures may result in power outages on the grid but not actual power interruptions to customers, because of redundancy and/or switching, for example.
[11] Customer Minutes Interrupted, Customers Experiencing Long Interruption Durations, Customers Experiencing Multiple Interruptions, respectively.
[12] As noted in the previous section, grid vulnerability also involves the nature of extreme weather-caused damage when it occurs: resilience measures such as redundancy and switching capacity may prevent loss of customer electricity service in the event of asset failure.
[13] Although we don't do so here, similar expressions can be written to describe both the risks to DER customers, and the risks of long-duration interruptions specifically.

The metrics proposed in the previous section apply to this template as follows. Customer service metrics are the fundamental gauge of risk. Extreme weather metrics are needed to define the potential impacts of precipitating events, and could be supplemented by "hazard curves," which quantify the likelihoods of such events.[14] Grid vulnerability metrics help to characterize the likelihood of power interruptions conditional on extreme events. Finally, utility response metrics facilitate measurement of risks of long-duration interruptions.

This discussion highlights several facts. First, because weather obviously cannot be controlled by regulators or utilities, the sole means of reducing the risks of electric service interruptions (their occurrence or their durations) are i) increasing resilience in order to reduce grid vulnerabilities that might result in power interruptions (including through storm hardening, advanced monitoring and controls, etc.), ii) deploying distributed generation, and iii) enhancing utility emergency response and restoration performance. Second, all else being equal, these three strategies should be considered symmetrically – i. e., from the customer perspective, avoiding or minimizing electric service loss is the priority. The overall strategy should be coordinated analysis and deployment of grid engineering and operational measures, other preventive actions, DER, and emergency response.

Third, even these actions cannot *guarantee* that interruptions will not occur, or not be long duration. There are several reasons for this. Above all, because of weather uncertainty, there is always the possibility of extreme events more severe than utilities or regulators anticipate and prepare for. In addition, however, as noted above, information provided during the Proceeding suggested that utilities may not yet be able to precisely predict how well resilience measures will perform in practice *even given assumptions about weather.*

Moreover, it may be the case that, with whatever weather and other assumptions are made, the costs of some resilience measures will exceed utilities' and/or their customers' ability or willingness to pay. *How much risk to bear is a critical policy question that will need to be addressed by regulators and other Vermont policy-makers, utilities, and electricity customers.*

Distinguishing between weather uncertainty related to extreme weather events, and that related to *ex ante* estimation of resilience measure performance conditional on weather, is critical for regulation. The Proceeding revealed very little regarding the second type of uncertainty. In practice – e. g., in utility resource plans - utilities should provide the Department with details on both their assumptions about extreme weather and on how they estimated resilience measure outcomes conditional on the weather assumptions. This would entail assertions like "in the event of extreme event X the project will reduce vulnerability between Y% and X%..." assuming appropriate vulnerability measures have been developed and implemented. Note that the Northview study cited above reported increases in unconditional outage risk due to extreme weather. The study did not distinguish the contribution of weather from the contribution of vulnerability in its risk estimates of power interruptions. Going forward, these two should be explicitly decomposed as just described.

We learned during the course of the Proceeding that various models, data, and tools are available to utilities for projecting climate and weather. How extreme event uncertainty is addressed varies among

[14] These are discussed in the EPRI Climate READi report.

them. In some cases, it is explicit - i.e., in terms of likelihoods or probabilities. [15] In others - like the Argonne National Laboratory ClimRR modeling tool[16] - it is not quantified, and only point estimates are given. All-else-being-equal, the latter are insufficient for resilience risk analysis planning (whether from Argonne or another source): Point estimates *per se* in general provide no information about uncertainty.[17] Striking a balance between the need for quantitative risk analysis, and accessibility/feasibility for small utilities, on the other, will be an important goal for Vermont. [18] [19]

[15] Several detailed climate analyses conducted for utilities in other Northeast states have included such information.
[16] ClimRR
[17] Even without actual probability distributions, point estimates in the context of scenario analysis can provide some uncertainty information. But in the Argonne tool, the only scenario choice is that of future global climate projection. No quantitative weather uncertainty *conditional* on this choice is generated.
[18] Stowe Electric has used/is using the Argonne tool. But this does not reflect a lack of technical sophistication per se – e.g., the utility's latest IRP discusses how it does quantitative risk analysis in the context of resource planning.
[19] This section has focused on ex ante analysis. How to conduct ex post evaluations of resilience outcomes and measure performance is a more complicated problem in general. Pragmatically, it is to be expected that Vermont utilities will follow GMP's lead in simply comparing particular circuits before and after storm hardening, for example, is done. However, this does not control for the myriad of variables that might confound the outcomes. For example, it is possible that that a resilience measure is implemented but performance subsequently appears worse because of greater-than-predicted severity of extreme events. Normalization is challenging when the events one wants to control for are specifically not "normal." This *ex post* evaluation problem is at this point on the research frontier. For now, the metrics proposed in the preceding section can assist in at least interpreting results more clearly.

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