# Hybrid Power Plants for Energy Resilience: A Case Study

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**Technical Report**
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# Executive Summary

As renewable energy technologies are increasingly adopted, they pose an opportunity to improve the sustainability and resilience of distributed grids, especially when their design and operation is coordinated as a hybrid power plant. When included in hybrid power plants, distributed wind turbines in particular have the potential to enhance the resilience of distributed grids in areas with good wind resource, due to their ability to complement photo-voltaic (PV) solar panels by providing more consistent generation and ancillary services. Despite this benefit, U.S. distributed wind adoption is lower than other comparable renewable energy technologies.

In this study, we seek to demonstrate how hybrid power plants that include distributed wind turbines can contribute to distribution grid resilience by meeting loads (especially critical loads) more consistently, increasing reserve capacity, and providing value to customers during outages. To demonstrate these contributions, we integrate three separate frameworks and apply them to a case study in a rural electric cooperative in Iowa. Through this case study, we simulate and compare hybrid power plant design and operation during two hazard events: a tornado that causes a 48-hour distribution outage and a winter weather event that causes a 6-hour generation outage. The inclusion of a hybrid power plant that leverages 1) increased battery duration and 2) advanced forecasting and dispatch strategies that reserve capacity leading up to a hazard event best reduce lost loads as well as diesel consumption that would otherwise be used to meet those loads during short- and long-duration hazard events.

Depending on the hybrid power plant capacity and operation, we find that the outage mitigation value of a hybrid power plant (measured in value to customers to avoid an outage and avoided lost revenues for the utility) is most significant in the tornado hazard event. Adding wind, solar, and battery assets to the existing system in the tornado hazard event provides about $50M-$100M in value to almost 5,000 customers from avoided lost load (averaging between about $10k and $20k in value per customer) and $570k-$2.2M (about $30 to $100 in value per customer) in avoided lost load in the winter hazard scenario. Minimal value is captured from avoided lost utility revenues: $4k-$8k of saved revenue in the tornado hazard event and $220-650 of saved revenue in the winter hazard scenario, which is far less than one day of normal revenues. In both the tornado and winter hazard scenarios, optimizing the operation of the hybrid system for resilience can lend similar value as increasing battery duration by 5 MWh for the lower capacity systems considered.

Acknowledgments

We would like to thank Bret Barker and Patrick Gilman at the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office for their support of this work; our collaborators at Algona Municipal Utilities and Iowa Economic Development Authority, as well as Tom Wind for their support and input during the development of this research; and our NREL colleagues for their input via the U.S. Department of Energy Technical Assistance Group on critical infrastructure. We are thankful to all project team members from partnering laboratories on the Microgrids, Infrastructure Resilience, and Advanced Controls Launchpad (MIRACL) project:

- Idaho National Laboratory
- Pacific Northwest National Laboratory
- Sandia National Laboratories.

We also express our sincere gratitude to our industry advisory board members for their valuable insights and real-world test system recommendations during the annual advisory board meeting: Venkat Banunarayanan (National Rural Electric Cooperative Association), Chris Rose (Renewable Energy Alaska), Rob Wills (Intergrid), Paul Dockrill (Natural Resource Canada), Jeff Pack (POWER Engineers), Arvind Tiwari (GE Global Research), Kristin Swenson (Midcontinent Independent System Operator), Jonathon Monken (PJM Interconnection), and Scott Fouts (QED Wind Power).

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# 1 Introduction

The rapid increase in renewable energy contribution is challenging the United States (U.S.) electrical grid. The U.S. target of 100% carbon-pollution-free electricity by 2030 (50% locally supplied) (The White House 2021) presents a particular challenge for the rapid build-out of distributed energy resources (DERs), as well as on-site and community-scale renewable energy projects that are required to meet the local fraction of this demand, contribute to economic benefits, and enhance grid resilience in the communities they serve. Rural electric cooperatives provide 12% of the nation's electricity and serve 80% of U.S. counties (Brehm 2016), making them key contributors to decarbonizing the U.S. grid. While DERs operated under net metering policies may not be economically advantageous to grid operators–as they reduce net demand and may transact renewable power at times that are undesirable for the utility grid operator –on-site and community-scale projects enable operators to meet grid needs most effectively. Further federal assistance through the Inflation Reduction Act (IRA) is aimed at enabling rural and historically disadvantaged communities to develop renewable energy projects, produce local electricity, and build resilient systems capable of contributing to ancillary services and community goals (117 U.S. Congress 2022).

Hybrid power plants (here defined as power plants with wind, solar, and battery assets) that leverage distributed wind in areas with even moderate wind resource have demonstrated significant capabilities in providing local generation and ancillary services during grid outages and resilience events. When distributed wind turbines—turbines connected at the distribution level of an electricity system or in off-grid applications to serve specific or local loads—are added in a hybrid power plant, they can help avoid transmission constraints and leverage the complementarity of disparate generation sources. This helps reduce risk associated with resource uncertainty and adequacy and enables the provision of more grid services than solar or wind assets alone, which is particularly important during outages. The value elements impacted by hybridizing distributed wind have been analyzed (Crespo Montañés et al. 2022; Gorman et al. 2022; Kahrl et al. 2022; Kazimierczuk, Mongird, and Barrows 2022) and the added benefit of complementary generation profiles has been demonstrated in hybrid power plant modeling (Clark et al. 2022; Reiman et al. 2020). Studies have also indicated the ability of advanced design and control of distributed wind turbines, particularly in hybrid power plants, to better equip the turbines to provide resilience services, such as black-start capabilities (Gevorgian 2018).

In this study, we demonstrate the added resilience value (in terms of minimizing load loss) of hybridizing distributed wind assets to grid resilience through a case study in an Iowa agricultural community of about 5,000 population, with a unique industrial mix, served by a public power utility. In Section 2, we describe the methodology of how we modify and integrate three frameworks to 1) design the hybrid power plants for resilience objectives, 2) model resilience of the system in stakeholder-defined hazard scenarios, and 3) quantify the resilience value, in monetary terms, to the utility and to customer types within the distributed grid. In Section 3, we describe the distributed grid run by the utility and the hazard events and resilience goals of the utility's stakeholders. Section 4 presents the hybrid power plant performance in the two hazard events and assesses the resilience added to the grid and the resilience value to the utility's customers and the utility.

# 2 Methods

We integrated three tools to design a distributed-wind-based hybrid power plant and analyze its resilience benefits. First, we used the Hybrid Optimization and Performance Platform (HOPP) (National Renewable Energy Laboratory 2021) to size the system component capacity to minimize lost load during two hazard events. Then, we assessed the electrical system response to the hazard event using the Resilience Framework for Electric Energy Delivery Systems (ResDEEDS) (Culler et al. 2021). Last, we assessed the outage avoidance value from the reduced load loss and resilience response of the distributed grid with a hybrid power plant with the Distributed Wind Valuation Framework (Mongird and Barrows 2021).

## 2.1 Hybrid Power Plant Design

We estimated component capacity sizing requirements via HOPP (National Renewable Energy Laboratory 2021), a component-level model for designing, analyzing, and optimizing utility-scale hybrid power plants. HOPP leverages resource data from the Wind Integration National Dataset (WIND) Toolkit (Draxl et al. 2015) and National Solar Radiation Database (Sengupta et al. 2018), alongside the System Advisory Model (PySAM) (Blair et al. 2018) to simulate generation in this study. It then uses a storage and dispatch model to simulate battery operation. HOPP was modified in this study to also include diesel generator assets. We base initial component capacity sizing on the current loads of the system, provided by the utility, while also minimizing diesel generation. A full sensitivity study of how component capacity impacts lost load (amount lost and percentage of time load served) is provided in Appendix A. Outputs from HOPP include energy generated and curtailed from each component, as well as the shortfall or load loss (or the difference between energy demand and energy available from the hybrid power plant) in terms of the total lost load (in megawatts (MW)) and percentage of time loads are met. Loads were based on data provided by the utility for the year 2021, and hybrid power plant capacity was based on both total load information and critical load information (also provided by the utility). Additional HOPP outputs include energy stored, the state of charge of the battery, the amount of battery used, and diesel consumption.

## 2.2 Resilience Analysis

We used ResDEEDS (Culler et al. 2021) to analyze the resilience response to two hazards, comparing the existing system response to a system that included the hybrid power plant design. ResDEEDS provides a methodology for resilience planning that involves identifying key system characteristics, resilience goals, and resilience hazards and simulates how the system performs against the hazards. We identified the system characteristics and relevant hazards to consider through interviews with the rural electric cooperative and a recent planning study (Davis 2022). In interviews with the rural electric cooperative, stakeholders were asked about natural disasters, cyberattacks, wildlife, and physical threats most likely to affect their system, how such hazards would affect system components, and what the key associated risks were. The rural electric cooperative defined their primary resilience goal to be reducing dependence on imported generation. They noted that solar, wind, and battery resources could help reach this goal. They also noted that a new and improved supervisory control and data acquisition (SCADA) system could help get resources back online quicker in the event of small outages or faults, enabling fewer energy imports and more energy sales. They also identified a robust utility communication system as a resilience goal. In our analysis, we focus on the primary goal of reducing dependency on imported generation.

## 2.3 Valuation Framework

We used Pacific Northwest National Laboratory's Distributed Wind Valuation Framework to identify value streams applicable to distributed wind systems considering multiple stakeholder viewpoints (Mongird and Barrows 2021). While a wide range of value elements from this valuation framework could be relevant to the system in this case study, we focused on outage mitigation value due to findings from related work by Kazimierczuk, Mongird, and Barrows (2022). Kazimierczuk et al. ranked distributed wind value elements from the Distributed Wind Valuation Framework according to which would be most impacted by hybridization, finding resilience and outage mitigation to be one of the potentially highest impacted value streams. We considered two stakeholders in our analysis: the utility and the community/customers. We did not evaluate the impact to society at large, as our focus is the impact to the rural electric cooperative stakeholders.

Valuation of resilience investments have been quantified in many ways: as avoided utility costs, avoided customer interruption costs, avoided impacts to critical facilities, and societal benefits such as safety impacts, avoided property damage, and ecosystem benefits (Zamuda et al. 2019). Due to scope limitations, we focused on the value to customers through avoided lost load in both the tornado and winter weather scenarios and the value to the utility of avoiding lost revenues using similar methods as Reilly et al. (2022) in a remote distributed wind system in St. Mary's, Alaska.

To estimate the value of avoiding an outage for customers, we utilized interruption cost estimates and willingness to pay (WTP) estimates from Sullivan, Schellenberg, and Blundell (2015), the data used in the *Interruption Cost Estimator (ICE) Calculator* (2018). Willingness to pay is defined as the maximum price a customer would be willing to pay, in this case to avoid an interruption to electricity service of a given duration. It does not represent an actual expectation of the customer to pay costs up to this amount to achieve resilience, but rather should be interpreted as the perceived value of added resilience of a system. These Sullivan et al. data give the dollar value of avoiding an outage up to 16 hours in duration, depending on the season and start time of the outage as well as the number of residential, large commercial, and small commercial customers. Note that these data are based on surveys from customers across the country, and that the numbers used may not correspond directly to the customers from this case study which is set in a small agricultural community with a unique industrial mix. Obtaining accurate outage mitigation values is a difficult task, and surveys like these, although they have limitations, represent one of the key ways of estimating the value of lost load (Schröder and Kuckshinrichs 2015). We adjusted for inflation so that our results are in 2022 USD using the Consumer Price Index (CPI) from the U.S. Bureau of Labor Statistics with an inflation rate of 8.73% (*Consumer Price Index* 2022). As longer-duration outages can have different implications to customers than shorter-duration outages, for outages above 16 hours we supplement the data from Sullivan, Schellenberg, and Blundell (2015) with 24-hour outage WTP estimates for residential customers from Baik, Davis, and Morgan (2018). Baik, et al. estimate $1.25/kWh for high priority loads and $0.35/kWh for low priority loads, which are the 2018 USD prices. Again, for our calculations, we account for inflation using the CPI so that our high priority and low priority load prices are in 2022 USD ($1.44/kWh and $0.40/kWh, respectively).

We calculated the value of outage mitigation to customers by multiplying these inflation-adjusted WTP estimates by the difference in load served in the wind-only versus the hybrid power plant scenarios by each load type. As Baik, Davis, and Morgan (2018) only provided estimates for loads that were high priority (critical load) or low priority (residential), we estimate long-duration, non-critical commercial and industrial customer value using data from Sullivan, Schellenberg, and Blundell (2015) and extrapolating to 48 hours, allowing the number of affected customers to vary proportionately with the difference in load served, by customer type. Though extrapolation to longer duration outages may cause some loss of accuracy, relevant WTP estimates specific to longer duration outages were not available in the literature. Utility value was estimated by multiplying the difference between total load loss with and without a hybrid power plant and multiplied by current rates (dollars per kilowatt-hour per month) by customer type, provided by the rural electric cooperative.

# 3 Case Study Definition

The case study is a community-owned utility in rural Iowa, which owns and operates an electric system to service the citizens of the town and nearby rural homes. The electric system consists of two substations, west and east, connected by a transmission tie line. The west substation is served by two incoming transmission lines from generation and transmission provider Corn Belt Power Cooperative (CBPC). The east substation is served by one incoming transmission line from CBPC. There are 14 distribution feeders, five from the west substation and nine from the east substation. We used meter-level hourly data for the distribution feeders, which includes identification of customer type and geographic location, although there are some gaps in the data that were provided. There is 16.1 MW of local diesel generator capacity on the current system, tied and co-located with the west substation.

There are three existing distributed wind turbines connected to the east substation, with a net capacity of 1.8 MW. In this study, we analyze the resilience benefits provided by the existing wind and compare that to benefits provided by an optimally sized wind-hybrid system designed by HOPP, leveraging these existing diesel generators and wind turbines. It is assumed that this potential hybrid system would also be connected to the east substation.

The system is a summer- and winter-peaking system (Figure 1). Average hourly loads range between 11.2 MWh and 14.7 MWh, peaking in February (13.1 MWh) and in June (14.7 MWh) during 2021. Average hourly critical loads range between 662 kWh and 963 kWh, with peaks in February (963 kWh) and in August (958 kWh). We identified critical loads using data collected for a technical assistance group project between the Iowa Economic Development Authority (IEDA) and the National Renewable Energy Laboratory (NREL) (Iowa Economic Development Authority and National Renewable Energy Laboratory 2022), which included hospital, critical care facilities, and schools, and amended the list with key industrial customers not originally in the IEDA and NREL study, but identified by the rural electric cooperative. Using geographic data from the IEDA and NREL study as well as the rural electric cooperative, these critical loads are matched to meter numbers so that their load data can be identified.

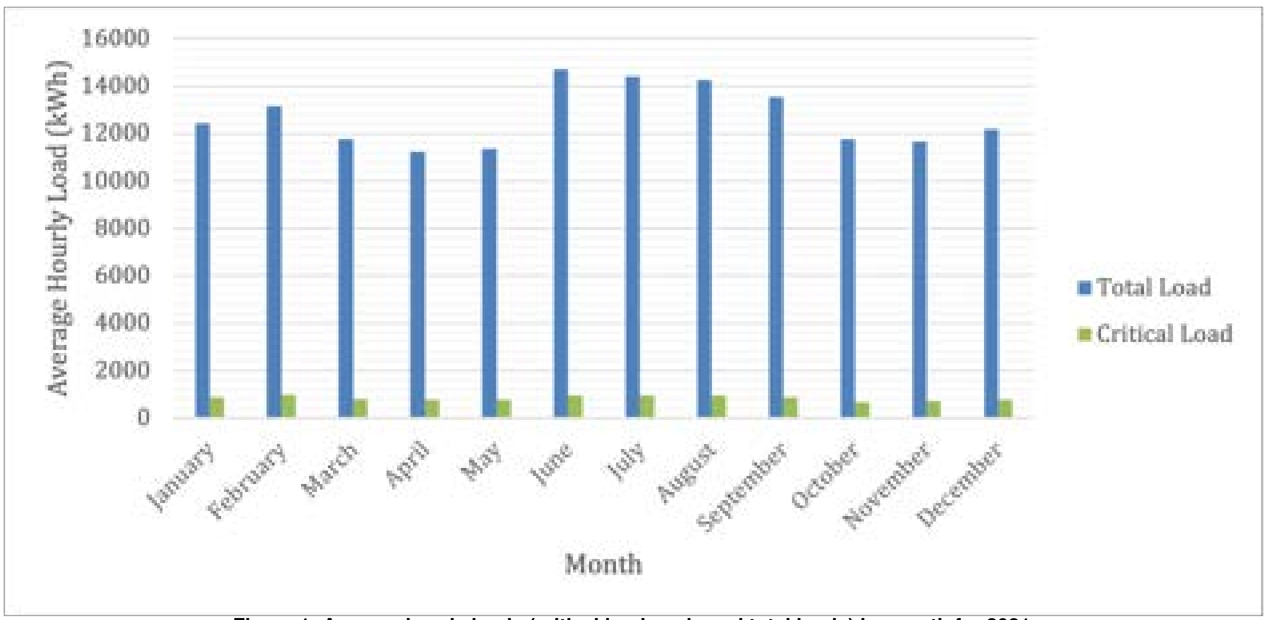



**Figure 1. Average hourly loads (critical loads only and total loads) by month for 2021.**

## 3.1 Hazards of Interest

We considered two hazard scenarios in this study to demonstrate the hybrid power plant resilience and valuation framework. The first scenario is a tornado event, occurring from 16:00 local time on May 14, 2021, to 16:00 on May 16, 2021. The second scenario is a winter weather event, lasting 6 hours on February 7 from 05:00 to 11:00 local time. This winter weather event was designed to reflect an actual regional event experienced in February 2021 (Market Monitoring Unit 2021), part of the storm system that caused widespread outages in Texas and stress across the Midwest.

### 3.1.1 Tornado Hazard Event

The rural electric cooperative expressed that lost power from storm damage and dependence on imported power were major resilience concerns for outages on their system. To simulate these resilience concerns, we assume an extreme storm passes through the system – a tornado in the worst-case scenario – that damages infrastructure on the tie line between the two substations and the transmission line feeding the east substation. The path that a tornado would take to damage these lines would also affect three overhead feeder lines. Two of those three lines are fed from the east substation, and one from the west. There is still power from CBPC feeding the west substation, but the east substation is entirely cut off from incoming transmission because of damage to the tie line and the incoming feeder. The east substation loads, a mix of commercial, residential, and industrial loads, are then fully fed by local generation, but since the diesel generation is on the west substation, the only local generation is the renewable hybrid power plant. The existing wind assets owned by the rural electric cooperative are on an east substation feeder, and we assume a future hybrid power plant would also be in this part of the system and leverage these existing assets. Additionally, the three overhead feeders in the path of the tornado drop all their load that is electrically downstream of the tornado path. For this hazard, we track the amount (in kilowatt-hours) of load lost due to the tornado path and due to a partial loss of generation on the east substation. We track this metric for both the full load and the critical loads. Without knowing the exact switching and relay structure, we assume partial outages occur on each feeder. The lost load primarily occurs to loads on the east substation since that is where the generation mismatch occurs, but both substations are affected by loss of load related to the damage to a few distribution feeders. Critical loads are prioritized for service, which we recognize would realistically require robust switching architecture and/or demand response capabilities, but no prioritization occurs between residential, industrial, or commercial load types.

### 3.1.2 Winter Weather Hazard Event

Stakeholders at the rural electric cooperative also identified icing on their diesel generators as a resilience concern. To simulate this resilience concern, we examine an extreme scenario in which there is icing on the cooling towers of the generators, which causes derating or halted operation. We also assume a regional drop in generation capacity, which limits the amount of generation imports from CBPC. We label this as limited "G&T capacity” to indicate that it is limited generation capacity from the transmission system and to avoid confusion with limitations on the local generation capacity but note that carrying capacity of the transmission system is not the primary limiting factor. Multiple variations and combinations of G&T capacity limits and diesel capacity limits are analyzed. The period of low (local and incoming) generation lasts for 6 hours, and is assumed to start on February 7, 2021, at 05:00 local time. We track how much CBPC generation and diesel generation capacity must be lost to start experiencing load loss. The combination of incoming CBPC generation, local diesel generation, and hybrid power plant renewable generation under normal operating conditions exceeds the local load, so there must be a high amount of lost generation capacity to experience any lost load. Because of this, in addition to the metric of lost load, we also track the amount of backup local generation available as another metric of resilience.

# 4 Results and Discussion

To analyze the resilience value of a hybrid power plant to the grid during the defined hazard scenarios, we first sized the hybrid power plant components to meet critical and total loads and simulated the plant operation throughout the year, tracking wind, solar, and diesel generation, as well as battery state of charge and dispatch. We used those outputs in the resilience analysis to simulate power flow under different dispatch strategies for the two hazard scenarios. The resulting load loss was then used in the valuation analysis to estimate outage mitigation value by customer type and avoided lost revenues to the utility.

## 4.1 Hybrid Power Plant Design

To design the hybrid power plant, we sized the plant component capacities (for wind, solar, and battery assets) for two objectives: to meet critical loads and to meet total loads during the two hazard events. We sized the components by considering technical and financial limitations and by using a sensitivity study that varied component capacities and calculated percentage of time over the year (2021) that critical loads and total loads were met. The results of this sensitivity study are included in Appendix A. Because one resilience concern of the rural electric cooperative is diesel dependency, we did not include diesel generation in the hybrid power plant sizing but did include existing assets in the hazard scenarios as backup generation, if needed. In the hybrid power plant design, we assume generation and storage equipment performs as it would nominally (which in the winter hazard scenario, would require, for instance, wind turbines to have de-icing mechanisms), and is able to distribute power to loads. We do not optimize hybrid power plant location on the grid nor layout of the hybrid power plant, instead assuming that the renewable assets are connected to the east substation. This part of the analysis only considers sizing hybrid power plant capacity to meet loads over the duration of a year. The impact to specific feeders due to line damage in the tornado hazard event is analyzed in Section 4.2. The hybrid power plant component sizing to meet critical loads was 5 MW of wind capacity, 5 MW of solar capacity, and 5 MW of battery. We produced results for 2 battery duration options to compare the impact of battery duration on lost load: 1-hour battery duration (resulting in 5 MWh capacity) and 2-hour battery duration (resulting in 10 MWh capacity). To meet total loads, the resulting component sizing was 25 MW of wind capacity, 25 MW of solar capacity, and 25 MW/MWh of battery capacity.[1] We simulated the hybrid power plant over the year and used a simple battery dispatch model which does not reserve capacity for resilience events, but instead provides electricity when needed. As a result, the battery can enter the hazard event with less than 100% state of charge. We refer to this control as 'max dispatch' in Section 4.2. Diesel generators are only used when generation and battery storage are depleted.

### 4.1.1 Tornado Hazard Event

In the tornado hazard event, the hybrid power plant with 5 MW of wind, 5 MW of solar, and 5 MW/MWh of battery capacity meets critical loads with the assistance of diesel generation, but the hybrid power plant with increased battery duration (10 MWh) is able to meet all critical loads without diesel generation (Figure 2 and Figure 4, respectively). In the former system, the hybrid power plant can meet most critical loads over the year, with 899,961 kWh of lost critical load in a hybrid power plant without battery, and 235,876 kWh of lost critical load in a case with a battery over the year. Increasing the battery duration from one to two hours reduces the critical load loss to 51,033 kWh over the year. In both hybrid power plant designs, the battery is used twice during the hazard event, both times at night when there is no solar generation. During the first 24 hours of the hazard event, wind and solar generation are relatively complementary and abundant, resulting in the battery remaining near fully charged and a significant amount of wind and solar generation curtailment. During the second 24 hours of the hazard event, wind and solar generation is low, so the battery state of charge is reduced to 0% by hour 35 in the hybrid power plant with 5 MWh of battery capacity and to 30% by hour 38 in the hybrid power plant with 10 MWh of battery capacity. Diesel generation on the east substation is used to supplement the renewable hybrid power plant with 5 MWh of battery at hour 35, when the battery is depleted, resulting in 265.2 gallons of diesel consumed to provide 1.852 MWh of power (Figure 3). Increasing solar generation from hours 38–48 of the hazard event recharges the battery, while wind generation remains low.

[1] We include an additional study to calculate diesel fuel consumption avoidance and energy import avoidance for the addition of solar and battery assets to existing assets based on likely investments in Appendix B.

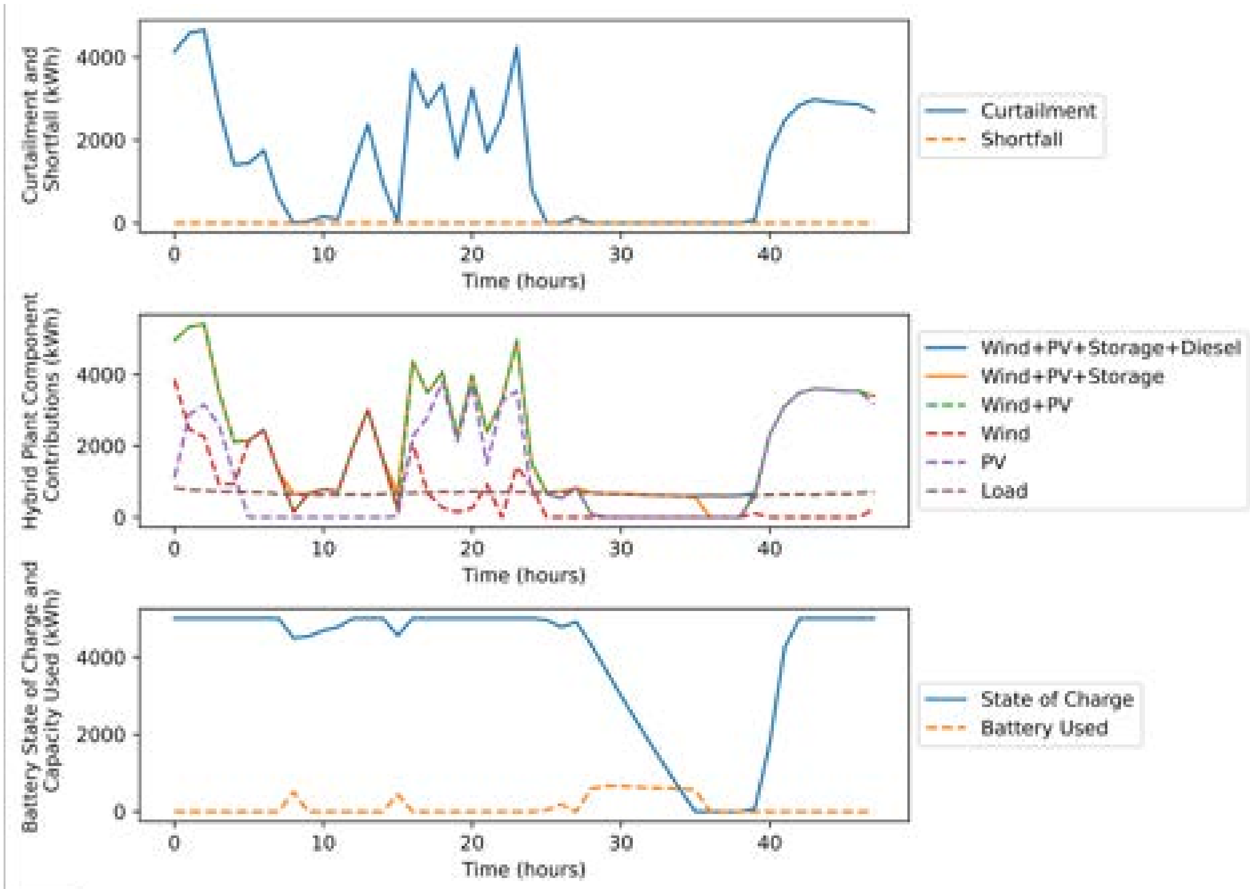



**Figure 2. Hybrid power plant outputs (in kWh) for the tornado scenario, when designed to meet critical loads for the system with 5 MW wind capacity, 5 MW solar capacity, and 5 MW/5MWh of battery capacity.**

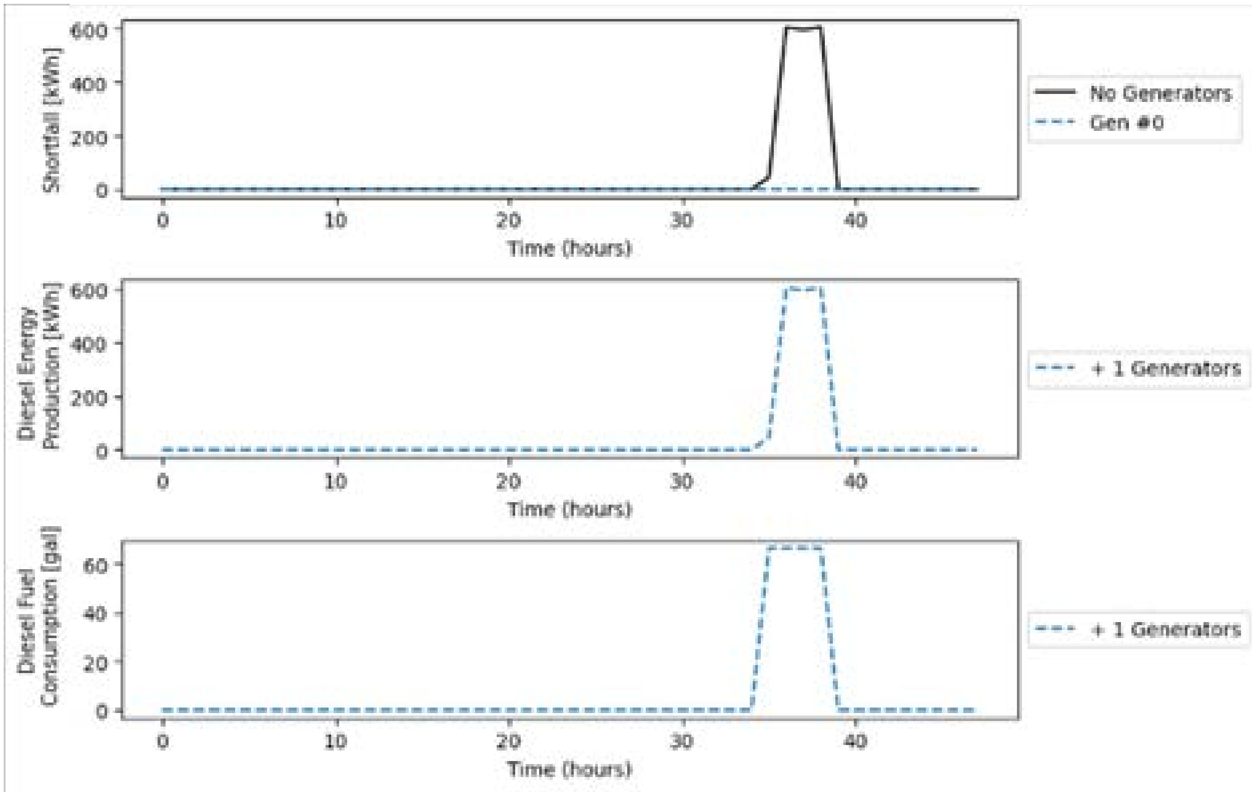



**Figure 3. Cumulative outputs of diesel generator modeling (a single, 2.825 MW Caterpillar generator) for the 5 MW wind, 5 MW solar, and 5 MW/MWh battery hybrid power plant during the tornado hazard event.**

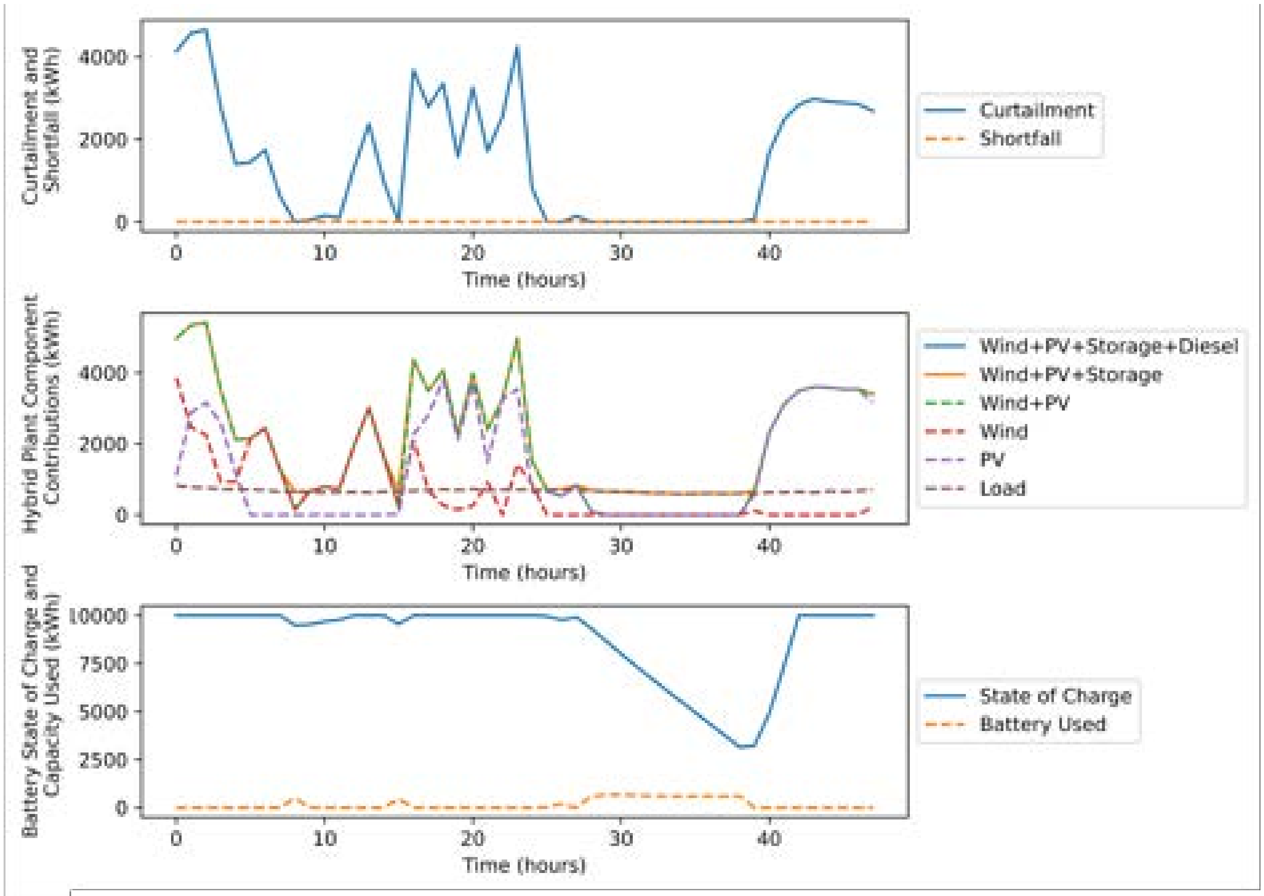



**Figure 4. Hybrid power plant outputs (in kWh) for the tornado scenario, when designed to meet critical loads for the hybrid power plant with 5 MW wind capacity, 5 MW solar (PV) capacity, 5 MW/10 MWh of battery capacity.**

The hybrid power plant designed to meet the total loads of the system during normal operation (25 MW of wind capacity, 25 MW of solar capacity, and 25 MW/MWh of battery capacity) sufficiently meets most load demand during the 48-hour hazard event, and with the addition of diesel generation, completely meets load, as depicted in Figure 5. Some loads would be lost in hours 36–38 without diesel generation. This load loss could be compensated by increasing the hybrid power plant capacity, but due to the cost of sizing up the capacity to reach 0 kWh of lost loads annually (which would require approximately 35 MW of wind, 35 MW of solar, and 35MW/140 MWh of battery capacity), we did not increase the size of the hybrid power plant. Given the chosen sizing, the battery is minimally used in the first 24 hours of the hazard event, since wind, while variable, is mostly sufficient to meet the load. The battery is significantly used in the second 24 hours, with the battery fully depleted from hours 35 to 40, during which diesel generation meets load, and after which solar resource increases and the battery is recharged by solar generation. Five diesel generators were required to meet loads during hours 35-40, providing just over 120 MWh and consuming 8365 gallons of diesel (Figure 6).

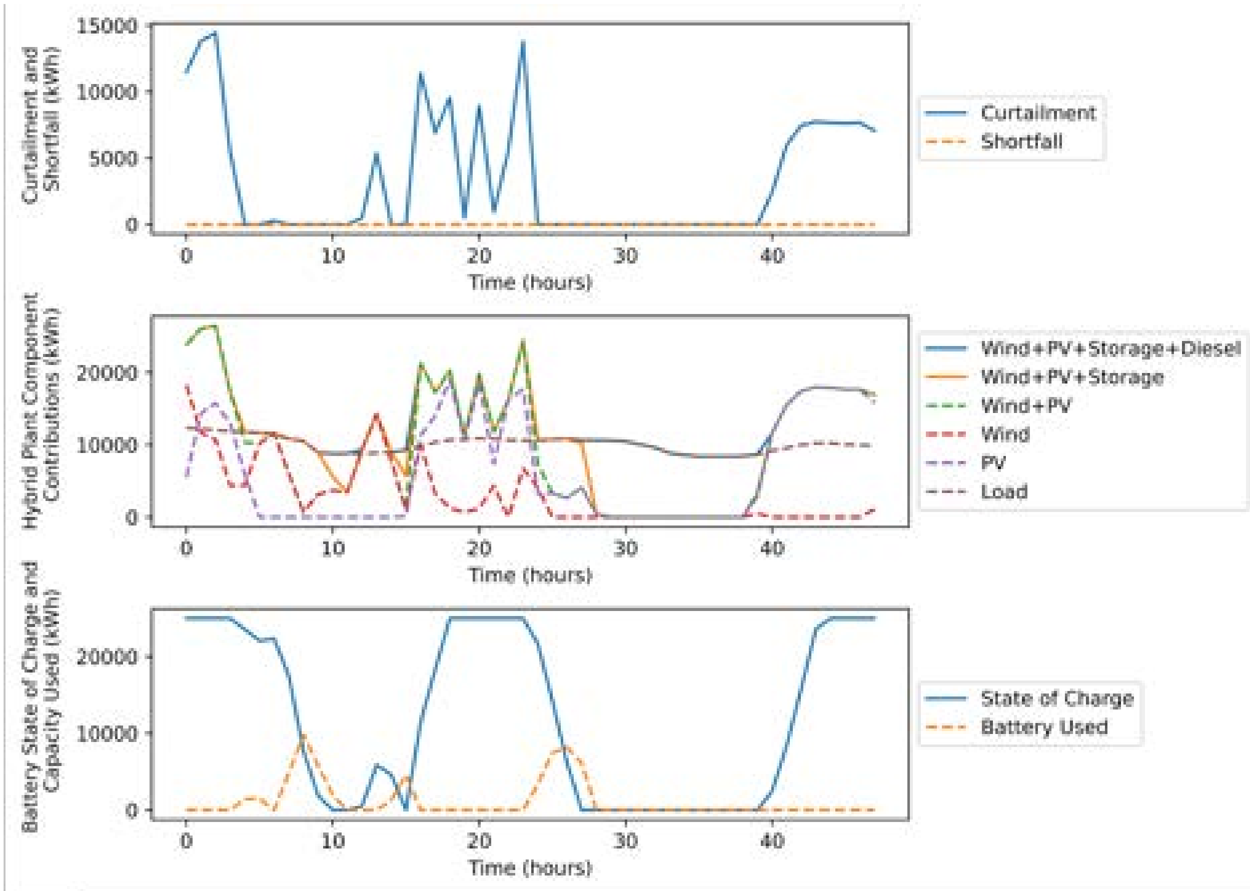



**Figure 5. Hybrid power plant outputs (in kWh) for the tornado scenario, when designed to meet total loads for the hybrid power plant with 25 MW wind, 25 MW solar, and 25 MW/MWh battery capacity.**

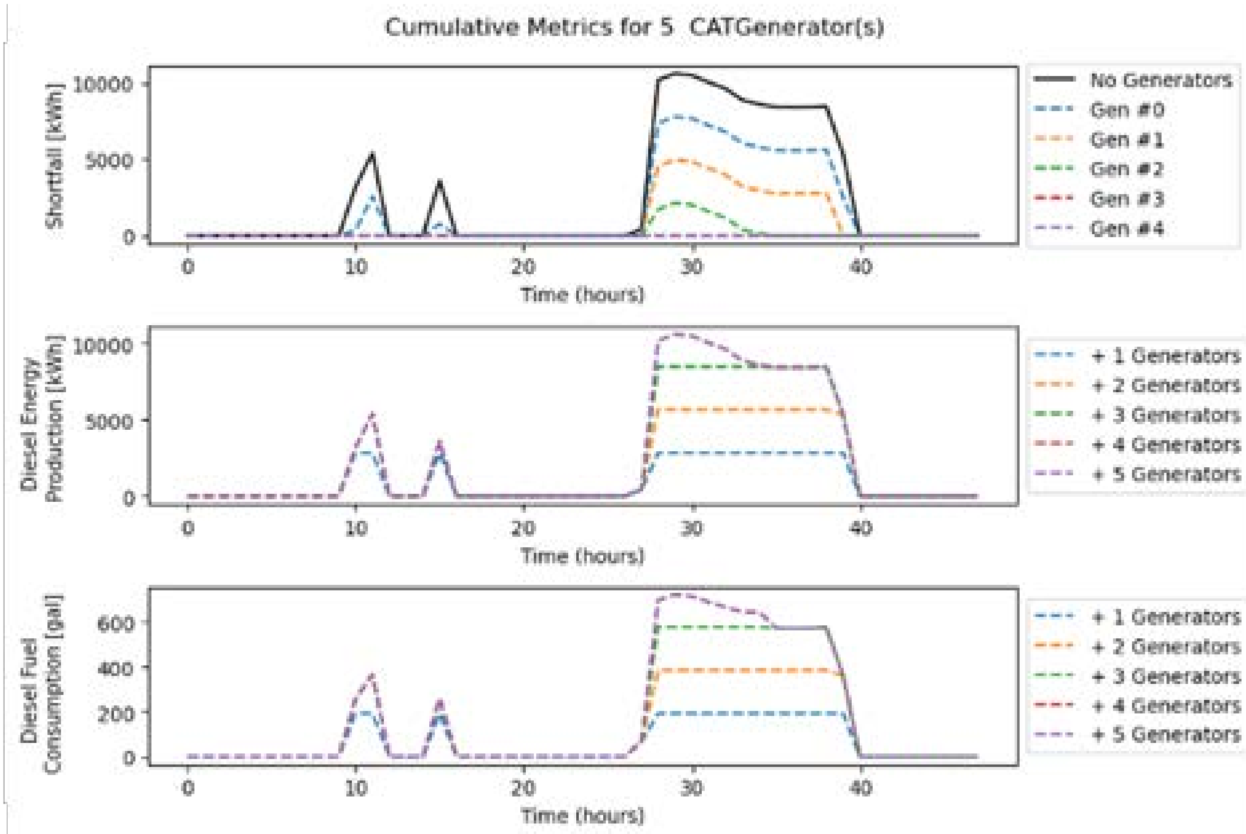



**Figure 6. Cumulative outputs of diesel generator modeling (five, 2.825 MW Caterpillar generators) for the 25 MW wind, 25 MW solar, and 25 MW/MWh battery hybrid power plant during the tornado hazard event.**

### *4.1.2 Winter Weather Hazard Event*

In the winter weather hazard event, the hybrid power plant with 5 MW of wind, 5 MW of solar, and 5 MW/MWh of battery capacity meets critical loads with the assistance of diesel generation, but the hybrid power plant with increased battery duration (10 MWh) is able to meet all critical loads without diesel generation (Figure 7 and Figure 9). Entering the hazard event, the battery state of charge is nearly depleted (less than 20% state of charge) when the hazard event begins. There is no solar energy generation the first three hours of the hazard event and minor solar energy generation the last three hours of the hazard event. Because of the small amount of solar energy generation, wind energy generation and battery storage meet most loads during the first half of the hazard event, with diesel generation making up the difference between the wind and solar energy and the load. In this scenario, one diesel generator is required to meet loads, providing 590 kWh and consuming 200 gallons of diesel (Figure 8).

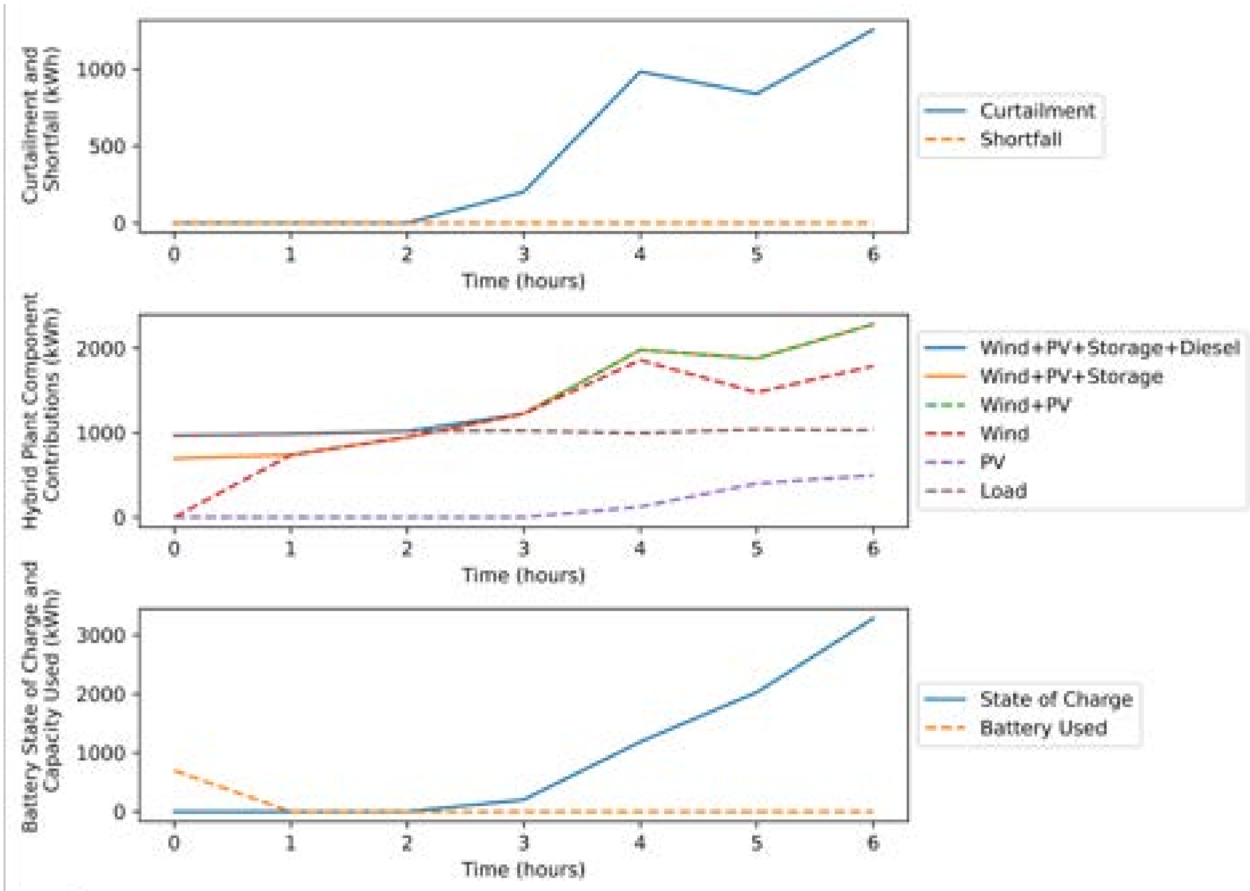



**Figure 7. Hybrid power plant outputs (in kWh) for the winter storm scenario for the hybrid power plant with 5 MW of wind, 5 MW of solar, and 5 MW/MWh of battery capacity.**

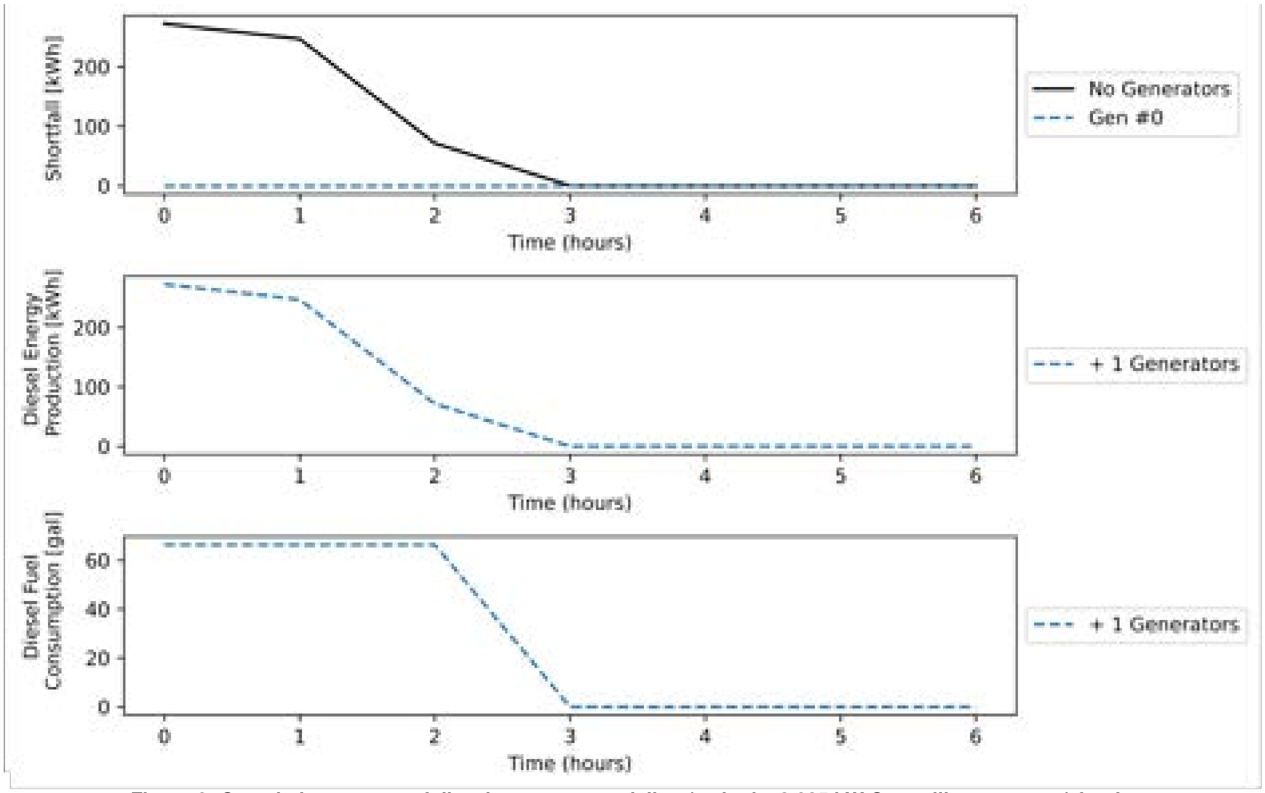



**Figure 8. Cumulative outputs of diesel generator modeling (a single, 2.825 kW Caterpillar generator) for the 5 MW wind, 5 MW solar, and 5 MW/MWh battery hybrid power plant during the winter weather hazard event.**

In the hybrid power plant with increased battery duration (10 MWh), the battery enters the hazard event with increased state of charge (50%) and stored capacity (5 MW). Because of this, the wind energy generation and battery storage can meet critical loads without diesel generation in the first three hours of the hazard event, which is then supplemented with solar energy generation in the last three hours of the hazard event.

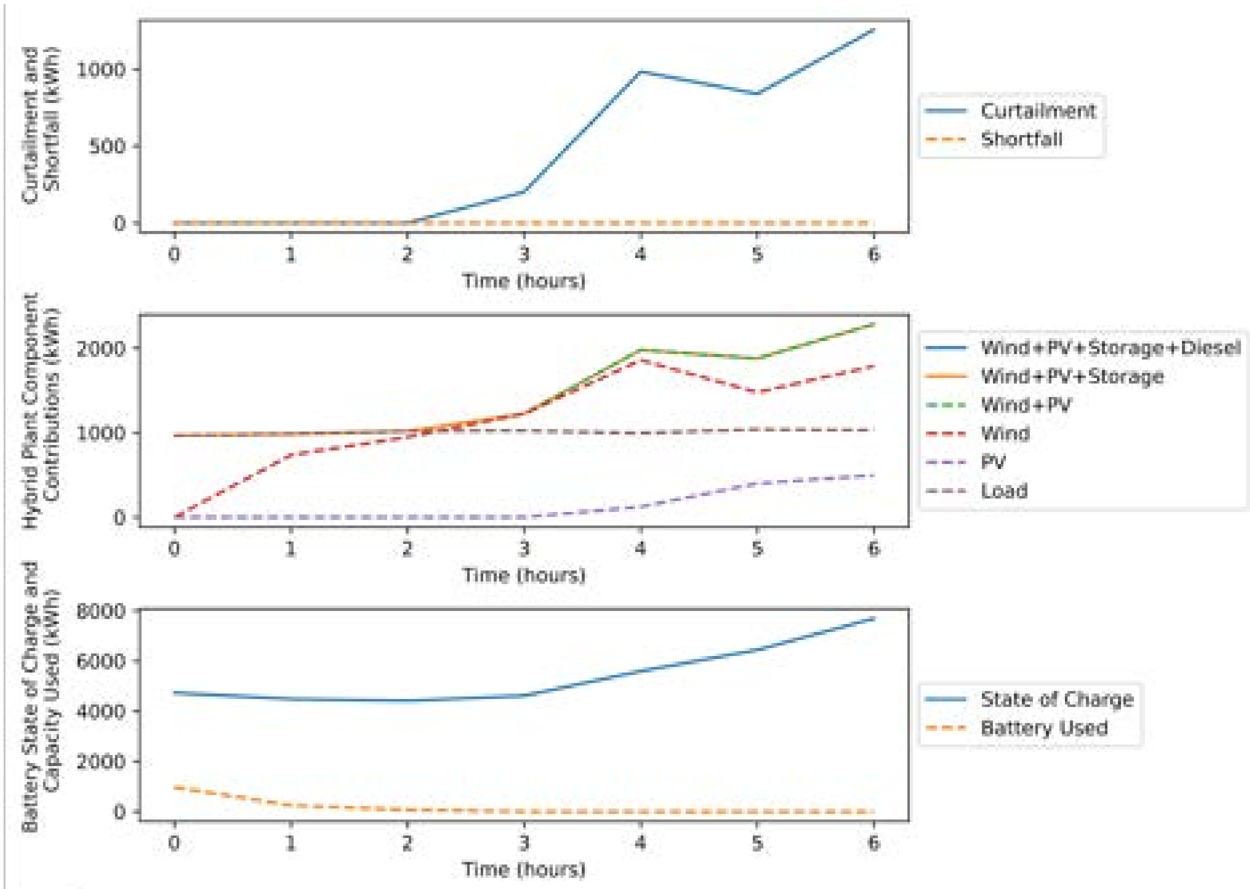



**Figure 9. Hybrid power plant outputs (in kWh) for the winter storm scenario for the hybrid power plant with 5 MW of wind, 5 MW of solar, and 5 MW/10MWh of battery capacity.**

The hybrid power plant designed to meet total loads of the system (25 MW wind, 25 MW solar, and 25 MW/MWh battery capacity) only partially meets load demand during the 6-hour hazard scenario, as depicted in Figure 10. The battery is fully depleted entering the hazard and unable to contribute to meeting loads, resulting in no battery use during the hazard event. Additionally, there is no solar generation for the first 3 hours of the hazard event and only marginal generation in the last 3 hours. Thus, wind generation is the only renewable energy source during the first three hours of the hazard, meeting 10% of loads in the first hour of the hazard event and, on average, 85% of loads for the remainder of the event, with solar generation contributing during the last three hours. Thus, meeting the total loads of the system relies on significant diesel generation. As Figure 11 demonstrates, diesel generation supplies 43.452 MWh, consuming 3058 gallons of diesel, and requiring five generators to meet the load.

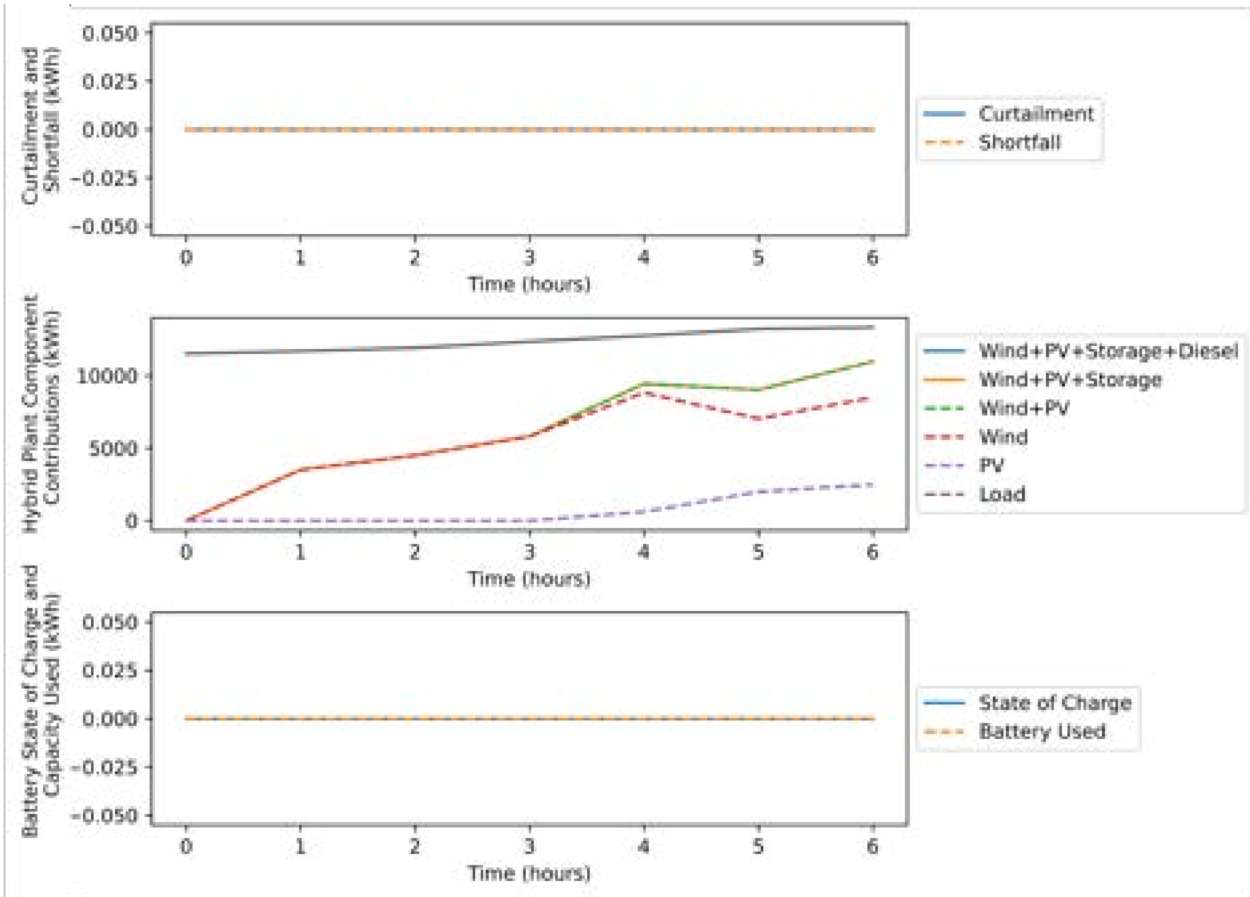



**Figure 10. Hybrid power plant outputs (in kWh) for the winter storm scenario to meet total load for a hybrid power plant with 25 MW of wind, 25 MW of solar, and 25 MW/MWh of battery capacity.**

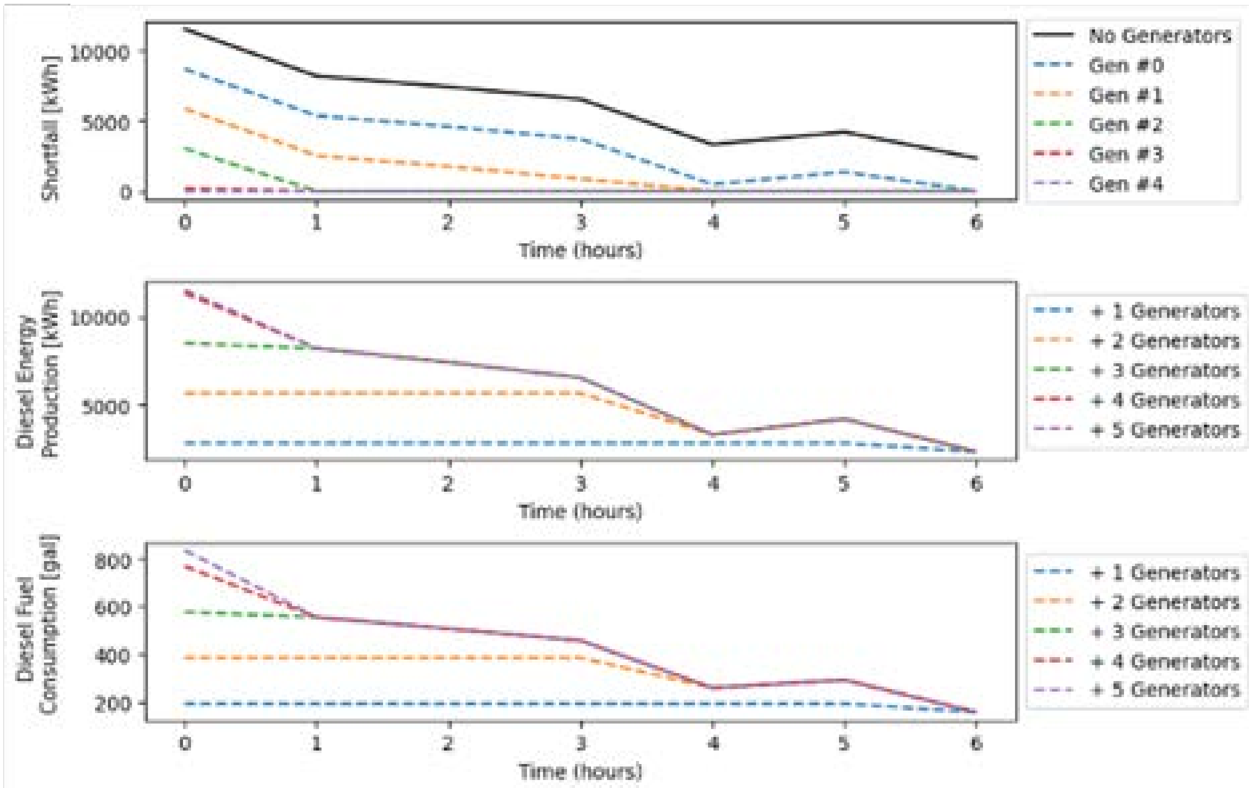



**Figure 11. Cumulative outputs of diesel generator modeling (five generators totaling 16.1 MW of capacity) for the 25 MW wind, 25 MW solar, and 25 MW/MWh battery hybrid power plant during the winter weather hazard event.**

## 4.2 Resilience Analysis

In the resilience analysis, we simulated the two hazard scenarios using the existing system components (the load and wind generation) and select hybrid power plant designs from Section 4.1. For the renewable hybrid power plant (not including diesel generation) we used hourly outputs of generation and battery storage directly and substituted varying battery dispatch control strategies, which allowed us to compare resilient and maximum load dispatch strategies. The resilient dispatch strategy controls battery output to at least meet the critical load (like the HOPP dispatch model), whereas the maximum load dispatch strategy controls battery output to serve as much load as possible. Note, there are slight differences between the HOPP and hazard simulation critical load dispatch models, resulting in some cases where the hazard simulation dispatch methods allow critical load loss. In addition, this resilience analysis considers lost load in the event of complete and partial diesel capacity outages, because it gives geographic context to Section 4.1 results (HOPP does not consider placement of assets on the grid, just capacity sizing). Therefore, lost load results will differ from those in Section 4.1, in which no diesel generator capacity loss was assumed for the purpose of diesel capacity sizing.

### *4.2.1 Tornado Hazard Event*

When comparing the existing capacity against the hybrid power plant designs (Figure 12), results indicate that existing local generation (1.8 MW of wind generation capacity) is not sufficient—and not designed—to support the load on the east substation. The existing local wind generation provides limited benefits compared to having no local generation on the east substation. Adding a hybrid power plant that is sized to meet critical loads (5 MW solar, 5 MW wind, 5 or 10 MWh of storage capacity) nearly halves total load loss. Note that since the diesel generation is on the west substation, which has been disconnected from the east, diesel is not used to supplement lost load. The same hybrid power plant dispatched to meet nominal loads sees only slightly higher lost load, largely because the battery is depleted in this scenario prior to hazard start. A hybrid power plant sized to meet nominal loads (25 MW solar, 25 MW wind, 25 MWh battery) cuts lost load by 75% compared to the base case. This scenario assumes there is a grid-forming source, which could be achieved through upgrading the inverters to have grid-forming capabilities.

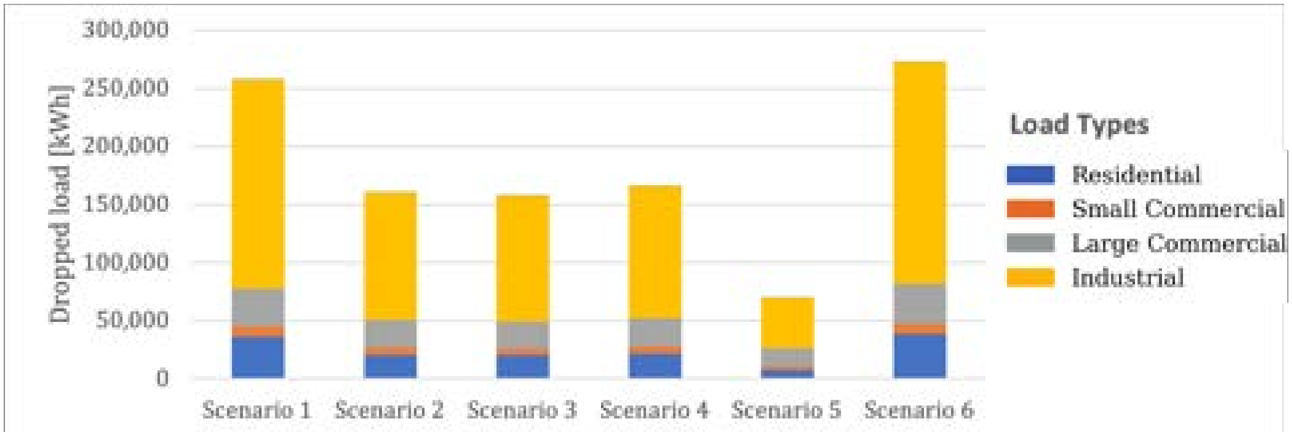



**Figure 12. Total load loss for various hybrid power plant scenarios for the resilience analysis of the tornado scenario hazard. Scenario 1: Base Case, 1.8 MW wind. Scenario 2: 5 MW wind, 5 MW solar, 5 MWh battery, resilient dispatch. Scenario 3: 5 MW wind, 5 MW solar, 10 MWh battery, resilient dispatch. Scenario 4: 5 MW wind, 5 MW solar, 5 MWh battery, max dispatch. Scenario 5: 25 MW wind, 25 MW solar 25 MWh battery, max dispatch. Scenario 6: No renewables.**

When comparing the dispatch strategies for the hybrid power plant, results indicate that dispatch strategy makes a notable impact on the resilience performance during the hazard (Figure 12), although not as large of an impact as increasing generation or storage capacity. When the maximum dispatch strategy is used, the battery is already drained when the hazard event starts and cannot provide additional capacity during the hazard event. Using the resilient dispatch strategy, the hybrid power plant has not been dispatched prior to the hazard event and is kept in reserve during nominal conditions, so there is full battery capacity at the beginning of the transmission outage, which helps supplement the wind and solar generation to serve more load on the east substation. Additional battery capacity (increasing from 5 MWh to 10 MWh) with resilient design provides limited benefits, since the smaller battery capacity is sufficient to meet critical load needs. With the resilient dispatch, the excess capacity is not used to serve total loads. Increases in renewable generation capacity and storage capacity have the biggest impact on performance. The distribution of impacted customer load types is approximately proportional to the system composition of load types but is influenced by the designation of critical loads and their locations relative to the grid components affected by the tornado. Industrial loads make up the largest component of load loss. Large commercial and residential loads were also impacted. City-owned loads were least impacted because they are primarily located on the west substation and were not in the path of the tornado.

Critical load loss follows similar trends in how hybrid power plant design and dispatch strategy affect total load loss (Figure 13), however, the impacted customers differ, which is largely related to where the critical loads are located relative to the grid components impacted by the hazard. The critical industrial loads are located on Feeders 4 and 5, which are not impacted by this hazard. This leaves primarily large commercial critical load and a minimal amount of small commercial critical load that are impacted by the hazard.

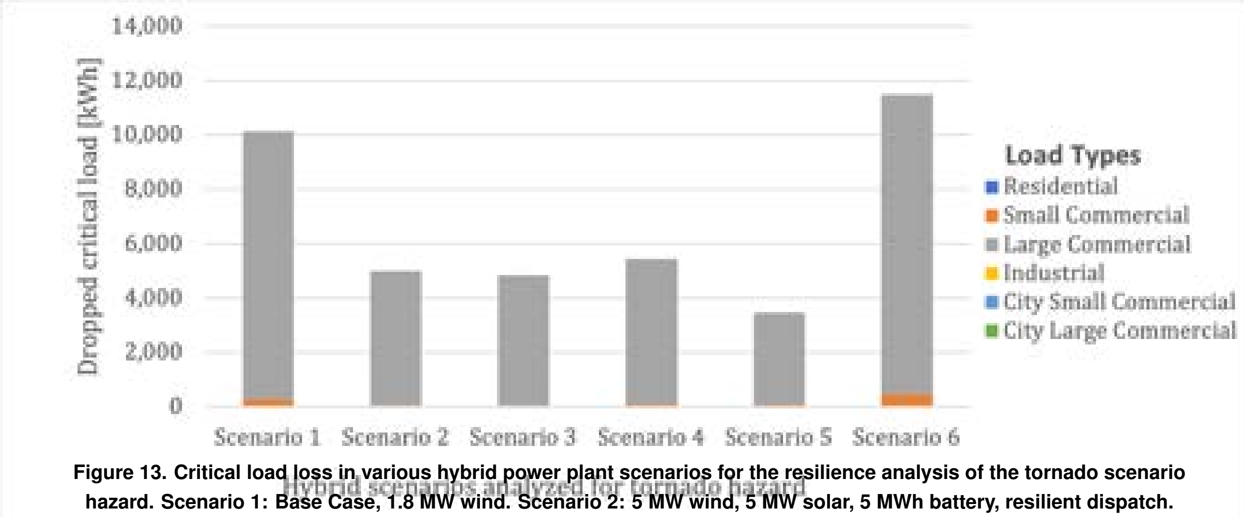



**Figure 13. Critical load loss in various hybrid power plant scenarios for the resilience analysis of the tornado scenario hazard. Scenario 1: Base Case, 1.8 MW wind. Scenario 2: 5 MW wind, 5 MW solar, 5 MWh battery, resilient dispatch. Scenario 3: 5 MW wind, 5 MW solar, 10 MWh battery, resilient dispatch. Scenario 4: 5 MW wind, 5 MW solar, 5 MWh battery, max dispatch. Scenario 5: 25 MW wind, 25 MW solar 25 MWh battery, max dispatch. Scenario 6: No renewables.**

#### *4.2.2 Winter Weather Hazard Event*

The winter storm hazard event derated the capacity of the local diesel generators and reduced the amount of possible incoming transmission. The maximum load during the hazard event was less than 13 MW. The diesel generators alone have a capacity of 16.1 MW, so even derated, in combination with limited incoming power from the transmission system and a hybrid power plant, there is enough capacity to serve all loads unless significant generation capacity is lost. Our results bound the extreme cases, which are combinations of reduced diesel capacity and reduced G&T capacity, that cause lost load. Because the system capacity is sufficient and results in excess generation in many cases, we also report the amount of local backup generation—a combination of excess diesel and hybrid power plant capacity—during the hazard. Additionally, we compare this case to a case that uses no diesel generation. Although the value of carbon offset is not presented in this report, there are methods for calculating this value stream (Mongird and Barrows 2021). This case serves to highlight how the local hybrid power plant could replace the diesel generators, or at the least, offset their usage.

As can be expected, the base case with the existing 1.8 MW of wind generation capacity is the least resilient. More load is lost in comparable scenarios for that configuration than any other hybrid power plant configuration (Figure 14). Less than 15% of the total load is lost when hybrid power plant capacity is included, even in the most extreme scenarios.

Increasing battery duration from 2 to 4 hours, resulting in increased battery capacity of 5 MWh to 10 MWh, results in no difference in load loss (which is why Figure 14b and Figure 14c look identical). As in the tornado scenario, the smaller battery capacity is sufficient to meet critical loads, so the addition of battery capacity does not change the hybrid power plant output using resilient dispatch. In fact, the batteries are only used in the first hour in the resilient dispatch cases. After that, the output from wind and solar is sufficient to cover the critical loads. Like the tornado scenario, the battery is at a low state of charge in the max load dispatch case at the start of the winter storm, and the system relies only on the solar and wind. This means the cases that use the maximum dispatch strategy closely match the cases that use the resilient dispatch strategies. For the reasons described above, the battery is not used in either, so the hybrid power plant output is the same for same-capacity wind/solar hybrid power plant.


(a) 1.8 MW wind

(b) 5 MW wind, 5 MW solar, 5 MWh battery, resilient dispatch

(c) 5 MW wind, 5 MW solar, 10 MWh battery, resilient dispatch

(d) 5 MW wind, 5 MW solar, 5 MWh battery, max dispatch

**Figure 14. Load lost during the winter storm scenario, by hybrid power plant design and dispatch case, for varying transmission and diesel capacities.**

Figure 15 shows that there needs to be a significant loss of G&T and diesel generation capacity to experience any load loss. Residential and industrial loads make up the biggest portion of lost load, which corresponds to the typical load profile. Unlike the tornado hazard, there is some city load lost since this hazard affects the whole system and not just a portion of it. Less than 60 kW of critical load is lost in any of the scenarios.

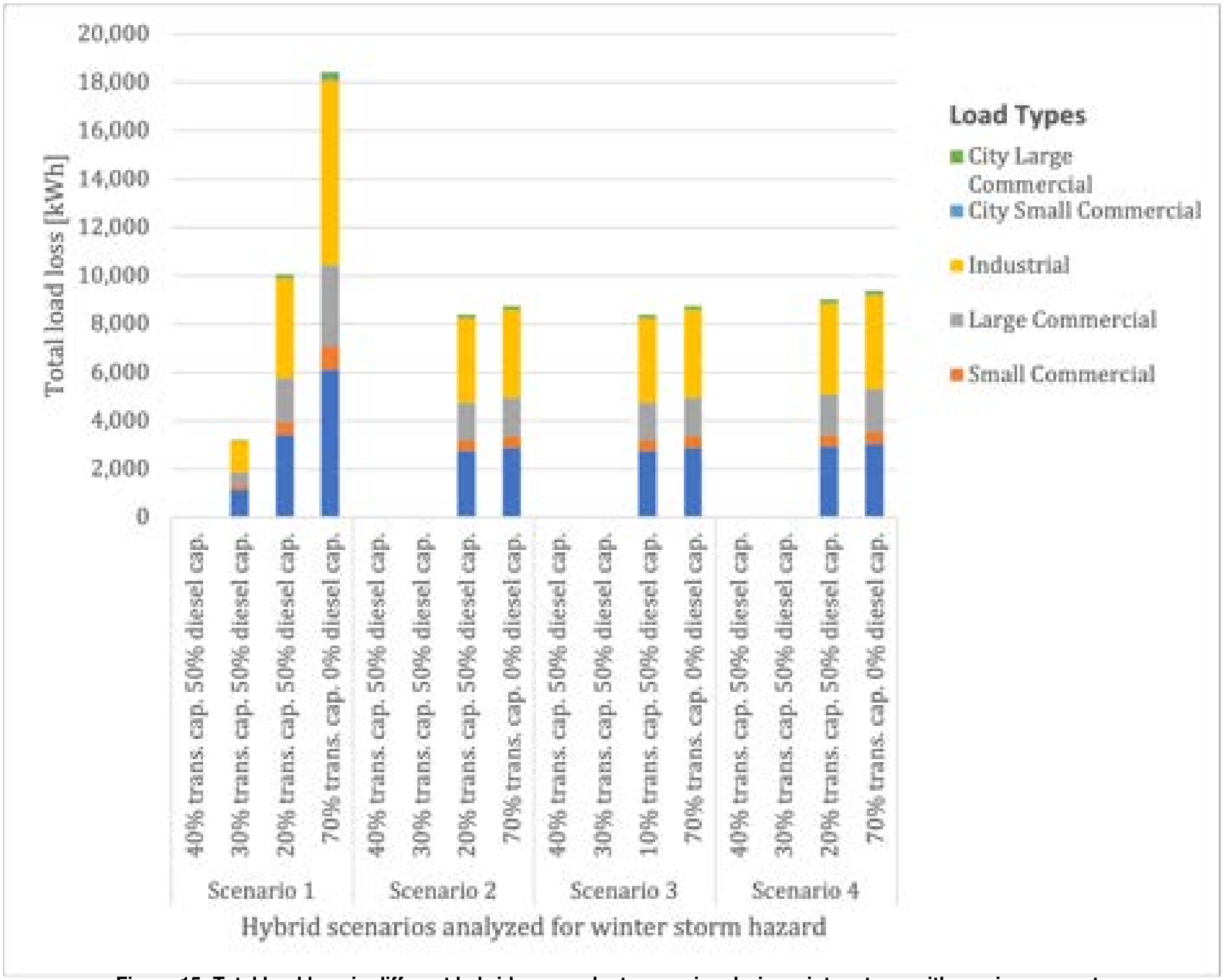
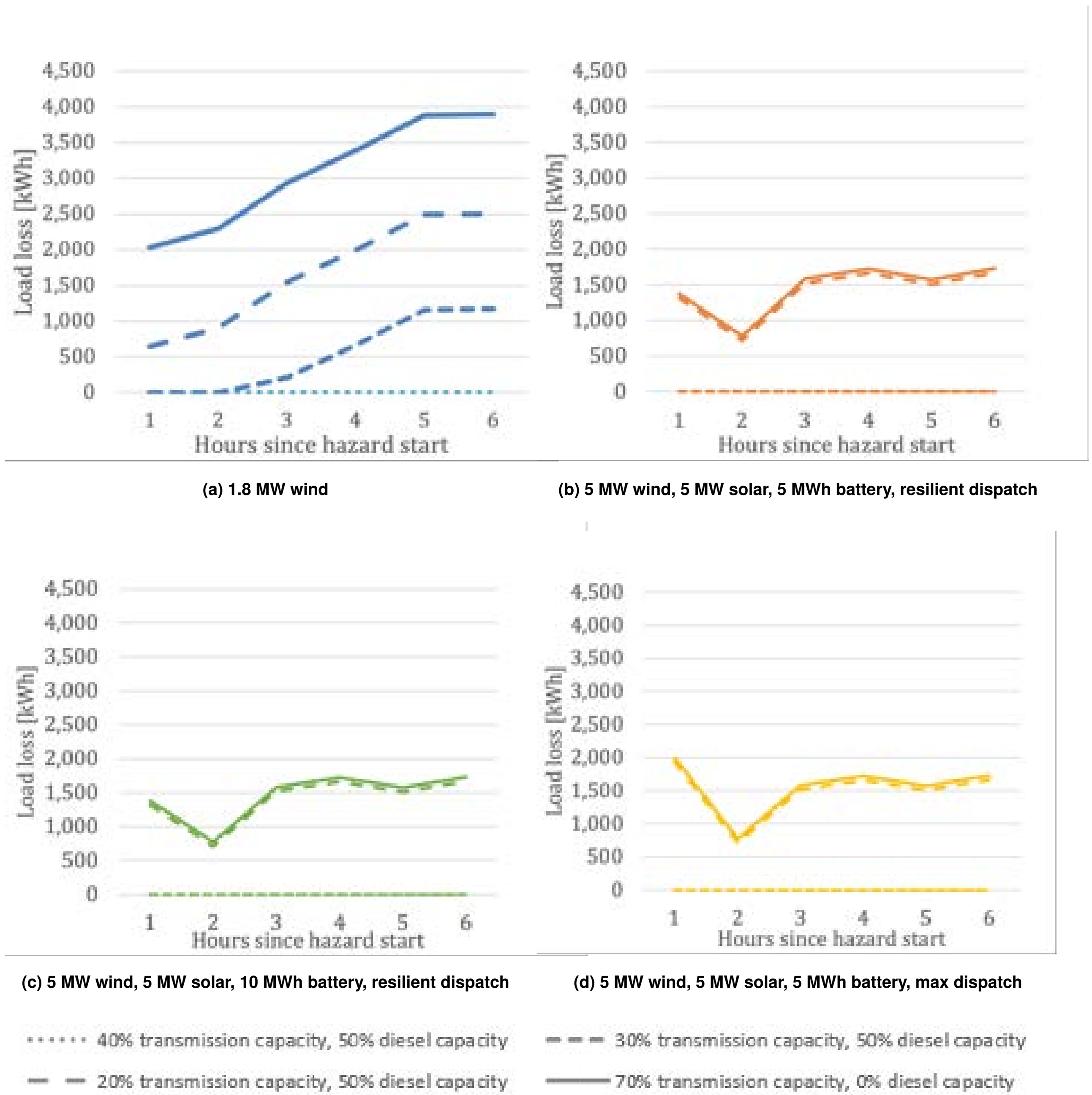



**Figure 15. Total load loss in different hybrid power plant scenarios during winter storm with varying amounts of G&T capacity (trans. cap.) and diesel capacity (diesel cap.) available. Scenario 1: Base Case, 1.8 MW wind. Scenario 2: 5MW wind, 5MW solar, 5MWh battery, resilient dispatch. Scenario 3: 5 MW wind, 5 MW solar, 10 MWh battery, resilient dispatch. Scenario 4: 5 MW wind, 5 MW solar, 5 MWh battery, max dispatch. Scenario 5: 25 MW wind, 25 MW solar 25 MWh battery, max dispatch. Scenario 6: No renewables.**

In addition to load lost, we track the available local backup generation capacity at each time step in the hazard, which is calculated as the sum of excess generation available from the diesel generators and hybrid power plant (Figure 16). Like the tornado scenario, hybrid power plant design and dispatch strategy significantly affect this metric. With a resilient dispatch strategy, the battery is partially charged at the start of the winter storm scenario. High wind and solar generation allows the battery to fully charge within the first hour of the hazard event since the hybrid system is only being dispatched to meet critical loads. Following the first hour, wind and solar generation is sufficient to meet critical loads, so no battery power is dispatched. This means that some non-critical loads are lost, even though there is a reserve of local generation available. This prepares the system to maintain power to critical loads in, for instance, a longer-duration hazard event or a decrease in wind or solar generation. Using the maximum dispatch scenario, the battery is fully drained at the start of the winter storm, so it is not able to provide reserve capacity or charge during the hazard event.




**(a) 1.8 MW wind**

**(b) 5 MW wind, 5 MW solar, 5 MWh battery, resilient dispatch**

**(c) 5 MW wind, 5 MW solar, 10 MWh battery, resilient dispatch**

**(d) 5 MW wind, 5 MW solar, 5 MWh battery, max dispatch**

**Figure 16. Available local backup generation capacity during the winter storm.**

## 4.3 Economic Analysis

For the valuation analysis, we capture the impact of hybridizing the existing wind assets with additional wind, solar, and battery assets from two perspectives, utility load (customers) and the utility. For customers, the value of hybridizing the wind system is estimated as the stated value of avoiding lost load by customer type. We find the added value of hybridization for the utility as the avoided lost revenue to the utility. In this analysis, we consider the lost load from the renewable hybrid power plant components, as depicted in Section 4.2, rather than the total system designed in Section 4.1, to encompass the impacts of the hazard on specific distribution system infrastructure, which is location-specific (such as feeder lines affected) and asset-specific (such as diesel generating due to icing).

### 4.3.1 Tornado Hazard Event

In the tornado scenario, we assume power is cut from three overhead feeders due to the path chosen for simulation of the tornado. For the 48-hour tornado simulation, we evaluated four hybrid options presented in Section 4.2. The baseline case consists of the existing wind turbine capacity of 1.8 MW and does not include the diesel generators as they are located on the west substation, which is cut off from the east substation, so they cannot cover lost load. We also considered two resilient dispatch hybrid power plant cases (hybrid power plants are deployed to meet critical loads): 1) a hybrid power plant with 5 MW wind, 5 MW solar, and 10 MWh battery capacity and 2) a hybrid power plant with 5 MW wind, 5 MW solar, and 5 MWh battery capacity. The fourth case is one in which a hybrid power plant is designed to meet total system loads (max load dispatch), with 25 MW wind, 25 MW solar, and 25 MWh battery capacity. From our analysis, we found that hybridization adds about $50-100 million in avoided lost load (Figure 17) and $4-8 thousand in utility value (Figure 18) if the hazard event occurs. The largest value, by far, is seen for the 25 MW wind, 25 MW solar, and 25 MWh battery capacity system. However, even though the largest system considered has five times the capacity of the smallest system considered, its resilience value is only about twice as high as the smallest system. Given the likelihood of the scenario occurring, such a large investment may or may not be justified. Dispatch strategy also impacts resilience value, with equivalent capacity systems showing more value in a resilient dispatch mode that prioritizes critical load, rather than in a maximum dispatch mode that simply tries to meet all load.

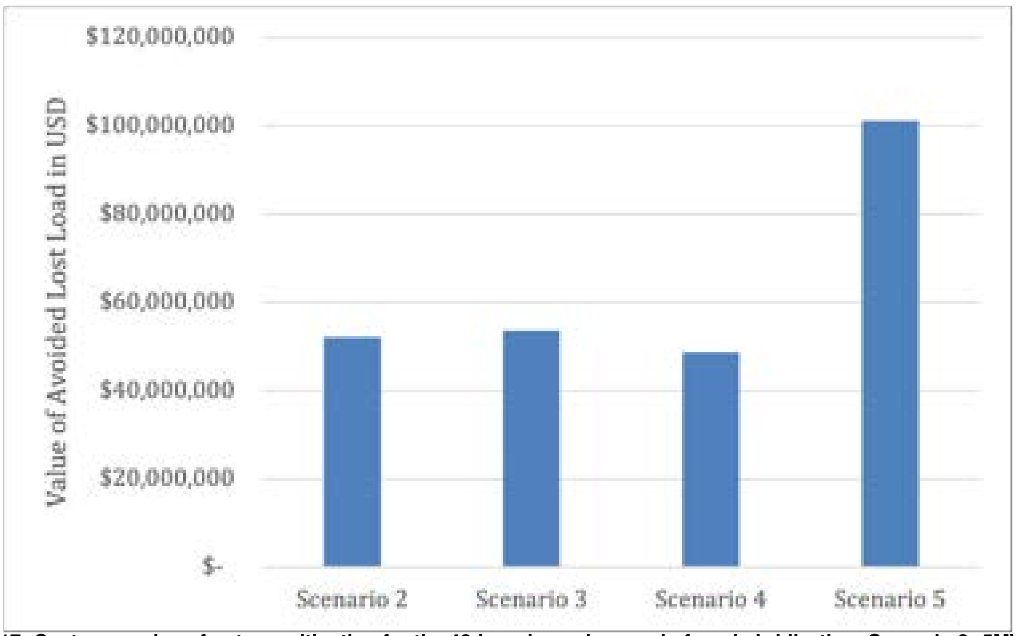



**Figure 17. Customer value of outage mitigation for the 48-hour hazard scenario from hybridization. Scenario 2: 5MW wind, 5MW solar, 5MWh battery, resilient dispatch; Scenario 3: 5MW wind, 5MW solar, 10 MWh battery, resilient dispatch; Scenario 4: 5MW wind, 5MW solar, 5MWh battery, max dispatch; Scenario 5: 25MW wind, 25MW solar, 25MWh battery, max dispatch.**

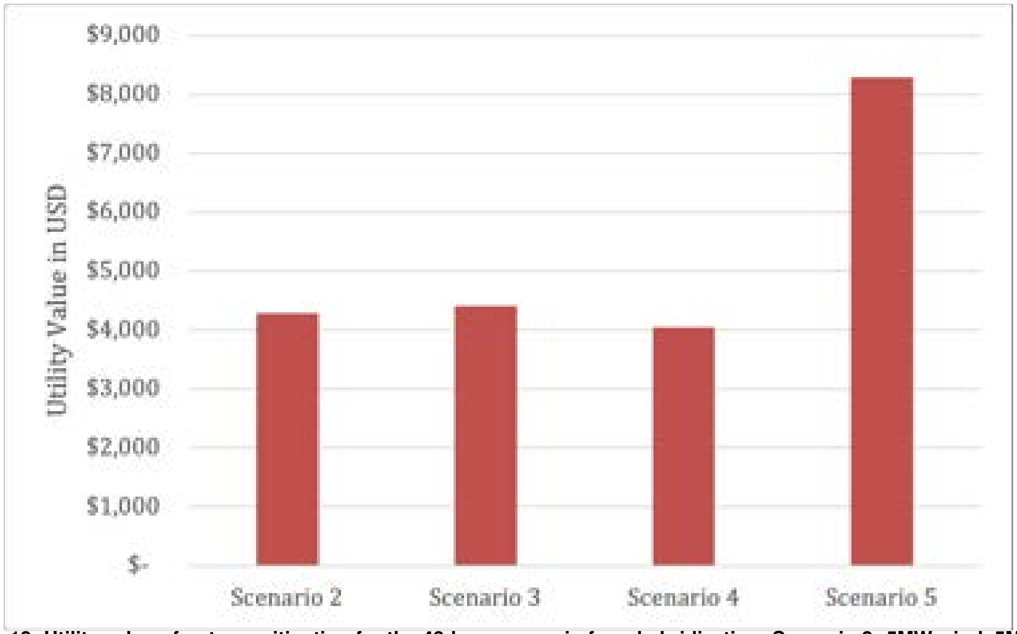



**Figure 18. Utility value of outage mitigation for the 48-hour scenario from hybridization. Scenario 2: 5MW wind, 5MW solar, 5MWh battery, resilient dispatch; Scenario 3: 5MW wind, 5MW solar, 10 MWh battery, resilient dispatch; Scenario 4: 5MW wind, 5MW solar, 5MWh battery, max dispatch; Scenario 5: 25MW wind, 25MW solar, 25MWh battery, max dispatch.**

#### *4.3.2 Winter Weather Hazard Event*

For the winter storm scenario, we compare two potential scenarios – (1) CBPC generation capacity at 30%, diesel capacity at 50% and (2) CBPC generation capacity at 70%, diesel capacity at 0%. For each of these potential scenarios, we look at load lost in the base case (1.8 MW of wind) and for all hybrid power plant cases. We find the added utility and customer value by taking the difference between the hybrid power plant and respective base case scenario. We calculated avoided lost load value of $570,000 for the 30%/50% scenario and a range of $2.18-2.28 million for the 70%/0% scenario (Figure 19). For utility value, we calculated about $220 for the 30%/50% scenario and $620-650 for the 70%/0% scenario (Figure 20). There is minimal variation in value added across the different hybrid power plants, within each hybridization scenario, for both the 30%/50% and 70%/0% scenarios, as the amount of load loss is similar between each hybrid system. This shows that, for the winter hazard scenario, the difference in transmission and diesel availability are driving the potential bulk of added value from hybridization. We therefore see greater resilience value in the 70%/0% scenario because more load is lost during the hazard.

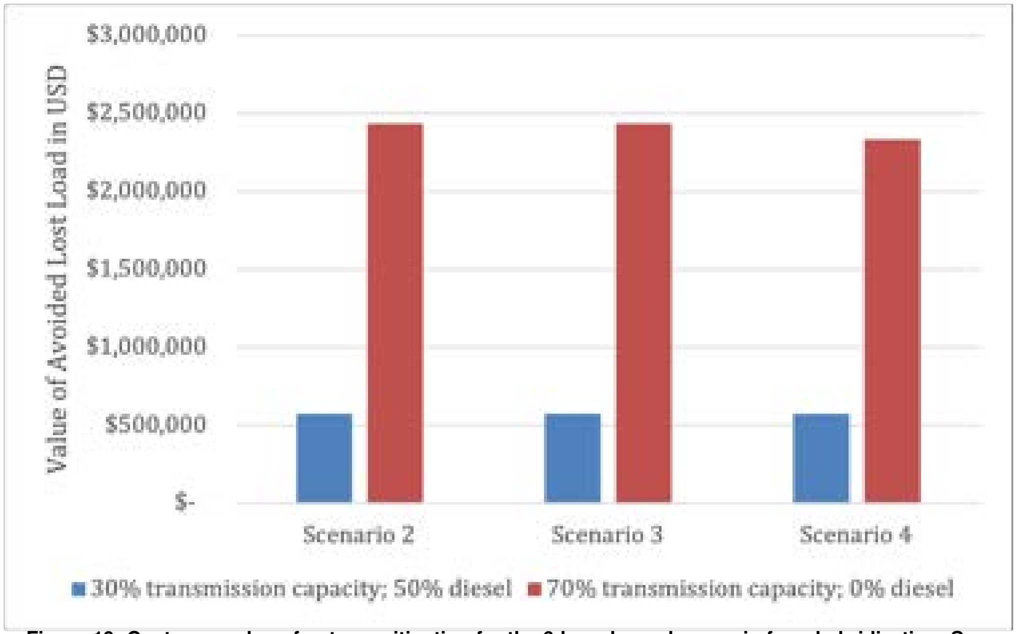



**Figure 19. Customer value of outage mitigation for the 6-hour hazard scenario from hybridization. Scenario 2: 5 MW wind, 5 MW solar, 5 MW/MWh battery, resilient dispatch; Scenario 3: 5 MW wind, 5 MW solar, 5 MW/10 MWh battery, resilient dispatch; Scenario 4: 5 MW wind, 5 MW solar, 5 MW/MWh battery, max dispatch.**

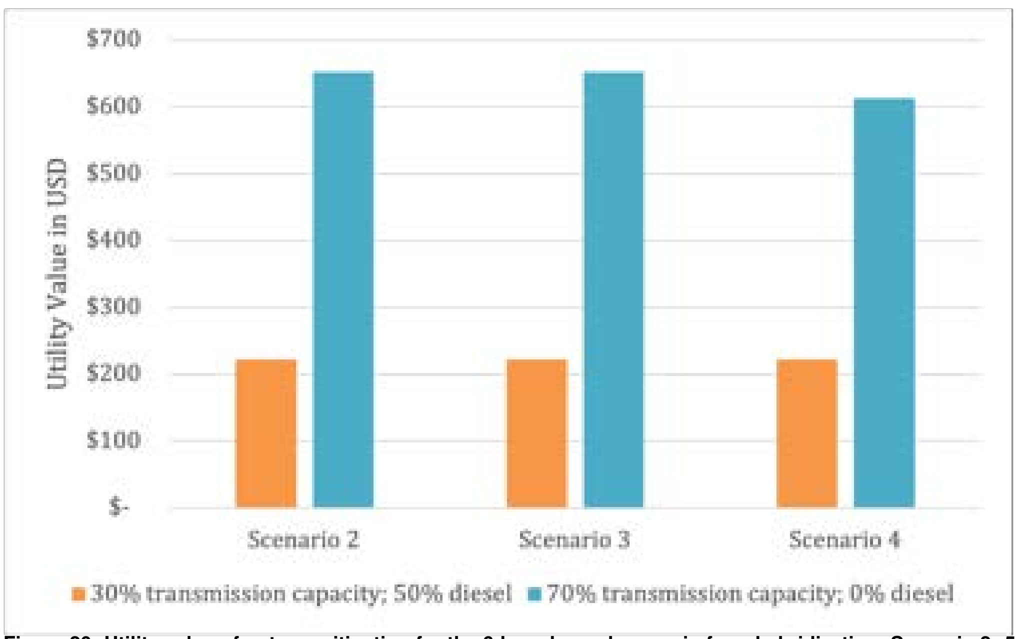



**Figure 20. Utility value of outage mitigation for the 6-hour hazard scenario from hybridization. Scenario 2: 5 MW wind, 5 MW solar, 5 MW/MWh battery, resilient dispatch; Scenario 3: 5 MW wind, 5 MW solar, 5 MW/10 MWh battery, resilient dispatch; Scenario 4: 5 MW wind, 5 MW solar, 5 MW/MWh battery, max dispatch.**

Hybridization provides outage mitigation value for both the tornado and winter hazard scenarios. Since there are more recorded tornadoes within a 50-mile radius of the town than ice storms (84 tornadoes vs. 39 winter storms between 1950 and 2010), the value of the tornado scenario is more likely to be realized than the value of the icing scenario (*Storm Events Database* 2022). Multiplying the calculated values of hybridization by the probability of a tornado occurring would give us the expected value which could be used in investment decision making. We would anticipate the resilience value estimates would increase if we were to account for avoided damages and regional economic impact from the hazards. There is some uncertainty around our estimates, as we assumed structures were still standing for our tornado scenario, though how many structures and corresponding loads might or might not be affected in a real scenario is difficult to predict. However, these estimates give insights into the relative benefit of various hybrid system design choices. Large commercial customers are the main drivers in both the tornado and winter hazard scenarios for customer value, and these results highlight that a hybrid power plant could contribute significantly to the town's economic resiliency in the case of a hazard. Additional savings to the utility may be possible through reduced fuel costs from these renewable hybrid power plants during hazards, though those savings were not analyzed here due to scope.

# 5 Conclusions and Future Work

In this study, we demonstrated the resilience value of a hybrid power plant in a distributed grid through a case study in rural Iowa under two hazard events. We integrated three disparate frameworks to create a methodology that designs and operates a hybrid power plant for resilience, and then values the impact of that plant on customer costs. While pioneering these capabilities, this framework is limited in its methodology. Hybrid power plant component capacities were not optimized in this study, so while the sensitivity analysis provided in Appendix A supports a good approximation to hybrid power plant component sizing, optimization should be considered in future work. Additionally, only one value element was considered in this study, resulting in the partial valuation of hybrid power plants. Despite this limitation, our results indicate significant outage mitigation value for customers, especially commercial and industrial customers; thus, expanding our analysis to include all unique value elements of hybridization is expected to increase system value. Expanding and automating this framework so that distributed grid stakeholders can easily access and use this framework and interpret its results would enable them to quantify the resilience value that distributed-wind-based hybrid power plants can provide to their systems.

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# Appendix A. Hybrid Power Plant Design Sensitivity Study

To minimize loss of loads in the distributed grid and investigate the effect of wind, solar, and storage capacity on loss of load, we completed a sensitivity study. In Figure A.1, we show how the percentage of time total loads are met (out of total hours in a year) changes with solar and battery capacity with solar capacity held constant at 25 MW. Figure A.2 depicts how this percentage changes with wind and battery capacity, holding wind capacity constant at 25 MW. We incrementally increased solar (0, 5, 10, 15, 20, and 25 MW) and wind (1, 5, 10, 15, 20, 25 MW) capacity. Limitations of HOPP required at least 1 MW of wind, hence the difference in starting capacity. The reason these capacity values were chosen (holding a constant 25 MW of one asset type and varying the other two asset types up to, for instance, 25 MW or 50 MWh) is based on the rural electric cooperative's load data and financial limitations. Minimizing loss of load during resilience events outlined by stakeholders was the goal of hybrid power plant sizing, rather than designing a hybrid power plant to minimize loss of load as if it independently supported the grid. To note, the data that produced these graphs, along with the interactive plot file (Tableau) can be found in the supplemental material. The results in Figure A.1 and A.2 indicate that the relative impact of incremental generation (solar or wind) capacity increases on load loss are greater than incremental increases in battery. For instance, a 25 MW wind system will meet 50% of loads just over 51.75% of the time with no solar capacity (Figure A.1). As battery capacity increases to 50 MWh, the percent of time the system can meet 50% of loads increases nearly linearly to 56.81%. Compare this impact of increased battery capacity ( 5% increase) to the impact of increasing solar capacity; an increase of just 5 MW increases the percentage of time loads are met to 55.57% (Figure A.1). These results indicate that too little generation, rather than lack of resource adequacy, is likely driving load loss. More generation is needed to meet system loads. The added value of increasing solar and battery capacity is not linear, and changes depending on how much load the system is designed to meet. For instance, the greatest increases in time loads are met (for 50% of loads) occur when solar capacity is incrementally increased from 5 to 10 MW and from 10 to 15 MW (both over 6.5%) (Figure A.1). Further increases in solar capacity result in smaller percentages ( 2.5% for the increase from 15 to 20 MW and 1% for the increase from 20 to 25 MW). This pattern, however, changes as you move from designing a system to meet 50% of the load to designing a system to meet 100% of the load. Whereas meeting 50% of the load results in a near-linear relationship between storage capacity and percent time load is met, meeting 100% of the load results in a non-linear relationship, in which the greatest increases in time load is met are from 0 to 5 MWh (6.32%), with decreasing return on investment as the battery capacity continues to increase (increasing battery capacity from 45 to 50 MW increases the percent time 100% of loads are met by 0.23%) (Figure A.1). Conversely, the percent of time 100% of loads are met increases as solar capacity increases, with the increase from 0 to 5 MW of solar capacity providing an increase of time load is met by 2% and the increase from 20 to 25 MW of solar capacity providing an increase of time load is met by 5% (minimum). From a design perspective, these results suggest that to design a hybrid power plant that meets a given percentage of loads reliably with as little generation capacity as possible, investing in battery capacity will provide a good return on investment up to a certain point, after which diminishing returns might indicate a need to either increase battery duration or increase generation component capacity. Battery capacity and duration will enable a system to provide power during peak loads are during periods of low generation, so defining events and hazards a system must endure based on long-term resource and load analysis (including hazard events), will help to define a battery capacity appropriate for the system. Results in Figure A.1 and A.2 also suggest that baseline wind capacity (25 MW, as in Figure A.1) enables the rural electric cooperative to better meet loads than baseline solar capacity (25 MW, as in Figure A.2). For instance, in Figure A.1, 28.62% of the time, 100% of loads can be met with 25 MW wind alone, compared to 14.25% of the time, 10% of the loads can be met with 25 MW of solar capacity alone (note that this is also conservative, since the 25 MW baseline solar capacity case also included 1 MW of wind capacity). These results could be due to relatively high abundance and consistency of wind resource in the case study area, and indicate a distributed-wind-based hybrid power plant (one that is predominantly wind and compensates for low wind resource events with solar and battery) best suits the rural electric cooperative's system.

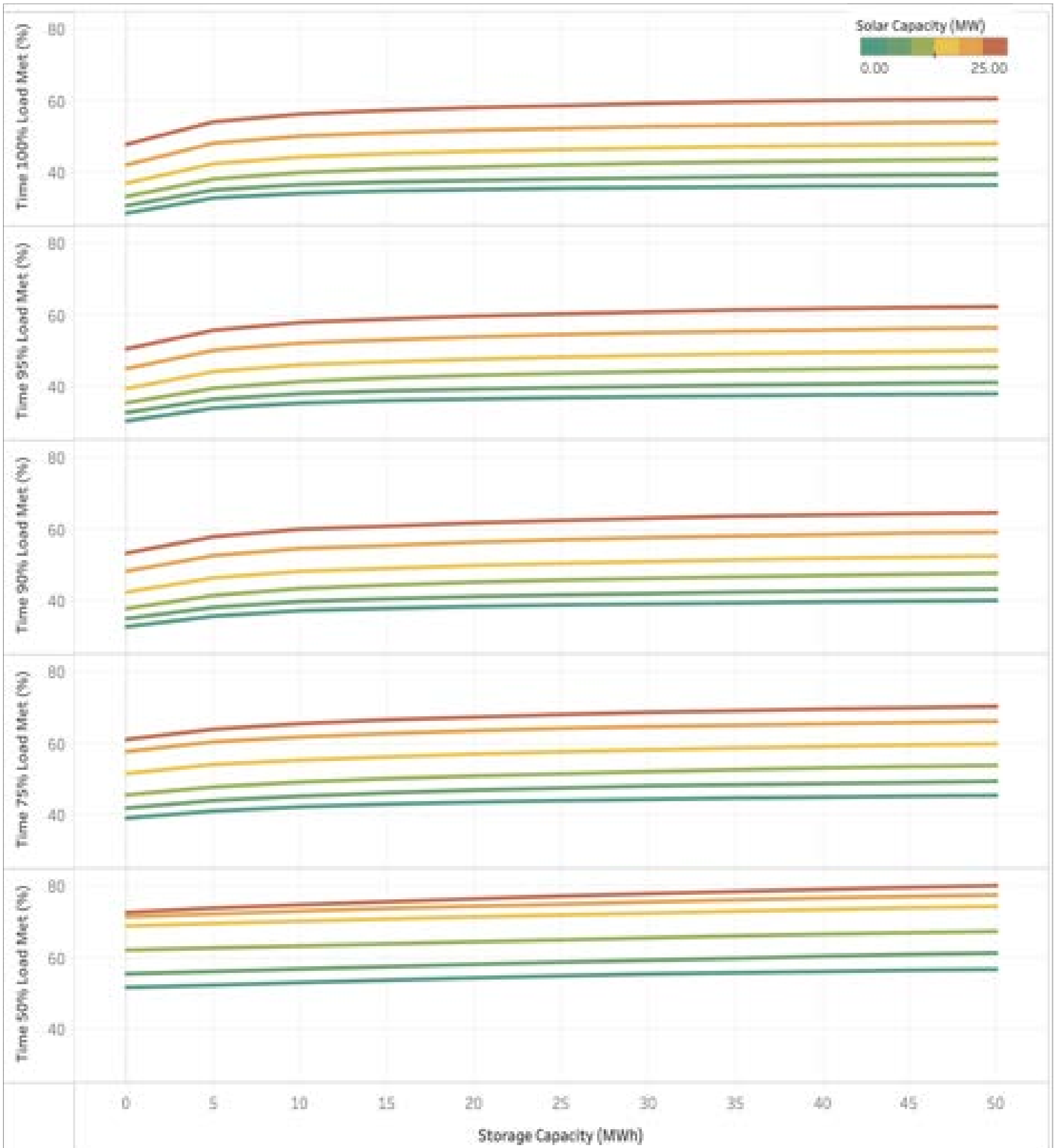


**Figure A-1: Loss of load (the percent of time a given percent of load is not met) for varying wind and battery capacity, with wind capacity equal to 25 MW.**

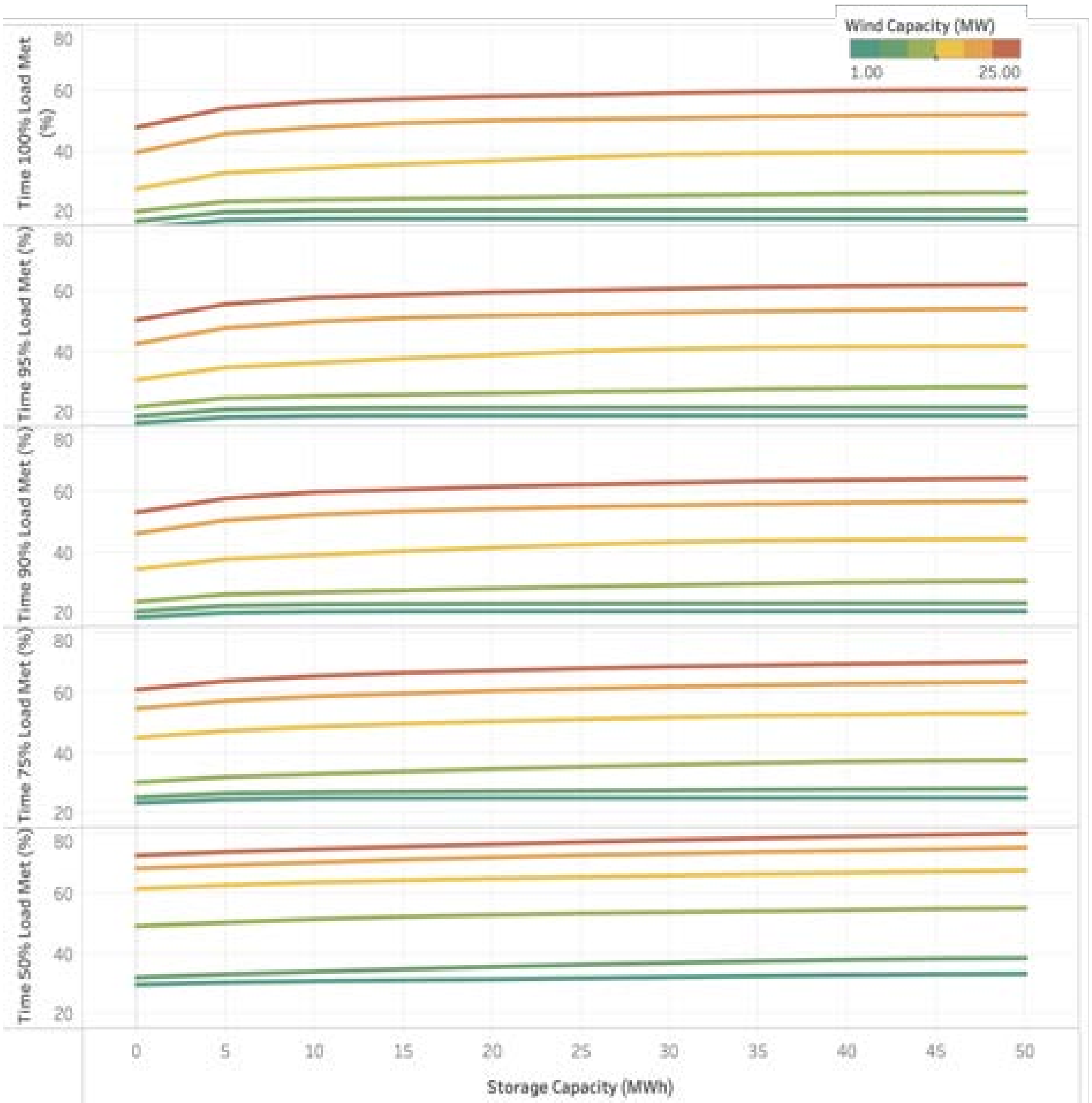


**Figure A-2: Loss of load (the percent of time a given percent of load is not met) for varying wind and battery capacity, with solar capacity equal to 25 MW.**

Figure A-2. Loss of load (the percent of time a given percent of load is not met) for varying wind and battery capacity, with solar capacity equal to 25 MW.

# Appendix B. Hazard likelihood impacts on resilience value

The resilience values calculated reflect the value to customers and the utility if the hazard occurs exactly as simulated. One of the most challenging parts of resilience risk analysis is to project accurate probabilities for events to occur. On top of that, the likelihood that an event would occur exactly as simulated (in the exact location with the exact effects) is so small it is negligible, but the fact that similar events can and do occur means they are still worth considering.

To address this challenge, we discuss a few scenarios that consider the likelihood of an event occurring. This also allows us to illustrate how to develop the expected resilience value from a system for a given hazard. The expected value is the value the system provides, discounted by the likelihood of the hazard occurring. The formula is simple – merely multiply the value of resilience in each scenario by the probability of that scenario occurring. The expected value of resilience can then be used in cost-benefit analysis or to find other decision metrics. We note that traditional decision metrics for utility investment decisions may not capture all relevant impacts to different stakeholders, such as health risks to residents, loss of community economic productivity, etc. so additional decision criteria or non-monetary metrics may be established, such as a jurisdiction-specific tests as outlined in the National Standard Practice Manual for Distributed Energy Resources by the National Energy Screening Project.[2] These jurisdiction-specific tests can allow projects to be considered if they meet pressing policy needs or provide other important impacts to the community, if that is something the utility would like to evaluate. As we calculate the expected value of resilience for each scenario in this analysis, we must first define the lifetime of the system, so that the probability can be found for that timeframe. In this analysis, although the solar, wind, and battery components will have separate expected lifetimes and maintenance cycles, we consider that the overall lifetime for the hybrid system is 25 years.

Resilience values of the different hybrid scenarios in the tornado hazard event are given in Table B.1 and B.2. If a tornado occurs in or near the town approximately once every 50 years, then the exceedance probability of a tornado[3] of this magnitude occurring during the 25 years of the system's life is 0.4 and the expected resilience benefit to the community over the lifetime of the project is between $19-40 million, with higher value seen for higher capacity systems and systems with resilience dispatch. The expected resilience benefit to the utility during the lifetime of the project is between $1,600 - $3,300, again with higher value seen for larger capacity systems and systems with resilient dispatch.

**Table B.1. Resilience value to the customer of hybrid scenarios for the tornado hazard, by likelihood of occurrence (1-in-500-year, -100 year, -50-year, -25-year, and -20-year tornado).**

| | Customer Value | 500-year | 100-year | 50-year | 25-year | 20-year |
|---|---|---|---|---|---|---|
| Scenario 1 | $52,110,238 | $2,543,928 | $11,577,782 | $20,663,547 | $33,329,879 | $37,655,401 |
| Scenario 2 | $53,706,576 | $2,621,858 | $11,932,454 | $21,296,552 | $34,350,902 | $38,808,932 |
| Scenario 3 | $48,718,231 | $2,378,336 | $10,824,150 | $19,318,497 | $31,160,341 | $35,204,302 |
| Scenario 4 | $101,150,813 | $4,938,001 | $22,473,550 | $40,109,865 | $64,696,392 | $73,092,632 |

**Table B.2. Resilience value to the utility of hybrid scenarios for the tornado hazard, by likelihood of occurrence (1-in-500-year, -100 year, -50-year, -25-year, and -20-year tornado).**

| | Utility Value | 500-year | 100-year | 50-year | 25-year | 20-year |
|---|---|---|---|---|---|---|
| Scenario 1 | $4,287 | $209 | $953 | $1,700 | $2,742 | $3,098 |
| Scenario 2 | $4,407 | $215 | $979 | $1,747 | $2,818 | $3,184 |
| Scenario 3 | $4,050 | $198 | $900 | $1,606 | $2,590 | $2,926 |
| Scenario 4 | $8,294 | $405 | $1,843 | $3,298 | $5,305 | $5,993 |

Given that the tornado we analyzed specifically affects key electric infrastructure, this scenario is less likely than just any tornado touching down. If this type of extra-damaging storm were to occur once every 500 years, then the probability of the event occurring during the 25 years of the project's life is 0.05 and the expected resilience benefit

[2]NESP. 2020. National Standard Practice Manual for DERs. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[3]Exceedance probability is calculated as $1-(1-p)n$ where $p$ is the annual exceedance probability and $n$ is the period of interest. A useful calculator can be found at https://www.weather.gov/epz/wxcalc_floodperiod

to customers is between $2.4-$5 million over the lifetime of the asset and the expected resilience benefit to the utility is between $200-$400. As seen in Table B.3 and B.4, if an extreme winter storm is considered to be a once per century event, then the probability of the event occurring in 25 years is 0.64 and the expected resilience benefit provided by the hybrid system against this hazard is $127,000-$541,000 to customers and $49-$145 to the utility over the lifetime of the asset, again with higher value seen in higher capacity systems and in scenarios where less energy generation is available through the transmission system and the diesel generators.

**Table B.3. Resilience value to the customer of hybrid scenarios for the winter hazard, by likelihood of occurrence (1-in-500-year, -100 year, -50-year, -25-year, and -20-year storm).**

| | Customer Value | 500-year | 100-year | 50-year | 25-year | 20-year |
|---|---|---|---|---|---|---|
| **30% transmission/50% diesel capacity** | | | | | | |
| Scenario 2 | $53,706,576 | $2,621,858 | $11,932,454 | $21,296,552 | $34,350,902 | $38,808,932 |
| Scenario 3 | $48,718,231 | $2,378,336 | $10,824,150 | $19,318,497 | $31,160,341 | $35,204,302 |
| Scenario 4 | $101,150,813 | $4,938,001 | $22,473,550 | $40,109,865 | $64,696,392 | $73,092,632 |
| **70% transmission/0% diesel capacity** | | | | | | |
| Scenario 1 | $4,287 | $209 | $953 | $1,700 | $2,742 | $3,098 |
| Scenario 2 | $4,407 | $215 | $979 | $1,747 | $2,818 | $3,184 |
| Scenario 3 | $4,050 | $198 | $900 | $1,606 | $2,590 | $2,926 |
| Scenario 4 | $8,294 | $405 | $1,843 | $3,298 | $5,305 | $5,993 |

**Table B.4. Resilience value to the utility of hybrid scenarios for the winter hazard, by likelihood of occurrence (1-in-500-year, -100 year, -50-year, -25-year, and -20-year storm).**

| | Utility Value | 500-year | 100-year | 50-year | 25-year | 20-year |
|---|---|---|---|---|---|---|
| **30% transmission/50% diesel capacity** | | | | | | |
| Scenario 1 | $52,110,238 | $2,543,928 | $11,577,782 | $20,663,547 | $33,329,879 | $37,655,401 |
| Scenario 2 | $53,706,576 | $2,621,858 | $11,932,454 | $21,296,552 | $34,350,902 | $38,808,932 |
| Scenario 3 | $48,718,231 | $2,378,336 | $10,824,150 | $19,318,497 | $31,160,341 | $35,204,302 |
| Scenario 4 | $101,150,813 | $4,938,001 | $22,473,550 | $40,109,865 | $64,696,392 | $73,092,632 |
| **70% transmission/0% diesel capacity** | | | | | | |
| Scenario 1 | $4,287 | $209 | $953 | $1,700 | $2,742 | $3,098 |
| Scenario 2 | $4,407 | $215 | $979 | $1,747 | $2,818 | $3,184 |
| Scenario 3 | $4,050 | $198 | $900 | $1,606 | $2,590 | $2,926 |
| Scenario 4 | $8,294 | $405 | $1,843 | $3,298 | $5,305 | $5,993 |

Given that climate change is exacerbating extreme weather, load across the country is increasing, and changes to generation mixes are affecting the availability of power, it is possible that this extreme winter storm may occur once every 20 years. If that were the case, then the probability of it occurring in the lifetime of the project is 0.72 and the expected resilience benefit would be $412,000-$1,800,000 for customers and $160-$470 to the utility over the lifetime of the asset.

The wide ranges in value seen in these winter scenarios is due to the wide variety of hybrid systems considered (see section above) and the variation in transmission/backup diesel limitations considered which affected how much load would be lost. Once a hazard probability range is established, expected values like the ones above can be calculated for the utility to better evaluate the appropriateness of various resilience investments.