North Coast Resiliency Initiative

STAFF REPORT

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California Public Utilities Commission

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Executive Summary

The Challenge

Over the last decade, California has experienced increasingly intense, record-breaking wildfires. Fires attributed to power lines, though a minority overall in terms of number, comprise roughly half of the most destructive fires in California history. To reduce wildfire risk from electrical infrastructure, utilities have used Public Safety Power Shutoffs (PSPS) to de-energize power lines during severe fire weather conditions. PSPS events can impact either distribution or transmission lines or both simultaneously.

In the past, the North Coast segment of Pacific Gas and Electric Company's (PG&E) electric grid has been significantly impacted by PSPS events. For example, transmission and distribution lines in the North Coast area were de-energized during the October 26 and 29, 2019 PSPS events, affecting approximately 245,000 customers. This is partially due to the designation of much of this area as either Tier 2 or Tier 3 High Fire Threat Districts (HFTDs). HFTDs are areas at higher risk for destructive fires and where stricter fire-safety regulations apply. This means that transmission and distribution lines serving customers in the region might need to be de-energized when certain weather and fuel conditions are present to avoid wildfire risk.

However, many customers in the North Coast who are otherwise "safe-to-energize" also lose power during PSPS events. In this case, safe-to-energize refers to customers who are located outside of the conditions that triggered the need for a PSPS event, but are served by a transmission line or lines that have been de-energized. If the grid configuration were different, they would be able to remain online.

Addressing the Challenge

The California Public Utilities Commission (CPUC) founded the North Coast Resiliency Initiative (NCRI) in 2021 to determine the causes of, and to craft mitigations for, electrical outages that impact customers along California's North Coast during wildfire season. Along with the CPUC, representatives from other state energy agencies, PG&E, and two Community Choice Aggregators (CCAs) comprised the NCRI's Steering Committee which was responsible for the majority of the initiative's work.

Specifically, the NCRI focused on *transmission-level* PSPS outages affecting otherwise *safe-to-energize customers*. For the purposes of the NCRI, the "North Coast" was defined as Marin, Sonoma, Napa, and portions of Mendocino, Lake, and Solano counties. The CPUC determined these geographic boundaries at the beginning of the initiative, based on the locations of actual and predicted future PSPS events and on the structure of the local electrical grid.

The NCRI Steering Committee then developed a four-phase problem solving framework and began working through each of the key steps. This framework could be used to address other regional grid challenges that require multijurisdictional collaboration.

- Phase 1: Build the foundation

- Phase 2: Define the problem
- Phase 3: Explore and compare mitigations
- Phase 4: Conduct comprehensive regional planning

The Solution

The NCRI Steering Committee completed the first two phases in the problem-solving framework, but stopped short of completing Phases 3 and 4. This occurred for three reasons:

First, by mid-2022, PG&E identified mitigations for PSPS impacts at the Calistoga and Monticello substations. The Monticello substation has an existing transmission switching option which will allow it to be served from a separate line during PSPS events. PG&E also plans to deploy a clean substation microgrid capable of powering the Calistoga substation through PSPS events. These substations had the highest number of *direct* PSPS impacts in the North Coast in PG&E's 10-year modeling effort, the first of two major types of transmission-level PSPS impacts explained in more detail below.[1]

Second, PG&E's updated PSPS modeling, which became available in early 2023 after the NCRI was well underway, showed fewer impacts from transmission-level PSPS events along the North Coast than prior years' models. With each passing iteration, PG&E's PSPS modeling tools became more granular, the company's grid conditions improved, and the model incorporated a new year of weather data.

Third, during Phase 3 of the initiative, PG&E's analysis showed that repairing or replacing several components on transmission lines in the North Coast could reduce the likely number of *indirect* transmission-level PSPS events in the region from nine events to three over a 10-year period, well below the threshold of 10 direct PSPS impacts previously adopted by the CPUC for prioritization of substation microgrid solutions.[2] Indirect impacts are the second of two major types of transmission-level PSPS impacts. PG&E estimated that these repairs and replacements could be implemented before the end of 2023 at a cost of potentially less than $500,000. Phase 3 concluded early with the Steering Committee unanimously approving this cost-effective mitigation, which was already in PG&E's workplan, and there was no longer a need to conduct comprehensive regional planning (Phase 4).

In short, clear preferable mitigations emerged in the course of the NCRI which allowed the initiative to conclude without the need to consider a broader set of more costly mitigation alternatives.

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[1] See *Types of Transmission-level Impacts in the North Coast* in this report, pages 17-18.

[2] See D.22-11-009, pp. 15-16: "The threshold of 10 or more predicted PSPS events with 100 or more safe-to-energize customers is a reasonable method for selecting substations for mitigation."

> Updated PSPS modeling indicated a reduction in the number of potential future transmission-level PSPS events along the North Coast. Repairing or replacing several components on transmission lines could reduce the remaining transmission-level PSPS events even further, reducing the modeled number of regional impacts from nine to three over a 10-year period. PG&E estimated that this mitigation could be implemented before the end of 2023 at a cost of potentially less than $500,000.

With this information in hand, the NCRI concluded earlier than initially anticipated. Regardless, the insights gained through the NCRI are worth documenting and sharing with the public. While the NCRI targeted a geographically specific resiliency problem, the initiative's structure, framework, and analytical approach could serve as a blueprint to those working to address other regional energy challenges which may require multijurisdictional collaboration across government agencies, utilities, and other stakeholders to better understand and then identify, compare, select, and eventually implement preferred mitigations.

Key Learnings and Findings

The following summarizes the key learnings and findings of the NCRI:

On PSPS and wildfire risk…

1. Safe-to-Energize Customers: Many customers along the North Coast who are otherwise "safe-to-energize" also lose power during PSPS events. In this case, safe-to-energize refers to **customers who are located outside of the conditions that triggered the need for a PSPS event, but are served by a distribution or transmission line that has been de-energized**. If the grid configuration were different, they would be able to remain online.
2. Line Impacts: Transmission lines are impacted by wildfire risk and resulting PSPS events in different ways. These **differences alter the suite of available mitigations and their effectiveness**.
    a. Some lines are "**directly impacted**," meaning they are de-energized because they **pass directly through an area experiencing weather conditions** that drive the need for a PSPS event.
    b. Some lines are "**indirectly impacted**," meaning they **become at risk of overloading** (and damage) during PSPS events when they are required to take on the load typically served through other directly impacted transmission lines, requiring load drop.
3. Substation Effectiveness: For indirect impacts, **substations vary in their ability to relieve overloading conditions** on a transmission line during a PSPS event. Dropping load from one substation may have a greater impact than dropping the same amount of load from another substation within the same region due to a variety of factors.
4. Investment Decision-making Processes: PSPS impacts are complicated, driven by many factors each with different mitigations. As a result, **investments in PSPS mitigations must be carefully considered over time.** Hasty decision-making, common in emergency situations, can result in unnecessary spending and adverse outcomes.

On PSPS in the North Coast region…

5. System and Modeling Improvements: Improved modeling and asset conditions on PG&E's electric system are driving a **reduction in the frequency and size of transmission-level PSPS events along the North Coast**.
6. Direct Impact Mitigations: **Mitigations for** direct transmission-level outages impacting the **Monticello and Calistoga substations are already underway or completed**.
7. Indirect Impact Mitigations: **Repairing or replacing several components on transmission lines in the North Coast** could reduce the impact from projected indirect transmission-level PSPS events in the North Coast by 80%.[3]

On the methodology and structure of the initiative…

8. Initiative Structure: The NCRI's structure contributed significantly to its successful identification of a timely and cost-effective solution. Steering Committee members expressed that the **collective knowledge gained and trust built** over the course of this initiative will also **enable productive future dialogue**.
    a. The **informal nature** of the initiative allowed participants to comfortably exchange draft documents and share interim thinking in a way that **facilitated productive conversations**.
    b. The **absence of hard deadlines provided the Steering Committee the time it needed** to explore the drivers of the problem in depth, ensure all participants had a shared understanding of key information, and allow PG&E's PSPS modeling to evolve.
    c. The Steering Committee **included the organizations and people** needed to gather the necessary information, conduct analyses, and implement solutions. The group's small size eased coordination.
9. Applicable Framework: While the NCRI did not need to complete all of the steps in its four-phase problem solving framework, **others could still use the framework to address regional energy challenges they face**.
10. Facilitation and Engagement: The NCRI was a small part of most participants' work duties, and occurred outside any standard leadership structure. This situation led to the possibility of low engagement and incomplete work, and made it more difficult to build and maintain the technical knowledge required to carry out analyses. **The initiative required strong facilitation, with the facilitation team consistently completing draft work, providing technical summaries, and checking in with Steering Committee members to keep the initiative on track.**

[3] This projection is based on the past 10 years of historical weather data and may not prove a perfect predictor of future conditions.

Background

PSPS Events Along California's North Coast

In the past, the North Coast segment of PG&E's electric system has been significantly impacted by PSPS events. For example, transmission lines in the North Coast area were de-energized during the October 26, 2019 PSPS event, affecting 370 MW or about 30 percent of regional load. This is partially due to the designation of much of this area as either Tier 2 or Tier 3 HFTDs. HFTDs are areas at higher risk for destructive fires and where stricter fire-safety regulations apply. This means that transmission and distribution lines serving customers in the region might need to be de-energized when certain weather and fuel conditions are present to avoid wildfire risk.

However, many customers in the North Coast who are otherwise "safe-to-energize" also lose power during PSPS events. In this case, safe-to-energize refers to customers who are located outside of the conditions that triggered the need for a PSPS event, but are served by a distribution or transmission line that has been de-energized. If the grid configuration were different, they would be able to remain online. PG&E estimates that approximately 86 substations serving over 270,000 safe-to-energize customers across their service territory lost power one or more times during transmission outages that occurred as a result of 2019 PSPS events. This occurred for two primary reasons:[4]

1. **Direct Transmission-level Impact**: Transmission lines typically travel long distances and may pass through pockets of weather conditions or relatively small areas of a HFTD that necessitate a PSPS event but end in safe-to-energize areas. Many of the customers served by these transmission lines would not otherwise need to be de-energized. This is called a "*direct impact*."
2. **Indirect Transmission-level Impact:** De-energization of certain transmission lines during a PSPS event can have a cascading effect on the electric grid. For example, in some PSPS events, additional transmission lines that remain energized during a PSPS event could become overloaded and require regional load drop in order to avoid equipment damage that occurs when these lines attempt to supply larger numbers of additional customers. This is called an "*indirect impact*."

In 2020, PG&E launched its temporary generation program to keep the lights on for these otherwise safe-to-energize customers during PSPS events. It included plans to deploy over 200 MWs of temporary diesel generators at up to 32 substations in the North Coast. PG&E also considered, but did not pursue, longer-term solutions at 17 of these 32 substations.[5] It is also worth noting that the NCRI was initiated in part to identify alternatives to temporary diesel generation in the area due to concerns about local air quality and environmental impact.

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[4] For more detail see *Types of Transmission-level Impacts in the North Coast* in this report, pages 17-18.
[5] See PG&E Track 1 Proposal in R. 19-09-009.
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M324/K944/324944715.PDF

Electric System Configuration Along the North Coast

For the purposes of the NCRI, the "North Coast" includes Marin, Sonoma, Napa, and portions of Mendocino, Lake, and Solano counties. These geographic boundaries were determined at the beginning of the initiative, based on the locations of actual and predicted future PSPS events and on the structure of the local electrical grid. In electric planning terms, the North Coast is considered a "Local Capacity Area," meaning it is a transmission constrained area dependent on local generation in order to meet reliability standards.[6] The CAISO regularly studies the North Coast to ensure that local load can be reliably met during contingencies with a combination of local generation and energy imports. Because of this unique grid configuration, the North Coast has limited import capability and is particularly vulnerable to indirect PSPS impacts. Specifically, the Geysers Geothermal plants provide the majority of local generation for the region and are located in a Tier 3 HFTD. During extreme weather conditions, some of the 230 kV electrical transmission lines connecting the Geysers Geothermal plants to the rest of the North Coast region may present significant fire risk, leading PG&E to de-energize these lines as part of a PSPS event and isolate the Geysers from the rest of the grid. The loss of these key lines connecting the region's largest generators to the local grid puts the reliability of the North Coast grid at risk, potentially overloading and damaging other parts of the transmission system. To mitigate these risks, PG&E may drop load throughout the region, creating an indirect PSPS impact. In short, the key role of the Geysers Geothermal plants and the potential fire risk from the transmission lines connecting them to the local grid make the North Coast particularly vulnerable to large indirect PSPS impacts.

[6] See http://www.caiso.com/Documents/AppendixA-MasterDefinitionSupplement-asof-Feb11-2023.pdf at page 106; or http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Feb11-2023.pdf at page 7.

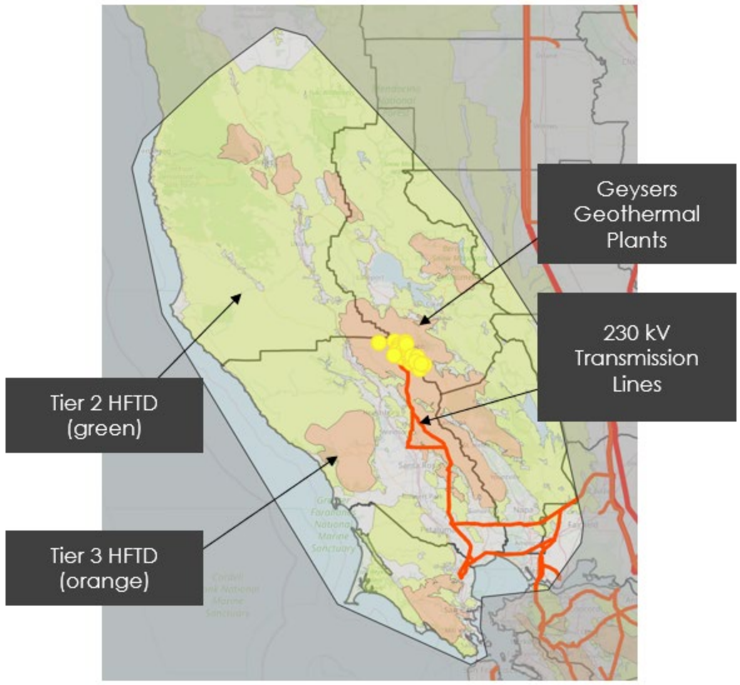


Image 1: *Map of "North Coast" for Purposes of the NCRI*

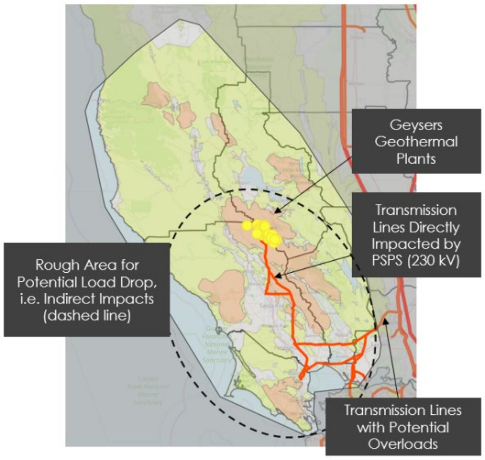
The NCRI Steering Committee further divided the North Coast region into two smaller sub-areas. These two sub-areas were studied separately because they are relatively isolated and independent areas of the grid within the North Coast. The sub-areas are:

1) The Vaca-Dixon–Lakeville Area, and
2) The Mendocino Area.

In the first sub-area, the Vaca-Dixon–Lakeville and Corona-Lakeville transmission lines become overloaded during certain PSPS events. Thermal overloading occurs when the temperature of a component in the power system, such as a transformer or a transmission line, exceeds its design limit. If the temperature exceeds the design limit, the component can fail and may lead to a wider cascading failure.

In the Mendocino area, the Clear Lake-Konocti and Granite-Hopland Junction transmission lines become overloaded, and in some cases, the sub-area experiences voltage collapse. Voltage collapse refers to the inability of the power system to supply reactive power or an excessive absorption of the reactive power by the system itself.[7] Voltage collapse can result in a cascading failure of the entire system, leading to widespread blackouts.

[7] Reactive power is essential to maintaining consistent voltage levels on the transmission system (think of voltage like the pressure needed to deliver water via a municipal water system).



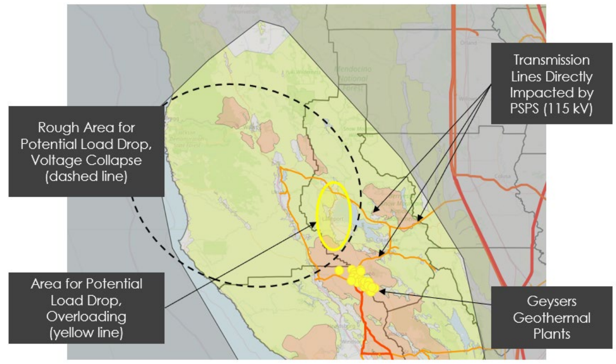


Image 2 (left): *Map of Vaca-Dixon–Lakeville Area, Showing the Directly-Impacted Transmission Lines that Cause Indirect PSPS Impacts, Lines with Potential Overloads, and Areas for Potential Load Drop*
Image 3 (right): *Map of Mendocino Area, Showing the Directly-Impacted Transmission Lines that Cause Indirect PSPS Impacts, and Areas for Potential Load Drop during Overloading and Voltage Collapse*

The NCRI: An Overview

The NCRI was formed to determine whether reasonable, permanent, low emission solutions, exist to keep the lights on for safe-to-energize customers during transmission-level PSPS events affecting the North Coast. While other PSPS mitigation and transmission planning processes are in place in California, there was no existing effort focused on exploring the drivers behind indirect transmission-level impacts and addressing those directly and comprehensively. [8] Moreso, depending upon the eventual mitigation(s) selected, different entities might have responsibility for implementation.

Specifically, the NCRI intended to:

- Determine the key drivers of transmission-level impacts during PSPS events in the North Coast area;
- Assess the likelihood of these key drivers persisting into the future;
- Identify potential mitigation measures;

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[8] The CPUC's PSPS proceeding (R.18-12-005), for example, was initiated to examine and modify rules that govern the safe de-energization (and re-energization) of power lines in case of dangerous weather conditions, not to explore the indirect reliability impacts of those de-energization events. Furthermore, the CAISO's transmission planning process does account for contingencies on the grid, but does not generally plan for scenarios where three or more major grid elements are not operating at the same time such as large-scale PSPS events. CPUC Decision 22-11-009 approved a framework for addressing direct PSPS impacts through substation microgrids and other alternatives, but declined at the time to address indirect PSPS impacts.

- Evaluate the cost-effectiveness of these mitigations in reducing the likelihood of PSPS outages;
- Facilitate comprehensive planning of these mitigation measures, considering how they might interact and their potential benefits to the wider grid;
- Offer recommendations for preferred mitigations;
- Outline a pathway to implement the recommended mitigations, including identification of potential funding sources; and
- Offer a framework that could be used to address other regional energy challenges.

Distribution-level Outages: Out-of-Scope

Note that the NCRI did not intend to look at *distribution-level* outages in the North Coast caused by PSPS events, which represent a majority of total PSPS impacts. Distribution-level PSPS outages typically occur in areas experiencing conditions driving the need for a PSPS event, meaning the distribution lines themselves are "directly impacted" and thus not safe to energize. Mitigations for distribution-level PSPS events to directly impacted customers are different from transmission-level mitigations. Distribution-level impacts generally do not lead to outages for otherwise safe-to-energize customers that could be mitigated by new utility-scale generation. Because mitigations to distribution-level outages are local, relatively straightforward, and involve neither the same range of mitigation options nor the same range of decision makers, they do not fit into the scope or intent of the NCRI. Although not covered here, mitigations for distribution-level outages in PG&E territory, including the North Coast, are considered in PG&E's Wildfire Mitigation Plan (WMP).[9] Examples of mitigations for distribution-level outages include undergrounding of distribution lines and individual customer back-up generation.

Early Findings

It is important to acknowledge up front that the NCRI concluded earlier than anticipated. This occurred for three reasons. By mid-2022, after the NCRI was underway, PG&E had already identified mitigations for PSPS impacts at the Calistoga and Monticello substations, the substations in the region with the highest number of direct PSPS impacts. The Monticello substation has an existing transmission switching option which PG&E noted will allow it to be served from a different transmission line during many PSPS events, and PG&E had plans to deploy a substation microgrid capable of powering the Calistoga substation through PSPS events.[10]

Second, PG&E's updated PSPS modeling, which became available in late 2022, showed fewer impacts from transmission-level PSPS events along the North Coast. With each passing iteration, PG&E's PSPS tools became more granular, the company's grid conditions improved, and the model incorporated a new year of weather data.

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[9] See PG&E's 2023 Wildfire Mitigation Plan (WMP) https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan.page

[10] PG&E's plan for a clean substation microgrid was approved by CPUC vote on April 27, 2023, and is expected to be operational by June 2024.

Third, during Phase 3 of the initiative, PG&E conducted analysis which showed that repairing or replacing several components on transmission lines in the North Coast could reduce the likely number of indirect PSPS impacts in the Vaca-Dixon–Lakeville area from nine events to three over a 10-year period. PG&E estimated that this mitigation could be implemented before the end of 2023 at a cost of potentially less than $500,000. Similar repair work would also reduce the number of smaller indirect PSPS events in the Mendocino area from 12 to five over a 10-year period, with a further reduction to three from improved modelling.

In short, clear preferrable mitigations emerged during the course of the NCRI which allowed the initiative to conclude before exploring more costly mitigations or conducting regional planning. Regardless, the insights gained through the NCRI are worth documenting and sharing with the public. While the NCRI targeted a geographically specific resiliency problem, the initiative's structure, framework, and analytical approach could serve as a blueprint to those working to address other regional energy challenges.

Proposed Project Phases

The NCRI developed and intended to leverage a four-phase framework to structure the initiative. This framework could be replicated by others to address other regional energy challenges that require cross-functional collaboration.

- <u>Phase 1: Build the Foundation</u>
    - Establish governance structure
    - Craft problem statement, objectives, and principles
- <u>Phase 2: Define the Problem</u>
    - Assess potential for future direct and indirect impacts in North Coast, including affected transmission lines and frequency
    - Determine root cause(s) of these impacts
- <u>Phase 3: Explore and Compare Mitigations</u>
    - Identify potential mitigations
    - Collect data on costs and impact on customer outages for each mitigation
    - Establish methodology for comparing mitigations against one another and the status quo
    - Compare mitigations
    - Select preferred mitigations
- <u>Phase 4: Conduct Comprehensive Regional Planning</u>
    - Combine preferred mitigations into a comprehensive regional plan considering the timeline, priority, and impact of these projects
    - Identify potential funding sources and implementation owners

Phase 1: Build the Foundation

NCRI Governance

The roles and responsibilities for carrying out the collaborative planning process of the NCRI were distributed between CPUC staff and various committees and working groups specific to the NCRI. The NCRI governance structure included:

1. A **Coordinating Committee** made up of Commissioners from the CPUC and CEC that provided policy or other guidance to the NCRI Steering Committee when needed;
2. A **Steering Committee** composed of representatives from the CPUC, the California Energy Commission (CEC), the California Independent System Operator (CAISO), PG&E, Marin Clean Energy (MCE) and Sonoma Clean Power (SCP). MCE and SCP are Community Choice Aggregators (CCAs).[11] The group met regularly to carry out the initiative and was tasked with developing a comprehensive PSPS mitigation plan for transmission-level impacts occurring in the North Coast area for Coordinating Committee review, facilitating the implementation of this PSPS mitigation plan upon approval by Coordinating Committee, and launching and maintaining working groups to resolve specific technical and/or policy problems; and
3. A **Facilitation Team** including CPUC staff and their consultant, Gridworks, who together facilitated the NCRI and provided analytical support along with drafting of materials, including this report.

Problem Statement, Objectives, and Principles

The NCRI was launched based on the following problem statement:

- Assumptions*:*
    - The North Coast of California has historically been impacted by transmission-level PSPS events to a greater extent than other areas of the state.
    - Modeling available at the creation of the NCRI in 2020 indicates the North Coast area may continue to face transmission-level PSPS events affecting otherwise safe-to-energize customers.
    - PSPS events are expected to result in de-energizing multiple transmission lines in the region, directly affecting some substations by cutting them off from transmission-level power and others indirectly by exceeding the load-serving capacity of the regional transmission network.

[11] Under California's CCA program, cities, counties and other qualifying governmental entities within the service areas of investor-owned utilities (IOUs) can purchase and/or generate electricity for local residents and businesses. The IOU delivers the electricity through its transmission and distribution system. https://www.cpuc.ca.gov/consumer-support/consumer-programs-and-services/electrical-energy-and-energy-efficiency/community-choice-aggregation-and-direct-access-/consumer-information-on-ccas---frequently-asked-questions

- Primary Question:
    - How can transmission hardening,[12] new energy resources, and other measures be used to cost-effectively mitigate transmission level PSPS events in the North Coast area, without utilizing temporary diesel generation?

- Secondary Questions:
    - How should the NCRI identify and evaluate these alternatives against each other and diesel temporary generation?
    - How should the NCRI evaluate cost-effectiveness of these measures and compare mitigations to one another as well as to the status quo?
    - How should an eventual solution or solution set be selected?
    - How are vulnerable customers and disadvantaged communities impacted differently by each potential alternative?[13]

The NCRI sought to accomplish the following objectives. Ultimately, these objectives were only partially addressed because the mitigations identified to address transmission-level PSPS outages along the North Coast did not necessitate regional planning or new large-scale investments.

1. **Minimize transmission-level PSPS events through comprehensive regional planning.** Make this region of the grid resilient by minimizing the number of safe-to-energize customers affected by PSPS events in the long term. Specifically, reduce the risk of transmission-level PSPS outages, coordinating distribution hardening or new intra-regional resources with this larger transmission-level plan as needed.
2. **Pilot new grid planning strategies.** Use this initiative to pilot grid planning strategies and grid innovations that could be adopted more widely.
3. **Where reasonable, develop this region of the grid so it contributes to wider grid needs.** Potentially, intra-regional resources could provide PSPS resiliency as well as energy and/or resource adequacy to the larger grid outside of PSPS events.[14]

The following principles were adopted to guide the work of the NCRI:
1. Preferably, NCRI standards should reference existing standards or investment decisions and not cause undo costs to ratepayers.
2. The NCRI should align with, or otherwise enhance or inform, existing regulatory investment planning frameworks like the CAISO Transmission Planning Process (TPP).

[12] Transmission ‘hardening’ refers to work that lowers the wildfire risk from these transmission lines, such as upgrading or replacing weakened components to reduce the risk of failure, covering the conductors to reduce the risk of sparking, or rebuilding the lines underground.
[13] This question was ultimately not addressed due to the early conclusion of the NCRI.
[14] Resource Adequacy refers to the need for sufficient energy supplies. Resource adequacy ensures there is enough capacity and reserves for the grid operator to maintain a balanced supply and demand across the electric system.

3. The NCRI should be solution neutral, for example treat transmission hardening and microgrid projects equally.
4. The NCRI should focus on attributes and outcomes of mitigations, not on a specific technology.
5. The NCRI should be temporally flexible and encourage innovation.

Phase 2: Define the Problem

10-year Historical Lookback Analysis

The NCRI is built upon PG&E's 10-year historical lookback analysis (HLA). The lookback analysis examines 10 years of historical weather conditions through the lens of current PSPS de-energization criteria and grid conditions. This enables the HLA to estimate how many PSPS events would have been triggered during that 10-year historical period if current PSPS criteria and grid conditions had been in effect throughout the period. It also provides an overview of the nature of each event, including transmission and distribution-line outages. The HLA further incorporates a power flow analysis, which analyzes the expected flow of power across the grid system and ensures that it remains safe and stable. This analysis informs how the de-energized transmission lines ultimately affect the grid system and may require load drop. In this sense, the HLA is a hypothetical exercise, but it is based upon actual PSPS assessment criteria and meteorological data. This serves as a proxy for what future PSPS events may look like on average. However, it is important to note that the HLA does not predict future weather conditions. It is possible that future weather conditions could be more or less severe than seen in the prior ten years. The use of ten years of weather data is intended to help capture natural variability in the weather, including the potential for extreme events.

To craft the HLA, PG&E modeled the actual operation of the grid during a period of high demand, which typically occurs during the summer into September, to establish a worst-case scenario. Note that PSPS events have previously occurred well into late fall when peak loads tend to be lower.[15]

The NCRI leveraged three different versions of the historical lookback as they became available (2020, 2021, 2022) to determine the key drivers of PSPS events along the North Coast and the resulting impacts on customers. With each passing iteration of the HLA, PG&E's PSPS tools became more granular, its grid conditions improved, and the model incorporated a new year of weather data.

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[15] See https://www.cpuc.ca.gov/consumer-support/psps/utility-company-psps-reports-post-event-and-post-season

The HLA includes the following data for each simulated PSPS event:

- Distribution and transmission lines de-energized due to wildfire risk,
- Substations facing transmission-level outage, and the reason for the outage (direct or indirect, see next section).
- Extent of safe-to-energize distribution load served by each substation; and
- Additional effects on the transmission system (*i.e.,* potential overloading of components).

PG&E's first 10-year historical lookback data used PSPS criteria and models from the 2020 fire season, which was only the second year of systematic use of PSPS by PG&E. During the course of the NCRI, PG&E completed an update to the lookback using data and models from the 2021 fire season. Another version was produced in early 2023, using data and models from the 2022 fire season. Each historical lookback was produced using increasingly advanced modeling techniques (for example, using historical ignition data to develop machine learning algorithms that predict potential ignitions) and an improved understanding of the asset conditions within PG&E's system (for example, filling in proxy values in models with actual values from field inspections). Many of the models and techniques PG&E currently uses were not in use for the original 2020 lookback, and these changes significantly affected modeling results. In addition to modeling changes, PG&E has endeavored to further harden or otherwise upgrade portions of its electric system to reduce the scope of PSPS events.

The improvements in PG&E's modeling capabilities in the historical lookback analysis, as well as improved asset conditions, resulted in the need for fewer and smaller transmission-level PSPS events over time. As a result, the extent of the problem that the NCRI sought to address waned over the course of the initiative.

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Types of Transmission-level Impacts in the North Coast

Direct Transmission-level Impacts

Direct PSPS impacts occur when a substation loses power because the transmission line supplying it is deenergized due to wildfire risk occurring somewhere along its path. In this case, there is no safe connection between the substation and the larger electrical grid during the PSPS event. For example, a substation serving customers could be solely supplied with power from a transmission line that travels through a high fire risk area during a high wind event (Image 4 below). Note that the substation itself may or may not reside within an area experiencing wildfire risk, and the customers typically served by the substation may or may not be otherwise safe-to-energize.

Depending upon the root causes of risk along a transmission line, different mitigations are available. Distribution lines can be also directly impacted during PSPS events, but as previously mentioned, distribution-level impacts were not in-scope for this initiative.

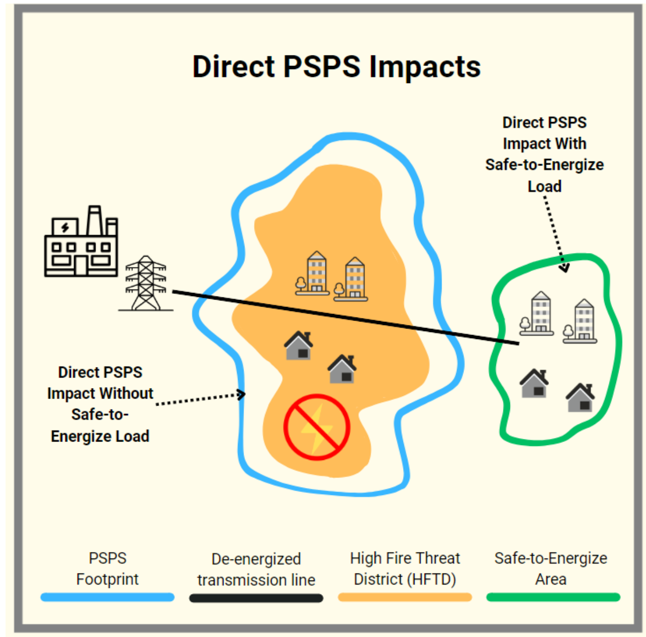

Image 4: *Two Types of Directly Impacted Customers. The area on the left has no Safe-to-Energize load, while the area on the right has Safe-to-Energize load.*

Indirect Transmission-level Impacts

Indirect impacts occur during PSPS events when local energy resources, and the capacity to import energy from the larger grid, are inadequate for reliably serving the local load. Indirect impacts typically coincide with significant de-energization of transmission lines in a region of the grid, which can cause the remaining energized lines to become overloaded. In this case, load must be dropped to prevent damage to the overloaded line or other negative grid conditions. Indirect impacts by definition leave otherwise "safe-to-energize" customers without power (*i.e.*, the conditions driving the need for a PSPS event are not present at their location). Indirect impacts within the North Coast were frequent during the early years of PG&E's PSPS program, because the region is relatively isolated from the larger grid and heavily affected by PSPS. For a deeper explanation of the causes of indirect impacts, see Appendix 2.

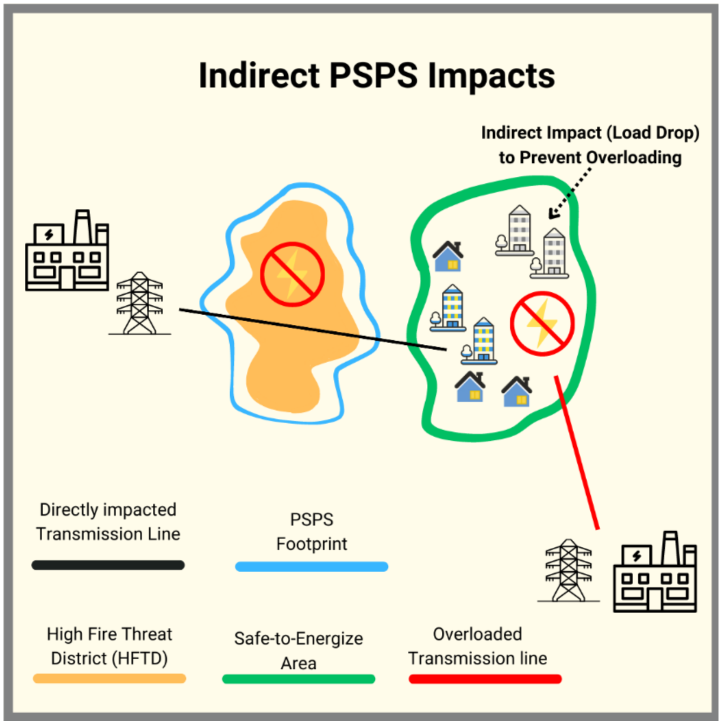

Image 5: *Simplified Diagram of an Indirect PSPS Impact. De-energization of the directly impacted transmission line on the left causes the transmission line on the right to become overloaded, requiring load drop in the Safe-to-Energize area.*

Results of the 2021 Historical Lookback Analysis for the North Coast

This section details the results of PG&E's 2021 HLA for the North Coast. Of the three HLA versions, the Steering Committee used the 2021 version most predominantly, because it was the best data available during most of the time the Steering Committee was conducting its analysis. PG&E released the 2021 version of the lookback analysis in December 2021, and then released the 2022 version in February 2023.

Direct Transmission-level Impacts

Based on the 2021 Historical Lookback, PG&E's Calistoga and Monticello substations would have experienced multiple direct PSPS impacts (8 and 9 respectively over a ten-year period). The Calistoga substation currently has a large distribution microgrid, and a clean substation microgrid pilot has been approved for development with expected operation by June 2024.[16] Monticello has an existing transmission switching solution that would mitigate many PSPS impacts by utilizing transmission switches to supply energy to the substation from an alternate transmission line that is not considered in-scope for the anticipated PSPS event.

Other substations in the region are expected to face direct, transmission-level impacts in the future, but with an estimated frequency of three occurrences or less in ten years. These

[16] See https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K896/507896518.PDF

substations may warrant smaller mitigations, such as microgrids covering critical loads,[17] but because of the low likelihood of transmission-level PSPS they were not considered further within the NCRI.[18]

Given these factors, it was determined that direct PSPS impacts in the North Coast do not need further study or action from the Steering Committee. The NCRI therefore chose to focus on substations impacted by indirect transmission-level events.

> Given the existing or in progress mitigations at all substations likely to face frequent direct PSPS events, it was determined that direct PSPS impacts in the North Coast do not need further study or action from the Steering Committee. The NCRI Steering Committee therefore chose to focus on substations impacted by indirect transmission-level events.

[17] Community-level microgrids can utilize PG&E's existing Community Microgrid Enablement Program (CMEP) and the associated Community Microgrid Enablement Tariff (CMET). Additionally, CPUC Decision 23-04-034, issued in April 2023, approved a statewide Microgrid Incentive Program that will provide additional funding for community-driven microgrids, focusing on disadvantaged communities. Finally, customers interested in behind-the-meter microgrid solutions can refer to PG&E's Behind-The-Meter Microgrid Tariff, approved in Resolution E-5162.

[18] Any consideration of mitigations for the remaining direct impacts should use the most up-to-date historical lookback data.

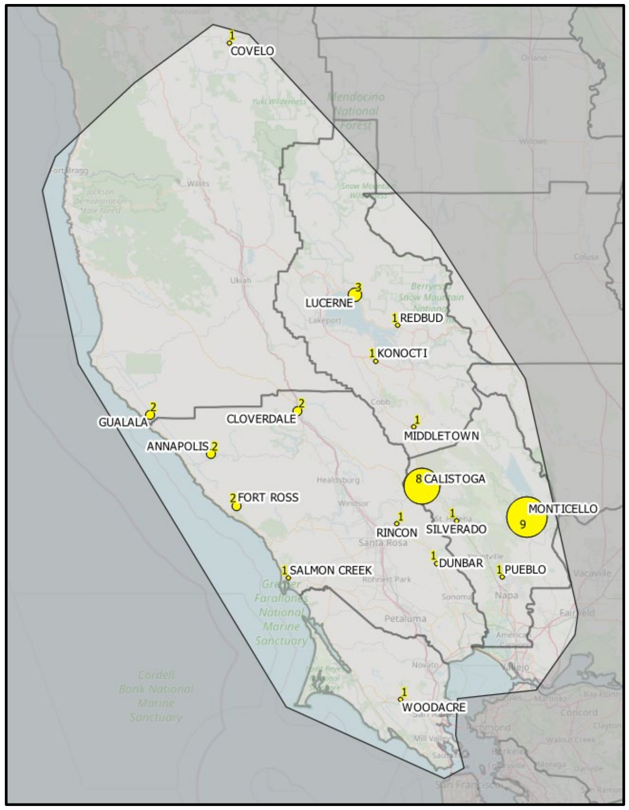

Image 4: *Direct impacts to Substations in the North Coast from the 2021 HLA*[19]
(Size of circle grows with number of impacts)

Indirect Transmission-level Impacts

The 2021 HLA showed nine indirect impacts in the North Coast region over the course of the 10-year period it modeled. For each indirect impact, an estimated 10-30 percent of regional load would need to be dropped, up to about 320 MW of total load. Approximately 40 substations emerged as candidates for providing load drop during an indirect impact event seen in the North Coast in the 2021 Historical Lookback. Not all 40 "candidate substations" would experience load drop during an indirect impact event. Actual load drop would be based on the electrical "effectiveness" of dropping load at a specific substation and the amount of load that needed to be dropped. This issue of substation load drop effectiveness is addressed further below.

While the list of these 40 candidate substations was made publicly available by PG&E in its testimony for Application 21-06-022, it is not included in this report. [20] Further study revealed that many of these substations were only marginally effective at mitigating indirect impacts. Modeling updates and mitigations described here also lower the likelihood that any of these substations would be de-energized due to indirect transmission-level impacts during future PSPS.

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[19] Note that newer data subsequently became available based on PG&E's 2022 HLA. The findings from this newer analysis are addressed later in this report.
[20] PG&E Supplemental Testimony in A. 21-06-022, 10-Year Historic Lookback 2021 Update, December 17, 2021.

Indirect Impacts and Critical Loading Levels

Indirect impacts can be roughly modelled as occurring when regional load exceeds a 'critical loading level' during a PSPS event.[21] This critical loading level value represents the amount of total regional load at which an overloading or other negative grid condition is triggered. Generally, the critical loading level is the total amount of load that can be reliably served by local generation and current import capacity. When more transmission lines are de-energized due to direct impacts, cutting off local generation from the Geysers Geothermal plants, the critical loading level decreases (meaning an indirect impact is triggered at a lower load level), resulting in a larger indirect impact. The concept of a critical loading level allowed the Steering Committee to more easily analyze and model indirect events under various conditions, including with expected future load growth.

For the purposes of the NCRI, the Steering Committee used the CEC's 2035 mid-electrification scenario as the load forecast to estimate the future loading level for the region.[22] The Steering Committee agreed that it would be preferable to use a publicly accessible load forecast, and chose the 2035 scenario because long-term PSPS mitigations are likely to be in operation through at least 2035. Typical daily load for the North Coast during the fall currently peaks at about 1000 MW, though load on a hotter September day can reach as high as 1500 MW. According to the CEC's mid-electrification scenario, this load would grow approximately 25 percent by 2035, reaching 1250 MW average peak in fall. The Steering Committee chose not to use the high-electrification scenario, with regional load growth of about 40 percent, because this load growth could require larger changes to the regional grid that could overshadow the specific PSPS issues studied in the NCRI. The Steering Committee may have returned to the high-electrification scenario during Phase 4 (Comprehensive Planning), but instead identified a clear preferrable mitigation that made this phase unnecessary.[23]

There are two approximate 'critical loading levels' for the North Coast / North Bay area:

- When three or more Geysers tie lines are deenergized due to wildfire risk, the critical loading level is **about 780 MW**. When load exceeds 780 MW, an indirect event is triggered.
- When only one Geysers tie line is de-energized (Geysers #9 - Lakeville 230 kV line), the critical loading level is **about 1070 MW**. When load exceeds 1070 MW, an indirect event is triggered.

Under either scenario, the estimated daily peak load for fall 2035 (1250 MW) would require an indirect PSPS event.

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[21] The Steering Committee determined that, for the scenario considered here and for the level of accuracy and precision needed, this rough modeling was adequate. The critical loading levels were roughly determined based on more accurate power flow analyses of various events from the 10-year Historical Lookback.
[22] The CEC forecasts future electrical demand growth, including scenarios with high or low electrification of heating and transportation. The forecasts are available here: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1
[23] See *Phase 4: Comprehensive Regional Planning* in this Report, page 31.

Finding: Indirect Impacts and Substation Load Drop Effectiveness

Although dropping most regional load has some effect on reducing overloading conditions on indirectly impacted lines, the effectiveness of dropping different substations may not be proportionate. A substation's "effectiveness" is also not constant, but instead varies from event to event depending upon the area being affected and the line(s) experiencing overloading conditions. Effectiveness varies based on a variety of parameters. These are detailed further in Appendix 1. Determining which substations are most effective in reducing overloading conditions during an indirect impact is important because it helps limit the number of substations that must be deenergized. As previously mentioned, PG&E identified approximately 40 substations that could be selected from during a given event for de-energization, with significant variations in effectiveness.

Under a critical loading level of 780 MW, modeling shows that a regional load of 1450 MW may require only 243 MW of load drop. This presumes that the most effective load is dropped first. If load was instead dropped evenly over the entire region, 670 MW of load drop may be needed (1450 - 780 = 670).

The results of this analysis indicate that *where* the utility drops load, or where it places mitigations capable of behaving like load drop, is important. A battery placed at one substation may not have the same mitigating effect if it were placed in another location. The Steering Committee determined that the substations which consistently proved to be "effective" should be prioritized in the subsequent mitigation planning efforts. These would be ideal locations for energy resources solutions that could offset the need for load drop at the substation.

As mentioned below, the issue of substation effectiveness eventually proved a moot point given the identification of an extremely cost-effective grid hardening solution. This preferred mitigation reduced the likelihood of indirect impacts to the region. An abridged list of the most effective substations is included in Appendix 2 below.

Results of the 2022 Revised 10-year Historical Lookback Analysis for the North Coast

PG&E updated its rolling 10-year HLA for PSPS events in late 2022 to include a new year of weather data, reflect improved asset conditions, and incorporate modeling refinements. These updates altered the outlook for future transmission-level PSPS events in the North Coast. The revised 2022 10-year HLA showed a reduction in the number of direct impacts to a key transmission line in the North Coast (Geysers #17 - Fulton 230 kV line). This reduction in direct impacts to the Geysers #17 - Fulton 230 kV transmission line then also reduces the likelihood that a large-scale indirect PSPS event would occur. This is because keeping the Geysers #17 - Fulton 230 kV transmission line energized increases the critical loading level for the region, meaning that any indirect impacts would be smaller in scope and triggered only at higher loading levels. Because the Steering Committee identified a clear preferrable mitigation, it did not quantify this potential change in the critical loading level.

Transmission Line Name	Number of Deenergizations due to Wildfire Risk, 10-Year Period (2021 HLA)	Number of Deenergizations due to Wildfire Risk, 10-Year Period (2022 HLA)
Geysers #9 - Lakeville	9	9
Geysers #12 - Fulton	5	5
Geysers #17 - Fulton	5	0
Fulton - Ignacio #1	1	1

Table 1*: Change in Deenergizations for key North Coast Transmission Lines causing Indirect Impacts: 2021 vs 2022 HLA.*

The new HLA data on direct impacts is also shown in the table below, with notes. No new substations needed study in the NCRI related to direct PSPS impacts.

Substation Name	Number of Direct PSPS Impacts Over 10-Year Period (2021 HLA)	Number of Direct PSPS Impacts Over 10-Year Period (2022 HLA)
Monticello	9	9
Calistoga	8	5
Lucerne	3	5[24]
Redbud	1	4[25]
Covelo	1	1
Dunbar	1	1
Salmon Creek	1	1
Woodacre	1	1
Middletown	1	1
Annapolis	2	0
Gualala	2	0
Konocti	1	0
Fort Ross	2	0
Cloverdale	2	0
Pueblo	1	0
Rincon	1	0
Silverado	1	0

***Table 2**: Change in Direct PSPS Impacts to Substations in the North Coast: 2021 vs 2022 HLA*

[24] Lucerne substation is directly impacted in five events, but in only one event does it have more than 100 safe-to-energize customers connected to the substation. PG&E currently has a distribution microgrid able to serve some safe to energize customers in the Lucerne area during PSPS events.

[25] Redbud substation is directly impacted in four events, and in three of those events there are 100 or more safe-to-energize customers connected to the substation.

Phase 3: Explore and Compare Mitigations

Mitigations Considered for Indirect Transmission-level Impacts

Keeping in mind that the NCRI did not further consider mitigations for direct impacts, several potential mitigation options for indirect transmission-level PSPS impacts along the North Coast were considered. These mitigations fall into two categories, with a total of four mitigation types considered:

1. Mitigations that reduce the *need for* PSPS events by reducing wildfire risk
    a. Harden directly impacted transmission lines
2. Mitigations that reduce the *impact of* PSPS events that occur
    a. Expand the capacity of indirectly impacted transmission lines
    b. Install new energy resources
    c. Pursue operational changes to PSPS events

Each of these four mitigations is explored in more detail below.

1. Reduce Wildfire Risk: Harden Directly Impacted Transmission Lines

Hardening directly-impacted transmission lines so they present less fire risk and do not need to be de-energized eliminates the primary cause of indirect impacts. In this case, hardening the transmission lines connecting the Geysers Geothermal plants to the local grid could maintain local generation during PSPS events, in effect maintaining the normal operation of the grid. This hardening may take the form of undergrounding, implementing covered conductors, or other more selective upgrading and replacement of elements on the transmission lines and/or the structures supporting them. The cost and feasibility of undergrounding transmission lines might have made this particular form of the hardening mitigation untenable, though other forms of hardening ultimately proved cost effective.

2a. Mitigate PSPS Impacts: Expand Capacity of Indirectly Impacted Transmission Lines

If the import capacity of the North Coast region can be expanded, then the grid should be able to run adequately even when local generation is cut off. Effectively, this would mean upgrading the regional transmission system so that it can provide sufficient power imports when one or more transmission lines coming from the Geysers Geothermal plants cannot safely operate. Expansion of import capacity into the region may warrant consideration. This could be achieved through constructing additional transmission lines or reconductoring existing lines to support higher load levels (e.g., reconductor the Vaca Dixon - Lakeville 230 kV line). This type of mitigation would typically be explored in the CAISO's Transmission Planning Process, and would likely prove expensive. Additional justification for capacity expansion beyond PSPS mitigation would likely be needed.

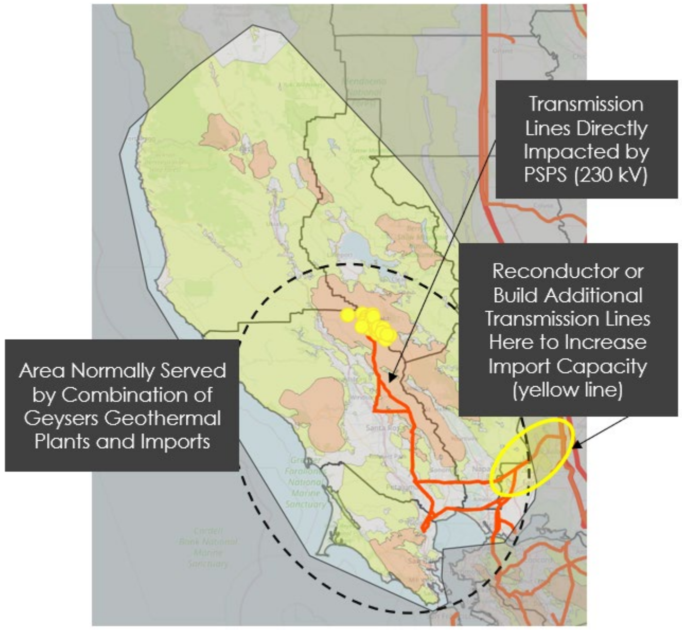

***Image 6:** Map Showing how and Expansion of Import Capacity into the North Coast could Lessen or Prevent Indirect PSPS Impacts.*

2b. Mitigate PSPS Impacts: Install New Energy Resources

New energy resources can play two roles:

1) **Serve safe-to-energize customers directly as a microgrid:** New energy resources placed in traditionally safe-to-energize areas can keep the lights on for safe-to-energize customers when their transmission source is either directly or indirectly impacted during a PSPS event. New energy resources could be placed at the substation and/or distribution level. To fully mitigate the impacts of PSPS events, energy resources would need to be sufficient to serve all local load. This form of mitigation would likely encounter significant cost and space constraints.
2) **Reduce the size of indirect PSPS events:** New local energy resources can reduce the need for energy imports into the region and thus reduce or eliminate the overloading conditions that lead to an indirect impact. In this case, new energy resources are effectively standing in for the local generation normally provided by the Geysers Geothermal plants, so that lines connecting the Geysers can be de-energized during extreme weather events without requiring load drop. They would not need to be sufficient to serve all local load at all hours of the day, but instead only to reduce load sufficiently to prevent overloads or other grid issues. Additionally, this form of mitigation has greater locational flexibility.

In the case of the latter, a storage or storage plus generation solution would not need to cover all load for all hours of the day. It would just need to cover the incremental demand that leads to overloading or other negative grid conditions. Generally, this means that energy resources could be placed at particularly effective locations and focus on reducing peak load rather than overall energy usage. These resources could potentially provide other benefits to the grid outside of PSPS events. Compensation for these services could improve the cost-effectiveness of energy resource mitigations. However, it should be noted that deliverability constraints in the North Coast could limit energy resource's availability to provide resource adequacy to the system.[26] Analyzing the cost-effectiveness of new energy resources required extensive data gathering and modeling. The Steering Committee assembled public data on the cost of implementing various energy resources in California. Additionally, the Steering Committee developed an Outage Minutes Model to understand the capacity needed to reduce the frequency and scale of indirect impacts during transmission-level PSPS events in the region. The outage minutes model is described in greater detail below as well as in Appendix 3. Appendix 3 also includes a compilation of the energy resources cost data collected.

2c. Mitigate PSPS impacts: Pursue Operational Changes to PSPS Events

Even if the drivers of an indirect impact are not removed, their effects can be lessened or distributed differently through operational changes in how the events are carried out. Potentially, PG&E could implement load drop only during peak loading hours, rather than for the full duration of a PSPS event, to reduce regional load below the critical loading level.
Designing and successfully implementing a strategy to only de-energize indirectly impacted transmission lines during actual overloading conditions, rather than throughout the entirety of the PSPS event, seems prohibitively complex. PG&E usually visually inspects indirectly impacted lines before re-energization, which can make it difficult to limit the duration of the outage. In addition, before de-energizing and re-energizing major lines, PG&E conducts power flow and protection modeling. It would be difficult to do this work quickly, multiple times in a single day, during an active PSPS event. Further exploration of an operational mitigation that would repeatedly select a relatively effective subset of substations for de-energization, combined with mitigation of outages at those substations (*e.g.*, via a critical load microgrid), may be warranted.

Comparing Mitigations: Cost-effectiveness Methodology

Next, the Steering Committee endeavored to develop a methodology to compare the cost-effectiveness of mitigations against one another and the status quo. In this case "effectiveness" refers to the ability of a mitigation to reduce or fully eliminate wildfire and/or PSPS risks. Cost-effectiveness would then refer to how effective a mitigation is per dollar of spend. Comparing cost-effectiveness would inform which, if any, mitigations warranted further exploration. The Steering Committee decided to perform this comparison by combining:

1. An outage minutes model to assess how different mitigations could reduce the duration and scale of each transmission-level PSPS event in the historical lookback;
2. Data estimating the costs of various mitigations;
3. A tool for quantifying the benefits of various mitigations (i.e., wildfire and/or PSPS risk reduction); and
4. A qualitative list of any additional benefits that cannot be easily quantified.

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[26] Deliverability specifies the amount of resource adequacy capacity a generating facility is eligible to provide. See full definition in Appendix A of the February 11, 2023, version of the California Independent System Operator Corporation Fifth Replacement Electronic Tariff. http://www.caiso.com/Documents/AppendixA-MasterDefinitionSupplement-asof-Feb11-2023.pdf at page 57.

The additional qualitative information could be used to potentially alter the initial ranking of mitigations (e.g., revenue generated by energy resources outside of PSPS events, etc.).

Outage Minutes Model

To support the identification of preferred mitigations for indirect impacts in the North Coast Region, an "outage minutes" model was developed. This model determines the number of minutes customers experience an outage during an indirect transmission-level PSPS event, based on the amount of load that must be dropped to avoid overloading of transmission lines serving the region. It was to be used when analyzing potential mitigations to determine how many outage minutes individual solutions and combinations of solutions can reduce. This is important because not all mitigations can reduce every minute of every outage seen in the historical lookback. More information on this model can be found in Appendix 3.

This outage minutes model proved particularly useful when determining the role battery storage could play in reducing overloading conditions that lead to indirect impacts. Rough estimates from CPUC staff indicate that 100-200 MW of 4-hour storage, especially if paired with a smaller amount of generation, would significantly reduce the likelihood and size of indirect impacts by keeping electricity imports from the regional transmission system below the critical loading level. However, there could still be large indirect impacts if a PSPS event occurs on a high-load day. Moreover, the Steering Committee discovered that there are upper limits to the benefits gained through installing additional battery capacity. A battery stores energy but does not generate energy, so it cannot reduce the amount of energy imports needed to the North Coast area. Instead, a battery works to reduce PSPS by reducing peak load, effectively flattening the load curve for the region. As the load curve becomes flatter, adding additional battery storage becomes less and less effective.

Data on Mitigation Costs

Through support from PG&E, MCE, and SCP, data on the potential costs of new energy resources was collected. Data was collected on the cost of diesel and geothermal generation from recent contract costs, and on the cost of natural gas generation, solar and battery energy storage from the National Renewable Energy Laboratory.[27]

Tools for Measuring Mitigation Benefits

The Steering Committee explored a variety of standards, each of which would have needed modifications to adapt them to the needs of the NCRI. A number of tools exist to help users quantify the value of resiliency. Those are further detailed in Appendix 4. The NCRI Steering Committee decided to rely on the existing, approved metrics used by PG&E to evaluate their investments in risk mitigation, because these metrics have been vetted through a multi-stakeholder process and follow the NCRI principles of relying on existing standards and aligning with existing planning processes.

[27] See https://atb.nrel.gov/electricity/2022/index

The Steering Committee initially considered leveraging PG&E's Risk Spend Efficiency (RSE) Framework to evaluate the benefits of PSPS mitigation options as this was the CPUC-approved metric for most of 2021 and 2022. The RSE is a benefit-cost ratio for risk reduction programs. However, because a relatively simple and affordable mitigation for indirect transmission-level PSPS events was determined early in the process, the RSE was not explored further and adapted to the needs of the NCRI.

In December 2022, however, the CPUC directed the three major IOUs to adopt a new risk-based decision-making framework (i.e., cost-benefit approach) that standardizes dollar valuations for safety, electric reliability, and gas reliability consequences from risk events.[28] The new methodology is intended to improve transparency for external parties to better understand how IOUs assess and mitigate safety risks and provide a clear indication whether proposed mitigation benefits outweigh costs. Had there been a need for a cost-effectiveness method for the NCRI, the Steering Committee members may have considered using this updated version.

Co-Benefits of Mitigation Solutions

The Steering Committee also discussed the need to include information about co-benefits in the evaluation of mitigations. Co-benefits like revenue generated by new energy resources operating under blue sky conditions, could be factored in as a reduction in the cost input for the RSE. Other less quantitative co-benefits like reducing PSPS impacts for particularly vulnerable customers could be part of a subsequent screen after the RSE was calculated.

Preferred Mitigations for Indirect Transmission-level Impacts Identified

Improved Modeling

Over the past two years, PG&E has enhanced its transmission asset modeling tools and is now able to determine which specific transmission structures are causing a transmission line to be considered in-scope for a PSPS event, rather than noting the entire transmission line as "at risk." These modeling improvements, along with refined PSPS protocols and criteria, allow PG&E to more easily assess the potential for avoiding a PSPS event by undertaking asset-level repairs via PG&E's ongoing transmission hardening and transmission maintenance programs. These asset-level mitigations are far simpler and more cost-effective than mitigations targeting an entire line (e.g., undergrounding). For further information regarding the modeling updates and refined PSPS protocols, please refer to PG&E's 2023 WMP Section 9.2.[29]

Exploration of Further Mitigation Options

With the revised 2022 HLA and this structure-level modeling capability in place, the Steering Committee asked PG&E to provide an initial assessment of the potential to use existing transmission hardening programs to mitigate transmission-level impacts in the North Coast.

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[28] See D. 22-12-027, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668

[29] See PG&E's 2023 Wildfire Mitigation Plan https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan/2023-wildfire-mitigation-plan.pdf

PG&E found that only nine structures that surpassed fire risk thresholds were causing key transmission lines in the North Coast to be deenergized during PSPS events, leading to indirect impacts in the Vaca-Dixon–Lakeville Area. Direct impacts to these key transmission lines were then creating cascading effects throughout the region leading to the need to drop load (i.e., indirect impacts). Addressing nine open corrective action or maintenance "tags," each referencing one structure on the three key transmission lines, would reduce the number of transmission-level PSPS events that cause indirect impacts in the area from nine to three in the historical lookback. PG&E inspects its lines and occasionally issues tags when a component needs repair or replacement in the near- or medium-term. Because de-energization of these directly impacted transmission lines leads to indirect transmission impacts in the region, these repairs have a significant impact on resolving the problem which the NCRI has been endeavoring to address. Addressing these open tags does not entail any new projects or process changes at PG&E. The tags identified will follow the approved prioritization process that is detailed in PG&E's WMP, which complies with CPUC policy in General Order 95. Adding structure-level granularity to PG&E's models, which previously referred to entire transmission lines, made it easier to identify this transmission hardening solution and to judge that it reduced wildfire risk sufficiently to avoid de-energization. PG&E estimates that these repairs could potentially cost approximately $500,000 in total based on unit cost forecasting. Current expectations are that this work could be completed before the end of 2023, with multiple tags already cleared as of the publishing of this report.

After reviewing this analysis from PG&E, the Steering Committee unanimously decided to select this mitigation as the preferred one, and to forgo using a cost-effectiveness methodology to compare alternatives because this mitigation was clearly more cost effective.

> Addressing open corrective action or maintenance tags on these transmission structures would reduce the number of transmission-level PSPS events that cause indirect impacts in the North Coast from nine to three in the 10-year historical lookback, reducing customer outage-minutes from indirect impacts by an estimated 80%. PG&E estimates that these repairs could potentially cost approximately $500,000 and this work could be completed before the end of 2023.

A Caveat: Using Historical Data to Predict the Future

If the past 10 years of weather data remains a strong predictor of future weather, these planned transmission structure asset improvements will reduce the likelihood of future indirect transmission-level PSPS events in the North Coast. If weather significantly worsens in the future, it is possible that direct and indirect transmission-level events in the North Coast may persist or even increase in frequency. At present, research is still insufficient to determine how wind conditions, a key driver of PSPS events, will alter due to climate change. It is currently uncertain how rising temperatures will affect wind speeds, wind direction, and the duration of wind events. In the case of California, wind direction can impact humidity levels depending upon whether the wind is coming over the Pacific Ocean or over the Eastern Sierra mountains. Additionally, PG&E is in the process of replacing proxy values with actual design information in one of its models. For smaller transmission lines (i.e., those supported by wood poles), there may be an increase in risk. The Mendocino sub-area has several of these transmission lines. Direct distribution-level events are still possible as much of the area is classified as HFTDs.

Transmission Line Name	Number of Deenergizations due to Wildfire Risk, 10-Year Period (Before Mitigation)	Number of Deenergizations due to Wildfire Risk, 10-Year Period (After Mitigation)
Geysers #9 - Lakeville	9	3
Geysers #12 - Fulton	5	1
Fulton - Ignacio #1	1	0

***Table 3**: Change in Deenergizations for Key North Coast Transmission Lines Causing Indirect Impacts: Before and After Hardening Lines by Removing Tags.*

Phase 4: Comprehensive Regional Planning

Given the findings above, the NCRI Steering Committee determined that there was no longer a need to pursue Phase 4 of the initiative, “Conduct Comprehensive Regional Planning.” If it had moved forward with this Phase, the Steering Committee planned to use the following approach:

1. **Evaluate whether transmission upgrades to increase regional deliverability are reasonable and cost effective based on any new energy resources proposed as a result of the work in Phase 3, as well as any other plans for energy resources in the region.** The North Coast has limited deliverability, limiting the potential for energy resources to provide resource adequacy to the larger grid. Upgrades to the transmission system farther inland could resolve this problem, but these upgrades are likely to be expensive and only reasonable if part of a larger plan for new resources in the North Coast. Thus, this evaluation should account for other potential and existing energy resources in the region (e.g., offshore wind development, expansion of the Geysers geothermal plants, expansion of storage resources).

Because no new energy resources were proposed through the NCRI, this step was not necessary.

2. **Combine the projects proposed in Phase 3 into a comprehensive regional plan considering the timeline, priority, and impact of these projects.** As part of this step, the Steering Committee planned to consider the potential timelines of the various projects, and evaluate how they might affect one another and be prioritized. A list of preferred mitigations does not automatically translate into a plan for constructing those mitigations in the real world. Resources are limited, and different projects may have different costs and benefits, so prioritization may be necessary. Each project, when considered concretely, may provide additional local benefits, may correspond with local

economic or clean energy plans, and/or may run into roadblocks based on local conditions. All of this would have been considered in this step, and may have required bringing local governments or other key stakeholders into the initiative. The Steering Committee would also consider the extent to which other state, regional or local policy goals or initiatives may fit into the NCRI comprehensive plan.

Because addressing transmission tags on key lines already fits in to PG&E's existing work process, this step was not necessary.

3. **Evaluate the extent to which PSPS mitigation projects can contribute to regional or wider grid needs, including with the incorporation of local or regional control systems.** Because of limited deliverability and a constrained grid system in the North Coast, energy resources acting independently may create risks for the grid and either trigger expensive upgrades or be forced to curtail their actions. If resources are controlled on a regional scale, these upgrades may be avoided. In addition, these controlled resources may be able to provide local benefits to the grid system, making it more robust or reducing costs. Similarly, grid hardening or upgrades to the transmission system may improve regional reliability and resiliency even outside of PSPS events. In either case, it makes sense to evaluate the extent to which projects proposed in the NCRI could provide larger benefits outside the direct scope of the initiative.

Because the NCRI proposed mitigation involved maintenance to existing grid lines, and did not involve any upgrades or new resources, this step was not necessary.

Key Findings and Lessons Learned

The following summarizes the key learnings and findings of the NCRI:

On PSPS and wildfire risk…

1. Safe-to-Energize Customers: Many customers along the North Coast who are otherwise "safe-to-energize" also lose power during PSPS events. In this case, safe-to-energize refers to **customers who are located outside of the conditions that triggered the need for a PSPS event, but are served by a distribution or transmission line that has been de-energized**. If the grid configuration were different, they would be able to remain online.
2. Line Impacts: Transmission lines are impacted by wildfire risk and resulting PSPS events in different ways. These **differences alter the suite of available mitigations and their effectiveness**.
    a. Some lines are "**directly impacted**," meaning they are de-energized because they **pass directly through an area experiencing weather conditions** that drive the need for a PSPS event.

   b. Some lines are "**indirectly impacted**," meaning they **become at risk of overloading** (and damage) during PSPS events when they are required to take on the load typically served through other directly impacted transmission lines, requiring load drop.
3. Substation Effectiveness: For indirect impacts, **substations vary in their ability to relieve overloading conditions** on a transmission line during a PSPS event. Dropping load from one substation may have a greater impact than dropping the same amount of load from another substation within the same region due to a variety of factors.
4. Investment Decision-making Processes: PSPS impacts are complicated, driven by many factors each with different mitigations. As a result, **investments in PSPS mitigations must be carefully considered over time.** Hasty decision-making, common in emergency situations, can result in unnecessary spending and adverse outcomes.

On PSPS in the North Coast region…

5. System and Modeling Improvements: Improved modeling and asset conditions on PG&E's electric system are driving a **reduction in the frequency and scope of transmission-level PSPS events along the North Coast**.
6. Direct Impact Mitigations: **Mitigations for** direct transmission-level outages impacting the **Monticello and Calistoga substations are already underway**.
7. Indirect Impact Mitigations: **Repairing or replacing several components on transmission lines in the North Coast** could reduce the impact from projected indirect transmission-level PSPS events in the North Coast by 80%.[30]

On the methodology and structure of the initiative…

8. Initiative Structure: The NCRI's structure contributed significantly to its successful identification of a timely and cost-effective solution. Participants expressed that the **collective knowledge gained and trust built** over the course of this initiative will also **enable productive future dialogue**.
   a. The **informal nature** of the initiative allowed participants to comfortably exchange draft documents and share interim thinking in a way that **facilitated productive conversations**.
   b. The **absence of hard deadlines provided the Steering Committee the time it needed** to explore the drivers of the problem in depth, ensure all participants had a shared understanding of key information, and allow PG&E's PSPS modeling to evolve.
   c. The Steering Committee **included the organizations and people** needed to gather the necessary information, conduct analyses, and implement solutions. The group's small size eased coordination.

[30] This projection is based on the past 10 years of historical weather data and may not prove a perfect predictor of future conditions.

11. Applicable Framework: While the NCRI did not need to complete all of the steps in its four-phase problem solving framework, **others could still use the framework to address regional energy challenges they face**.
12. Facilitation and Engagement: The NCRI was a small part of most participants' work duties, and occurred outside any standard leadership structure. This situation led to the possibility of low engagement and incomplete work, and made it more difficult to build and maintain the technical knowledge required to carry out analyses. **The initiative required strong facilitation, with the facilitation team consistently completing draft work, providing technical summaries, and checking in with Steering Committee members to keep the initiative on track.**

Proposed Problem-solving Framework

Framework for Addressing Regional Energy Challenges

Over the course of the initiative, the NCRI developed a four-phase problem-solving framework and intended to methodically explore the root cause(s) of transmission-level outages in the North Coast and then identify, compare, and select mitigations. While the NCRI ended before completing all four phases, the initiative did end by successfully identifying a preferred mitigation to indirect PSPS impacts affecting safe-to-energize customers along the North Coast. In this way, NCRI helped to fill a gap in understanding and methodology identified in D.22-11-009, where the Commission stated that it sought to "ascertain the complexity of indirect PSPS impacts more closely" before allowing them to be considered in PG&E's standard framework for identifying needed substation microgrid projects to mitigate PSPS impacts.[31] The NCRI sought to develop and describe in this report a replicable model for how such indirect impacts can be considered in PSPS mitigation planning and how mitigation alternatives can be evaluated for cost-effectiveness. The Steering Committee recommends that PG&E incorporate the NCRI's approach to indirect PSPS impacts into PG&E's existing substation microgrid evaluation framework.

More broadly, the Steering Committee strongly recommends that others involved in grid planning follow a similar process to ensure they correctly understand a grid challenge and select the most cost-effective solutions that solve the problem. This framework is particularly suited for grid challenges that require multijurisdictional collaboration across government agencies, utilities, and other stakeholders. Below is a general framework that can be used to better understand and identify preferred solutions for any regional energy challenge. The framework demonstrates a sequential set of phases and relevant questions to consider. However, the framework should be used flexibly, and may even end early if a clear preferred mitigation emerges in Phase 2 or Phase 3 as happened in this case. Following this high-level framework, this report includes two examples demonstrating how this high-level process can be customized to explore grid challenges around wildfire risk reduction and PSPS impact mitigation.

[31] See D.22-11-009, pp. 32-33.

This framework can serve as a starting point for others and should be adapted to the grid challenge at hand. For example, some of the phases can be conducted concurrently and the stakeholder group involved may need to evolve over time. Grid challenges are complex technical issues that need information housed within different organizations.

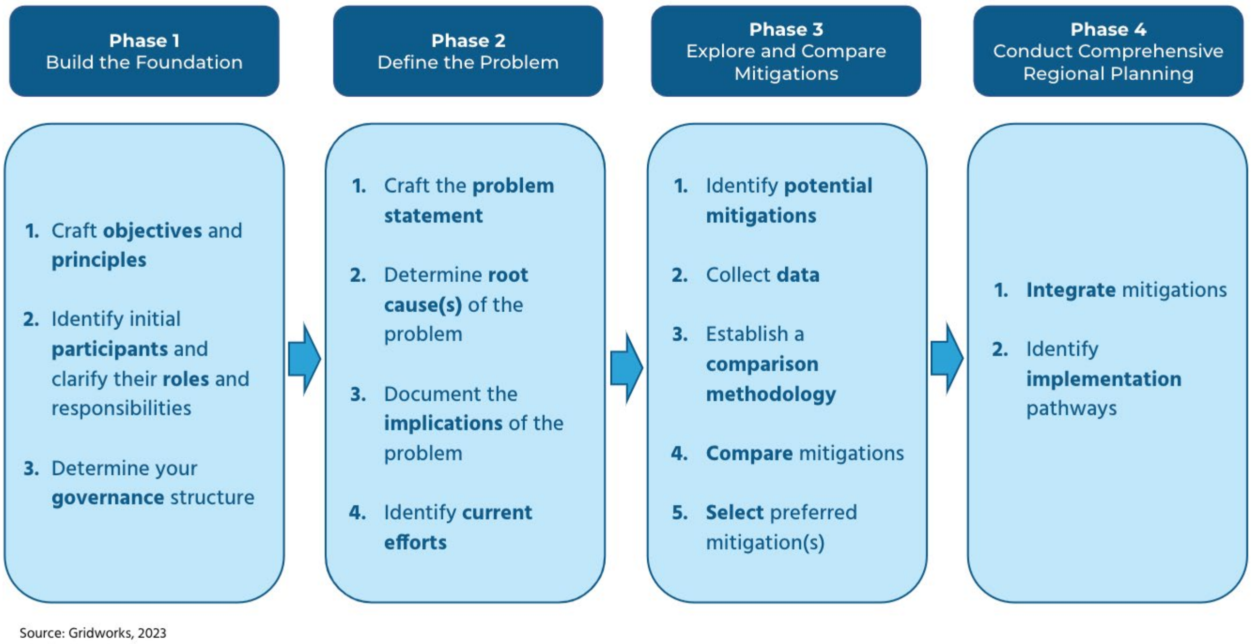

Image 7: *Framework for Addressing Regional Energy Challenges Diagram*

<u>Phase 1: Build the Foundation</u>

1. Craft objectives and guiding principles
2. Identify initial participants (organizations and individuals) and establish their roles/responsibilities
    a. Who has the information needed to identify the problem and potential solutions?
    b. Who has the skills needed to explore the problem and potential solutions (e.g., conduct analytics)?
    c. Who will play a role in implementing possible solutions?
    d. Who will be a productive contributor to a multi-stakeholder process?
3. Determine your governance structure
    a. How will you make decisions?
4. Are the structure and principles workable?
    a. Keep in mind that this is a temporary structure aimed at addressing a grid challenge quickly, and need not be perfect.

<u>Phase 2: Define the Problem</u>

1. Craft the problem statement
    a. What is the problem you are looking to solve? Determine any additional questions to explore.
2. Determine root cause(s) of the problem

   a. Identify and gather relevant data.
   b. What are the main drivers of the problem? When and how do they appear? With what frequency?
3. Document the implications of the problem
   a. Who is impacted by the problem, how, and to what extent?
   b. Will the problem persist into the future? Worsen? Resolve itself?
4. What is already being done about the problem and by whom? To what extent are these mitigation measures insufficient?
   a. Could current work be modified or expanded as part of an eventual solution?
5. How accurately are you modelling the issue? Do you expect your models to remain relatively consistent, or to significantly evolve?
6. Based on the work above, can the scope of the investigation be narrowed? Are there areas or aspects of the grid challenge that do not need further consideration?

Phase 3: Explore and Compare Mitigations

1. Identify potential mitigations
   a. What mitigations are available today?
   b. What mitigations are still under development and might require additional time and/or research?
2. Collect data
   a. Gather data on costs and impacts to relevant stakeholders of each mitigation.
   b. Determine the extent to which each mitigation can address the problem you are intending to solve; note what conditions may alter the effectiveness of each mitigation.
   c. Document whether mitigations need to be implemented in partnership with other mitigations or if they can stand alone.
   d. Do any mitigations stand out as clearly preferrable, negating the need for further comparison?
3. Establish a comparison methodology
   a. What existing comparison methodologies could be applied to this project? What are their strengths and weaknesses? In what ways might they need to be adapted?
   b. What attributes would be needed if you were to develop your own methodology?
   c. If necessary, develop your own methodology to compare solutions against one another and the status quo or other baseline scenario.
      - This methodology can be quantitative with qualitative factors layered in afterwards.
   d. Include evaluation criteria such as cost, regulatory considerations, social and environmental impact, and other relevant qualitative and quantitative factors.
      - When exploring costs, be clear on who bears the costs and when.
4. Compare mitigations
   a. Apply the methodology to compare mitigations, factor in qualitative considerations.

   b. Who will play a role in implementing each solution? Do those organizations support this work?
5. Select preferred mitigation(s)

Phase 4: Conduct Comprehensive Regional Planning

1. Integrate mitigations
   a. Combine preferred mitigations into a comprehensive regional plan considering the timeline, priority, and impact of these projects to stakeholders, the environment, and economy.
2. Identify implementation pathways
   a. What are potential funding sources?
   b. Who is responsible for implementation?
   c. Is there a different or adjusted governance structure to implement the selected solution?

Example 1: Framework for Reducing Wildfire Risk

This section provides an example of how the high-level framework explained above can be adapted to a specific problem. PSPS events are themselves a response to the underlying problem of wildfire risk, so it makes sense to examine this problem first. After these steps are complete, the framework can be applied toward mitigating PSPS impacts that remain.

Phase 1: Build the Foundation

1. Craft objectives and principles
2. Identify initial participants (organizations and individuals) and clarify their roles/responsibilities
   a. Who has the information needed to identify the problem and potential solutions?
   b. Who has the skills needed to explore the problem and potential solutions (e.g., conduct analytics)?
   c. Who will play a role in implementing possible solutions?
   d. Who will be a productive contributor to a multi-stakeholder process?
3. Determine your governance structure
   a. How will you make decisions?

Phase 2: Define the Problem

1. Which electric lines are at risk and where? Under what conditions?
   a. Distribution lines? Transmission lines?
   b. How likely are those conditions to occur in the future? With what frequency?
   c. Which lines are at the greatest risk?
2. What particular structures along those lines are at risk and where (if any)? Under what conditions?
   a. How likely are those conditions to occur in the future? With what frequency?
   b. Which structures are at the greatest risk?
3. What is driving the risks to these lines and/or individual structures?
   a. Asset condition? Vegetation? Something else?

   b. Will those drivers evolve in the future (e.g., will they worsen)?
4. What is already being done about the problem and by whom? To what extent are these mitigation measures insufficient?
   a. Could current hardening or maintenance work be modified or expanded as part of an eventual solution?
5. How accurately are you modelling the issue? Do you expect your models to remain relatively consistent, or to significantly evolve?

Phase 3: Explore and Compare Mitigations

1. What current risk mitigation measures are in use for these lines and/or structures?
   a. To what extent is PSPS used? Anything else?
      i. What about at the customer level (e.g., procurement of back-up generation)?
   b. What are the costs/impacts of these existing mitigation measures?
   c. If PSPS, how does deenergizing these lines affect the system as a whole?
      i. Who loses power and where? Which, if any, of these customers are otherwise safe-to-energize?
      ii. Does it create overloading conditions that must then be mitigated?
      iii. Does it constrain delivery of supply resources elsewhere?
   d. How well do these existing mitigation measures reduce the risks?
2. What risk reduction measures are currently planned/awaiting implementation that could reduce some/all of these risks?
   a. What are these measures?
   b. Which risks do they reduce and to what extent (e.g., frequency, scope, etc.)?
   c. Which areas and customers would benefit from these risk reduction measures and how?
   d. What are the planned completion date(s)?
3. What additional risk reduction measures could be further explored?
   a. Which additional lines and/or structures remain at risk? Under what conditions?
   b. What are the costs of the measure?
   c. Where would funding come from to implement these measures?
   d. How much of the risk is reduced and where?
   e. Do the measures offer any benefits beyond wildfire risk reduction (e.g., local resource adequacy)? If so, what are they? Who benefits?
   f. How might measures complement one another?
   g. How should funding and resources for implementing these additional measures be prioritized?

Phase 4: Conduct Comprehensive Regional Planning

1. Integrate mitigations
   a. Combine preferred mitigations into a comprehensive regional plan considering the timeline, priority, and impact of these projects to stakeholders, the environment, and economy.
2. Identify implementation pathways
   a. What are potential funding sources?

b. Who is responsible for implementation?
c. Is there a different or adjusted governance structure to implement the selected solution?

Example 2: Framework for Mitigating PSPS Impacts that Remain

Once the ways to reduce the frequency and scale of PSPS events by addressing wildfire risk are identified, the focus can be shifted toward mitigating PSPS impacts that remain.

Phase 1: Build the Foundation

1. Identify relevant organizations and individuals
    a. Who has the data needed to answer the questions below?
    b. Who might play a role in implementing solutions? (e.g., decision-making authority around funding, procurement, siting, permitting, etc.)

Phase 2: Define the Problem

1. Which communities will continue to experience PSPS impacts?
    a. With what frequency?
    b. What would be the scale of the outages (e.g., how easy is it to access services nearby)?
    c. Which impacted customers are safe-to-energize?
    d. Which impacted customers are not safe-to-energize?
2. To what extent are impacts direct or indirect? If indirect, what grid issue is arising that requires load drop?
3. To what extent do existing or in progress mitigation measures reduce PSPS impacts?
4. How accurately are you modeling the issue? Do you expect your models to remain relatively consistent, or to significantly evolve?

Phase 3: Explore and Compare Mitigations

1. Explore mitigations
    a. Identify potential mitigations.
    b. Collect data on costs of each mitigation.
    c. Collect information on benefits of each mitigation (e.g., reduction in outage minutes, provision of essential services, etc.)
        i. Identify potential co-benefits beyond PSPS mitigation.
        ii. Who receives these benefits?
    d. Establish methodology for comparing mitigations against one another and the status quo.
    e. Compare mitigations.
    f. Select preferred mitigations.
    g. How should funding and resources for implementing these additional measures be prioritized?

Phase 4: Conduct Comprehensive Regional Planning

1. Mitigation Implementation

a. Combine preferred mitigations into a comprehensive regional plan considering the timeline, priority, and impact of these projects.
b. Identify potential funding sources and implementation processes.

Appendices

Appendix 1: Substation Effectiveness

The following parameters can impact the electrical "effectiveness" of dropping load at a specific substation:

- Network Topology: The "effectiveness" is sensitive to the network topology of the power system. A change in the topology of the system, such as the addition or removal of a transmission line or a generator, can alter the "effectiveness" values.
- Power System Operating Conditions: The "effectiveness" is also sensitive to the power system's operating conditions, such as the generation dispatch and the load demand. A change in these operating conditions can cause a shift in the "effectiveness" values.
- Location of the Injection and Withdrawal Nodes: The location of the injection and withdrawal nodes in the power system can also affect the "effectiveness" values. A change in the location of these nodes can change the distribution of power flow in the system, resulting in different "effectiveness" values.
- Line Impedances: The "effectiveness" is sensitive to the line impedances of the transmission lines in the power system. The line impedance determines the amount of power flow that can be transmitted through the line and affects the distribution of power flow in the system.
- Voltage Profile: The voltage profile of the power system can also affect the "effectiveness" values. A change in the voltage profile can change the distribution of power flow in the system and, in turn, affect the "effectiveness" values.
- Reactive Power Sources: Reactive power sources, such as capacitors and synchronous condensers, can also affect the "effectiveness" values. The location and capacity of these sources can change the distribution of power flow in the system and affect the "effectiveness" values.

Appendix 2: Technical Description and Modelling of Indirect PSPS Impacts in the North Coast

Overview of an Indirect PSPS Impact

Indirect impacts occur during PSPS events when local energy resources, and the capacity to import energy from the larger grid, are inadequate for reliably serving local load in a region of the grid. Indirect impacts typically occur when a significant number of transmission lines across the grid system are de-energized because of direct wildfire risk, leading to a grid that effectively has a different configuration than it would under normal operation. Under this new configuration, the normal load in a region of the grid may cause overloads of transmission lines or other key transmission equipment, requiring load drop to prevent the risk of long-term grid damage or larger-scale outages. Even if no overloads occur, grid operators are responsible for maintaining the grid in a stable condition, anticipating contingency events and ensuring that no substantial damage or cascading effects would occur after those events. In short, grid operators model not only the new configuration of the grid during a PSPS event, but also the potential contingencies that might occur to disturb that new configuration, and then use load drop or other mitigation measures to ensure the grid operates safely and reliably. By definition, indirect impacts involve dropping otherwise "safe-to-energize" customers in order to reduce load and thus mitigate issues at the level of the local transmission grid. Indirect impacts are relatively common in the North Coast, because it is relatively isolated from the larger grid and heavily affected by PSPS.

Indirect Impacts in the North Coast

Over 10 years, PG&E's 2021 Historical Lookback Analysis showed 9 indirect impacts in the North Coast region. For each indirect impact, an estimated 10-30 percent of regional load may need to be dropped. Further developments in PG&E's PSPS modeling and decision criteria continue to affect these results.

These indirect impacts affect distinct "areas" of the North Coast transmission grid. First, the overall North Coast area is affected by potential overloads on transmission lines connecting the region to central California and the high-voltage network. The overloads can occur when local generation from the Geysers Geothermal plants is cut off. The Geysers Geothermal plants provide the majority of local generation for the region and are located in a Tier 3 HFTD. During extreme conditions, some of the 230 kV electrical transmission lines connecting the Geysers Geothermal plants to the rest of the North Coast region may present significant fire risk, leading PG&E to de-energize the lines as part of a PSPS event and isolate the Geysers from the rest of the grid. The loss of these key lines connecting the region's largest generators to the local grid means that power instead is imported across the Vaca-Dixon corridor (see Figure 1 below). This new grid configuration leads to risk of direct overloads on the Vaca-Dixon lines if regional load is high enough, and also puts the local grid at significant risk of instability if one of the lines along the Vaca-Dixon corridor were to fail. To mitigate these risks, PG&E may drop load within the North Coast region to reduce the flow of power across the Vaca-Dixon corridor. Additionally, in some events the 230 kV connection between Fulton substation, near Santa Rosa, and Lakeville substation, near Petaluma, can be de-energized due to wildfire risk. Power then flows upward along the 115 kV network, leading to additional overloads. The situation described here represents the large majority of predicted indirect impacts in the North Coast according to PG&E's 2021 Historical Lookback.

Second, the local grid in Mendocino and Lake counties, referred to as the Mendocino sub-area here, can be affected by indirect impacts. These effects are generally small scale, but during 2 of the 9 events from the 2021 Historical Lookback they lead to potential voltage collapse in that region of the grid. To mitigate this voltage collapse, most of the available load in the Mendocino sub-area must be dropped.

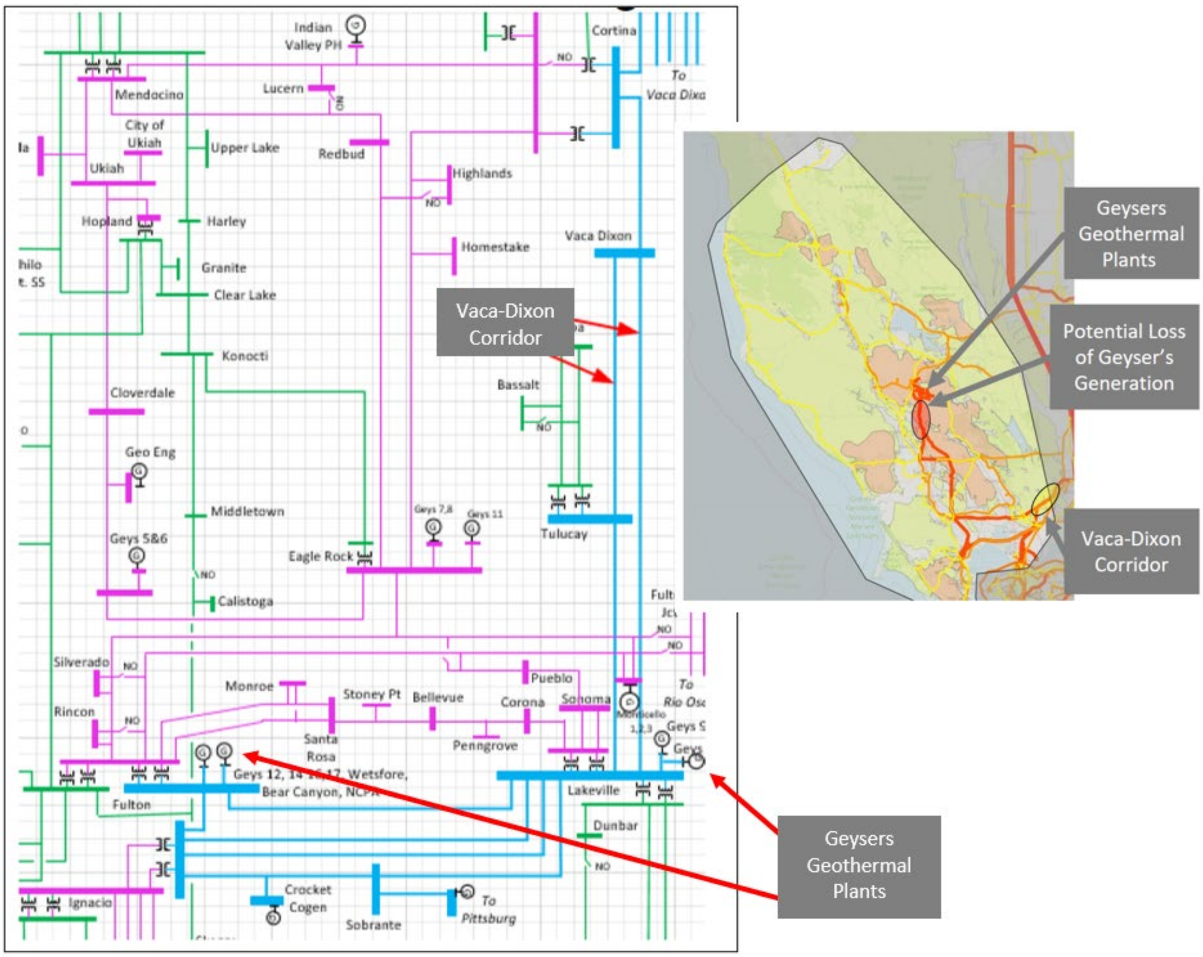

Figure 1: *Single line diagram and geographic map showing the locations of the Vaca-Dixon Corridor and the Geysers Geothermal Plants.*

Key Transmission Lines De-energized During Indirect Impact

In the 2022 PG&E Historical Lookback, both the Geysers #9 – Lakeville and the Geysers #12 – Fulton 230 kV transmission lines occasionally present wildfire risk and are de-energized, leading to a potential indirect impact. According to PG&E's models, an estimate of the maximum probability of failure of any structure on these respective lines is shown in Table 4 below.

***Table 4:** Maximum Projected Probability of Failure for Structures on Geysers Lines – Scaled, 1000 = 100%*

Transmission Line	10/08/2017	11/07/2018	11/10/2018	10/09/2019	10/23/2019	10/26/2019	10/29/2019	09/07/2020	10/25/2020
GEYSERS #12 - FULTON	25	15		21		145			45
GEYSERS #9 - LAKEVILLE	226	79	26	169	44	169	29	45	45

The more lines that are deenergized, the more the Geysers Geothermal Plants are isolated from the larger grid. This leads to roughly two levels of indirect impact in the North Coast area, a smaller impact when only the Geysers #9 line is de-energized and a larger impact when both lines are de-energized. This is reflected in the concept of critical loading level described in the report above. Note that updates to the 2022 Historical Lookback eliminated the Geysers #17 – Fulton transmission line from PSPS scope in all events. Because most of the analysis for the NCRI was done based on the 2021 results, this is not reflected below. In the 2021 data, whenever the Geysers #12 – Fulton line was in scope for PSPS, the Geysers #17 – Fulton line was also in scope.

Potential Contingencies and Overloads on the Vaca-Dixon Corridor

As noted above, when the Geysers Geothermal Plants are relatively isolated from the larger grid, this can lead to overloads and other issues on the Vaca-Dixon Corridor connecting the North Coast to the high-voltage transmission network. The Vaca-Dixon Corridor refers to two 230 kV transmission lines connecting the Vaca-Dixon substation, near Vacaville and connected to the 500 kV transmission system, to the Lakeville substation, near Petaluma. Even when both lines are operating, the loss of the Geysers Geothermal Plants can lead to potential overloads (Figure 2 below). Potential contingencies on either of these lines from Vaca-Dixon present an additional issue for the grid because they would lead to significant overloads on the line that was still operating (Figures 3-4 below). These overloads could cause permanent damage to the transmission line, or could cause the transmission line to trip offline leading to potential cascading impacts for the region and perhaps the larger grid. Grid operators should operate the grid such that a single contingency will not lead to significant equipment damage or cascading effects. In other words, PSPS may cause immediate overloads on the Vaca-Dixon Corridor and may put the grid at risk of future equipment damage or cascading effects. If any or all of these cases are true, the operating procedure is to drop regional load until all of them are mitigated. Three typical scenarios are shown in Figures 2-4 below.

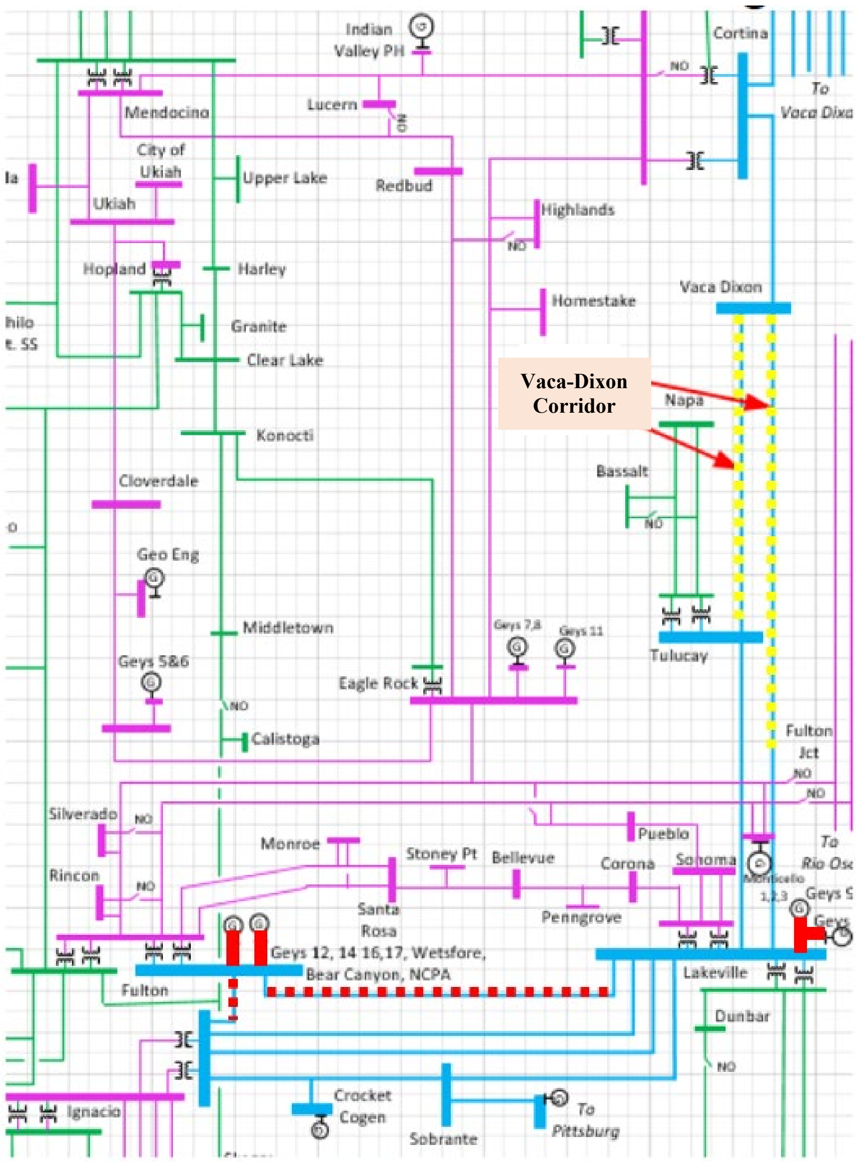

__Figure 2:__ Power Flow Under PSPS N-0 (no contingency) Situation

Directly Impacted: Geysers Tie Lines (RED), potentially 230 kV path connecting Lakeville and Fulton substations (DASHED RED).
This scenario leads to high imports and potential overloads on the Vaca-Dixon Lakeville Corridor (DASHED YELLOW), even without further contingency.

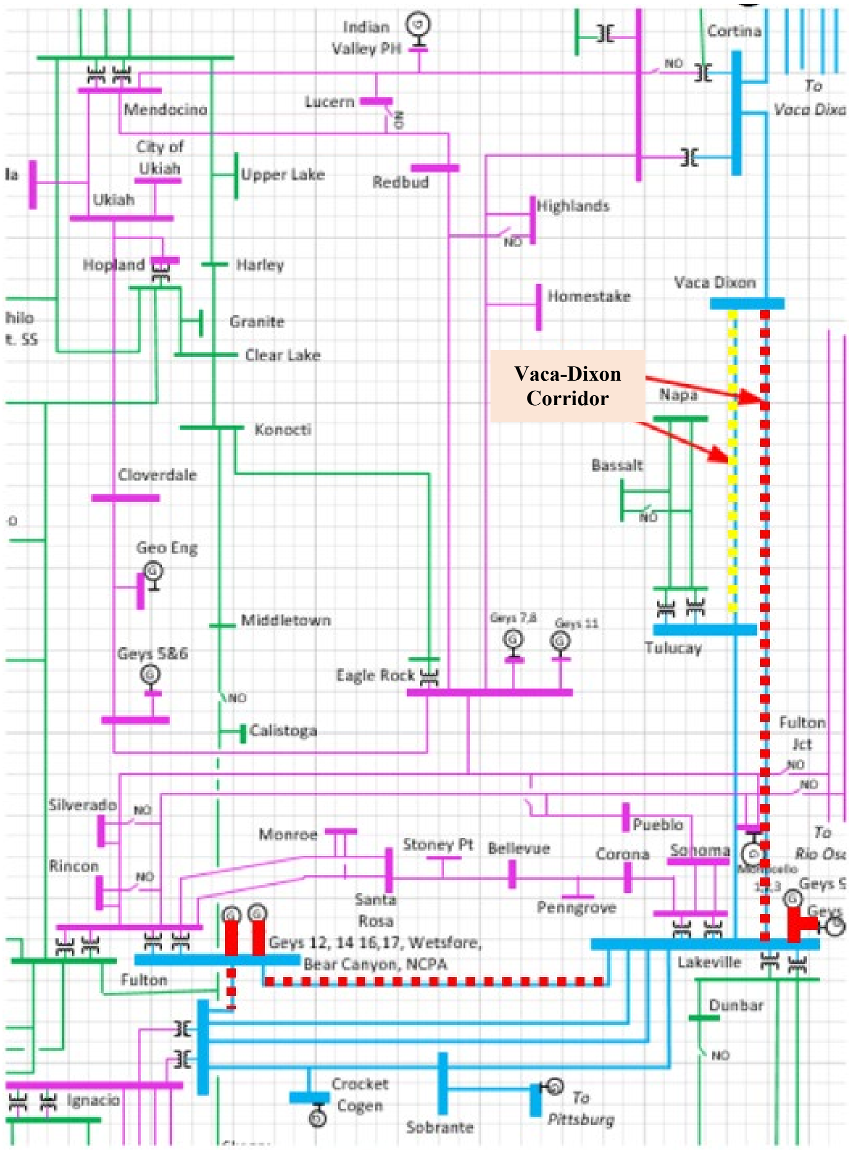

Figure 3: Contingency on Vaca-Dixon – Lakeville direct line.

Directly Impacted: Geysers Tie Lines (RED), potentially 230 kV path connecting Lakeville and Fulton substations (DASHED RED).
Contingency: Vaca-Dixon – Lakeville direct line (DASHED RED).
This scenario leads to overload on the Vaca-Dixon – Tulucay line (DASHED YELLOW). Note that in this configuration, Napa, Basalt and Tulucay substations are located directly after the overload, and thus load drop here is *highly effective* at mitigating this overload.

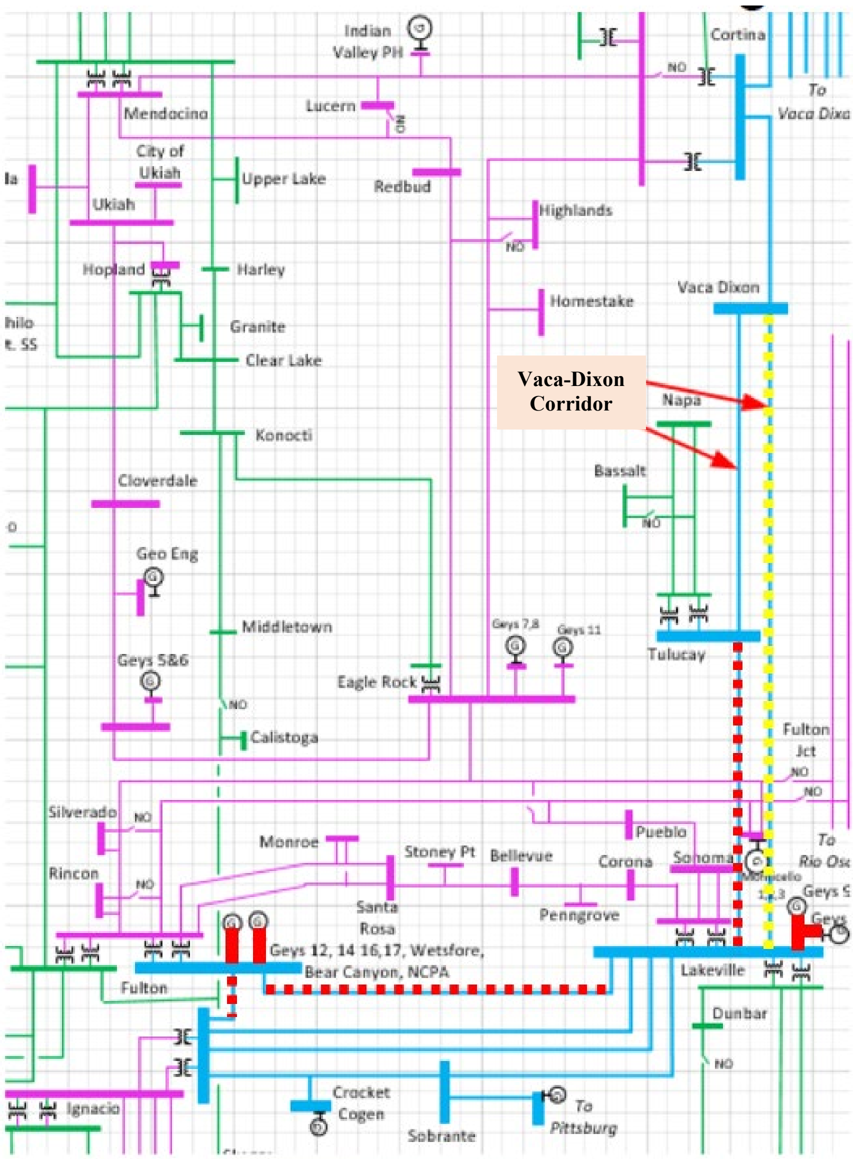

Figure 4: *Contingency on Tulucay – Lakeville direct line.*

Directly Impacted: Geysers Tie Lines (RED), potentially 230 kV path connecting Lakeville and Fulton substations (DASHED RED).
Contingency: Tulucay – Lakeville line (DASHED RED).
This scenario leads to overload on the Vaca-Dixon – Lakeville direct line (DASHED YELLOW). Note that, in this configuration, Napa, Basalt and Tulucay substations have *no effect* in mitigating this overload, because they are powered through the Vaca-Dixon – Tulucay line which is not overloaded.

Power Flow Analysis of Typical Indirect Impact Events

PG&E and its consultants performed power flow analysis on various PSPS scenarios to determine the potential scope of indirect impacts. These power flow analyses showed that when the three Geysers lines described above are deenergized, the regional critical loading level[32] is about 780 MW. When regional load exceeds 780 MW, an indirect event is triggered. When only the Geysers #9 – Fulton line is de-energized, the critical loading level is about 1070 MW. When regional load exceeds 1070 MW, an indirect event is triggered.

In addition to using power flow to determine these critical loading levels, PG&E conducted power flow analysis for all events in the historical lookback using a peak regional load of 1450 MW. These power flow analyses showed multiple possible grid issues, as described in the section above. However, the various issues often required roughly similar amounts of regional load drop. For the sake of simplicity, this analysis focuses on the worst-case scenario, which ultimately determines the total amount of load drop needed. However, the Steering Committee did consider all the different possibilities when important. For example, see the notes under Figures 3-4 on the varying effect of load drop at the Napa, Basalt and Tulucay substations. These power flow analyses showed that, for a typical event with three Geysers lines de-energized and a contingency on the Vaca-Dixon Corridor, the remaining operating line may have a power flow of 633 MW, well above the line limit of 420 MW. For a typical event with only one Geysers line de-energized and a contingency on the Vaca-Dixon Corridor, the operating line may have a power flow of 539 MW. These data points were used to construct a simplified model of indirect impacts in the North Coast area, as described below.

Modelling Power Flow for Indirect Impacts in General

To support the identification of preferred mitigations for indirect impacts in the North Coast Region, the NCRI Steering Committee developed an "outage-minutes" model to estimate the indirect impacts likely to result under different assumptions or mitigation options. This model estimates the total impact of indirect PSPS impacts to the North Coast area in customer outage minutes, based on the 2021 Historical Lookback data, under various assumptions and scenarios. It can be used to analyze potential mitigations to estimate how individual solutions and combinations of solutions might reduce impacts from indirect PSPS events.

All indirect PSPS impacts to the North Coast area in PG&E's 10-year historical lookback follow three basic configurations of the larger grid, which the NCRI Steering Committee modeled as three distinct scenarios. Each scenario involves (1) direct PSPS impacts to key regional transmission lines, (2) a set of relevant transmission lines that are indirectly impacted, i.e. may be overloaded during a PSPS event, and (3) a method for estimating the power flow over these indirectly impacted lines.

> **Scenario 1:** One of the Geysers tie lines is directly impacted.
> Directly Impacted: Geysers #9 – Lakeville line.
> Indirectly Impacted: Vaca-Dixon – Lakeville transmission corridor.
> Power Flow Estimate:

$$Power\ Flow\ (MVA) = 0.315 * Regional\ Load + 82$$

[32] As a reminder, this Report refers to the amount of total regional load at which an overloading condition is triggered as the critical loading level, see page 21.

Scenario 2: All three of the Geysers tie lines are directly impacted.
Directly Impacted: Geysers #9 – Lakeville; Geysers #12 – Fulton; and Geysers #17 – Fulton lines.
Indirectly Impacted: Vaca-Dixon – Lakeville transmission corridor.
Power Flow Estimate:

$$Power\ Flow\ (MVA) = 0.315 * Regional\ Load + 176$$

Scenario 3: All three of the Geysers tie lines are directly impacted along with Fulton-Ignacio and/or Lakeville-Fulton lines.
Directly Impacted: Geysers #9 – Lakeville; Geysers #12 – Fulton; Geysers #17 – Fulton; Fulton – Ignacio #1; and potentially Lakeville – Fulton.
Indirectly Impacted: Vaca-Dixon – Lakeville transmission corridor; Corona – Lakeville line.
Power Flow Estimate for Vaca-Dixon – Lakeville corridor:

$$Power\ Flow\ (MVA) = 0.315 * Regional\ Load + 176$$

Power Flow Estimate for Corona – Lakeville line:

$$Power\ Flow\ (MVA) = 0.34 * Regional\ Load - 33$$

Power flow modeling can be extremely complex and take significant time and computing power. For that reason, the NCRI Steering Committee developed these simpler linear models of power flow from a few sets of more complex analyses. This method would not be appropriate for all power flow modeling, but was deemed appropriate here because the analysis focuses on overloads on a single transmission corridor carrying power into a load pocket. If more complex issues were at play, such as voltage collapse or network effects, this type of linear modeling would be inappropriate. The power flow estimate equations here are linear approximations based on data from full power flow analysis but will not have the same accuracy or precision.

Effectiveness of Load Drop at Various Substations

To reduce the power flow on indirectly impacted lines, load must be dropped (or new energy resources deployed) at substations in the region. Different substations will have different effectiveness in reducing load across both the Vaca-Dixon – Lakeville corridor and the Corona – Lakeville line. Effectiveness estimates for 12 substations that are consistently effective in all PSPS events are provided in the table below.

Substation Name	Effectiveness for Reducing Power Flow on Vaca-Dixon - Lakeville Corridor	Effectiveness for Reducing Power Flow on Corona - Lakeville Line
BELLEVUE	38%	82%
COTATI	37%	71%
FITCH MOUNTAIN	36%	71%
FULTON	38%	71%
GEYSERVILLE	36%	71%
MIRABEL	37%	71%
MOLINO	37%	71%
MONROE	38%	75%
MONTE RIO	37%	71%
PENNGROVE	38%	88%
SANTA ROSA A	38%	76%
WINDSOR	36%	71%

Appendix 3: Outage Minutes Model

Data Sources for the Outage Minute Model

The NCRI Steering Committee used the following data as basic inputs into the model:

1. *PG&E's 10-year historical lookback* – Provides a statistical picture of how often certain transmission lines are directly affected (de-energized by PG&E because they risk starting catastrophic wildfires) during modeled PSPS events over the last 10 years. These data on directly affected lines serve as the basis for creating the scenarios below.
2. *Historical load data* – Actual average regional load over recent years, for each hour of each day from August to November. The Steering Committee used this data to determine regional load in the model, selecting specific days based on modelled PSPS events in the 10-year historical lookback.
3. *Forecasted load growth* – As previously mentioned, the Steering Committee used the CEC's 2035 mid-electrification scenario to model load growth due to electrification in the region. This data was used to adjust the historical load data to represent future loads more accurately.
4. *Transmission line power limits* – Determines the maximum allowed power flow across key transmission lines to prevent damage to the line. Generally, protection devices will trip the line if power flow is consistently above this threshold. The Steering Committee used this data to determine when power flow on a line is too high, triggering an indirect PSPS impact.
5. *Historical substation information* - Information on the total load of each substation, the total number of customers at each substation, and the number of customers who are typically safe-to-energize in historical PSPS events.

Calculating Outage Minutes

With the transmission line ratings, the scenario information, and the effectiveness figures included in Appendix 2, any indirect impact can be modeled, a set of most effective substations

can be selected for de-energization, and thus the total customer outage minutes from indirect PSPS impacts can be estimated.
First, the estimate of total regional load is combined with the scenario information to determine the power flow across any indirectly impacted lines. For the 9/7/2020 event, the NCRI Steering Committee chose to use an estimated peak regional load of 1450 MW rather than average historical regional load for September. This choice reflects the unlikely possibility of a PSPS event overlapping with a high heat event, which otherwise would not be captured in the model.
Second, according to the following equation, a set of substations can be selected to reduce the power flow on key lines back below the line rating. The effect of dropping substation load must be at least enough to reduce the power flow on an impacted line below its line rating.

$$(Modeled\ Power\ \ Flow\ on\ Line\ ) - (Line\ Rating) \leq \sum (Substation\ Load) * (Substation\ Effectiveness)$$

Third, using the average number of safe-to-energize (STE) customers for each substation and the estimated PSPS event duration of 48 hours, total customer outage minutes can be estimated.

$$Customer\ Outage\ Minutes = \sum (Substation\ STE\ Customers) * (2880\ minutes)$$

Base-Case Results from the Outage Minutes Model

Based on the model assumptions and inputs laid out above, and importantly on the 2021 PG&E Historical Lookback analysis, the Outage Minutes model predicts about **1.8 billion customer outage minutes** from indirect PSPS impacts in the North Coast over 10 years. By comparison, PG&E's current yearly outage minutes over its entire territory, excluding major outage event days, is about 800 million customer outage minutes. Note that this figure is based on the CEC's 2035 mid-electrification scenario, so predicted indirect impacts in the near term would be smaller in scale. With the mitigation to transmission tags as described in the body of this report, the Outage Minutes model predicts **a reduction of about 80 percent outage minutes, with 354 million customer outage minutes** from indirect PSPS impacts in the North Coast over 10 years.

Considering Mitigations Using the Outage Minute Model

The Outage Minute model can capture the effects of wildfire hardening, increases in line capacity, or addition of energy resources, though it captures these effects in different ways. Modeling wildfire hardening requires the use of PG&E's PSPS models, but can be represented by reducing the frequency of deenergization for Geysers transmission lines, leading to an decrease in the total number and/or severity of events. Increases in the capacity of indirectly impacted lines can be modeled by raising the line limits used to model overloads. New Energy Resources can be modeled as equivalent to load drop at the relevant substations.

There are additional complexities that come into play when modeling variable energy resources like solar and wind, or when modeling energy storage which can only deliver its full power for a limited time. In brief, energy resources must be capable of providing enough consistent power to reduce the daily peak load by a set amount in order to count as the equivalent of substation load drop. Based on rough estimates from historical loading data, 4-hour storage can reliably reduce peak loads by approximately 15 percent without issue, and the addition of solar generation can raise that to approximately 20 percent.

Effectiveness of Energy Resources at Mitigating Indirect PSPS Impacts

Based on the Outage Minutes model, adding new energy resource capacity to the region would reduce the impacts from indirect PSPS impacts in a relatively linear fashion, up to about 250 MW of added capacity (See Figure 5 below). The remaining approximately 300 million outage minutes remain difficult to mitigate with energy resources. This remaining impact reflects the 9/7/2020 event where the NCRI Steering Committee chose to use maximum peak load in the model instead of average peak historical load. For an extreme event of this kind, with high regional loads, even significant new energy resources would not be sufficient to fully mitigate an indirect PSPS event.

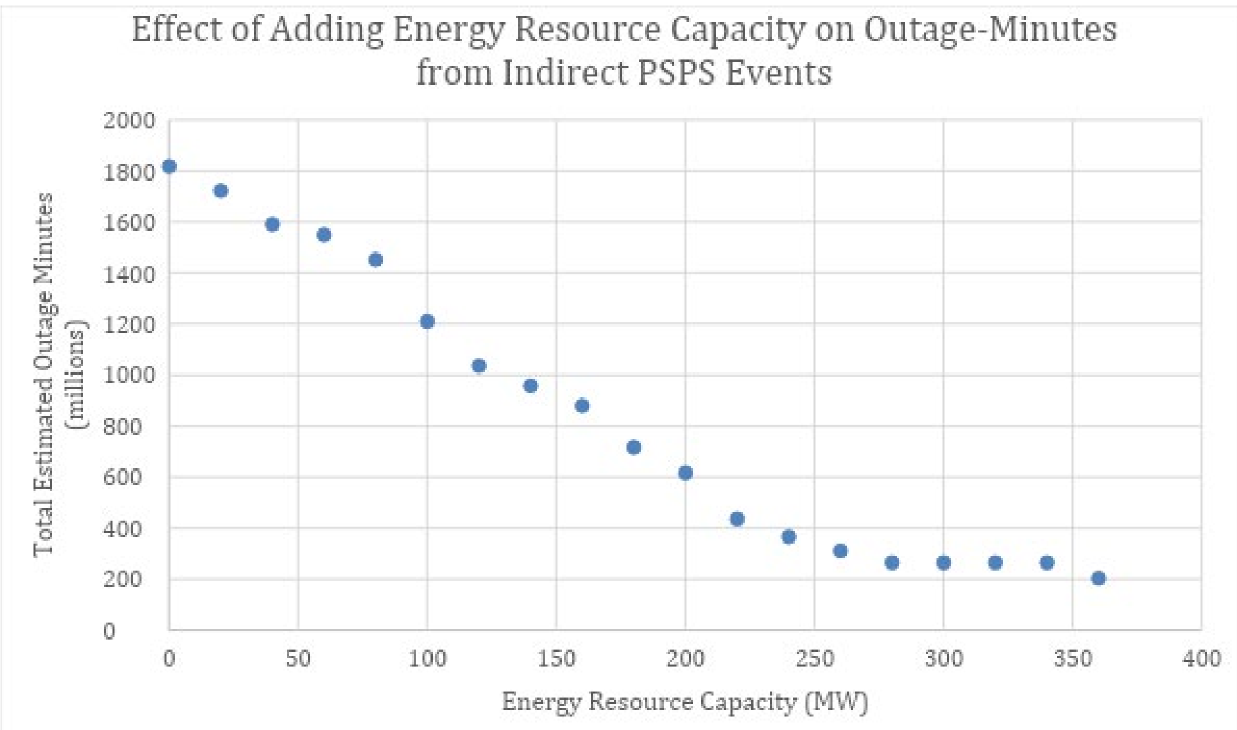

Figure 5: *Effect of Adding Energy Resource Capacity in Reducing Outage Minutes from Indirect PSPS Events*

Early Selection of the NCRI Preferred Mitigation Based on Wildfire Hardening Results

As noted in the report, the NCRI identified a preferred option for mitigating indirect PSPS impacts without completing its full analysis. Wildfire hardening, specifically the removal of tags on key transmission structures, reduced indirect PSPS impacts to such an extent and at such low cost that the Steering Committee no longer saw the need for further analysis. Thus, a full investigation of mitigation options using the outage minutes model was not completed.

Appendix 4: Tools for Valuing Resiliency

There are two primary types of models for valuing resiliency: bottom-up and top-down.

Valuing Resiliency: Bottom-up Models

Bottom-up models calculate the value of resiliency for specific customers using stated preference and revealed preference methods.

- Stated preference: uses surveys to assess customers' willingness-to-pay for better service or a willingness-to-accept a payment for less reliable service
- Revealed preference: uses real-world data to infer a value based on costs incurred or experienced during a power outage

Benefits of this approach include:

- The value of resiliency is usually very localized.
- Different customer segments value resiliency differently. (While a 5-minute outage may be a slight annoyance for a residential customer, it can require industrial or commercial customers to recalibrate equipment or other automated systems. However, longer outages may affect low-income residential customers significantly, for example by reducing savings or income.)
- Even within customer segments, resiliency can be valued differently (a wealthy residential customer may be able to access back-up generation solutions, while a low-income customer may lose perishable food that they cannot afford to replace and may not be able to work).
- This approach better reflects what happens to people, not just the grid generally (captures not only home outages but also impacts to the access to work, transportation, and community services like hospitals).

Drawbacks of this approach include:

- Customer surveys depend on customers' experience with outages. Those who have not recently experienced long-term outages may not have a realistic assessment of their impacts.
- Willingness to pay can be distorted by different abilities to pay for a better service.

Valuing Resiliency: Top-down Models

Top-down models leverage economy-wide tactics for estimating the economic impacts of power outages. Benefits of this approach include:

- Could support development of a general jurisdiction-wide value of resilience; it could then be further refined/customized for specific areas.
- Could be useful for high-level decision-making or policy development.
- Best suited for outages longer than 24 hours.

Drawbacks of this approach include:

- Differences between customer classes are not well captured and differentiated.
- Wealth disparities and equity issues are not well captured.

Development of a “hybrid” approach is also underway at Lawrence Berkeley National Lab.

Valuing Resiliency: Top-down Models

Model/Tool	Developers	Description	Data / Calculation Methods	Notes
Computational General Equilibrium (CGE) Models	Various	Economy-wide models that measure economic output, employment, and/or financial flows and transfers associated with power outages within a specified geographic area. These models tend to better reflect the impacts of long-duration outages.	Models use mathematical descriptions to represent and simulate customer behavioral responses to changes in prices, regulations, and shocks. Models can be incorporated into commercially-available tools, such as the IMPLAN tool. The IMPLAN tool leverages historical databases to allow users to model economic impacts.	Regional economic models are well-suited to understand the impacts of outages longer than 24 hours since they can reflect non-linear impacts across sectors and do not rely directly on customer experience. Examples of how these methods have been applied can be found in NARUC's 2019 publication *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices*.
Macro-econometric methods				
Input-output models				

Valuing Resiliency: Bottoms-up Models

Interruption Cost Estimator (ICE) Calculator Tool	LBNL; Edison Electric Institute	Free, publicly-available tool considered the industry standard for estimating costs of power outages lasting 24 hours or less. The ICE Calculator provides dollar values associated with power outages affecting residential, small commercial and industrial, and medium and large commercial and industrial customer classes.	Based on aggregated customer survey data completed between 1989 and 2012 in 10 utilities primarily on the West Coast and in the Southeast U.S.	Developers are currently updating the underlying survey data to cover a broader geographic area and outages lasting more than 24 hours. An upgraded version is expected in 2024.
Customer Damage Function Calculator Tool	NREL	Free, publicly-available tool for individual facilities/customers to calculate power outage costs, based on the specific losses they project will occur.	Guided assessment to estimate initial costs, spoilage costs, and incremental costs incurred by a facility (i.e., building, campus, or base) during outages of various durations (up to six months)	The output graphically shows outage costs as a function of outage duration to help facilities estimate the value of resilience as the potential avoided costs associated with resilience investments.

Social Burden Method	Sandia National Lab; University of Buffalo	Assessment method that focuses the social burden of power outages, rather than only focusing on the monetary value of critical infrastructure. The method better includes community needs and goals within infrastructure planning by focusing on the services that infrastructure provides. Adopts a more neutral treatment of the willingness to pay vs. the ability to pay for resilience.	Survey-driven and mode-driven approaches are used to assess the value of maintaining the delivery of services considered most valuable to a community. In one application in Puerto Rico, utility customers were surveyed to assess and rank the critical services that were most difficult to obtain during Hurricane Maria. The surveys used the time and cost to replace the lost services as proxies for the social burden imposed by the power outages.	Research is ongoing and expected to be completed soon. Initial findings indicate that the most valuable disrupted activities were storing and obtaining food and medicine, and the service with the greatest well-being impact was refrigeration.

Power Outage Economics Tool (POET)	LBNL/ ComEd	Valuation approach using survey methods to calibrate a regional economic model to estimate direct and indirect costs of a power outage incurred by customers and the regional economy. This hybrid approach seeks to overcome the limitations in traditional CGE models by using surveys to assess residential and C&I utility customers' adaptive behaviors during power	Survey of ComEd customers to better understand costs faced during longer duration, widespread power outages. Survey results will be used to calibrate a computational general equilibrium model.	The approach builds from a set of 58 resilience metrics initially developed by ComEd for microgrid development. The results will help better understand the economic impacts of an outage within the Chicago area, as well as areas with strong linkages to the Chicago economy. The pilot is expected to be completed soon.

		interruptions. These results can then be used to calibrate the CGE to better estimate regional economic costs.		