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Distribution Resilience and Reliability Planning

January 2022

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Jeff Taft, Ph.D., Pacific Northwest National Laboratory

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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1.0 Introduction

An Integrated Resilient Distribution Planning[1] process is designed to employ both near-term and long-term grid assessments in order to facilitate effective decision-making regarding grid needs and investments. Unlike traditional siloed distribution planning, the IRDP process includes a number of interrelated activities that are driven by planning objectives based on customer needs and public policies, such as electrification, DER integration, and use of non-wires alternatives. Additionally, planning must address engineering criteria based on safety, reliability and resilience standards and objectives. These planning criteria define the minimum performance requirements for the distribution system. The goal of the IRDP is to demonstrate the interconnected relationships between several objectives, which will then lead to more effective grid investments. The figure below illustrates a high-level flow of inputs into the several analyses with an IRDP process (Figure 1). The various planning analyses are shown in the yellow boxes (i.e., Granular Locational Forecasts and Scenarios, Resilience Threat Assessment, Near and Long-Term Distribution Planning, and Distribution Asset Management).

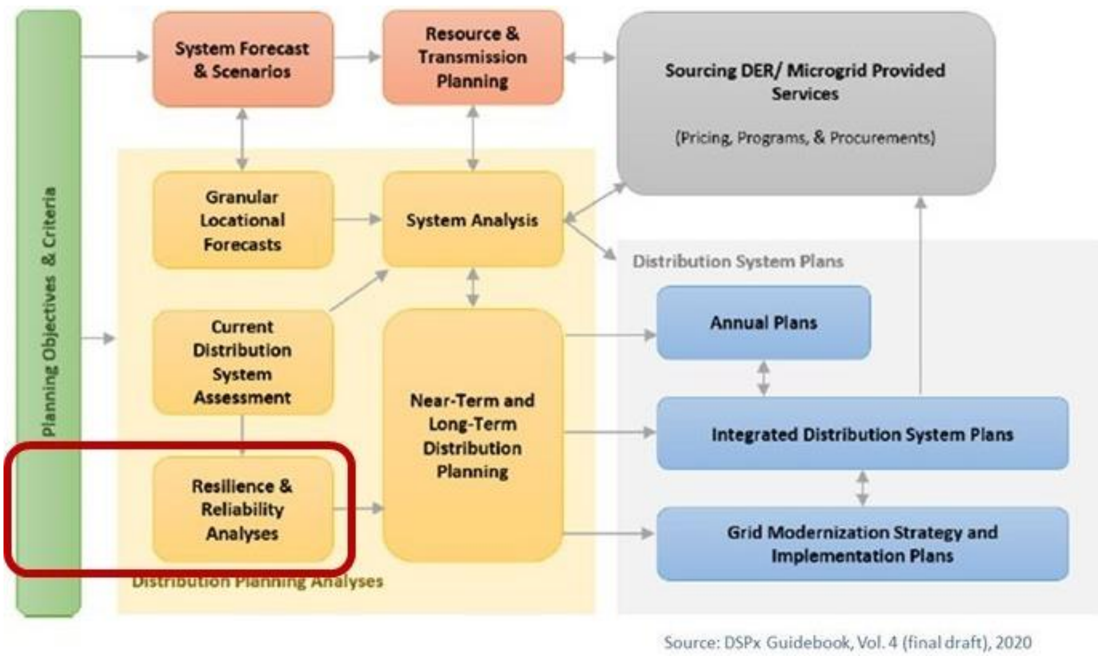


Figure 1. DOE Integrated Resilient Distribution Planning Process

This paper focuses on the Resilience and Reliability Analyses and related inputs (highlighted in the red box) to provide a next level of detail for the steps involved.

A resilient event involves several phases as illustrated the DOE-IEEE resilience event trapezoid[2] below (Figure 2). Phase I, Disturbance Progress, is the period when a resilience event initially occurs. During this initial period there are two actions that occur in rapid sequence:

[1] P. De Martini, Integrated Resilient Distribution Planning, for PNNL, 2022

[2] DOE-IEEE PES, Resilience Framework, Methods, and Metrics for the Electricity Sector, October 2020. Available at: https://www.naesco.org/data/industryreports/DOE-IEEE_Resilience%20Paper_10-30-2020%20for%20publication.pdf

1. Grid infrastructure in a location may either avoid or withstand the event to preventive failure, or the grid infrastructure may fail resulting in a power outage to customers.
2. If the grid infrastructure fails, corrective action may be possible to mitigate the scope and scale of power outage to customers.

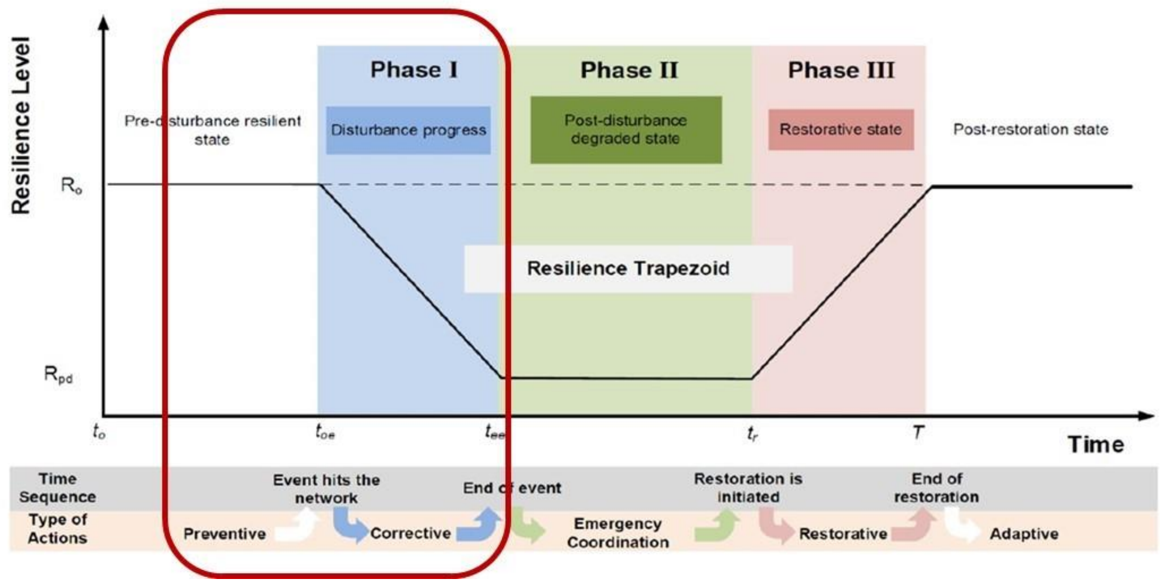


Figure 2. DOE-IEEE Resilience Event Trapezoid

The vast majority of grid resilience and modernization capital investments are oriented to addressing resilience risks during Phase I. These grid investments are intended to address potential failures by either a) avoiding a failure, such as undergrounding, or b) withstanding the impact of an event, such a pole hardening. Resilience investments also include those to enable corrective action to mitigate the scale of outages from potential failures, including flexible grid designs with automated switching schemes and microgrids, for example.

2.0 Distribution Resilience Planning

Delving into the Resilience and Reliability box in Figure 1 reveals three discrete steps and associated sub-steps:

1. Assessing resilience event threat-risk,
2. Evaluating potential grid and 3rd party solutions, and
3. Prioritizing investments based on risk-spend efficiency.

Step 1 involves determining community resilience needs though a structured threat-risk assessment. This step incorporates climate risk-threat analysis, community led vulnerability assessment and a determination of the probability of physical risk to components in a power system that may create an outage and related impact to a community and individuals. Step 2 involves identifying potential solutions to prevent and/or mitigate potential failures during a resilience event and to evaluate their engineering effectiveness to reduce/eliminate the identified risks. Step three involves determining an economically efficient resilience portfolio and roadmap of resilience measures that address community needs within a specific cost constraint derived from customer rate impact considerations. Step 3 uses the engineering effectiveness factor with consideration of community/individual outage reduction benefits in relation to project costs and other constraints to create a long-term resilience plan. These 3 steps are illustrated below (Figure 3).

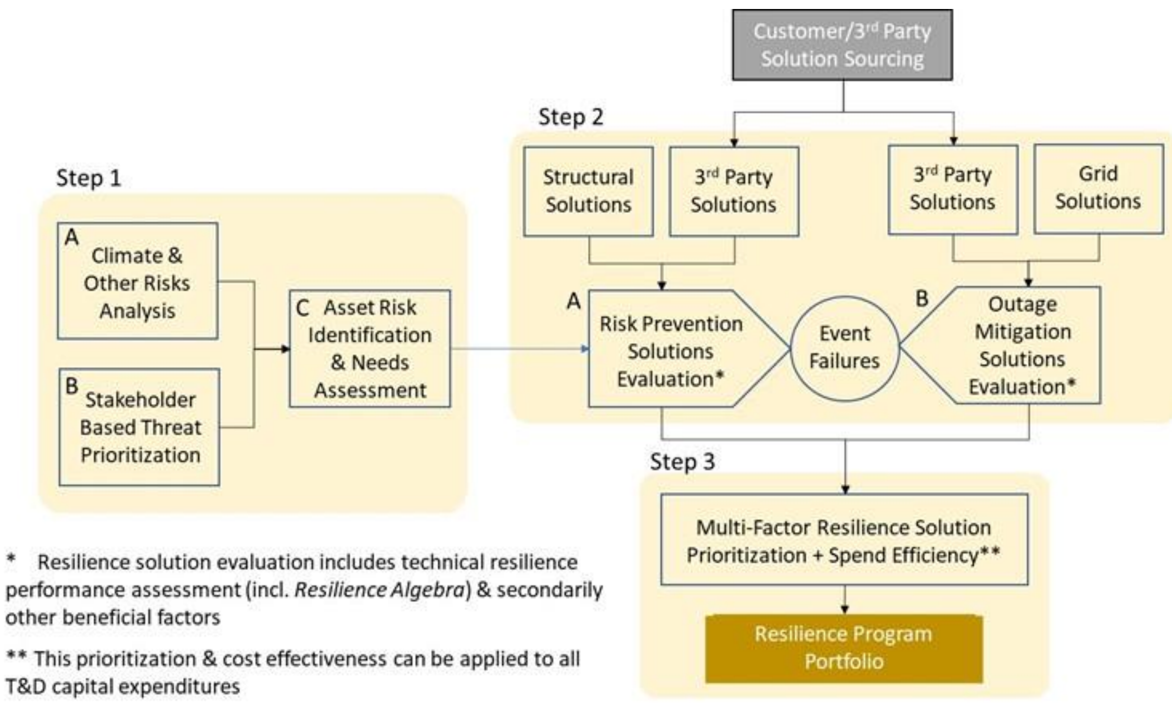
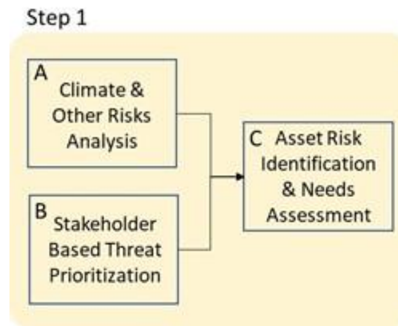


Figure 3. Resilience Planning Process

This methodology is based on emerging industry practices and practical considerations that include community resilience priorities, and customer rate impact considerations that place real spending limits for solutions.

2.1 Step 1. Threat-Risk Assessment

There is a need to be responsive to community resilience needs given various potential threats and develop efficient expenditure plans that fit within customer rate impact constraints. Both community threat-risk assessments and rate impact limitations are externally driven and should be considered as planning input.



The first step is to conduct a threat-risk assessment that combines a) detailed empirical climate and other threat risk analysis with b) community resilience needs input to identify and prioritize the scale and scope of resilience needs. These in turn support c) identification of specific grid infrastructure that may be at risk.

a. Environmental and other threats are individually assessed and prioritized in terms of propensity to impact specific geographical areas. This is conducted with high-resolution climate analytics to provide asset-level resolution for short and long-term flooding and wind risk to assess physical risks over a desired time horizon to help a utility address the resiliency of its generation, transmission, and distribution infrastructure. Figure 4 is one of several different climate threat assessment conducted by ConEdison as part of their resilience planning. [1]

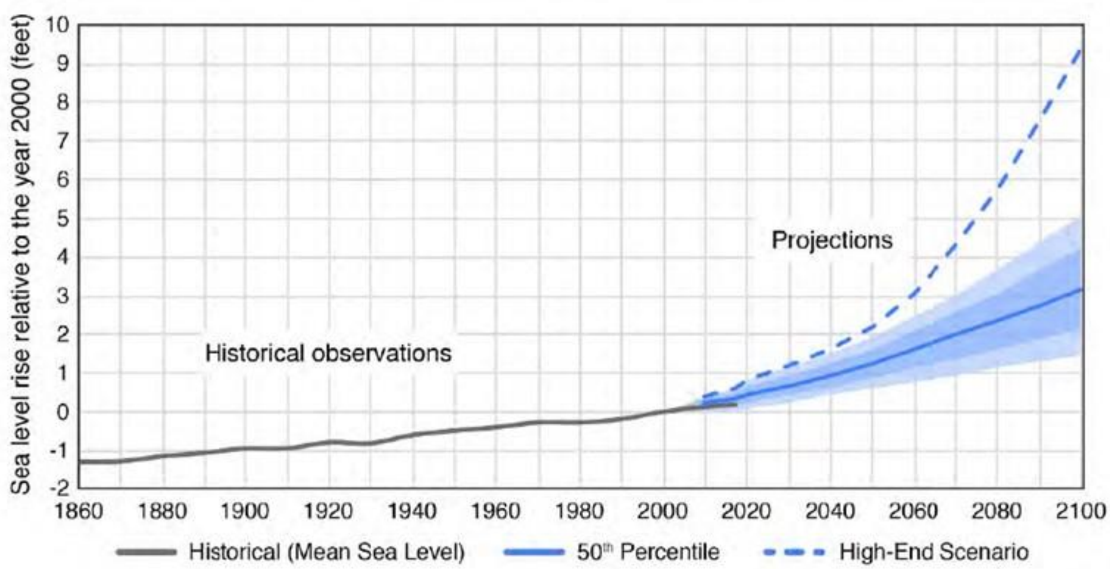


Figure 4. ConEdison Climate Threat Risk Projection Due to Sea Level Rise

This type of climate risk data will help communities and utility to prioritize geographic locations and related critical facilities and customers that are most at risk. This involves stakeholder driven threat identification and prioritization combined with the customer segmentation and prioritization to provides a key input into the resilience planning

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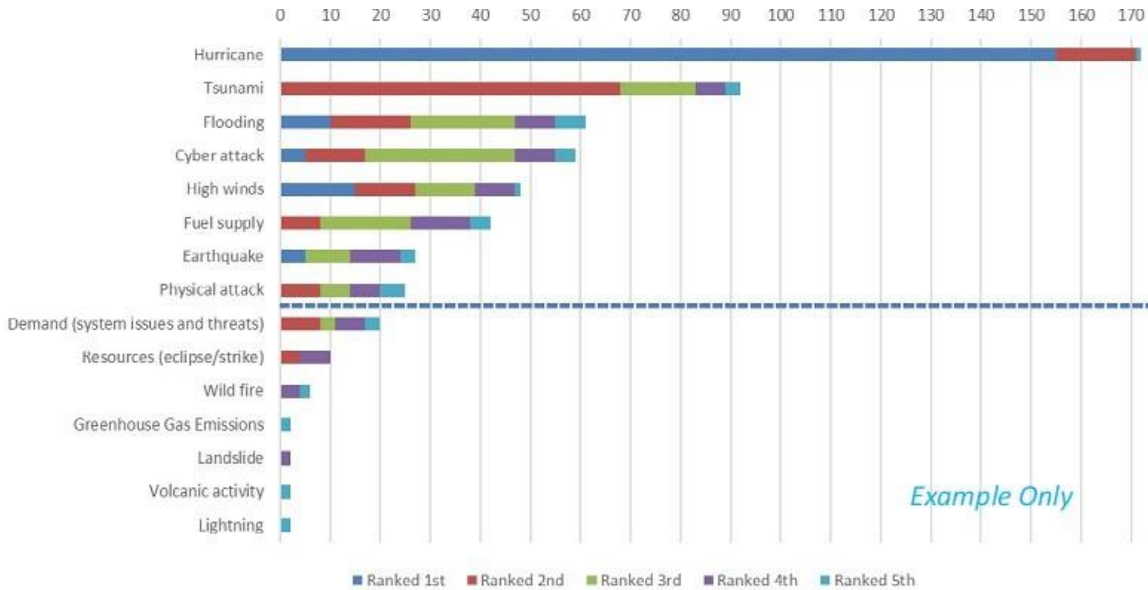
1 ConEdison, Climate Change Vulnerability Study, 2019. Available at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf?la=en

process. An example of this approach is the Hawaiian Electric Resilience Working Group (RWG) report[1] and their assessment and prioritization of resilience threats from natural causes, and man-made physical and cybersecurity attacks (Figure 5).



Source: Hawaiian Electric Resilience Stakeholder Working Group

Figure 5. Community Threat-Risk Prioritization

b. Additionally, state and community stakeholders should identify critical and essential facilities as well as vulnerable and access needs customers. These customer categories should be assessed for resilience vulnerabilities and the implication of anticipated outage duration on individuals and to the community. From this community government and stakeholder led assessment a set of prioritization weights may be developed for use later in Step 3 in order to prioritize resilience solution expenditures to address identified needs. A first step is prioritizing facilities and those customers most vulnerable to long duration outages. An example of facilities prioritization from Hawaii is shown in Figure 6.

[1] Hawaiian Electric Resilience Working Group Report, 2019. Available at: https://view.hawaiianelectric.com/jupiter-intelligence-special-report/page/1

Tier 1

- Military
- Telecommunications
- Hospitals and critical healthcare
- Water and wastewater
- Emergency management and first responders

Tier 2

- Transportation
- Hospitality
- Banking and finance

Tier 3

- Remaining customers

Source: RWG (Transportation included 'Energy' sector)

Figure 6. Hawaiian Electric RWG Customer and Facility Prioritization

From these prioritization and weighting methodology can be developed. The weighting can be simple as shown in Figure 7 below where weights for the population at risk are applied. In this simple example, critical and essential facilities are weighted by the populations they serve, and those individual vulnerable and access needs (incl., medical dependent) households are weighted higher than other households due to the greater impact from power outages.

	Population at Risk			
Solution	Critical/Essential Facility (Population Served)	Vulnerable Population (x2.0 weight)	Other Customers	Weighted Community at Risk
A	5000	1000	1000	8000
B	0	0	5000	5000
C	5000	0	500	5500
D	2500	1000	1000	5500
E	10000	1000	14500	26500

Figure 7. Example of Simple Weighting Method

c. Climate locational analysis combined with community prioritization provides the basis for a detailed customer and community-based threat-risk assessment of a utility's assets. Vulnerable and prioritized grid assets are identified from location specific implications of the threat assessments and priorities in A & B. This then informs the need, location, and timing of investment to cost effectively provide the level of electric system resilience our customers expect. The result is a set of resilience needs in the form of specific performance requirements to prevent and mitigate event-based risks. This type of granular analysis of at-risk grid infrastructure, based on climate analysis, informed by community priorities, as shown in Figure 8 below from PG&E's 2021 Wildfire Mitigation Plan[1] has become a best practice in the industry.

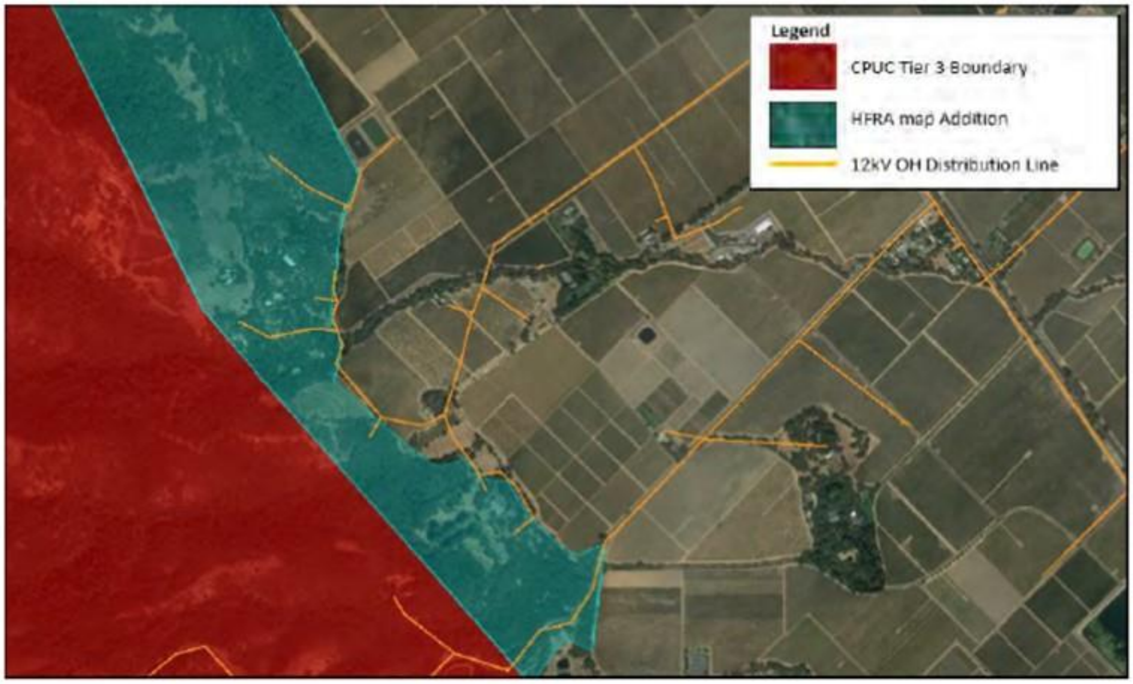
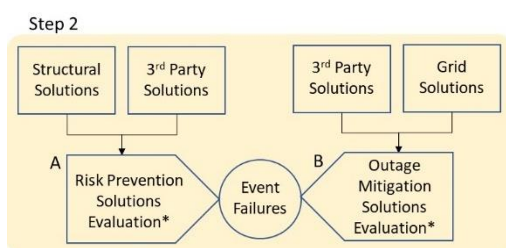


Figure 8. PG&E Wildfire Threat to Grid Infrastructure Assessment Example

2.2 Step 2. Resilience Solution Assessment



Once the specific threat risks associated with certain grid infrastructure has been identified, a set of solutions to prevent and/or mitigate the risk of failures can be identified and assessed. This involves the application of the "bowtie method"[2] (Figure 9) which involves, first identifying solutions that prevent failure, and then identifying solutions that mitigate potential failures. This bowtie method translates the threat-risk assessment and asset vulnerabilities identified in Step 1 into specific event risk prevention and mitigation analysis and solution identification. A bow-tie approach helps identify where and how solutions would have the greatest impact for customers and communities.

[1] PG&E, 2021 Wildfire Mitigation Plan. Available at: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan/2021-Wildfire-Safety-Plan.pdf

[2] European Commission, The 2nd International Workshop on Modelling of Physical, Economic and Social Systems for Resilience Assessment. 14-16 December 2017. Ispra, Italy. Available online at: https://www.whitequeen.nl/assets/papers/resilient-bow-tie.pdf

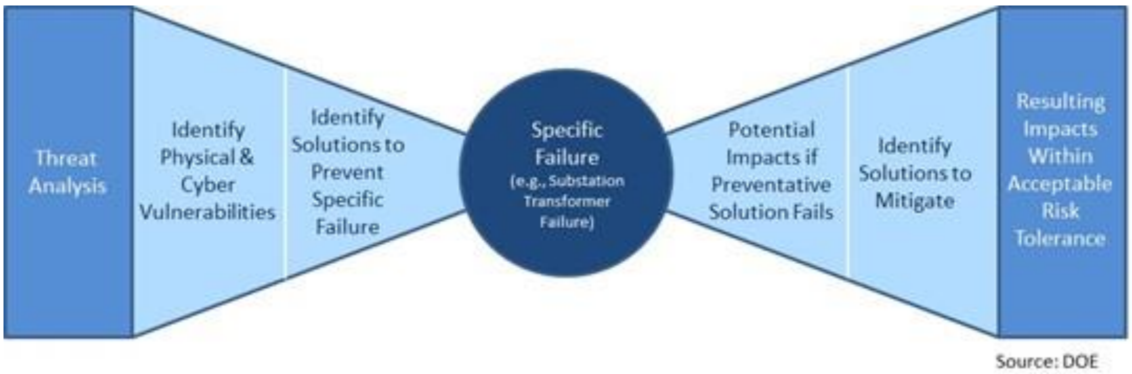


Figure 9. Resilience Bowtie Method

This is done by implementing solutions to prevent certain events from causing system failures. Preventive (i.e., those that either avoid or withstand events) solutions are shown on the left side of the bowtie. Mitigation solutions can either reduce the impact of a failure event or facilitate immediate power restoration from the failure to reduce the consequences in Phase I of a resilience event. Mitigation solutions are shown on the right side of the bowtie.

The specific prevention and mitigation solutions are identified through both utility asset options and potential third-party solutions. The utility asset options may include vegetation management, hardening, undergrounding, increasing switching flexibility, for example. Third-party solutions may involve microgrids, local energy producing resources and load management. The third-party solution opportunities are identified through non-wires alternatives sourcing process. The utility and third-party solutions will be evaluated against the respective prevention and mitigation performance requirements identified in Step 1. This is illustrated in the more detailed view below (Figure 10).

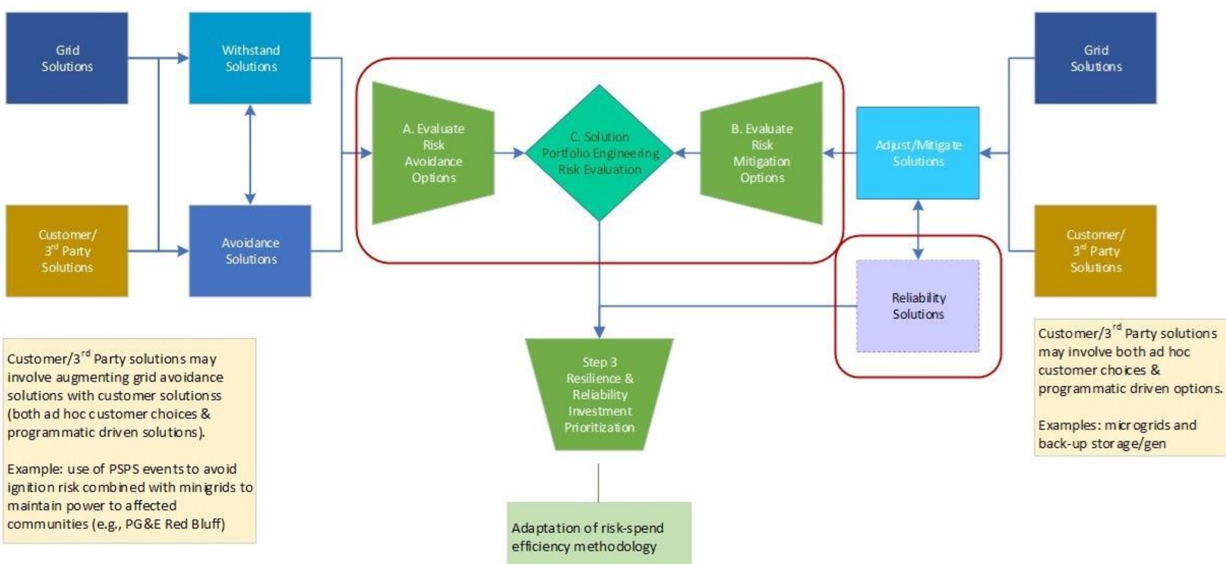


Figure 10. Bow-Tie Solution Identification and Assessment Process

The analytical methods employed to evaluate potential solutions and assess their benefits in Step 2 requires further elaboration. At the core of the bowtie methodology is a rigorous engineering assessment of potential solutions including both utility grid and potential non-utility projects. The solution identification process within Step 2 involves identifying both utility grid and non-utility projects that may address a specific threat risk identified in Step 1. These solutions may prevent failures through avoiding the risk (e.g., undergrounding, or remote microgrid), or hardening an asset to withstand a threat (e.g., pole hardening). Solutions may also be identified that mitigate potential failures (e.g., grid design changes, feeder automation, and microgrids). Each solution may fully or partially address the threat in terms of effectiveness in relation to the specific need (i.e., solution robustness) and scope of reliance provided (e.g., single customer or entire town). The resilience solution matrix below in Figure 11 illustrates this point.

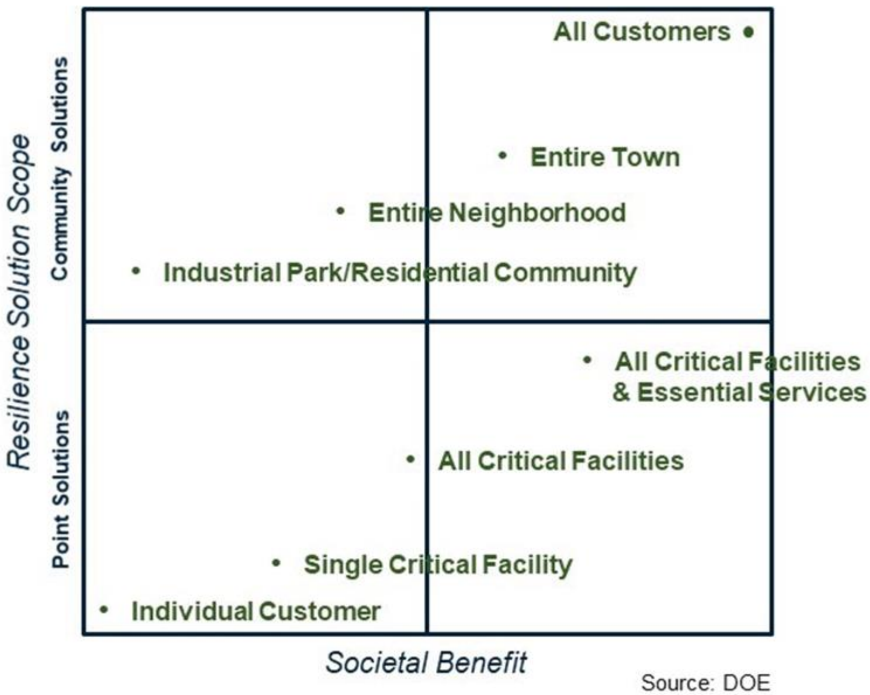


Figure 11. Resilience Solution Matrix

The goal is to develop an optimized portfolio of robust solutions to address as wide a set of customer and community resilience needs as budgets and related customer rate considerations will allow. This involves two steps:

- Individual solution effectiveness and comparative assessment for a specific need identified.
- Optimization of resulting preventative and mitigation solutions from 1 to create an initial financially unconstrained solution roadmap over the planning period.

2.2.1 Assessing Resilience Solutions' Technical Effectiveness

It is necessary to assess the engineering effectiveness of a potential solution in the context of a defined need. This analysis may also include comparative assessment among several alternatives to determine the best engineering solution. This includes evaluating multiple alternatives for a specific resilience vulnerability (e.g., transmission tower), or group of vulnerabilities (e.g., multiple distribution feeder segments in a location). This enables determination of the most technically effective solutions, thereby reducing the number of alternatives that must be considered in developing a resilience plan and roadmap.

The method recommended for this analysis is Resilience Algebra.[1] This method defines grid resilience in terms of a stress-strain model, in which the contribution of various components to grid resilience as seen at a specific grid asset or group of assets in an area may be quantified. Additionally, the effects of the grid structure can be considered by representing grid resilience as a structure itself using an approach modeled after the reliability treatment used in electronics and aerospace. This leads to a resilience algebra, a set of reduction rules and relatively simple algebraic methods that facilitate option decisions in the context of grid resilience.

Some key points about this approach:

- Grid resilience is affected by both grid asset characteristics and system structure, both of which are known to utility engineers and planners,
- Resilience can be modeled in terms of resilience determinants that reflect system (grid) dependencies and structural influences,
- Grid asset resilience determinants derive from its intrinsic stress responses (e.g., transmission tower strength characteristics), and
- By specifying the set of stresses to be considered and assigning values of the components appropriately, a very wide range of stress types can be considered.

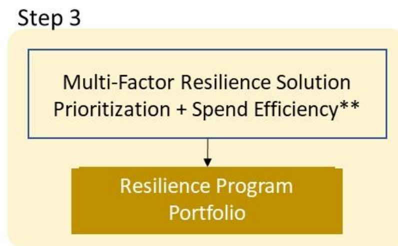
This method makes it practical objectively to compare very different options from an engineering perspective, such as whether to harden a distribution circuit or provide a back-tie to another circuit, or to employ microgrids (in any of various configurations) or to use storage at a system or local level. Resilience Algebra provides the means analytically to compare these options on a common footing. This method works on any grid scale, from local circuit section to entire regional grids. Planners may then use the resulting scores to select from among competing alternative solutions in an objective, analytical manner.

Once the selection of preferred solutions for respective needs are identified, it is necessary to develop a prioritized set of solutions in relation to their respective technical outage risk reduction (preventative or mitigation) value in relation to a given spending limit (e.g., capital and expense budget, incentive program, etc.). There is also a need to develop a roadmap that sequences preventative and mitigation solutions so that the maximum risk reduction can be achieved in the shortest time within financial and resource constraints. The resulting solution set is then be prioritized in Step 3.

This involves another set of analyses discussed in Step 3.

[1] JD Taft, Fundamentals of Structural Analytic Resilience Quantification, PNNL 30423, September 2020, available online: https://gridarchitecture.pnnl.gov/media/advanced/Resilence_Algebra_Foundation_final.pdf .

2.3 Step 3: Resilience Solution Prioritization



Resilience solution prioritization involves assessing the comparative customer and community risk reduction value of the preventative and mitigation solutions related to associated generation, transmission, substation and distribution infrastructure. One planning challenge is in assessing the residual risk of preventative solutions given the long-time to implement a complete set of investments and identifying the mitigation measures to address the residual risk from a range of threats and the system impacts given the increasing complexity of a more distributed power system. Another challenge is resolving the potential overlapping set of grid needs identified in the other Integrated Distribution Planning analyses associated with asset management and grid modernization. The approach that follows is designed to address these issues.

A two-part prioritization approach that determines the 1) benefit-cost based on the customer outage risk reduction in relation to the cost of the specific prevention or mitigation solution and then 2) sequences the prioritized set of individual preventative and mitigation solutions so that the maximum risk reduction can be achieved in the shortest time within financial and resource constraints.

2.3.1 Risk-Spend Efficiency

The benefit-cost method proposed here is a simplified risk-spend efficiency (RSE) approach. RSE is an estimate of the cost-effectiveness of initiatives based on the risk reduction benefits and costs for a specific solution.[1] An RSE score is determined for specific solutions by dividing the solution cost (i.e., capital investment or 3rd party solution expenditures) by the benefit expressed in terms of the magnitude of community/customer outage risk reduction in terms of avoided interruption duration represented as Phase 2 in the DOE-IEEE framework (Figure 2). For RSE a solution's benefit is assessed in terms of estimated customer interruption minutes (CIM) avoided over the planning horizon based on the locational propensity of potential threats and community priorities derived from Step 1. Applying the simple population at risk weighting method shown earlier in Figure 7 to include the outage risk to create a RSE type scoring method below (Figure 12).

	Outage Impact Reduction				Risk-Spend Efficiency	
Solution	Weighted Community at Risk	Annual Location Event Probability	Estimated Event Duration (min)	Weighted Avoided Community Interruption (mins)	Solution Cost	RSE Score
A	8000	10%	2160	1,728,000	$2,000,000	0.86
B	5000	20%	2880	2,880,000	$1,000,000	2.88
C	5500	5%	1440	396,000	$500,000	0.79
D	5500	8%	1440	633,600	$250,000	2.53
E	26500	3%	4320	3,434,400	$15,000,000	0.23

Figure 12. Simple Risk-Spend Efficiency Method

[1] California Public Utilities Commission (CPUC), Wildfire Safety Division (now Energy Safety) 2021 Wildfire Mitigation Plan Guidelines Template.

This RSE score is the metric used in the merit order optimization discussed in Step 3 below. The RSE metric proposed here is a generalized adaptation of the California method, developed for wildfire risks, to use for prioritizing utility and non-utility resilience solutions for a broad set of resilience threats. Figure 13 is the RSE calculation method used by Southern California Edison for its wildfire mitigation planning.[1]

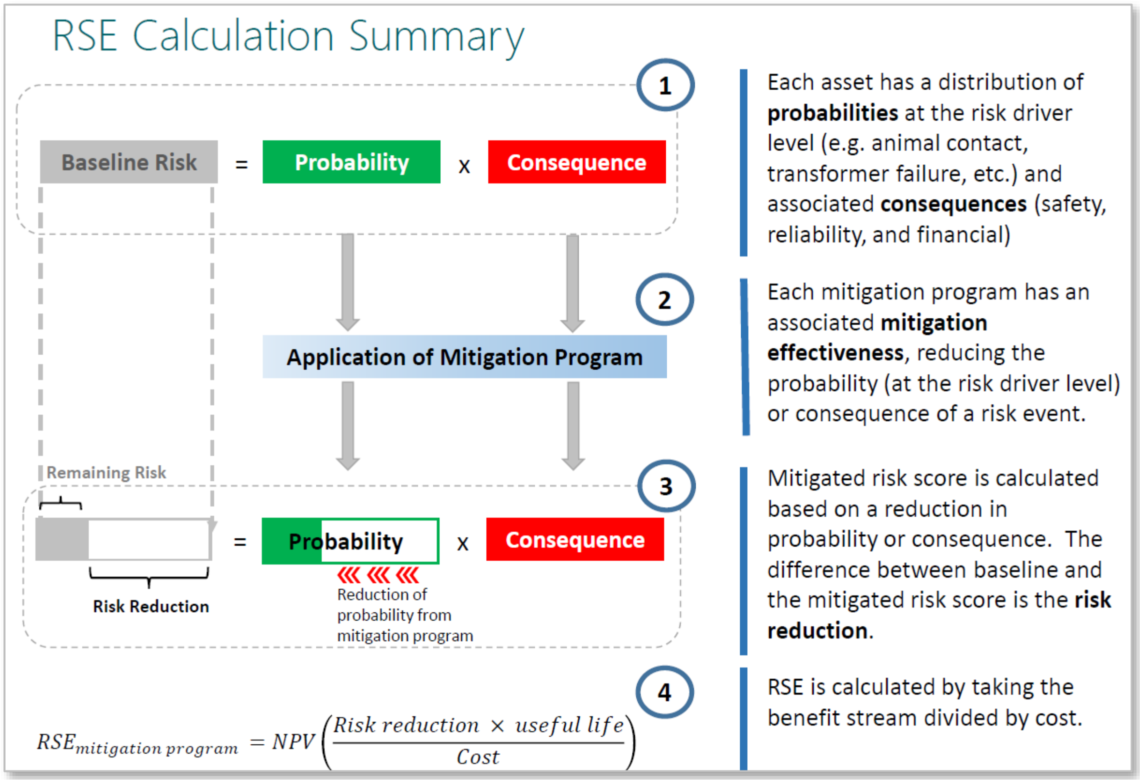


Figure 13. SCE Risk Spend Efficiency Calculation Method

It is important to note that this benefit-cost approach differs from other methods based on utility operating cost savings, customer economic value and/or societal economic value. This approach also avoids using conceptual societal and customer economic values as these methods are currently the subject of research efforts by the DOE and net yet readily available for use.[2] The proposed methods here can incorporate the economic values when available to replace or inform the weighting methods proposed here. This is because the customer and societal economic calculations are based on an assessment of the estimated avoided outage duration (in time) multiplied by the outage risk economic value (in dollars) for each type of customer and the outage impact on the community overall.

For now, it is proposed that the estimated outage duration combined multiplied by a weighting method for specific customer types, and critical and essential facilities be determined by the stakeholders and the regulator in Step 1. A similar weighting approach is being used in several states to prioritize projects within a given budget. The example below is an excerpt from a California Microgrid Incentive Program weighting method using scores for the purpose of

[1] SCE Risk Spend Efficiency Workshop Presentation, December 9, 2021
[2] U.S. Government Accounting Office, Electricity Grid Resilience, March 2021. Available at: https://www.gao.gov/assets/gao-21-346.pdf

prioritizing incentive funds for community microgrid projects within the overall approved budget. Figure 14 below is an excerpt from this California proposal showing the customer and community benefits scoring method (note: other project attributes were also scored).[1]

Benefit Scoring Category	Subcategory	Scoring Parameter / Criteria	Validation	Points	Points Cap	Max Points
Customer & Community Benefits	Low Income Customers	Number of CARE/FERA customers within MIP Project	Utility Records	0.1	8	50
	Vulnerable Customers	Number of AFN/Medical Baseline/Life Support customers within MIP Project	Attestation from Authority having Jurisdiction	0.2	10	
	Critical Facilities (CF)	Number of Critical Facilities within MIP Project Boundary	CPUC Definition	5	30	
		Number of Critical Facilities within MIP Project	CPUC Definition	10		

Figure 14. Customer & Community Benefits Excerpt

An RSE score is identified for each solution and then used to rank all the solutions to create a prioritized list of solutions within a given budget. The budget reflects the practical considerations of customer rate impacts and utility financial constraints. customer rate impact considerations. That is, given customer tolerance for a certain level of rate increase, a resilience budget for capital and operating expense ceiling is established. The approach here reflects the reality that resilience solutions are often incremental costs that can impact customer rates whether through utility expenditures and/or through rate surcharges for resilience programs such as California's Microgrid Incentive Program.[2]

However, this prioritized list needs to further refinement to develop an implementation roadmap combining prevention and mitigation solutions that achieve the highest level of resilience over a specific planning period relative to a given budget and resources (e.g., qualified workers and equipment to implement the plan).

2.3.2 Optimization of Identified Solutions to Create Solution Roadmap

In practice, there are two parallel plans, one for preventative measures, and one for mitigation measures and these need to dovetail to achieve an optimal outcome. Also, these plans will require implementation over several years and require adjustments as conditions change. For

[1] Proposed Microgrid Incentive Program Implementation Plan of San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39-E), and Southern California Edison Company (U 338-E)
[2] California Microgrid Incentive Program
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M372/K319/372319497.PDF

example, a T&D resilience plan often will have a 10-year horizon, with specific projects in each year. As such, development of a best plan involves a multi-stage decision process, where a total plan is built up in 10 one-year stages in such a way that an overall objective is optimized.

In this multi-stage decision process, the results from a preceding year become the initial conditions for the next year. The objective is to maximize a measure of total resilience improvement within the bounds of certain key constraints (e.g., budget and resources). Further we want the total objective curve to rise as fast as possible over the course of the multiyear plan to reduce outage risk for the benefit of the greatest percentage of population served. The total objective curve, therefore, is a composite of two sub-curves, one for preventative measures and one for mitigation measures.

This method involves starting with the RSE prioritized preventative measures and for each year in succession. Next, the measures are selected in merit order based on RSE but adjusted by applying the given constraints to determine limits on what can be done that year. Once that year's work plan is chosen, the objective curve is updated to show the cumulative results of the present year and any preceding years. The results of the current year plan include a stack of projects to be applied that year, along with how much of each project to apply (which determine that year's cost and contribution to cumulative risk reduction curve). The process continues until the full plan for the preventative measures is complete. The process is then repeated for the mitigation measures plan.[1] Figure 15 shows examples of the preventative and mitigation curves and the sum of those curves.

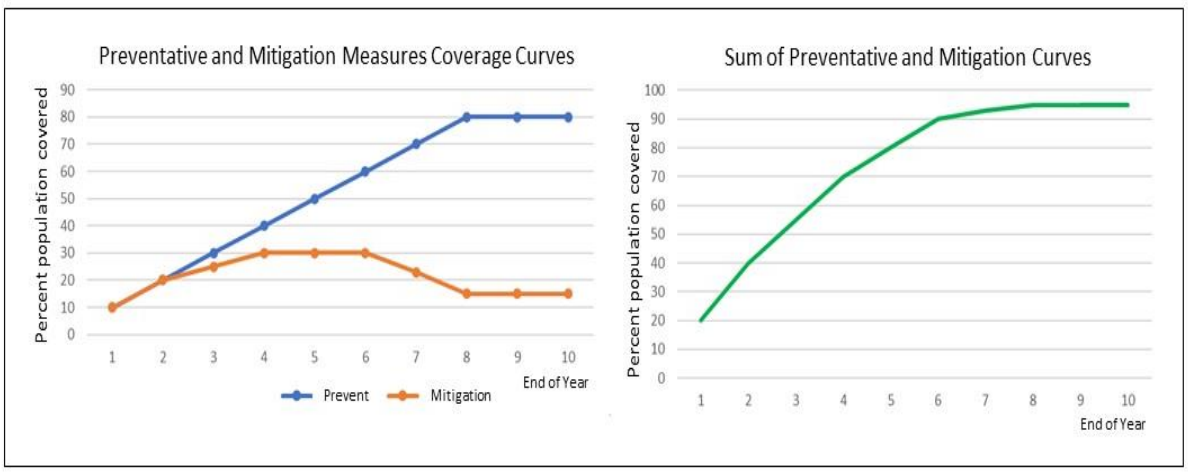


Figure 15 Example Curves from the Portfolio Roadmap Optimization Process

A simple resilience objective is the total percentage of a utility's service population that is covered by either a preventive measure or a mitigation measure. Part of the optimization problem is to choose the multi-stage plan that causes the resilience objective curve (in this case the percentage of population covered) to rise as fast as possible, given the constraints that must be satisfied.

At each stage (year) a set of four constraints must be satisfied. They are:

- Constraint C1: present year budget limit – the total cost of the measures for that year must not exceed the budget for that year

[1] Alternatively, the two sub-plans could be determined parallel, on a year-by-year basis.

- Constraint C2: In this formulation, the total coverage must not exceed 100%
- Constraint C3: the amount of any measure to be used must not exceed the opportunity for that measure. For example, if the measure is undergrounding circuits, that measure cannot exceed the number of circuits remaining to be undergrounded at that stage.
- Constraint C4: the amount of any measure must not exceed the resource limit for that measure in that year. For example, if the measure involves hardened utility poles, there may be a staffing resource limit on how many can be done in that year.

The process is then, given the cumulative results of previous years (which update the constraints) and the cumulative objective curve as initial conditions for the present year being planned, select measures from the RSE list, starting with the highest RSE solution and apply the constraints to determine how much of that measure can be applied in the present year. Work down the RSE merit list of available measures for that year until none can satisfy all four constraints. At this point the plan for that year is determined. Continue until all years have been planned. The process is repeated for the mitigation measures plan. This use of merit order allocation is similar to the use of merit order dispatch of generators in a bulk power system.

The RSE merit list must be redeveloped for each year in the process. This is because the set of available measures may change from year to year. This is because threat risks may change, some measures will be exhausted (e.g., all poles hardened), some may not be possible in early years but can be used in later stages (e.g., emergent technologies such as fast-acting protection schemes to reduce fire ignition risks). In some cases, the RSE merit list will be the same from one year to the next. Using an RSE metric and allocating measures in merit order is what ensures that the objective curve will rise as fast as possible.

It is important in this method that initial conditions be managed carefully at two levels:

- The initial conditions for any stage (year) must come from the final conditions of the previous year. This includes the cumulative value of the objective function, plus the depletion of any measure that may have been previously partially used.
- Within a year, the initial conditions for each candidate measure must include the changes to the objective function cause by all of the measures already chosen for that year.

These initial conditions must be strictly observed for the resultant plan to be optimal. When determining the mitigation plan, it is necessary to add its resilience contribution to the resilience value already determined at that same year in the preventative measures plan. Note that the mitigation plan may have a shorter total time horizon than the preventive measures plan (e.g., the preventative measures plan may cover 10 years, but the mitigation plan may be limited to perhaps five years). Mitigation measures are often not intended as the long-term solution to a more systemic risk, rather these mitigation measures are intended to address critical short-term needs until the longer-term preventative measure is implemented. Example of these two complementary preventative and mitigation plans are reflected in the California Wildfire Mitigation[1] plans (prevention measures plan) and associated Public Safety Power Shutoffs (PSPS) Mitigation Plans (mitigation measures plan). The illustration below (Figure 16) shows the cumulative outage risk reduction from PSPS events due to both the implementation of wildfire prevention measures and mitigation measures.

[1] California Utility Wildfire Mitigation Plans, Available at: https://www.cpuc.ca.gov/industries-and-topics/wildfires/utility-wildfire-mitigation-plans

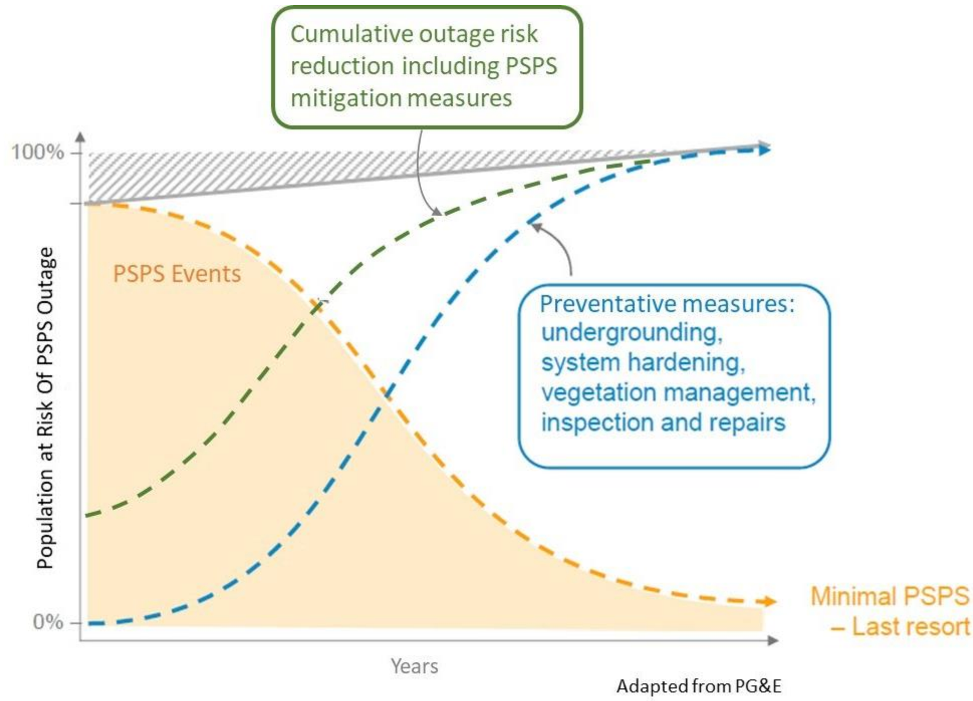


Figure 16. Combined Outage Risk Reduction from Preventative & Mitigation Measures

While PSPS events are man-made in response to wildfire threat-risks, the example still holds for the cumulative benefit in outage reduction for a set of preventative and mitigation measure if structured properly.

This multistage decision process provides an efficient, optimized plan based on how much of what measures are to be applied in each year within financial and other constraints. Note that while a 10-year horizon and yearly stages were used, this method works for any time horizon and set of intermediate stages. The optimality of the plan derives from the form of the resilience objective and the requirement that it rise as fast as possible within the constraints, carry forward of the final conditions from the previous stage or step, and the use of RSE metric to prioritize the measures at each stage.[1]

[1] The use of RSE prioritization here is similar to the use of merit order dispatch of generators in a bulk power system.

3.0 Conclusion

The utility industry is evolving toward a set of best practices that leverage climate science and other sophisticated risk management techniques as discussed above. This is resulting in a rigorous integrated resilient distribution planning process that generally employs three fundamental aspects:

1. Natural and man-made threat risk assessment informed by community priorities and help to identify specific priority grid infrastructure at risk.
2. Solution identification process employing a bow-tie methodology and an engineering-based evaluation that considers both preventative and mitigation solutions that may include utility and non-utility measures, and
3. Resilience solution prioritization methodology that assesses the risk reduction benefits to communities and vulnerable individuals as well as the spend efficiency to achieve desired resilience and economic objectives.

These three steps are the next level details behind the inputs and Resilience and Reliability Analyses box in the overall IRDP process flow in Figure 1. In practice, this planning and decision-making process may entail a level of analysis illustrated in Southern California Edison's process for wildfire mitigation planning (Figure 17).[1]

[1] SCE, Risk Spend Efficiency Workshop. Presentation, December 2021. Available at: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=51907&shareable=true

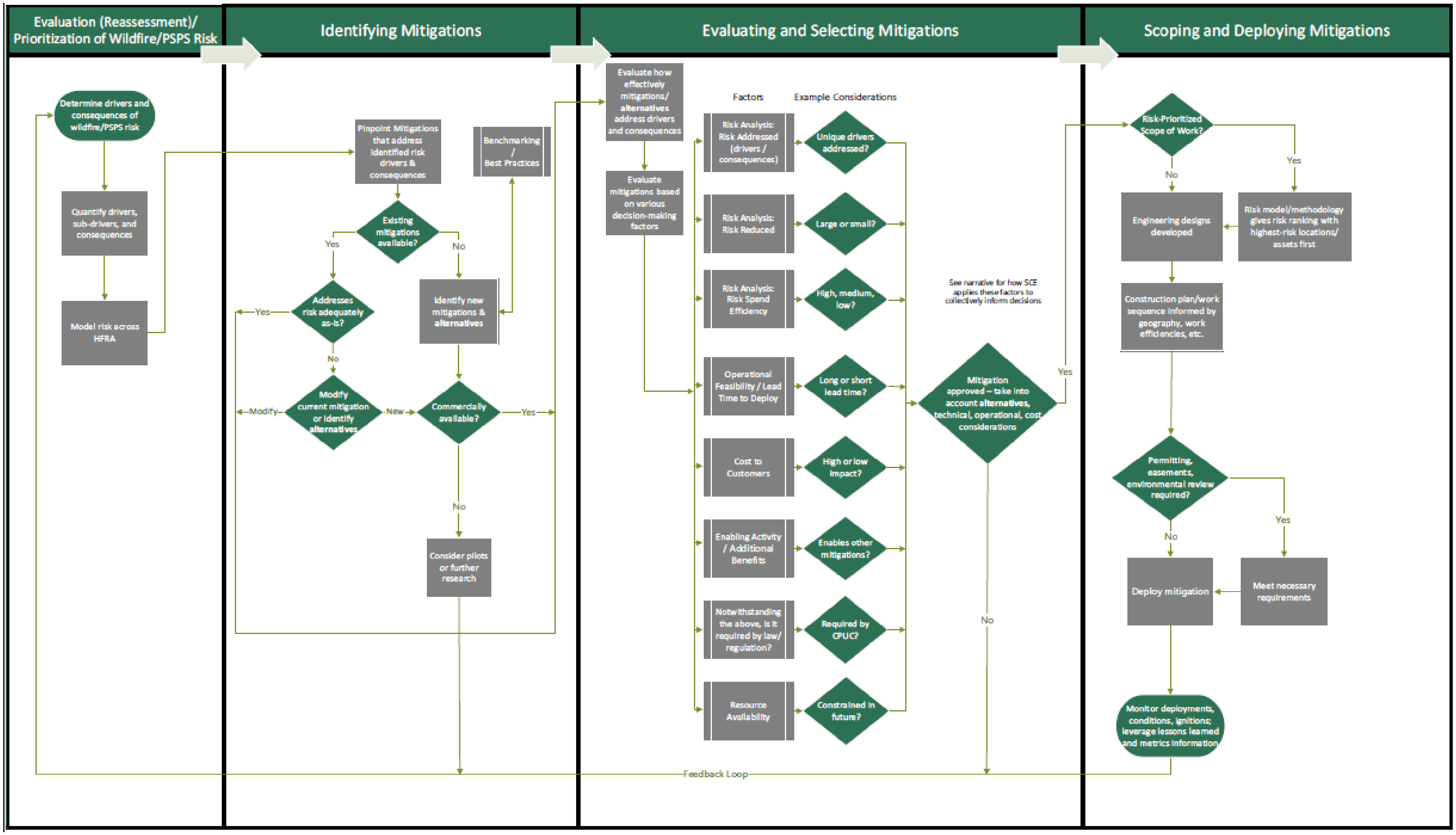


Figure 17. SCE General Decision-Making Process for Wildfire/PSPS Mitigations

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