Fiscal Year 2021 Isolated Grids and Grid-Connected Turbine Reference Systems

Microgrids, Infrastructure Resilience, and Advanced Controls Launchpad (MIRACL)

Jim Reilly,[1] Sarah Barrows,[2] Megan Culler,[3]
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1 National Renewable Energy Laboratory
2 Pacific Northwest National Laboratory
3 Idaho National Laboratory
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List of Abbreviations and Acronyms

AVEC	Alaska Village Electric Cooperative
AVERT	AVoided Emissions and geneRation Tool
BESS	battery energy storage system
C&I	commercial and industrial
CO_2	carbon dioxide
Corn Belt	Corn Belt Power Cooperative
CPI-U	Consumer Price Index for All Urban Consumers
DER	distributed energy resource
DOE	U.S. Department of Energy
DoS	denial of service
DDoS	distributed denial of service
EEDs	electrical energy delivery systems
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW/GWh	gigawatt/gigawatt-hour
IEEE	Institute of Electrical and Electronics Engineers
ILEC	Iowa Lakes Electric Cooperative
INL	Idaho National Laboratory
ISO	independent system operator
IT	information technology
JEDI	Jobs and Economic Development Impact
kV/V	kilovolt/volt
kW/kWh	kilowatt/kilowatt-hour
m	meter
m/s	meter per second
MAPP	Mid-Continent Area Power Pool
MIRACL	Microgrids, Infrastructure Resilience, and Advanced Controls Launchpad
mph	miles per hour
MVAr	megavolt-ampere reactive
MW/MWh	megawatt/megawatt-hour
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
OT	operational technology
PJM	PJM Interconnection
PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
PV	photovoltaics
REC	renewable energy certificate
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
Sandia	Sandia National Laboratories
SPP	Southwest Power Pool
WIRED	Wind Innovations for Rural Economic Development program

Executive Summary

For individuals, businesses, and communities focused on building resilient electrical grid infrastructure, wind energy can provide an affordable, accessible, and compatible distributed energy resource option that also enhances the capabilities of local grid operations. However, there are technical barriers to realizing the market value and resilience benefits of distributed wind, and there is little to no ability to quantify those benefits so that stakeholders can compare grid investment options.

The central aims of this report are: (1) to drive technology transfer of the methods and technologies developed under the Microgrids, Infrastructure Resilience, and Advanced Controls Launchpad (MIRACL) project and (2) increase the number of referenceable case studies available to stakeholders interested in additional value-added capabilities of wind systems beyond bulk energy supply. We achieve this aim by applying three major methods developed under MIRACL to two real-world distributed wind reference systems. The two real-world distributed wind reference systems are the isolated grid of St. Mary's, Alaska, and the two 10.5-megawatt (MW) front-of-the-meter wind turbine deployments owned and operated by Iowa Lakes Electric Cooperative (ILEC). The three main methods demonstrated in this report include:

1. A valuation framework to comprehensively value the services distributed wind can provide
2. Advanced control and hybrid system design methods to enable distributed wind turbines to provide greater benefit and resilience value to distributed grid operators and owners
3. A resilience framework to systematically characterize a distribution system's resilience.

The market valuation and resilience frameworks enable distributed energy system owners and operators to quantify the benefits and costs of distributed wind systems to various stakeholders, measure the resilience of current electrical grid systems, and compare grid investment decisions to improve resilience of the local electrical system. Complementing the valuation and resilience frameworks, the advanced control and hybrid system design methods enable distributed grid systems to provide the services outlined by the market valuation and resilience frameworks. These publicly available tools are for decision makers seeking a way to maximize resilience and market value of their distributed grid system.

Findings

Our analysis of the two reference systems informs four key findings. These findings are specific and limited to the data and modeling of the two reference systems considered, but they point to an overarching conclusion: distributed wind can enhance grid resilience and add additional value at the community scale. Future research is needed to further test and demonstrate the technical abilities noted in this study in a wider variety of systems and to investigate how benefits (beyond bulk power production) will be valued in future energy markets.

Finding 1: The resilience benefits of distributed wind are enhanced by hybridization and advanced control.

Advancements in forecasting and control have enabled distributed wind to provide many of the services of traditional generation resources. Adding other generation sources (such as diesel or solar generation), and storage assets further enable distributed wind to provide energy and services even during disturbance events. For instance, optimal sizing of a hybrid plant for ILEC showed that battery assets, paired with solar and wind, were able to meet assumed loads better than wind alone. In a separate analysis, demand response control and adding a battery enabled the wind system to provide additional resilience benefits that wind alone could not achieve. In addition, the ability of wind to supplement traditional sources can enhance resilience in select cases. For example, in St. Mary's, resilience benefits originated from the grid-forming capabilities provided by the addition of distributed wind assets to diesel generators. Appropriate sizing of the hybrid resources and effective operation are critical in achieving these benefits.

Finding 2: Advanced forecasting and control can increase the potential value of distributed wind systems, depending on revenue structure.

The ability to forecast wind resources farther in advance and with higher fidelity enables grid operators to better plan and control assets to meet loads with finer resolution. In St. Mary's, the value of wind energy generation increased by 16% because of the ability to forecast generation in advance and optimally control system assets to provide bulk energy and other services. In ILEC, this benefit was limited by the Power Purchase Agreement (PPA) that is in place for ILEC's wind energy generation but benefits from advanced forecasting and control could increase under post-PPA conditions in which the value of distributed wind could be compensated differently.

Finding 3: The value of the system to the community is dependent on quantitative *and* qualitative aspects. Qualitative aspects can significantly influence decisions around distributed electrical system design and investments.

To adequately capture all costs and benefits of a distributed electrical system design or investment, the valuation framework considered both quantitative and qualitative costs and benefits. Including qualitative aspects allowed for a more complete consideration of the impacts of investments on the system and its users. For St. Mary's, the proposed investment relied on grant funding. Since grant funding is often partially based on the potential societal benefits, the societal benefits generated by a system investment may be particularly relevant for similar projects (projects with a high capital cost but small customer base) that require external funding. Moreover, qualitative impacts could be critical to project success, limit the designs or investments a community is willing to consider, or change the control and design of the system. For example, local community concerns about viewshed can change the location of turbines or the consideration of wind turbines at all. Similarly, turbine curtailment during minor blade icing conditions is commonly employed to reduce noise impacts on local communities.

Similarly for the resilience framework, both qualitative and quantitative processes enabled the full characterization of a system's resilience and influenced the configuration or operation that maximized resilience. While quantitative metrics help define measurable goals and simulate hazards, they are dependent on the qualitative processes of identifying and prioritizing relevant hazards. For example, stakeholders in St. Mary's identified extreme cold snaps and fuel shortages as the two most important hazards to address. If this exact same electrical system with the same loads were placed elsewhere, with different weather patterns and easier fuel delivery systems, these hazards would be less relevant. The qualitative context allows us to prioritize and address hazards, ensuring that the resilience framework produces results that are useful and relevant to the community.

Finding 4: Including stakeholder perspectives in the analyses influences the consideration and viability of technical solutions or grid investment decisions.

In the valuation analysis, stakeholder perspective affected whether both quantitative and qualitative aspects are a cost or a benefit, and the magnitude of those costs and benefits.

Including multiple stakeholder perspectives enabled a broader analysis and discussion of relevant impacts that are normally ignored in these analyses. For example, including the societal perspective doubled the overall benefits for both St. Mary's and ILEC. However, which stakeholder's perspective was being considered dictated what was considered a cost or benefit. For instance, societal *benefits* through increased jobs and economic growth in the area were enabled by capital *costs* to the electric cooperative.

In the resilience analysis, the resilience goals, metrics, and hazards to evaluate are stakeholder-driven, dictating which investment decisions are considered. In the ILEC system, Corn Belt Power Cooperative (Corn Belt) owns the PPA for the generated wind power, and incurs high costs associated with ramping up or ramping down production. Because of this, one of the metrics of interest was the duration that the local distributed resources could serve the full load following a transmission failure, as opposed to evaluating the percentage of the load that could be served for the duration of the transmission failure, which might be more relevant for a system that could tolerate partial outages.

Conclusions

This report outlines the technical development and application of novel tools and methods developed under the MIRACL project to two reference systems. Using ILEC and St. Mary's as reference systems, we found that distributed wind has the potential to contribute to enhanced electrical grid system resilience and increased value at the community scale. Hybridization and implementation of advanced control enhanced the value and resilience benefits that distributed wind could provide. Furthermore, advanced forecasting and control enable grid operators to plan and operate their distributed system more efficiently. This increased the potential value of the distributed wind systems, unless limited by the system's revenue structure. However, market benefits and costs make up only a portion of the aspects that could be relevant to communities when making electrical system design and investment decisions. The value of the system to the community was dependent on quantitative *and* qualitative aspects, with stakeholder perspectives dictating whether (and how much) an aspect was a cost or benefit. Therefore, various stakeholder perspectives were included to determine community costs and benefits.

The frameworks and methods used in this study are aimed at enabling distributed energy system planners, operators, and community stakeholders to compare investment decisions to improve the value and resilience of their system. The reference system analysis and results are aimed to increase the number of referenceable case studies available to stakeholders interested in the additional value-add capabilities of wind systems beyond bulk energy supply.

There are several areas where further research is required. First, we need to further test and validate the technical abilities of distributed wind to provide services in a wider range of system configurations. Post-validation, we then need to ensure that technical how-to knowledge is publicly available and easily accessible by distributed wind operators. Second, we need greater certainty around market participation of hybrids and distributed energy assets in grid-connected configurations. This will enable us to say with more certainty what value distributed wind (and other energy) assets could provide in a market context. Lastly, we need to increase the number of outage scenarios we examined to include probabilistic outage variables (timing, magnitude, and frequency) to enable us to more comprehensively discuss the resilience of a given system.

Technical Summary

Recent outage events, whether caused by extreme natural disasters or weather events; cyberattacks or failing infrastructure; or mild, prolonged resource adequacy issues, have highlighted the grid's increased reliance on electricity and its vulnerability. Resilience issues are especially relevant for community-scale, distributed electricity systems, which often do not share the same inherent resilience attributes as their transmission-connected counterparts (such as interconnectedness, spatially distributed resources, and redundancy). Fewer assets and infrastructure spread over a smaller spatial extent can lead to concerns over resilience, especially as these systems turn to increasing amounts of variable renewable energy generation, such as solar and wind energy. Distributed wind energy, however, can provide an affordable, accessible, and compatible distributed energy resource option that also enhances the capabilities of local grid operations. However, there are technical barriers to realizing the market value and resilience benefits of distributed wind, and there is little to no ability to quantify those benefits so that stakeholders can compare grid investment options.

In this technical summary, we present the results from the application of tools developed under the MIRACL project to two reference systems: St. Mary's, Alaska, and Iowa Lakes Electric Cooperative (ILEC). These tools are applied to investigate the role distributed wind can play in improving value and resilience of the distributed electrical energy system.

Study Approach and Methods

The results presented here are divided into three themes: (1) valuation and modeling, (2) advanced control and hybrid system design, and (3) resilience and cybersecurity. Under valuation and modeling, we used data provided by the local utility (Alaskan Village Electric Cooperative (AVEC) for St. Mary's and ILEC) as well as the valuation framework developed by Mongird and Barrows (2021) to understand the benefits and costs of wind turbine deployment. For advanced control and hybrid design, we consider how proposed advanced control and optimal hybrid system design could achieve needed resilience. Hybrid system design methods are applied only to ILEC, given available data, resource adequacy, and stated goals from the communities. For resilience and cybersecurity, we used the *Resilience Framework for Electric Energy Delivery Systems*, developed by Culler et al. (2021), to evaluate the resilience value wind turbine deployment could provide to each community under simulated disruption events.

Findings

St. Mary's Alaska

St. Mary's is an electrically isolated village located in western Alaska. The electric grid at St. Mary's serves a second town, Mountain Village, and is primarily served by a roughly 2-megawatt (MW) diesel power plant and a 900-kilowatt (kW) wind turbine (installed in 2019). The combined peak load for St. Mary's and Mountain Village is approximately 950 kW. Diesel fuel is typically delivered by barge to St. Mary's from June through October but can be delivered by air if needed at much higher cost. Energy prices for electric power, gasoline, and diesel/heating fuel in these villages are among the highest in the United States.[1]

Valuation and Modeling

The benefits and costs associated with the St. Mary's wind turbine are detailed in Figure TS-1. The total system costs were determined to be roughly $8 million. The combined value of energy and renewable energy certificates were estimated to provide a benefit of almost $6 million from the electric cooperative's perspective. We find that this benefit-to-cost ratio is 0.72 when only considering the electric cooperative's benefits. However, when including the societal impacts of the wind turbine, the benefits are almost twice the costs ($15 million), meaning the turbine has significant benefits to the local community and to society in general.

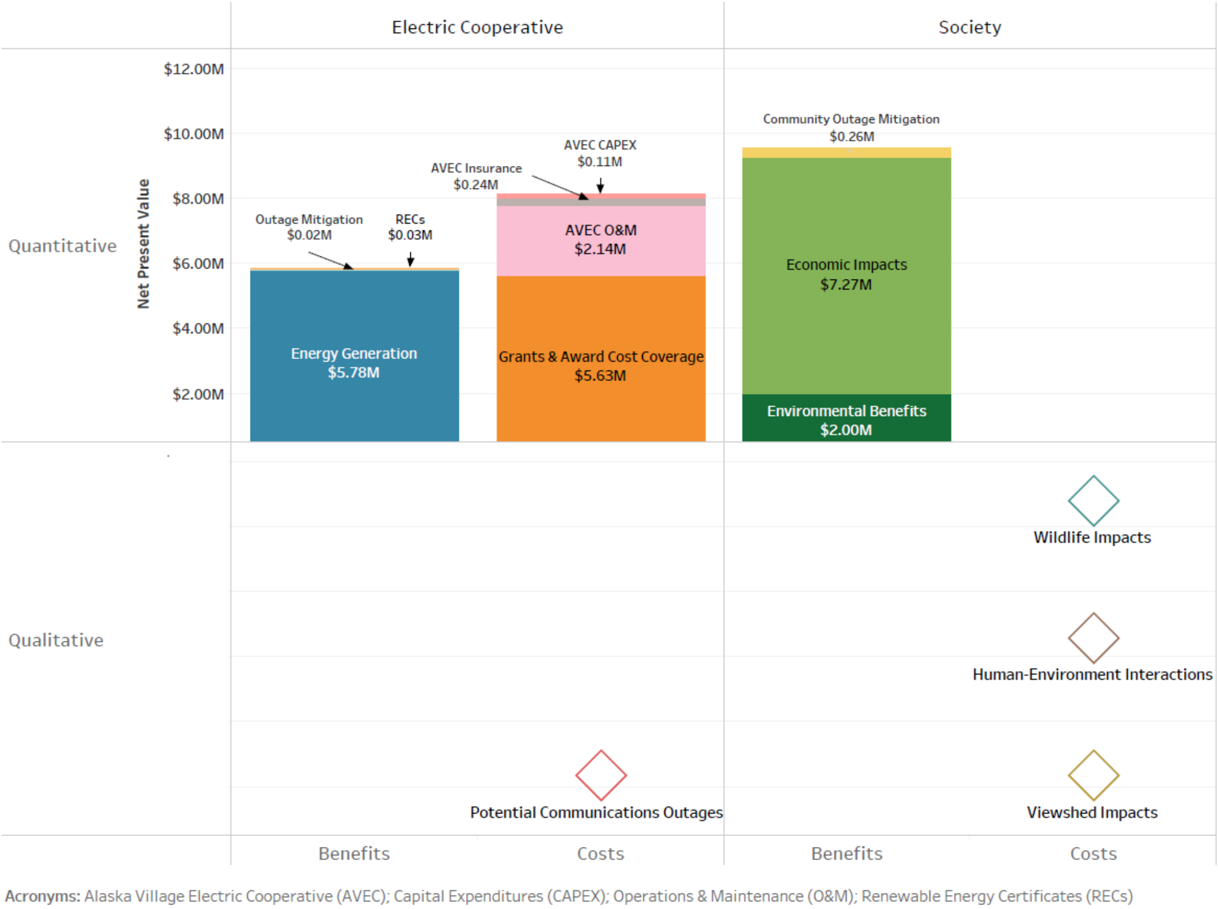

Figure TS-1. St. Mary's, Alaska, valuation results

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[1] Note that fuel prices can be volatile, especially so in remote communities where high fuel prices are exacerbated by the cost to transport fuel. If fuel prices were to double, as they did between 2019 (initiation of this study) and 2022 (publishing of this report), the costs and resilience value of including more diesel generation to the community may significantly change.

Advanced Control and Hybrid System Design

For St. Mary's, adding distributed wind assets and advanced control abilities to a system reliant on diesel was an integral part of achieving enhanced value and resilience. We identified three scenarios to compare for the valuation and resilience framework analyses:

1. **Baseline scenario with no wind turbine**: In the baseline scenario, the diesel power plant consumes roughly 375,000 gallons annually.
2. **Current wind turbine deployment at St. Mary's, basic wind control**: By deploying the wind turbine at St. Mary's it is expected that the diesel generators will consume 230,000 gallons annually.
3. **Wind with advanced control, a grid-bridging system, and improved forecasting**: This scenario poses the greatest potential benefit to St. Mary's. With advanced wind resource forecasting enabling a decrease in diesel operating reserves, it is estimated that St. Mary's and AVEC could save more than 200,000 gallons of fuel annually. The potential for fuel-cost savings at St. Mary's with advanced levels of wind control, forecasting, and energy storage are shown in Figure TS-2.

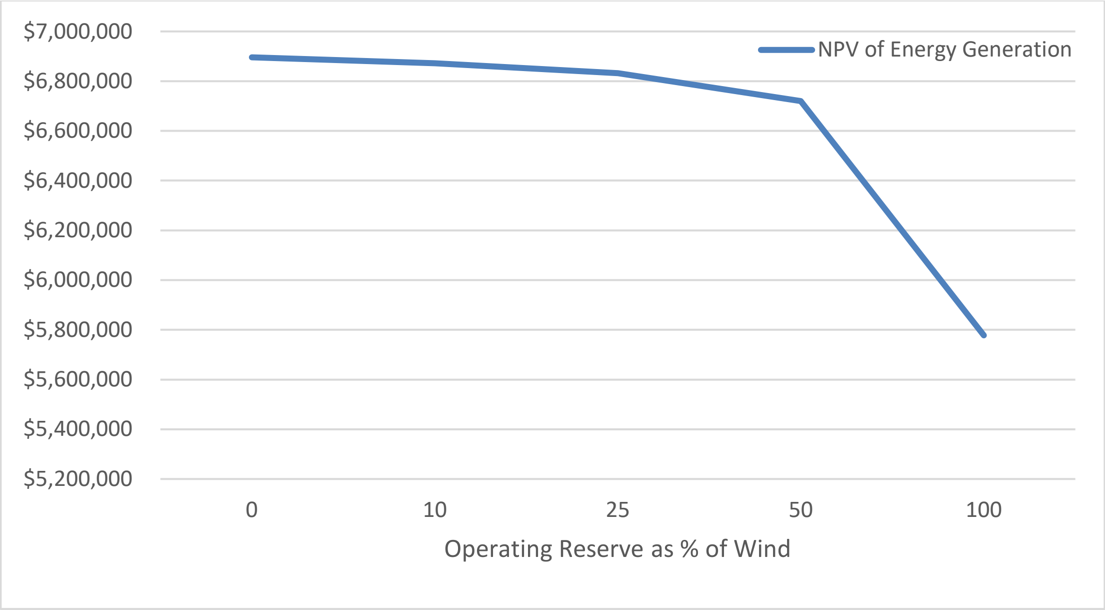


Figure TS-2. Net present value (NPV) of energy generation with diesel operating reserves as a percent of wind

Resilience and Cybersecurity

Although the wind turbine in St. Mary's has already been installed, the resilience benefits provided by the turbine were not well defined or quantified. We analyzed the operation of the St. Mary's power system—with and without the wind turbine installed —during different potential hazards to allow us to quantify the resilience benefits provided by distributed wind assets.

One hazard scenario analyzed was diesel fuel outages lasting for two weeks. We studied how wind energy and deployments can help sustain the load during that period. Figure TS-3 summarizes the amount of load that is dropped during a two-week diesel fuel outage, demonstrating that wind, though variable, prevents more load from being dropped no matter when the diesel outage occurs throughout the year.

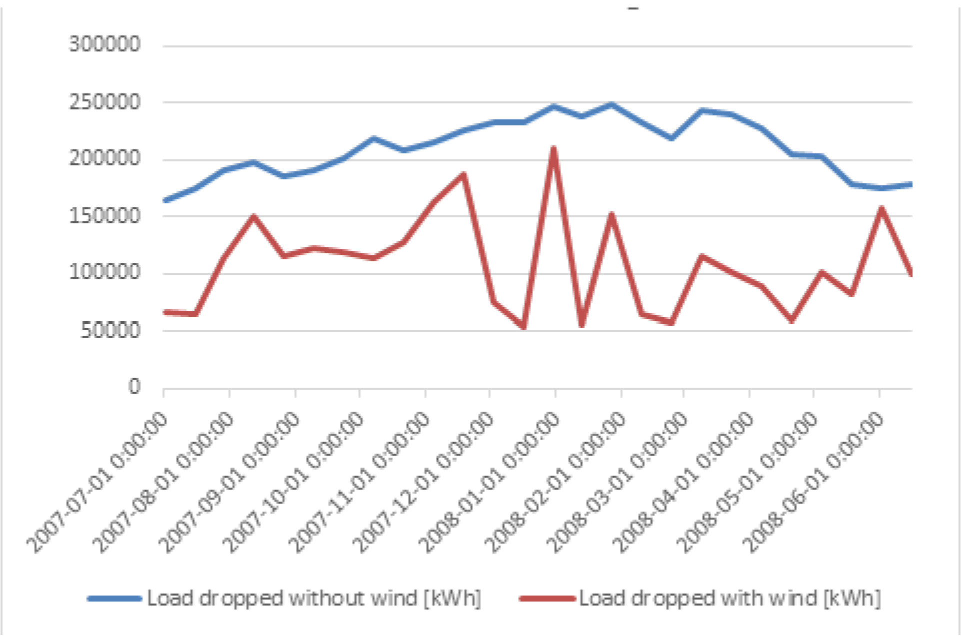


Figure TS-3. Load lost during 2 weeks of wind turbine being out of service (Culler et al. 2022b)

kWh = kilowatt-hour

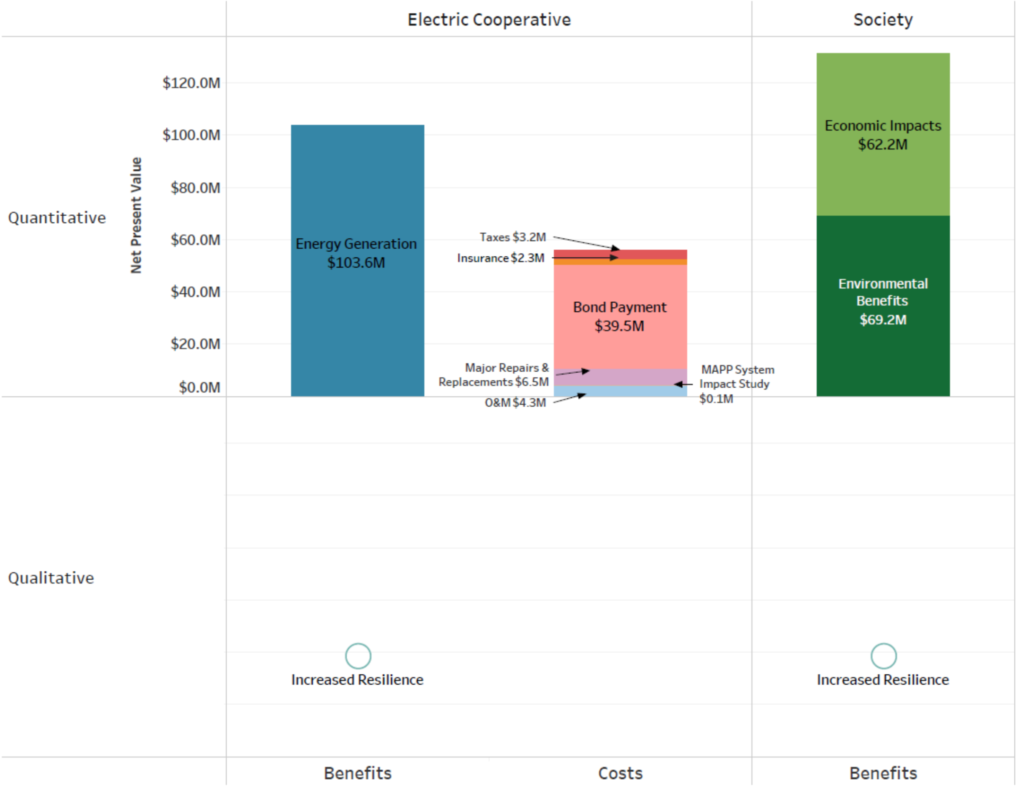
Iowa Lakes Electric Cooperative, Iowa

ILEC owns and operates two 10.5-MW front-of-the-meter wind turbine deployments in the Iowa towns of Superior and Lakota. The systems are grid-connected, participate in a regulated energy market, and are co-located with large commercial and industrial loads. Each of the two ILEC 10.5-MW wind power plants comprise seven GE 1.5-MW wind turbines on 80-meter (m) towers. ILEC owns and operates the two wind power plants and sells the power to the local generation and transmission electric cooperative, Corn Belt, which ultimately sells power to Basin Electric Power Cooperative. Each 10.5-MW wind power plant is sited next to, and primarily serves, an ethanol plant that uses about the same amount of energy that is produced by the wind turbines annually. These ethanol plants have peak loads of 9 MW and 8 MW. A 20-year power purchase agreement (PPA) was established in 2009; thus, ILEC is interested in understanding options for wind energy use once the PPA finishes.

Valuation and Modeling

To better understand the market opportunities for the ILEC wind turbines within the Southwest Power Pool (the regional transmission operator) we used the valuation framework and data provided by ILEC to determine baseline system costs and benefits (i.e., PPA still in place). We find the overall benefit-to-cost ratio to be extremely favorable at 4.19 when considering the combined societal and electric cooperative benefits. When just considering the electric cooperative benefits ($104 million), the ratio is still quite high at 1.84. The electric cooperative benefits from the wind turbines come through a favorable PPA that is in place with Corn Belt. Costs to ILEC are relatively low because of 0% bonds that were obtained through the Energy

Policy Act of 2005. There are also large benefits to society ($131 million), which total more than the energy generation benefits to the cooperative. Examples of these societal benefits include economic impacts to the state of Iowa from turbine-related construction and operations and maintenance (O&M) as well as environmental benefits in the form of avoided carbon dioxide emissions. The current PPA is set to expire in 2029. While bond payments will have ended by 2023 and the project will have already generated significant profit, additional market services might be worth investigating post-PPA to capture some additional value, such as peak shaving or regulating reserves. The valuation results are summarized in Figure TS-4.



Acronyms: Mid-Continent Area Power Pool (MAPP); Operations & Maintenance (O&M)

Figure TS-4. Iowa Lakes Electric Cooperative valuation results

Advanced Control and Hybrid System Design

Given the grid-connected, distributed wind assets and the PPA in place for ILEC, our consideration of alternate scenarios that would enhance the value and resilience of the system to stakeholders included post-PPA scenarios, both with and without hybridization (the addition of wind and solar). Three scenarios we compared included:

1. **Baseline PPA, 2009 to 2029**: To understand the system as it is deployed today, the MIRACL team established a representative baseline of the ILEC wind turbine deployments under its current PPA, which is active from 2009 to 2029.
2. **Post-PPA scenario, wind only**: This first hypothetical scenario investigates additional sources of revenue that might be available after the current PPA expires in 2029. This

scenario investigates using the existing wind turbine's advanced control functionality, enabling functions that are currently not being utilized.

3. **Post PPA wind-hybrid opportunities**: The second hypothetical scenario investigates adding a solar photovoltaic or utility-scale battery energy storage system to the existing wind plants. This scenario assumes a post-PPA wind scenario by adding generation of an undefined system capacity to investigate technical and market opportunities this may enable—in addition to the advanced control opportunities outlined in the post-PPA scenario.

A post-PPA wind-hybrid system could prove to be more valuable and resilient than a wind-only system. Hybrid systems leverage multiple resources to produce energy, which would produce more bulk energy supply in the case of adding solar to the wind system ILEC currently owns. Additionally, hybridizing ILEC's wind-only system would add ancillary service or resilience value through the addition of storage or through leveraging the complementarity of wind and solar resources to smooth electricity generation and reliably meet energy demand. Figure TS-5 depicts the component-by-component contribution of a hybrid power plant designed for the ILEC wind and solar resources, assuming a constant load, and minimizing plant cost and generation curtailment. The figure showcases how the complementarity of the wind and solar resources, paired with battery storage and dispatch, meets that constant load better than any one of the components on its own; when wind lulls during the middle of the day, solar photovoltaic generation is at its peak, and storage supplements generation during night hours (reducing the overbuilding and curtailment of wind turbines).

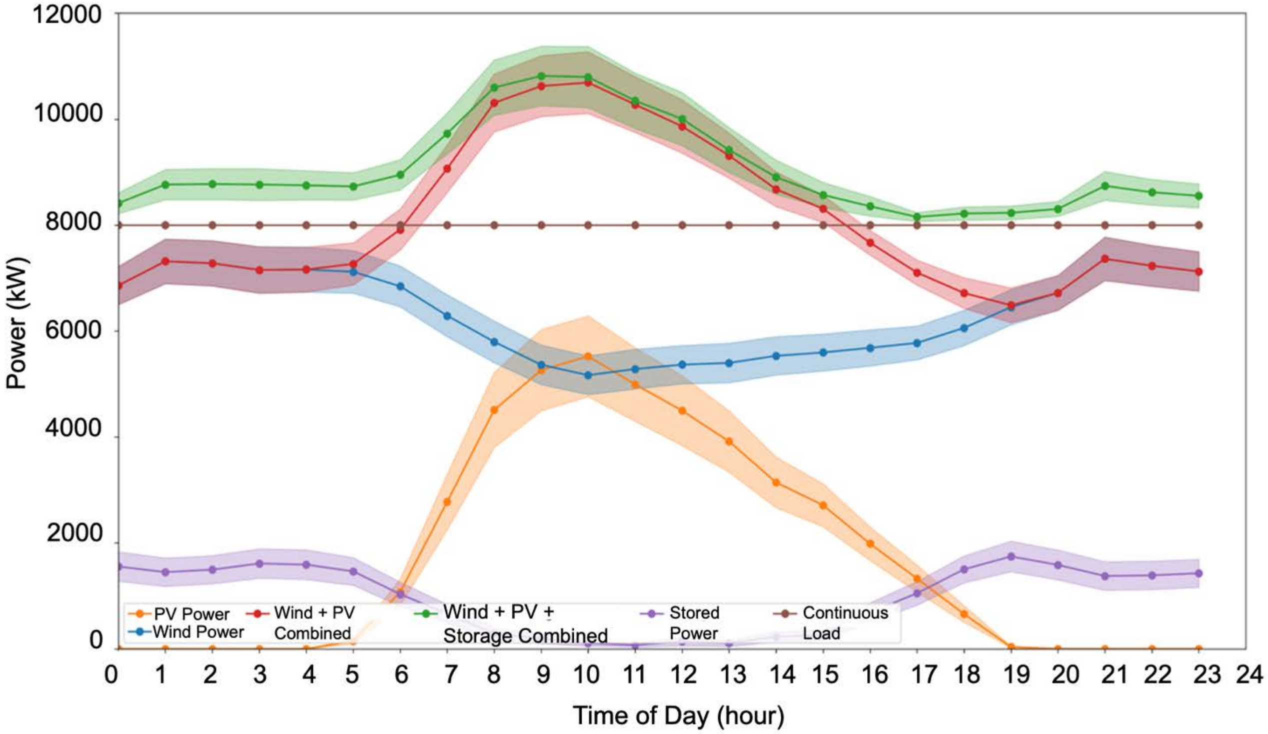


Figure TS-5. A hybrid power plant design at ILEC to meet a constant 8-MW load demand while minimizing cost and power curtailment. Note: stored power is always positive, so that discharging results in the stored power approaching 0 kW during mid-day.

Resilience and Cybersecurity

The most impactful cybersecurity hazard identified for the ILEC wind subsystem is an attack on the transmission system shutting down power production and/or transmission on the bulk system, leaving only distributed wind to serve the local load. Time until load is dropped during a transmission failure, customer outage duration, and total load not served under varying hazards and energy system designs are quantified. The analysis outlines scenarios in which having a distributed wind resource to serve local load can add resilience to a cybersecurity hazard, and ways in which the distributed wind resource can still be affected by, or even contribute to, a cybersecurity hazard. The distributed wind resource allows the local load to be served for longer continuous durations, for a larger percentage of the outage duration, and with less overall load dropped when compared to the system without wind. We find that wind-storage combinations best mitigate cyberattack impacts and that demand response to curtail customer load also has a significant mitigating effect, shown in Figure TS-6. With large amounts of storage and more extreme demand response (reducing load to only 25% of normal output), the system provides power to the load for near 100% of the transmission system outage duration. However, even smaller amounts of storage or less extreme demand response can help ensure that the load is served for at least 50% of the transmission system outage duration. Note, too, that even the base case of wind alone can serve the full load for at least 35% of an outage duration.

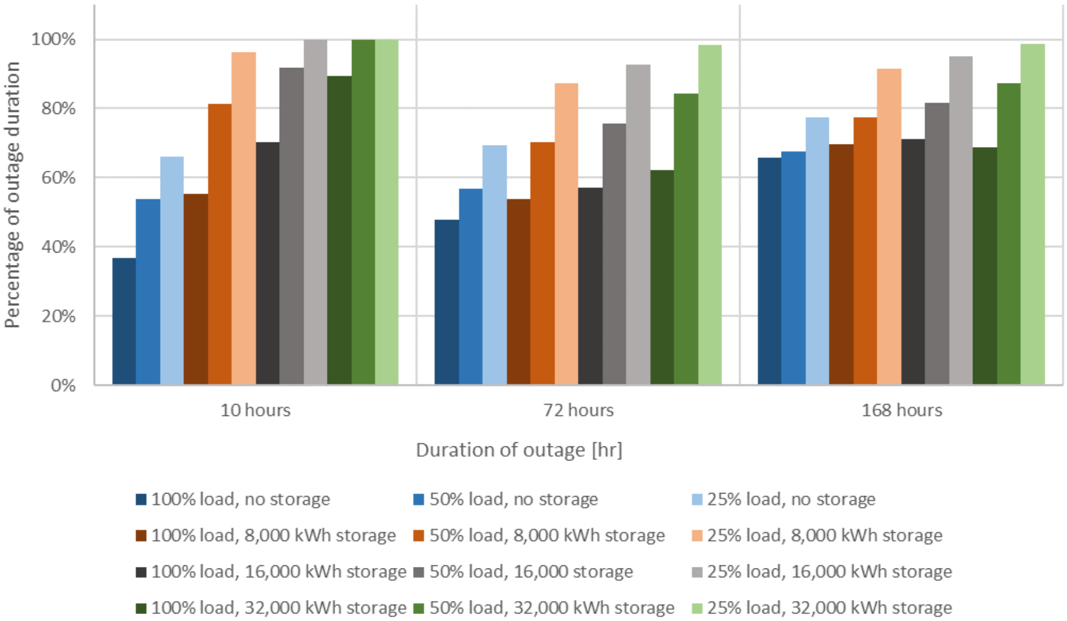


Figure TS-6. Summary of cases: percentage of time when load is fully served (Culler et al. 2022a)

Conclusions

In this work, we apply the tools developed under the MIRACL project to demonstrate the role distributed wind can play in improving the value and resilience of local distributed electrical energy systems. These publicly available tools are for planners and owners of distributed electrical energy systems seeking a way to maximize resilience and market value of their system.

The three main methods applied in this report include a valuation framework, advanced control and hybrid design methods, and a resilience framework. The market valuation and resilience frameworks enable distributed energy system owners and operators to quantify the benefits and costs of distributed wind systems to various stakeholders, measure the resilience of current systems, and compare investment decisions to improve resilience of these systems. Complementing the valuation and resilience frameworks, the advanced control and hybrid system design methods enable distributed systems to provide the services outlined by the market valuation and the resilience frameworks.

To increase the transfer of tools developed under the MIRACL project and empower stakeholders with referenceable case studies, we applied these tools to two reference systems: the isolated grid of St. Mary's, Alaska, and the two 10.5-MW front-of-the-meter wind turbine deployments owned and operated by ILEC.

Findings show that St. Mary's can reduce fuel consumption and reduce dependance on diesel generation if the existing wind turbine implements advances control. In the isolated system, the most valuable controls are frequency and voltage support. When including the societal impacts of the wind turbine, the benefits are almost twice the costs ($15 million vs. $8 million), meaning the turbine has significant benefits to the local community and to society in general. The resilience benefits provided by wind against relevant Alaskan hazards can be primarily attributed to local generation with an unconstrained energy source. However, these benefits are enhanced by advanced controls, namely, advanced wind resource forecasting. Additionally, the resilience analysis of St. Mary's demonstrated the difficulty of quantifying the impact of hazards, but qualitative analysis of the resilience benefits enabled the evaluation of a range of scenarios corresponding to the hazard.

The ILEC analysis showed that implementing advanced controls with the two distributed wind turbine deployments greatly increased the resilience of the system. The operation of a grid-connected system such as ILEC depends largely on the market with which it is associated. Currently, ILEC sells generated energy through a PPA and does not utilize any advanced controls. ILEC's PPA and the zero-interest bonds that funded the project allow for a very favorable benefit-to-cost ratio for the electric cooperative of 1.84, with added societal benefits of $131 million. The ability of ILEC and other grid-connected systems to provide ancillary services and improve system resilience increases with implementation of the proposed controls. The impacts of the hazards in this case study depend on the perspective of the stakeholder. We focused on the operator perspective, considering impacts to the local power system and local customers. The impact of the hazards would change if we focused instead on the transmission provider or the IT manager for the system.

For individuals, businesses, and communities focused on building resilient electrical grid infrastructure, this report demonstrates how wind energy can provide an affordable, accessible, and compatible distributed energy resource option that also enhances the capabilities of local grid operations. Through the application of the three main methods to St. Mary's and ILEC, we provide referenceable case studies for distributed electrical energy system planners, operators, and community stakeholders to compare investment decisions to improve the value and resilience of their system.

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Introduction

This report applies distributed wind research from the Microgrids, Infrastructure Resilience, and Advanced Controls Launchpad (MIRACL) project to two real-world distributed wind deployments. The work was funded by the U.S. Department of Energy (DOE) Wind Energy Technologies Office. The intent of this effort is to increase the number of case studies available to stakeholders interested in additional value-added capabilities of wind systems beyond bulk energy supply (i.e., kilowatt-hours).

The MIRACL project is a multiyear distributed wind research effort administered through a partnership of four national laboratories—the National Renewable Energy Laboratory (NREL), Pacific Northwest National Laboratory (PNNL), Idaho National Laboratory (INL), and Sandia National Laboratories (Sandia)—to accelerate distributed wind development by advancing the technology and highlighting the value it provides to distribution grids. The MIRACL project received feedback from an industry advisory board that one of the main barriers to increased distributed wind deployment was the limited number of available case studies documenting the next generation of wind turbine deployments in distribution applications. To respond to this challenge, the MIRACL team identified, based on feedback from our industry partners, more than 50 distributed wind systems that have common characteristics relevant to the broader distributed wind industry.

In this report, research and development from the initial three years of the MIRACL project are applied to two of these reference systems—wind in isolated grids and front-of-the-meter wind turbine deployments. The goal is that by applying our research toward real-world systems rather than generic or laboratory hardware-based systems, we will expedite the technology transfer of the theories, methodologies, and technologies developed under the MIRACL project.

MIRACL is structured into three primary research areas:

1. **Valuation and modeling**. Improve the representation and valuation of distributed wind in distribution planning tools, methods, and models by developing a valuation framework; evaluate, modernize, and validate existing tools; and explore use cases through co-simulation.
2. **Resilience and cybersecurity**. Research and implement methodologies to develop threat-resilient supervisory control; understand cyber vulnerabilities; and achieve greater, measurable resilience in microgrids and distribution systems through wind integration.
3. **Advanced control and hybrid system design**. Develop and demonstrate the grid-support functions of wind turbines in grid-connected and isolated microgrids and increase the control and communications compatibility of wind turbines with other distributed energy resources (DERs).

The applicability of these research areas can vary significantly depending on the structure of the market and power system within which the wind turbine is operating. To better align research products to end users, the MIRACL team developed a set of use cases (Reilly, Gentle, et al. 2021). Within the DOE distributed wind portfolio, a use case is a construct used in system analysis to identify, clarify, and organize system requirements. In MIRACL and other distributed wind research, use cases span the wide variety of distributed wind projects and form the basis of MIRACL discussions and targeted work packages. Distributed wind projects will be categorized into use cases with similar **technical** (interconnection, certification, and integration with other renewable energy systems), **financial** (cost structure and valuation), **market** (developer and owner), and **resilience** (energy security, cybersecurity, fuel diversity, and financial security) requirements, challenges, and benefits. The high-level use cases defined for distributed wind will encompass wind turbines scenarios in Figure 1.

1. **Isolated grids**: Grids that remain electrically independent of a bulk power grid.
2. **Microgrids**: A group of interconnected loads and DERs within defined electrical boundaries that can operate either connected or disconnected (islanded) from an external grid (Ton and Smith 2012).
3. **Behind-the-meter deployments**: Systems that are always connected to the grid, behind the utility meter, and are typically directly connected to load, offsetting power at retail rates and potentially providing grid services to those loads.
4. **Front-of-the-meter deployments**: Systems that are always connected to load-serving distribution grids and are typically owned by or sold to an electric utility or electric cooperative at wholesale prices. Power is then resold to customers or into energy markets and potential grid services used by the local electric utility.

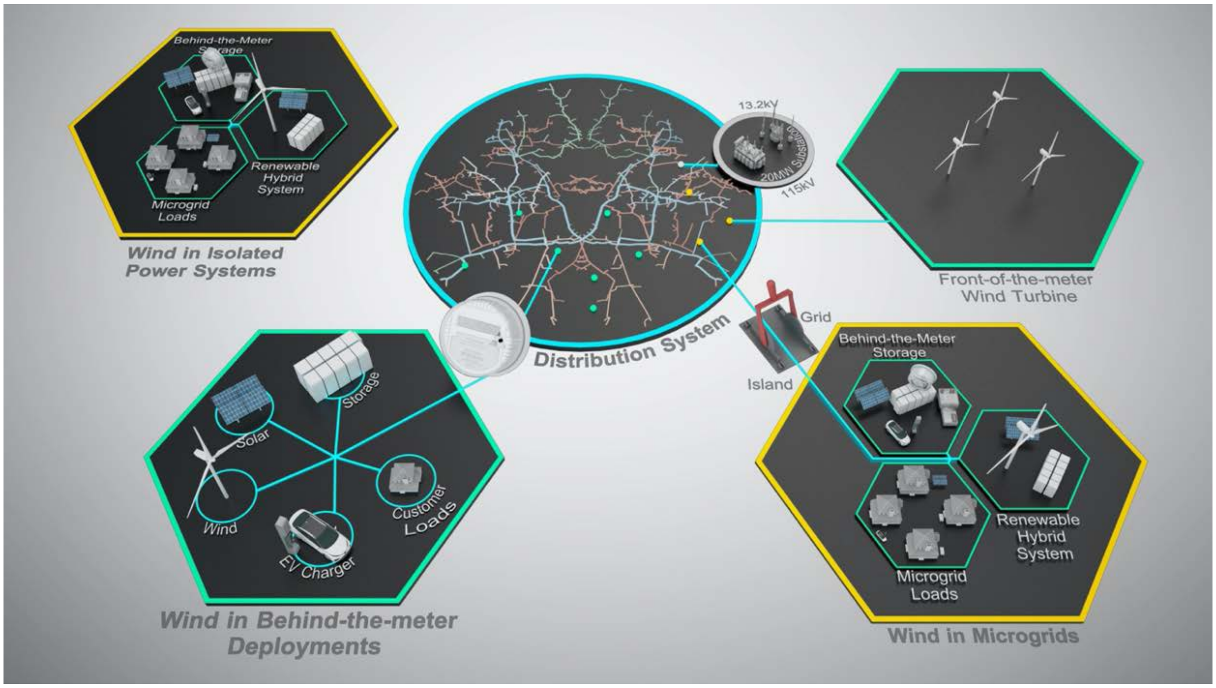


Figure 1. MIRACL use case definitions for distributed wind (Reilly, Gentle, et al. 2021). ***Image by Josh Bauer, NREL***

1.1 Reference Systems Introduction

Reference systems were defined by the MIRACL team as operational distributed wind systems with a significant amount of data available for use in MIRACL research. To identify the initial reference systems out of the list of 50 or more reference systems, the MIRACL team established the desired characteristics outlined below. Reference systems were selected because they had most of the following required and desired characteristics.

Required

- Represents an operating power system with an industry partner that included wind energy
- The industry partner is interested in sharing data
- Reference systems cover unique MIRACL use cases
- Selected site either has wind turbines or could feasibly add wind turbines.

Desired

- Control characteristics
    - A technical, economic, or resilience need or goal that could be supported by advanced control from a wind turbine or hybrid wind system
    - An existing dynamic model that includes power system parameters and component modules for generators and loads; this can be co-simulated or imported into MATLAB Simulink for coordination with other MIRACL control research
    - Access to high-fidelity power system and generator production time-series data or the ability to collect these data.
- Resilience and cyber characteristics
    - Defined resilience goal or understanding of potential threats to energy resilience, including climate/weather, cybersecurity, complex transportation, and similar characteristics that reliability concerns do not address
    - Recent changes to the electrical energy delivery system that might include capital investments to address system change
    - Openness to information sharing on cybersecurity policy, guidelines, and practices (e.g., detection and response) as well as information and/or operational technology network(s) for power systems operation and other associated networks.
- Valuation characteristics
    - Provide a variety of possible economic or societal value streams (e.g., in a location where it could be part of a market or with a particularly impactful policy or compensation system)
    - A system that already incorporates solar photovoltaics (PV), or on a grid with high PV deployment, to allow assessment of the value of resource diversity
    - A system with more than one set of stakeholders involved in the project (e.g., a community-owned project).
- Existing partnerships with the DOE Wind Energy Technologies Office to drive efficiencies and collaboration opportunities.

The multilaboratory MIRACL team unanimously identified two reference systems to be used as working examples and evaluated within this report:

- **St. Mary's, Alaska**: Selected as the first Fiscal Year 2021 MIRACL reference system based on the MIRACL team's ability to access data and models as well as the opportunity to collaborate with existing DOE and laboratory partners. This system falls under *MIRACL Use Case 1: Wind Turbines in Isolated Grids*.

- **Iowa Lakes Electric Cooperative (ILEC)**: ILEC's two 10.5-megawatt (MW) grid-connected wind turbine deployments were selected as the second FY 2021 MIRACL reference system. The selection was based on the ability to coordinate data requests, model development, and technical discussions with existing DOE Wind Innovations for Rural Economic Development, or WIRED, awardees at the National Rural Electric Cooperative Association and Iowa State University. This reference system falls under *MIRACL Use Case 4: Front-of-the-Meter Distributed Wind Turbine Deployments*.

Reference systems to represent the other two use cases were identified but were not considered in this round of system analysis.

1.2 Research Areas Overview

The investigation into the performance of distributed wind systems for the two target reference systems was approached using three different methods to develop a more complete perspective on the role of distributed wind. The three methods described below include a resilience framework, a valuation framework, and advanced power system control.

1.2.1 Valuation Framework Summary

PNNL's recently published valuation framework provides a consistent and comprehensive way to value distributed wind systems (Mongird and Barrows 2021). This framework describes a wide variety of key concepts, best practices, and considerations to keep in mind when evaluating the value of a distributed wind project. It contains several valuation charts that identify benefits and costs that might be available in various use cases, including whether a distributed wind project is a connected or isolated system and where it is located within that system. Each of the use cases includes several perspectives to which specific benefits can apply as well as different roles that those perspectives play in a given scenario. These charts are intended to help practitioners identify which value elements might be relevant to their project so that benefits and costs are not overlooked.

The steps in Table 1 outline a recommended path for those hoping to use the valuation framework charts to conduct a techno-economic valuation. This valuation framework guided our work in valuing the reference systems chosen for this report. It is important to note that in each reference system, lack of data for some items required assumptions to be made. This means that the valuations provided here give a representation of the benefits and costs realized at each project under various assumptions but do not reflect the project's real costs and benefits.

Table 1. Valuation Framework Guide

Step 1	Define reference system details, such as grid-connection status (connected vs. isolated), front-of-the-meter or behind-the meter project, microgrid, ownership/contract structure, and so on.
Step 2	Select valuation chart to section that applies to defined reference system.
Step 3	Define project-specific factors (e.g., technology type, market availability, co-located technologies, control capabilities) to narrow value element availability.
Step 4	Specify valuation perspective for base-case analysis.
Step 5	Define valuation methodologies applicable to project (e.g., market participation methods and compensation, applicable penalty avoidance, outage mitigation frequency, and associated value of lost load) for selected benefits and reference system characteristics. For services that are not monetizable, discuss potential impacts or externalities.
Step 6	Model operation of asset(s) and co-optimize benefits to determine present value of benefits during the asset's usable life, accounting for all technologies included in project.
Step 7	Define revenue requirements/costs associated with reference system considering the appropriate perspective of analysis.
Step 8	Calculate present value revenue requirements/costs for project from chosen perspective.
Step 9	Summarize any nonquantifiable impacts for stakeholders, giving relevant qualitative evidence.
Step 10	Compare co-optimized value stack to revenue requirement/cost stack for base case and calculate financial metrics of interest. Simultaneously present qualitative impacts with quantified impacts.
Step 11	Repeat process, as desired, conducting additional analyses for other perspectives of interest and/or conduct sensitivity analyses with changes to key parameters or assumptions to determine robustness of results.

1.2.2 Advanced Control and Hybrid System Design Methods Summary

As a larger portion of renewable energy generation sources is integrated into power systems, the ability of distributed sources of generation to provide essential grid services beyond energy becomes increasingly important. Advanced control methodologies can enable distributed wind turbines to provide grid services such that the wind turbine can play an enhanced role in the generation portfolio mix.

The research road map of distributed wind control (Reilly, Poudel, et al. 2021) for the MIRACL project documents a literature review of active and reactive control capabilities of different DERs and develops a path for the application of such control technologies for distributed wind turbines structured by MIRACL use cases. The MIRACL team created a Simulink model for isolated, grid-connected, and microgrid deployments (Anderson, Poudel, Reilly, et al. 2022) which is available on GitHub (Anderson 2021).

1.2.2.1 Isolated Grid Deployments

In isolated grids, a wind turbine is typically used to reduce fuel consumption by supplementing or offsetting generation from fossil-based generators. As wind becomes a larger percentage of the generation capacity, the isolated grid owner may require the wind turbine to support grid stability, provide essential grid services, and allow better visibility and control over turbine instrumentation. The MIRACL team's primary focus areas for wind to provide dynamic grid support services in isolated grids include voltage and frequency support.

Voltage support. Distributed wind assets can provide voltage support by providing reactive power. The active power (measured in MW) and reactive power (measured in megavolt ampere reactive [MVAr]) provided by each asset type in a hybrid plant is provided in the real (active)/reactive power capabilities curve shown in Figure 2 (Gevorgian, Baggu, and Ton 2019). Moreover, Figure 2 shows that the reactive power capability of a hybrid power plant is larger than that of the individual components of the plant.

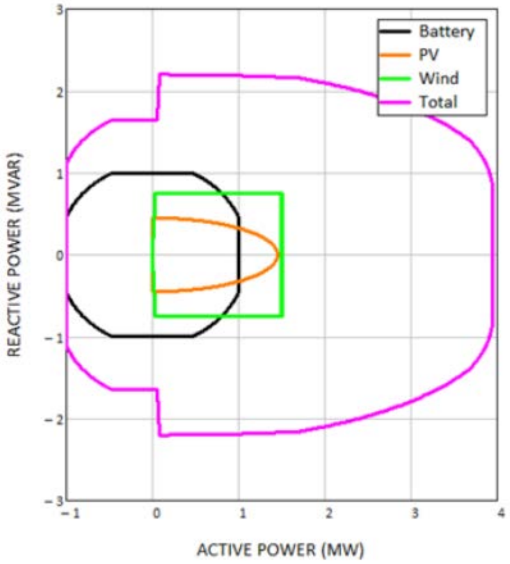


Figure 2. Real and reactive power characteristics of hybrid power plants (Gevorgian, Baggu, and Ton 2019)

By employing droop curve control, or a plant-level controller capable of quickly dispatching the wind plant's power electronics, the wind turbine can quickly respond to voltage deviations on the system and provide voltage support to the local distribution system. Figure 3 shows an example of wind support for voltage recovery after an event on an isolated grid (measured in MVAr) by employing 5% and 10% droop curve control. Voltage stability is regained faster in the two droop curve control cases than in the baseline case, as measured by the faster recovery in the root-mean-square of the voltage (Vrms, measured per unit, or pu) both in the 13.2 kilovolt (kV) bus and 575 kV bus systems. Further details on this scenario can be found in (Anderson, Poudel, Krishnan, et al. 2022).

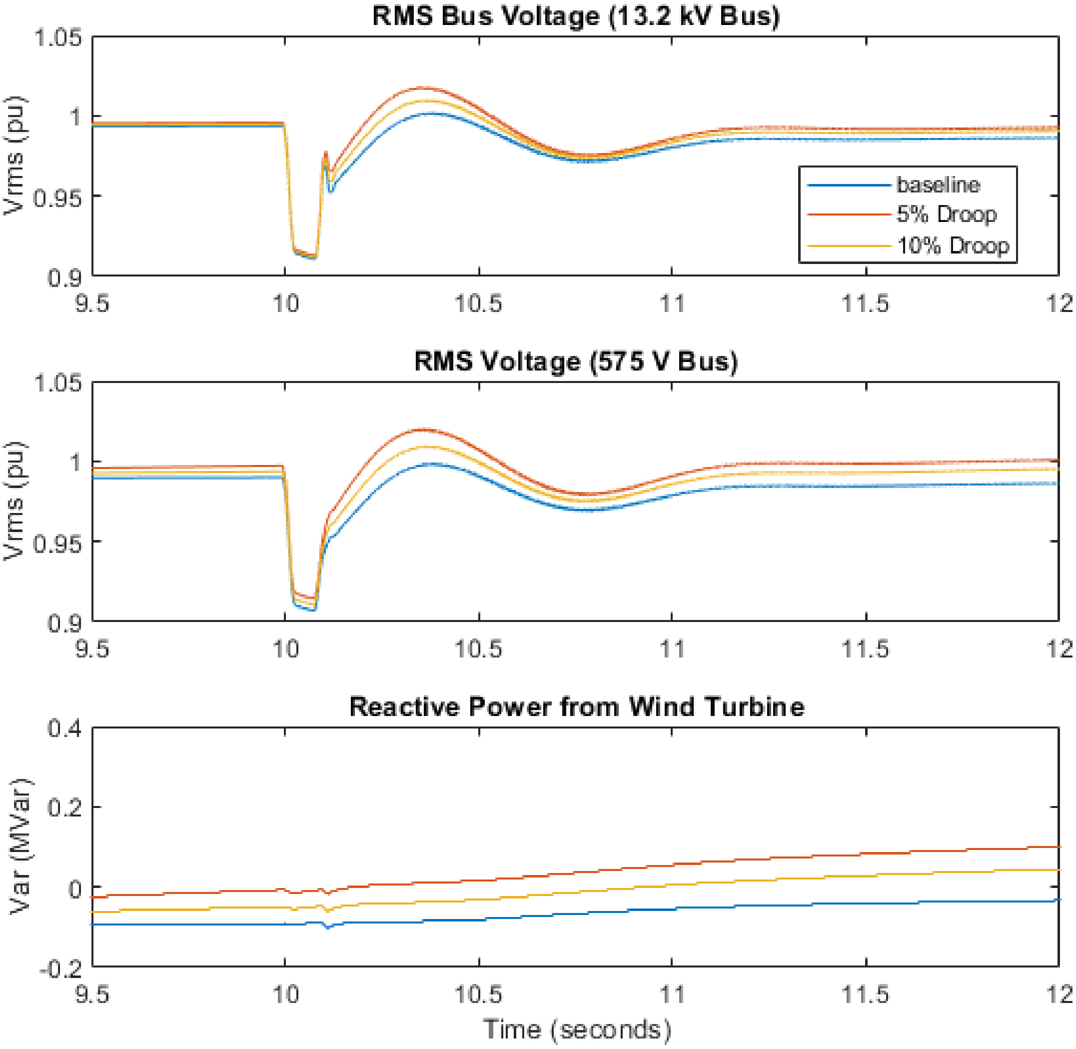


Figure 3. Reactive power support from wind turbine: baseline case versus 5%–10% reactive power–voltage droop curve control applied (Anderson, Poudel, Krishnan, et al. 2022).

RMS = root mean square

Frequency support. Inherent system inertia offered by the rotating mass of synchronous generators is key for grid stability to arrest an immediate change in grid frequency after a sudden generation-load imbalance event (Denholm et al. 2020). A wind turbine can also be configured to support the frequency of a power system. This capability is particularly beneficial in isolated grids because of the larger role that the wind turbine plays in the overall capacity of the isolated power system. The ability for a wind turbine to support frequency through active power control methodologies is further detailed in (Anderson, Poudel, Krishnan, et al. 2022). Figure 4 shows frequency response in different scenarios with a wind turbine providing the ancillary service. In the example below, we observe a baseline scenario without wind turbine and other cases with a wind turbine providing inertial response, primary frequency response, and these services after adding a battery energy storage system (BESS).

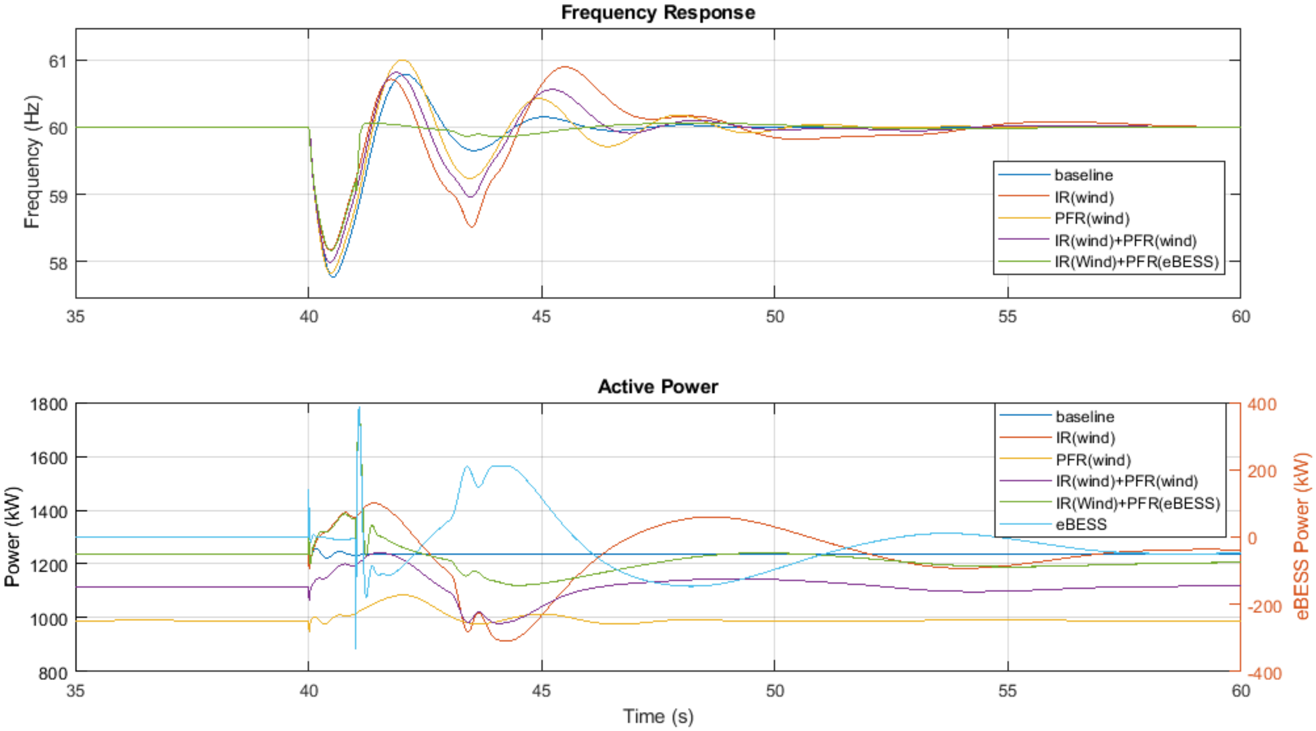


Figure 4. Comparison of active power control methods on frequency response (Anderson, Poudel, Krishnan, et al. 2022).

IR = inertial response; PFR = primary frequency response; eBESS = external battery energy storage system

1.2.2.2 Grid-Connected Deployments

In grid-connected deployments, such as behind-the-meter and front-of-the-meter configurations, distributed wind turbines are primarily deployed to provide a local source of renewable energy to loads. They may be offsetting electricity purchased from a utility through an electricity meter or participating in regional energy markets. In both scenarios, there are opportunities for wind to provide additional grid services and there might also exist a formal or informal market component to incentivize compensation for these ancillary services. Figure 5 shows some of the ancillary services that are commonly procured in the United States or that may be procured in the future. The number of wind resources that support or provide these services is increasing in U.S. energy markets, especially as wind contributions to the energy system increase.

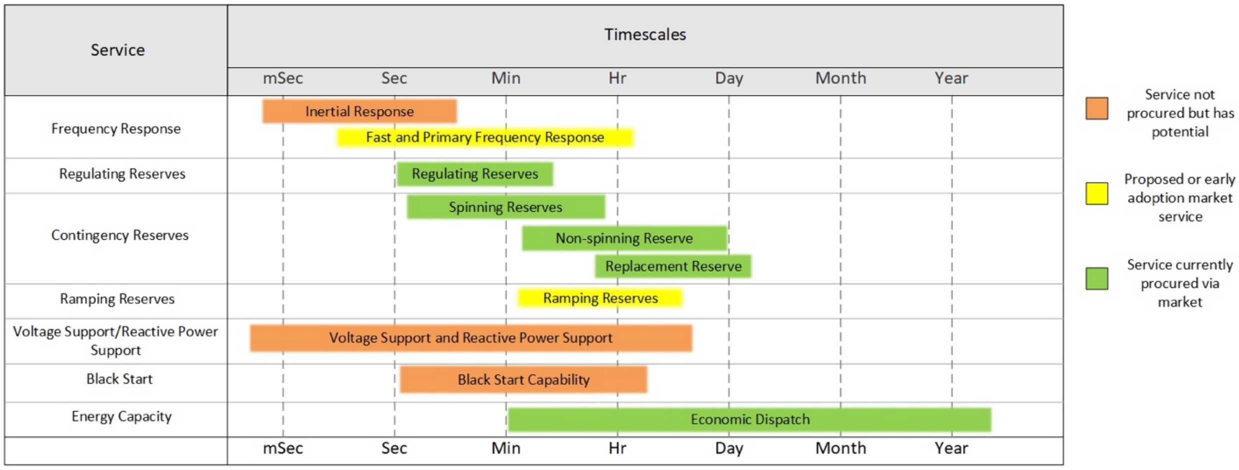


Figure 5. Main services procured in the U.S. power system

The 2018 update to the Institute of Electrical and Electronics Engineers (IEEE) standard 1547, the "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," required DERs to be capable of providing several advanced control functions (IEEE 2018). Many of these advanced control functions enabled by the requirements within the IEEE 1547 revision are directly related to a wind turbine's ability to provide grid services. The requirement that a wind turbine must be capable of riding through and supporting wide frequency and voltage deviations will guarantee that future turbine technology will be able to provide additional support to distribution systems, isolated grids, and microgrids. A few of these grid services are documented in a recent NREL report (Preus et al. 2021).

Table 2 shows grid services that modern wind turbines could technically support, but the technical capability is not aligned with the presence of a market or value of providing these services in the United States (Denholm, Sun, and Mai 2019). The lack of an active grid service market is likely based on the relative immaturity of these capabilities and the little understood risk-benefit assessment that variable resources play in power system planning and operation.

Table 2. Grid Services and Provision from Wind (Denholm, Sun, and Mai 2019)

Service	Market Procured and Compensated Services (Yes [Y]/No [N])	Wind Can Technically Provide[a] (Y/N)	Wind Currently Provides in United States (Y/N)	Requires Pre-curtailment for Wind to Provide (Y/N)
Capacity	Y	Y	Y	N
Energy	Y	Y	Y	N
Inertial Response	N	Y	N/A	N[b]
Primary Frequency Response	Required but not compensated – proposals only	Y	Limited	Y
Fast Frequency Response	N – proposals only	Y	Limited	Y
Regulating Reserves	Y	Y	Limited	Y
Contingency – Spinning	Y	Y	Limited	Y
Contingency – Nonspinning	Y	Y	N	Y
Contingency – Replacement	Y	Maybe	N	Y
Ramping Reserves	Y (some locations)	Y	Limited	Y
Voltage Support	Y – cost of service	Y[c] – location-dependent	Limited	N
Black Start	Y – cost of service	Unclear – location-dependent	N	N

[a] All services require actual wind generation potential (the wind must be blowing). The ability to provide all services except where noted is inherently limited by winds capacity credit.

[b] When providing an inertia-like response using extracted kinetic energy. Terminology around this service is still evolving.

[c] This service does not require the wind to be blowing, so it is the only service not limited by the capacity credit of wind.

NREL researchers applied several above-grid service opportunities as well as the benefits of the fault ride-through requirements of IEEE 1547 for wind turbines connected to distribution networks. The team used a MATLAB Simulink model connected to a distribution network to demonstrate the capabilities that a distributed wind turbine could provide to power systems in the future (Anderson, Poudel, Rane, et al. 2022).

1.2.3 Resilience Framework Summary

The INL resilience framework is a flexible set of guidelines that enables users to define, evaluate, and improve resilience for electrical energy delivery systems (EEDS), with a specific application to distributed wind systems (Culler et al. 2021). Although the concept of resiliency is not new, its application to the electric grid is neither standardized nor well-defined, and there is little to no guidance on how to evaluate resilience specifically for distributed wind systems. The need for this framework was established by INL, where the definitions of resilience and the resilience of EEDS were developed and where a critical characteristic of resilience for EEDS, the distinctiveness quality, was identified (Bukowski et al. 2021). This distinctiveness quality reflects the difficulty in applying resilience metrics broadly to the widely varied risk perception of stakeholders and stakeholder groups, the varied range of potential consequences to a system based upon events, and the large set of potential mitigation strategies.

The framework uses the definition of resilience for EEDS established in the resilience metrics report: "The resilience of an EEDS is described as a characteristic of the people, assets, and processes that make up the EEDS and their ability to identify, prepare for, and adapt to disruptive events (in the form of changing conditions) and recover rapidly from any disturbance to an acceptable state of operation" (Bukowski et al. 2021).

This definition suggests a few key considerations. Resilience is unique in the depth and breadth of factors associated with the topic. It spans an assortment of technology resources and systems, geographic factors and constraints, risk severity levels, and diverse stakeholder perspectives. This multiplicity of factors points to the need for a framework that is applicable across various situations and scenarios and that can be effectively implemented by different stakeholders.

A three-tiered approach is developed in the resilience framework. At the top level, three stages of resilience represent different times in a system's life cycle and different means of evaluating and executing resilience. At the intermediate level, five core functions of resilience are defined, spanning across the time stages. At the lower level, the process steps are described, which correspond to implementing practices for resilience in each of the core functions. This tiered breakdown is shown in Figure 6.

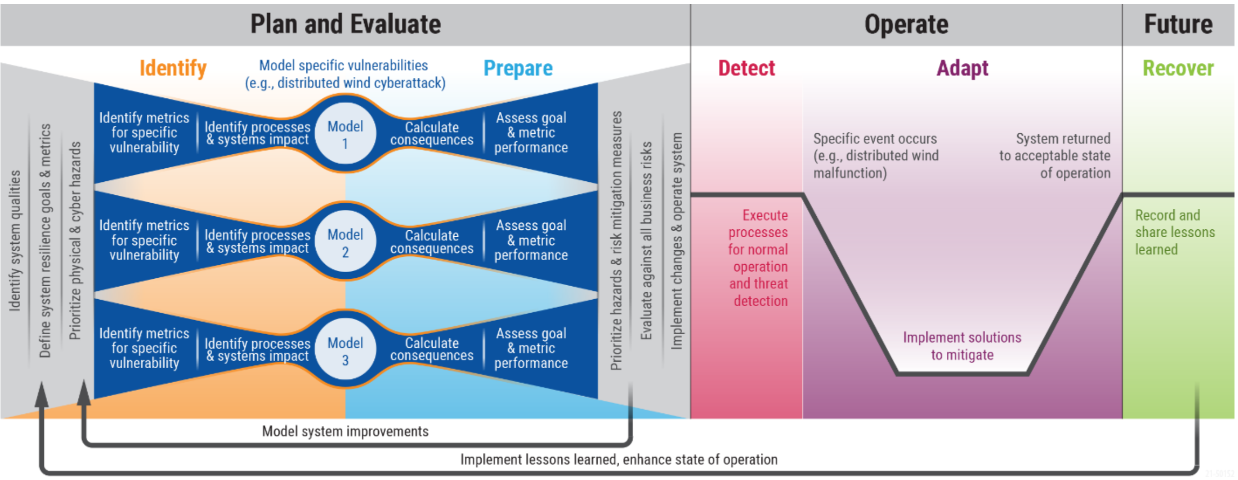


Figure 6. MIRACL resilience framework approach (Culler et al. 2021)

The framework considers three stages of resilience to enable stakeholders to assess and improve their system's resilience throughout its life cycle. The planning stage uses future organizational needs and current system status to prepare for potential risks. The operational stage seeks to respond to active risks as prudently and efficiently as possible to maintain system resilience. The future stage seeks to improve on current system resilience and feeds back into the planning stage to promote continuous improvement. Although all three stages are important, the planning and evaluation stage is critical in defining a system's resilience characteristics and in outlining how a system responds to an event. The framework intentionally emphasizes the planning stage to highlight the overarching theme that the planning stage heavily impacts those stages that follow.

The core functions in the framework are *identify, prepare, detect, adapt, and recover*. These five functions stem from a rigorous analysis of definitions used across the industry, and they represent the core capabilities that a system must have to enable life cycle resilience. Within each core function, process steps are described that help walk stakeholders through the information gathering, evaluation, decision-making, and implementation processes they will need to ensure their resilience goals are maintained throughout the system's life cycle.

Also highlighted in Figure 6 is the concept that a resilience framework should be cyclical in nature. Because a system's resilience is based on finite resources and time, it must continually evolve through this framework's risk management and capital investment steps at an appropriate level of scope and pace.

The framework is intended to be used alongside existing processes to determine gaps at each stage of resilience (planning, operational, and future) and to develop a program for improvement. It can be used as a key part of the process for identifying, assessing, and managing risks. One benefit from the framework is a systematic prioritization of improvement plans. Using the framework to guide resilience management, stakeholders can:

- Evaluate the status of system resilience
- Prioritize critical activities aimed at improving performance
- Monitor system resilience
- Establish resilience requirements.

The framework is intended to be extensible and applicable to a variety of systems, yet customizable to value the goals and metrics appropriate for a given system's distinct characteristics, drivers, and values. It is applicable at global and granular scales of system resilience planning and operations. The framework is also accessible to a wide variety of interested stakeholders, such as utility practitioners, regulators, environmental constituents, or interested researchers or others at national laboratories and academic institutions.

Although there are already extensive processes in place for power system planning, this framework differentiates itself from other related risk frameworks or resilience metrics by considering an all-hazards approach that complements traditional reliability analysis. INL fills a gap in existing work by creating a resilience framework for EEDS that considers multiple stages of resilience and manages risks throughout the system's life cycle. Additionally, this approach with three tiers of abstraction allows stakeholders to look at system resiliency from a high level, but also breaks down the process for evaluating and implementing resilience solutions into steps that are easy to follow and apply. The framework includes the integration of the uncertainty of cyber effects, weather events, or intentional physical damage, and creates a process for model-informed consideration of each hazard.

2 Reference System 1: St. Mary's

2.1 System Description

St. Mary's, Alaska, with a population of 683, is a village located in western Alaska, along the Andreafsky River, near the junction with the Yukon River, about 450 air miles west-northwest of Anchorage. A road and electrical intertie connect St. Mary's to the nearby community of Pitka's Point (population 117). Mountain Village, Alaska (population 860), is located about 20 miles further down the Yukon River, west-northwest of St. Mary's. A seasonal road connects St. Mary's to Mountain Village. An electrical intertie between St. Mary's and Mountain Village was completed in November 2020, creating a local electric grid serving all three communities with the diesel power plant in St. Mary's and a wind turbine near Pitka's Point. All three communities—St. Mary's, Pitka's Point, and Mountain Village—are serviced by Alaska Village Electric Cooperative (AVEC), a member-owned rural electric cooperative (AVEC 2020b).

2.1.1 Electric Power System

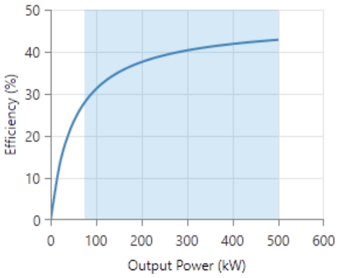
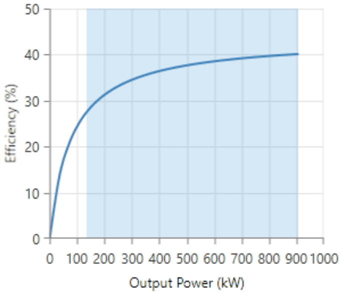
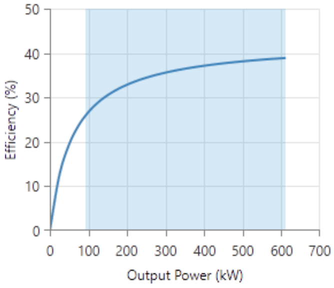
The combined St. Mary's–Mountain Village power system averages 500–750 kilowatts (kW) of load. St. Mary's is served by three diesel generator units operated at 480 volts (V) and the new 900 kW EWT turbine. The turbine is tied into the distribution system at 12.47 kV. The turbines are controlled by a Woodward EGC P2 controller that uses frequency measurement feedback. The tie-line is operated at 12.47 kV and is monitored by a switchgear. Mountain Village has four of its own diesel generators in a powerhouse, but they now serve as backup units; for this analysis, Mountain Village is represented by a single large load at the end of the approximately 20-mile, 12.47 kV tie line, and the generators are ignored for this analysis.

2.1.1.1 Power Generation

Diesel Generators

The St. Mary's powerhouse contains three diesel generators with technical parameters as shown in Table 3. The operation of the diesel generators depends on fuel efficiency considerations, maintenance needs, and spinning reserve requirements to ensure there is sufficient backup generation ready to ramp up in case one of the other diesel generators trips or the wind turbine ramps down due to low wind or a fault.

Table 3. Parameters for St. Mary's Diesel Generators (Vaught 2014)

	Cummins QSX15	Caterpillar 3512	Caterpillar 3508
Power (kW)	499	611	908
Intercept Coeff (L/h/kW)[a]	0.0222	0.0233	0.0203
Slope (L/h/kW output)	0.215	0.238	0.233
Minimum Electric Load	15%	15%	15%
Fuel efficiency curve produced from HOMER®			

[a] L/h/kW = liters/hour/kilowatt

Mountain Village currently has four diesel power generators with the following basic parameters:

- Detroit Diesel 12V2000: 710 kW
- Cummins QST30: 750 kW
- Caterpillar 3456: 505 kW
- Caterpillar 3412: 350 kW.

With the active tie-line between St. Mary's and Mountain Village as of 2021, these generators are only used for emergency backup power needs (e.g., if the tie-line fails). In normal operation, Mountain Village will be powered entirely by the wind turbine and diesel generators at St. Mary's. The Mountain Village generators were not included as part of the power system normal operation modeling.

Wind Turbine Generator

In May 2019, a single Type IV 900-kW EWT wind turbine (DW52-900HH50) was installed at Pitka's Point and connected to St. Mary's through a roughly 4-mile, three-phase, 12.47-kV distribution line. This turbine is oversized for both the average and peak loads at St. Mary's and was frequently curtailed until the new distribution tie-line integrated the additional Mountain Village load in November 2020. The turbine is outfitted with ice detection, a cold climate package, and black blades, allowing it to operate in temperatures as low as –40°C (Emergya Wind Technologies 2019).

The installed hub height is 50 meters (m), and the rotor diameter is 52 m (AVEC 2020b). Due to conflicting information regarding the exact model of turbine that was installed at St. Mary's, the power curve for the EWT-DW61 was mistakenly used in all of the subsequent analysis in this report rather than the EWT-DW52 (Emergya Wind Technologies n.d.[a]). In simulations, the EWT-DW61experienced a 5%–10% increase in energy generated compared to the EWT-DW52. Although the analyses are self-consistent across all labs in this mistake, future analysis will incorporate the correct power curve along with much more field data collected by AVEC to ensure the results are valid. The DW61 wind turbine power curve that was used in the analysis is plotted in Figure 7. During its first year of operation in 2019, the turbine produced 1.342 million kWh in 11 months of operation—offsetting 112,051 gallons of fuel and producing 41.5% of all power generated and consumed at St. Mary's. This equated to $319,559 of avoided fuel cost at a delivered rate of $2.8519 per gallon (AVEC 2020a).

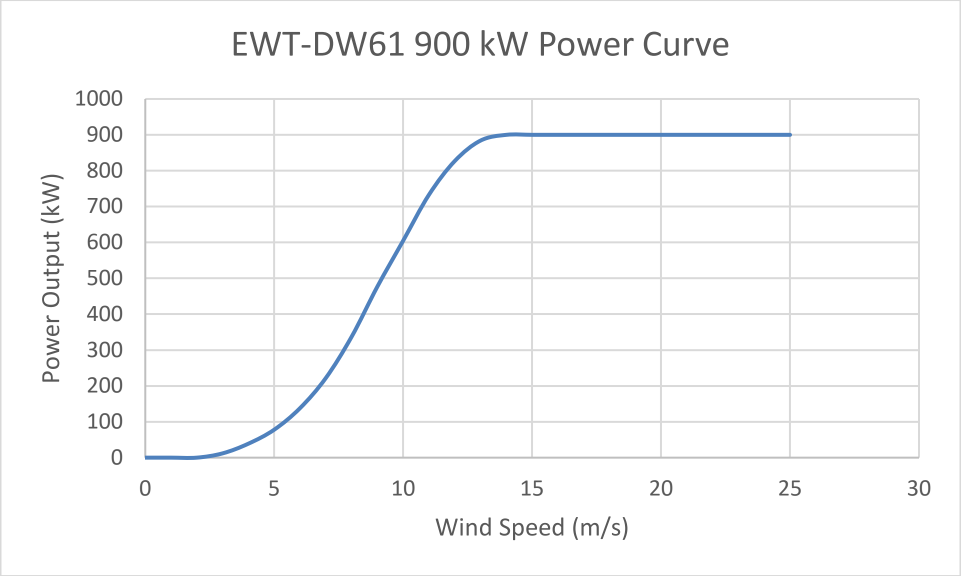


Figure 7. Power curve for the EWT DW61-900 wind turbine (Emergya Wind Technologies n.d.[b])

2.1.1.2 Resources

Diesel Fuel Delivery and Storage

In warmer months, fuel is delivered to St. Mary's primarily by barge, but it can be delivered by air, if needed, at a much higher cost. St. Mary's is located on the Andreafsky River, 5 miles upriver from the junction with the Yukon River. The Yukon River is typically ice-free and open to barge traffic from June through October, with the Andreafsky River providing the only deepwater dock in the area (Vaught 2014). Energy prices for these villages for electric power, gasoline, and diesel/heating fuel are among the highest in the United States. The 2019 AVEC annual report noted that the delivered cost of fuel to St. Mary's was $2.85 per gallon, which is lower than the overall AVEC average of $3.43 per gallon because St. Mary's is more accessible than many of the other communities (AVEC 2020a).[2]

The current tank farm in St. Mary's has a capacity of 244,264 gallons across 18 diesel tanks, which were refurbished in 2020. A new tank farm under construction will have a capacity of 414,000 gallons. This tank farm is designed to supply the new power plant that serves both St. Mary's and Mountain Village. The tank farms are filled by two AVEC tugs/barges—one with an 8,000-barrel capacity, which is equivalent to 336,000 gallons, and one with a 10,000-barrel capacity, which is equivalent to 420,000 gallons (Vitus Energy 2018a; 2018b).

Wind Resource

A wind resource assessment at St. Mary's was based on data collected from a meteorological evaluation tower installed on site temporarily between 2007 and 2009. A feasibility study was conducted around 2014 prior to the selection and installation of the wind turbine at Pitka's Point. The summary statistics provided in Table 4 and monthly statistics in Table 5 are based on data collected from the 38-m tower over the course of a year. For this analysis, the provided wind shear power law exponent was used to extrapolate to the 50-m hub height of the EWT wind turbine. These data were used to generate synthetic wind data as part of the power system analysis using the HOMER® microgrid design software.

Table 4. Pitka's Point Meteorological Evaluation Tower Data Synopsis (Vaught 2014)

Data collection dates	October 26, 2007, to February 12, 2009 (16 months)
Wind power class	Class 6 (excellent), based on wind power density
Wind power density mean, 38 m	558 W/m^2
Wind speed mean, 38 m	7.62 m/s (17.0 mph)
Max. 10-minute wind speed	29.5 m/s
Maximum 2-second wind gust	35.9 m/s (81.2 miles per hour [mph]), January 2008[3]
Weibull distribution parameters	k = 1.94, c = 8.64 m/s
Wind shear power law exponent	0.176 (low)
Roughness class	2.09 (description: few trees)
IEC 61400-1, 3rd ed. classification	Class II-c (at 38 m)
Turbulence intensity, mean (at 38 m)	0.076 (at 15 m/s)
Calm wind frequency (at 38 m)	20% (<4 m/s) (16-month measurement period)

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[2] Note that fuel prices can be volatile, especially so in remote communities where high fuel prices are exacerbated by the cost to transport fuel. If fuel prices were to double, as they did between 2019 (initiation of study) and 2022 (publishing of report), the costs and resilience value of including more diesel generation to the community may significantly change.

[3] Maximum 2-second wind gust is reported originally as 26.3 m/s (Vaught 2014), and has been edited in this report to be consistent with data in Table 5 (also from Vaught 2014). The discrepancy in the two reported values is used here to describe the wind resource at Pitka Point and was not used in this analysis, thus it does not affect results.

Table 5. Pitka's Point 38-m Anemometer Data Summary (Vaught 2014)

Month	Mean (m/s)	Median (m/s)	Max 10-min avg. (m/s)	Max gust (2 s) (m/s)	Std. Dev. (m/s)	Weibull (k) (-)	Weibull (c) (m/s)
Jan	10.17	10.70	29.5	35.9	5.34	1.97	11.45
Feb	9.21	9.20	20.1	23.3	4.07	2.41	10.36
Mar	8.62	8.5	21.8	26.3	4.33	2.07	9.71
Apr	7.98	7.80	16.9	20.6	2.83	3.05	8.90
May	7.27	6.90	21.8	27.1	3.67	2.06	8.19
Jun	5.70	5.80	13.2	15.3	2.62	2.28	6.40
Jul	7.98	7.70	21.7	26.3	3.33	2.55	8.99
Aug	5.89	5.70	15.3	17.9	2.95	2.05	6.62
Sep	6.37	6.70	12.5	16.8	2.44	2.85	7.11
Oct	6.80	6.60	20.1	24.8	3.81	1.80	7.62
Nov	7.32	6.40	24.1	29.8	4.48	1.72	8.23
Dec	8.97	8.90	22.9	27.5	4.69	1.95	10.07
Annual	**7.62**	**7.20**	**29.5**	**35.9**	**4.09**	**1.94**	**8.64**

2.1.1.3 Loads

The electrical loads at St. Mary's were estimated from a wind turbine feasibility study (Vaught 2014). The analysis was based on data provided by AVEC to a consultant and included historical (2009–2011) supervisory control and data acquisition (SCADA) data. The results of that analysis are detailed in Table 6.

Table 6. Average and Peak Loads for St. Mary's—Estimated From Prior Analysis (Vaught 2014)

Month of 2010	Average Load (kW)	Peak Load (kW)
Jan	366	430
Feb	360	423
Mar	357	419
Apr	323	379
May	293	343
Jun	262	307
Jul	253	297
Aug	277	325
Sep	280	329
Oct	314	369
Nov	336	394
Dec	351	412
Annual	**314**	**369**

The average monthly loads for one year at Mountain Village are provided in (Vaught 2014) and are also based on historical SCADA data from AVEC in 2011 and summarized in Table 7. The loads are similar in scale to the St. Mary's loads; in the HOMER model, the values generated for St. Mary's were simply doubled to approximate the two villages. This was necessary because the model runs in 1-hour time steps and generates statistical variation in the hourly load profiles based on the provided average and peak monthly values.

Table 7. Average Monthly Loads From Mountain Village in 2011 (Vaught 2014)

Month of 2011	Average Load (kW)	Peak Load (kW)
Jan	384	506
Feb	385	502
Mar	368	477
Apr	351	461
May	307	437
Jun	249	362
Jul	254	363
Aug	264	591
Sep	287	404
Oct	306	440
Nov	366	491
Dec	372	519
Annual	**330**	**591**

St. Mary's power system includes a secondary load control system comprising a 327-kW electric water heater and related control and switching relays to help integrate the naturally intermittent wind power. This system can absorb excess electrical energy during periods when the output of the wind turbines exceeds the community load and will transfer the excess energy to the glycol-based heat recovery loop in the AVEC power plant and, ultimately, to an existing heat-recovery loop serving St. Mary's municipal facilities (water treatment plant, city offices, and shop/hotel) (Vaught 2014). AVEC originally installed this system to better integrate NPS-100 turbines, which had much less controllability compared to the new EWT turbine. The system still exists and operates and could be used as part of a controllable load dispatch operation.

2.1.2 Temperature

Table 8 summarizes temperature data, also provided as part of the feasibility study and incorporated into the HOMER tool to account for temperature effects on the turbine operation due to density changes in the air mass.

Table 8. Average Temperature and Density From St. Mary's, Alaska (Vaught 2014)

Month	Mean (°F)	Min (°F)	Max (°F)	Mean (°C)	Min (°C)	Max (°C)	Mean (kg/m³)	Min (kg/m³)	Max (kg/m³)
Jan	4.7	−20.2	39.0	−15.1	−29.0	3.9	1.341	1.248	1.416
Feb	4.1	−24.7	32.4	−15.5	−31.5	0.2	1.343	1.264	1.430
Mar	11.0	−14.3	38.8	−11.7	−25.7	3.8	1.323	1.248	1.397
Apr	19.5	−6.3	44.2	−7.0	−21.3	6.8	1.299	1.235	1.372
May	39.4	13.8	65.5	4.1	−10.1	18.6	1.247	1.185	1.314
Jun	49.2	29.5	70.2	9.5	−1.4	21.2	1.223	1.174	1.272
Jul	50.5	37.9	81.9	10.3	3.3	27.7	1.220	1.149	1.250
Aug	51.3	33.1	70.9	10.7	0.6	21.6	1.218	1.173	1.263
Sep	45.1	30.0	64.6	7.3	−1.1	18.1	1.233	1.187	1.270
Oct	22.7	5.0	37.2	−5.2	−15.0	2.9	1.290	1.252	1.339
Nov	16.3	−14.6	44.6	−8.7	−25.9	7.0	1.308	1.234	1.398
Dec	13.9	−16.2	45.0	−10.1	−26.8	7.2	1.315	1.233	1.403
Annual	**27.3**	**−24.7**	**81.9**	**−2.6**	**−31.5**	**27.7**	**1.280**	**1.149**	**1.430**

2.1.3 Site/System Goals

The general St. Mary's and Mountain Village power system design and operational goals are twofold:

1. **Reduce diesel use/operate with diesel off.** Most remote Alaskan villages rely entirely on diesel fuel power generation. Diesel fuel is expensive and difficult to transport to many villages and is prone to weather-based disruptions and higher-than-average consumption in the winter months. Diesel fuel also generates carbon dioxide (CO_2) pollution that contributes to the climate change impacts that are especially affecting Arctic communities. Diversifying energy generation with on-site renewable power, such

as wind energy, can lead to lower energy costs, better community resilience, and reduced climate impacts.

2. **Improve power quality, including frequency and voltage stability.** As an isolated microgrid, the St. Mary's and Mountain Village power system does not have interconnection to adjacent electrical systems that can provide frequency and voltage support via inertia and injection/absorption of real and reactive power. Therefore, a second performance goal is to improve power quality. The commissioning of the intertie-line between St. Mary's and Mountain Village is a step toward making the combined systems more reliable and more resilient because they can now use generators in both villages to provide backup generation as needed. In this study, we are interested in analyzing the resilience of distributed wind, so we consider the impacts to power quality both with and without the wind asset, and with and without wind turbine-provided grid services.

The MIRACL project team's analysis works toward the St. Mary's and Mountain Village power system goals. Our valuation analysis demonstrates the value of reduced diesel usage, our advanced control analysis investigates reducing the diesel spinning reserves, and our resilience analysis explores the ways in which diversified generation increases community resilience.

2.2 Valuation Framework Results

Reference system details were defined to determine which valuation chart sections were relevant to our analysis (isolated microgrid, front-of-the-meter, and cooperative owned) from the distributed wind valuation framework. After gaining an understanding of the system through AVEC reports and discussions with researchers who had studied the system, we then determined which value elements were most important and how to value many of them. The narrowed list of value elements is provided in Table 9. The green cells indicate value elements that are quantified in this report, and the yellow cells indicate value elements that can be explored through future modeling and assumptions. These yellow value elements are not currently revenue streams for St. Mary's, but could be explored through advanced control and energy storage.

Table 9. St. Mary's Selected Value Elements

🟩 Quantified Here
🟨 For Future Analysis

		System Connection Type	Off-Grid (Isolated) Assets/Microgrids	
		System Location of Assets	Front-of-meter	
		Ownership Structure	Cooperative-Owned	
		Value Perspective	Electric Cooperative	Society
		Stakeholder Roles:		
		Distribution System Operator/Provider	✓	
		Energy Generation Owner/Operator	✓	
Category	**Value Elements**	**Quantifiable?**		
Bulk Energy Services	Energy Generation	Yes	🟩 ✓	
	Load Following	Potentially	🟨 ✓	
	Voltage Support (providing reactive/active power)	Potentially	🟨 ✓	
	Inertial Response	Potentially	🟨 ✓	
Distribution Services	Power Reliability/ Resilience/ Outage Mitigation	Yes	🟩 ✓	🟩 ✓
	Job Creation	Potentially		🟩 ✓
	Environmental Benefits	Potentially		🟩 ✓

Following the valuation framework guide, PNNL decided that the valuation would be conducted from the perspective of AVEC and that value elements impacting society would also be included. Customer perspectives were excluded due to data confidentiality/accessibility and the scope of the valuation. Equations for each of the relevant value elements were then constructed, considering the ownership structure, project configuration, and other business elements.

2.2.1 Value Element Calculation Methodology

Value elements were calculated across a 20-year project lifetime, and the net present value (NPV) of each value element stream was found using a nominal discount rate. To find this discount rate, we followed methodology used by the Northwest Power and Conservation Council (2010) and assumed that electric cooperatives can finance at about 100 basis points above 30-year Treasury rates. Using the median annual 30-year Treasury rate between 2009 and 2021, we calculated a nominal discount rate of 4.02% (equations presented in following sections). Sensitivity analyses were conducted for higher and lower discount rates, further detailed in Section 2.2.8. NPV benefits and costs were organized by entity and are presented in Section 2.2.8. Qualitative value elements that could be potentially significant are presented simultaneously with the benefit-cost figures.

2.2.2 St. Mary's Value of Energy Generation

The value of wind energy generation at St. Mary's and Mountain Village is calculated as the avoided cost of alternative energy generation—in this case, energy from diesel generators. Fuel consumption was compared between two scenarios: (1) a system with only diesel generators, and (2) a system with a wind turbine and diesel generators, with the generators providing 100% spinning reserves for the wind turbine. Through modeling of the wind resource, temperatures, average loads, and generator efficiencies, the annual fuel consumption was calculated for the no-wind and with-wind scenarios. (More details on this modeling are provided in Section 2.3.2.1.)

Fuel consumption in the no-wind scenario was estimated at 375,643 gallons per year, while fuel consumption for the with-wind scenario was estimated at 230,283 gallons per year. This meant the wind turbine provided an annual fuel savings of 145,360 gallons.

We then multiplied the annual fuel savings by the delivered fuel price of diesel for St. Mary's for each year of the project lifetime (2019–2039) and calculated the NPV of these revenue streams, as shown in Equation 1:

$$NPV\ Energy\ Generation\ =\ \sum_{t=0}^{20} \frac{(Fuel\ Savings_t \times p_t)}{(1+i)^t}, \qquad (1)$$

where

$Fuel\ Savings_t$ = fuel consumption (gallons [gal]) without wind in year, t – fuel consumption (gal) with wind in year, t

t = year
p_t = fuel price ($/gal) in year t
i = discount rate.

In our analysis, the annual fuel savings are a constant 145,360 gallons from Sandia's HOMER analysis. The discount rate for the electric cooperative is assumed to be 4.02% and the 2019 fuel price is $2.8519 per gallon (taken from the 2019 annual report from AVEC, which gives St. Mary's delivered cost of fuel) (Vaught 2014). To forecast future fuel prices through the project's lifetime, we used energy price forecasts from the U.S. Energy Information Administration (EIA) (2021a). Because AVEC's historical diesel prices, calculated from AVEC's annual reports, followed similar trends to EIA's historical prices from 2007 through 2015, we felt the EIA's *Annual Energy Outlook* provided a reasonable forecast for the region. We took the EIA distillate fuel oil price forecasts from 2019 to 2050 for the Pacific region and calculated indices for each forecasted year's price compared to the 2019 price in the EIA data set. We then multiplied St. Mary's 2019 fuel price by each year's index to obtain that year's forecasted price for St. Mary's. The prices used in this valuation are shown in Table 10.

Table 10. Forecasted Fuel Prices for St. Mary's[4]

Year	$/gal (2019$)	Year	$/gal (2019$)
2019	$2.85	2030	$2.54
2020	$2.78	2031	$2.58
2021	$2.69	2032	$2.60
2022	$2.62	2033	$2.65
2023	$2.54	2034	$2.68
2024	$2.48	2035	$2.71
2025	$2.39	2036	$2.74
2026	$2.44	2037	$2.76
2027	$2.45	2038	$2.79
2028	$2.50	2039	$2.82
2029	$2.52		

2.2.3 St. Mary's Job Creation and Economic Impacts

Job creation benefits and regional economic impacts for St. Mary's distributed wind project were calculated using NREL's Jobs and Economic Development Impact (JEDI) models, specifically the JEDI Distributed Wind Model rel. DW12.23.16 model (JEDI: Jobs & Economic Development Impact Models n.d.). JEDI results are divided into three types: on-site earnings, supply chain impacts, and induced impacts. The on-site earnings refer to the wages and salary compensation paid to workers for the project. The supply chain impacts are the impacts in supporting industries in Alaska (the increase in demand for goods and services from direct on-site project spending). Induced impacts are increases in activity from earnings being spent by workers involved in the first two categories (on-site labor and local revenue and supply chain impacts). All these impacts are broken out by the one-time impacts from the construction phase and the ongoing operations impacts. For our valuation modeling, we summed these three types of impacts to find the economic impacts to society (in this case, Alaska) from the St. Mary's distributed wind project. It is important to note that JEDI results show gross impacts, not net impacts, which means these numbers don't show losses associated with any displacement of alternative energy sources.

To implement the JEDI model, we input project data and used JEDI default inputs, which come from wind industry averages, where project data were not available. For example, total project costs were listed as $5,512,024 (AVEC 2020b), but default JEDI values were used to determine the proportion of this capital expenditure that went to each cost category (i.e., the turbine, tower, foundational materials, electrical wiring, and labor as well as the balance-of-systems costs). Similarly, we assumed ongoing operational costs to be 5 cents per kWh, based on (AVEC 2020b), which we multiplied by an annual output of 2,454,047 kWh, as estimated in Sandia's

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[4] Note that fuel prices can be volatile, and that even in the time since beginning this study, fuel prices have increased substantially, exceeding forecasted fuel prices. This underlines the importance of incorporating less volatile generation in remote communities, who may be disproportionally affected by fuel cost increases.

HOMER analysis. However, the breakdown of these costs by labor and material type was calculated using default values from the JEDI model.

The region being analyzed was defined in the model as the state of Alaska, meaning that economic impacts are calculated across the state's industries and workers. A more local analysis was not pursued due to data limitations (input-output data are not available for such a small community) and because local economic impacts are likely to be limited to mostly labor. Percentages of sales purchased in Alaska and manufactured in Alaska were estimated for each material/labor type specified, primarily using JEDI default percentages. Slightly lower percentages were estimated in some categories (such as the tower wiring kit) because of our assumption that there are relatively few Alaskan suppliers for these items.

There are several limitations of economic impact results from the JEDI model. First, the results from the model are based on approximations of industrial input-output relationships, not on actual relationships. Approximations are obtained by using expenditures within industrial sectors and resulting economic activity to estimate how new expenditures will affect the region. This also means that inputs are always used in fixed proportions in this model, which may not always be realistic. Additionally, the results of this model can only be as good as the initial inputs, and many assumptions were made in this analysis, especially regarding the percent of regional sales. Still, these results give an idea of the magnitude of the economic impact of this distributed wind project in Alaska.

2.2.4 St. Mary's Environmental Benefits

The environmental benefits of a renewable generation project, such as the wind turbine in St. Mary's, stem from the avoided pollution that would have been emitted by fossil fuel energy generation. In the case of St. Mary's, this means diesel generators. For the purposes of this valuation, we limited the scope of the benefits calculations to avoided CO_2. These benefits were calculated as shown in Equation 2:

$$NPV\ Env.Benefits\ = \sum_{t=0}^{20} \frac{Fuel\ Savings_t \times 10.18^{-3} \times 76}{(1+ i\ )^t}, \tag{2}$$

where

Fuel Savings_t = fuel consumption (gal) without wind in year, *t* – fuel consumption (gal) with wind in year, *t*
t = year
i = discount rate.

The discount rate for society is assumed to be 2%, which is consistent with Drupp et al. (2018). Annual avoided fuel was calculated, as above, in the energy valuation section. The amount of CO_2 emitted per gallon of diesel was taken from the U.S. Environmental Protection Agency's (EPA's) Greenhouse Gases Equivalencies Calculator—Calculations and References (EPA n.d.[b]), and we assume that all the carbon in the diesel is converted to CO_2. The social cost of carbon is estimated to be $76 per metric ton of CO_2 which is taken from a 2021 publication by the White House's Interagency Working Group on Social Cost of Greenhouse Gases (2021). The social cost of carbon value used in this analysis is the 2020 value, calculated at a 2.5% discount rate, deflated to 2019 dollars using the Consumer Price Index for All Urban Consumers (CPI-U) (U.S. Bureau of Labor Statistics 2021b).

2.2.5 St. Mary's Renewable Energy Certificates

Renewable energy certificates (RECs) are tradable certificates of proof of 1 megawatt-hour (MWh) of electricity generated through renewable energy or energy efficiency (Hamrin 2014). These RECs are often bought by utilities who use them in their overall efforts to meet state renewable portfolio standards. RECs can also be used for voluntary purposes, though this voluntary market tends to have lower prices because buyers can draw from a larger national supply of RECs (EPA n.d.[a]). Because Alaska does not have a renewable portfolio standard, RECs can be sold across state boundaries in the voluntary market. A voluntary national REC prices were about $0.7/MWh (Vitus Energy 2018b). We adjusted this value to 2019 dollars and multiplied it by the annual megawatt-hours produced (as estimated in the HOMER analysis), then grew it at a steady 2% growth rate over the life of the project. We then took the total NPV of REC value to the cooperative over the life of the project, including it in the results in Section 2.2.8.

2.2.6 St. Mary's Resilience Benefits

The resilience benefits of the St. Mary's distributed wind project are characterized as the added ability (provided by the distributed wind system) to adapt to disruptive events and recover rapidly to an acceptable state of operation. From a valuation perspective, these benefits can be described as the avoided costs of these disruptive events—costs that do not occur when the wind system is present.

To value these benefits, we use a scenario-based approach, adding monetary values to the resilience metrics defined by INL in Section 2.4. There are three identified types of hazards outlined in Section 2.4: fuel shortage, severe winter weather event, and communications outages. These hazards were analyzed separately, and their resulting values are independent of each other, as opposed to a multihazard risk assessment, which would investigate the possibility of them occurring simultaneously.

The severe winter weather event and communications outage metrics from INL only showed potential impacts to overall fuel consumption, so we did not include those in the value stack of benefits and costs for St. Mary's in Section 2.2.8, but rather as a scenario analysis in Section 2.4. The risk of fuel shortage, on the other hand, was directly linked to load being lost, affecting the value of outage mitigation to both AVEC and the community, so they were included in the St. Mary's benefit results in Section 2.2.8. The detailed discussion of these results is presented in Section 2.4.

2.2.7 St. Mary's Costs

Following the valuation framework, relevant costs were identified for the St. Mary's system. Costs that could be quantified using existing reports and assumptions are shown as green in Table 11, and costs that may be relevant but did not have supporting data for their estimation are shown in yellow. We also identified societal costs that, while difficult to quantify, could be described qualitatively. These are discussed in the results in Section 2.2.8.

Table 11. Selected St. Mary's Costs

System Connection Type		Off-Grid (Isolated) Assets/Microgrids	
System Location		Front-of-Meter	
Ownership Structure		Operator/Cooperative-Owned	
Cost Perspective		Operator/Cooperative	Society
Distribution System Operator/Provider		✓	
Energy Generation Owner/Operator		✓	
Cost/Impact Element	**Quantifiable?**		
Capital Costs	Yes	🟩 ✓	
Operations and Maintenance (not fuel-related)	Yes	🟩 ✓	
Major Overhauls and Replacements	Yes	🟨 ✓	
Taxes	Yes	✓	
Insurance	Yes	🟩 ✓	
Power Quality Costs	Yes	🟨 ✓	
Administrative Costs	Yes	🟨 ✓	
Viewshed Impacts	Potentially		🟩 ✓
Wildlife Impacts	Potentially		🟩 ✓
Human-Environment Interactions (e.g., vibration, sound, or shadow flicker)	Potentially		🟩 ✓

🟩 Considered here

🟨 Future analysis

Quantifiable costs for the St. Mary's system were estimated from the project closeout report written by AVEC for DOE in 2020 (AVEC 2020b). Initial capital expenditures summed to $5,512,024, of which $5,403,095 came from awards from DOE and the state of Alaska (AVEC 2020b). We assume that the remaining $108,929 were funded by AVEC through debt. We calculate the 2019 cost of debt as 3.37% by dividing interest payments by long-term debts from AVEC's *Annual Report 2019* (AVEC 2020a). Over the 20 years of the project's lifetime, total debt service payments were calculated as annualized payments of $7,574 (the sum of interest and principal payments). The NPV of this is $102,788 in 2019 dollars, which is lower than initial capital expenditure because the cooperative's weighted cost of capital is higher than its cost of debt.

Because we did not have actual insurance costs, we assumed them to be similar to insurance rates faced by Orcas Power & Light Cooperative in San Juan County, Washington (Mongird et al. 2018). Using this rate of 0.271% of the initial cost of the project, and growing insurance costs at a steady 2%, we found the NPV of insurance costs to be $235,249 in 2019 dollars.

As an electric cooperative, AVEC does not pay federal or state income tax. Additionally, St. Mary's does not have property taxes, so no taxes were included in costs (Caissie 2020).

Ongoing operational costs were assumed to be 5 cents per kWh, as assumed in the 2014 report prepared for AVEC by V3 Energy, LLC (Vaught 2014). We then multiplied this by the annual output of 2,454,047 kWh, as estimated in Sandia's HOMER analysis, to find an annual operations and maintenance (O&M) cost of $122,702 in 2019 dollars. We used an O&M escalation rate of 2.5% to find the cost for each year of the project. The NPV of these expenditures was found to be $2,059,384 in 2019 dollars. Compiled and calculated costs over the project's lifetime are shown in Table 12.

Table 12. St. Mary's Costs by Year of the Project

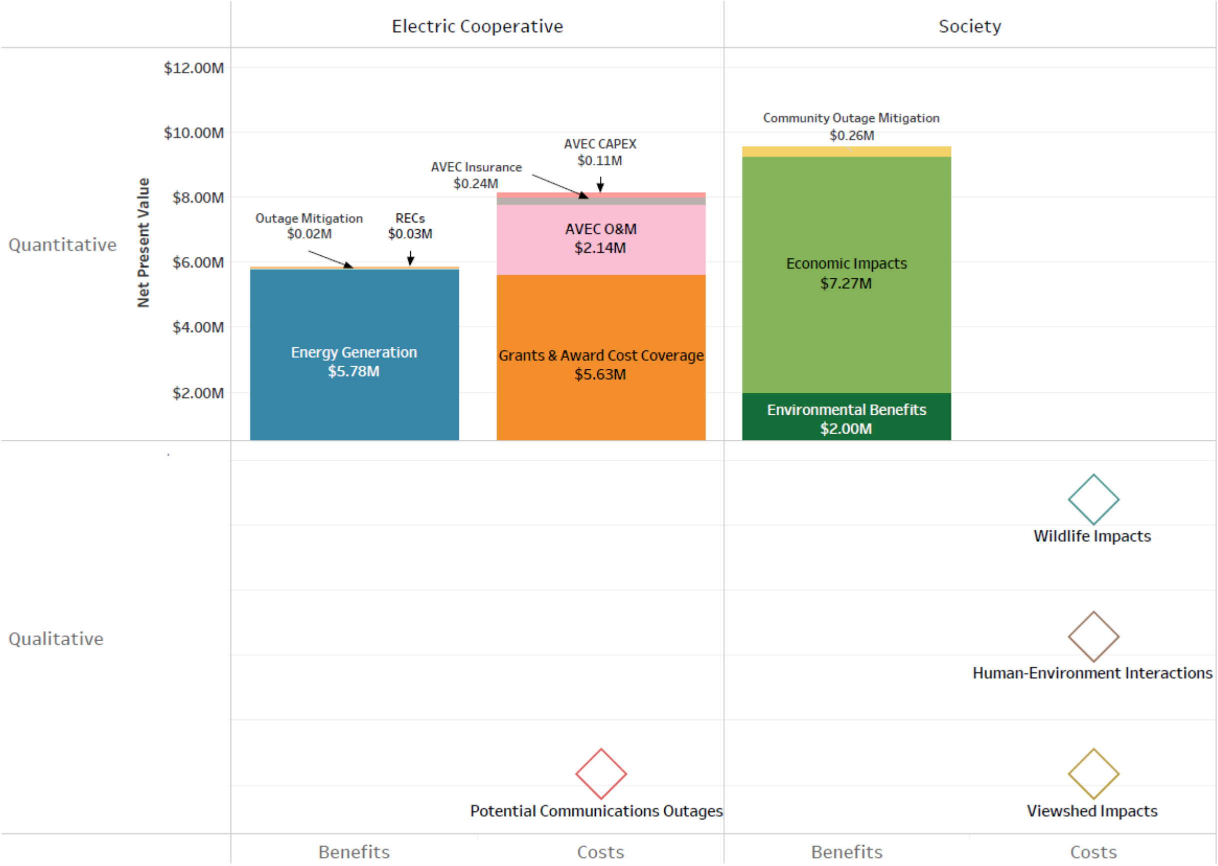
Year	Grants and Awards ($)	AVEC Debt Service ($) (as an annualized cost of interest and principal payments)	AVEC Insurance ($)	O&M ($)	Total ($)
0	5,403,095				5,403,095
1		7,574	14,642	122,702	144,919
2		7,574	14,935	125,770	148,280
3		7,574	15,234	128,914	151,723
4		7,574	15,539	132,137	155,250
5		7,574	15,849	135,440	158,864
6		7,574	16,166	138,826	162,567
7		7,574	16,490	142,297	166,361
8		7,574	16,820	145,855	170,249
9		7,574	17,156	149,501	174,231
10		7,574	17,499	153,238	178,312
11		7,574	17,849	157,069	182,493
12		7,574	18,206	160,996	186,777
13		7,574	18,570	165,021	191,166
14		7,574	18,941	169,147	195,663
15		7,574	19,320	173,375	200,270
16		7,574	19,707	177,710	204,991
17		7,574	20,101	182,152	209,828
18		7,574	20,503	186,706	214,783
19		7,574	20,913	191,374	219,861
20		7,574	21,331	196158	225064
NPV in 2019$	**5,403,095**	**102,788**	**235,249**	**2,059,384**	**7,800,516**
NPV in 2021$	**5,626,673**	**107,042**	**244,984**	**2,144,600**	**8,123,299**

2.2.8 St. Mary’s Valuation Results

Given the assumptions listed in the previous sections, we show the valuation results in Figure 8 for the St. Mary’s distributed wind system. Because we did not have full data for this system, these benefits and costs are representative and do not reflect the real costs and benefits of the system. Still, they give an idea of the likely magnitude and range of values. And, although NPVs were originally found for 2019—the first year of the project—we adjusted those to 2021 dollars using the CPI-U.

For AVEC, the NPV of energy generation was estimated to be $5,777,754, and utility outage mitigation and avoided lost revenues (discounted by the probability of its occurrence) were estimated to be $17,383. REC benefits were $31,670 over the life of the project, bringing total electric cooperative benefits to $5,826,807. Total system costs were estimated to be $8,123,299, though a large portion of this was funded through grants and awards (Hamrin 2014).

When we consider benefits and costs for stakeholders beyond the electric cooperative, the benefit-to-cost ratio is much less (ratio = 0.72), which highlights the need for the grants and awards that helped fund the project. This finding also suggests that it might be important to the electric cooperative to explore additional energy generation benefits by operating the wind turbine with fewer diesel spinning reserves. However, when including the societal perspective, the net benefits are almost twice the costs, meaning the turbine provides significant benefits to the local community and to society in general.



Acronyms: Alaska Village Electric Cooperative (AVEC); Capital Expenditures (CAPEX); Operations & Maintenance (O&M); Renewable Energy Certificates (RECs)

Figure 8. St. Mary's valuation results (Mongird and Barrows 2021)

There are several societal benefits that have a large value. The environmental benefits of the system, measured here as the avoided CO_2 from diesel generators, totaled $1,997,310 over the lifetime of the project. The economic impacts to Alaska through jobs, supply chain impacts, and induced effects were estimated to be $7,274,164, almost half of which came from the one-time costs of project construction. Resilience benefits, in the form of community outage mitigation, were estimated using the scenarios provided in Section 2.4. These benefits, discounted by the probability of their occurrence, are $255,438. Although this value may seem low, these estimates reflect just the average value of lost load for customers during a 2-day and a 2-week outage, and do not contain the local economic impacts or the health impacts of such a scenario, which could be significant if an outage occurs during winter.

In addition to the benefits and costs that are more easily quantifiable, there is a range of elements that are difficult to quantify but still valuable to include in some manner. This is typically the case in more subjective costs, such as viewshed impacts or noise impacts, which often rely on willingness to pay estimations. We also note that there may be potential communications outage costs to the utility related to the turbine, which we explore in greater detail in Section 2.4. The subsections that follow discuss a number of applicable value and cost elements that are relevant to the St. Mary's project but are limited to qualitative discussion as the form of assessment.

2.2.8.1 Viewshed Impacts, Wildlife Impacts, and Human-Environment Interactions

Just as with benefits, there are costs and impacts to society that can be difficult to monetize or quantify in general. For the St. Mary's project, these include viewshed impacts, wildlife impacts, and human-environment interactions, each of which are described in more detail below.

- **Viewshed impacts**. Viewshed impacts represent the costs of the "visual intrusion" of a distributed wind project. Usually the environmental impact assessment for a wind project will include viewshed analyses to ensure the project is not too disruptive. The visual intrusion of the wind turbine from various perspectives can be viewed through street-view-oriented visual analyses while accounting for atmospheric refraction and the Earth's curvature (Vaught 2014). Although there are accepted methods for calculating whether a wind turbine is part of a particular viewshed, it is difficult to put a cost on the visual disruption to those impacted. One method to measure this is willingness-to-accept, used in various studies in the literature (Buckley 2021; Chiang et al. 2016). However, these studies usually involve site-specific surveys and interviews with impacted stakeholders and, due to the scope of this project, this information was unavailable for St. Mary's. The expected viewshed impacts for this project are assumed to be small, given the distance from the wind turbine to the main locations of residential and commercial customers. Figure 9 shows both an aerial map of the distance between the wind turbine and the town as well as the view from the wind turbine site. Because the wind turbine is within sight of the town, it is possible that there could be some viewshed impact costs associated with the project. However, more analysis would need to be conducted to determine these impacts.

(a) (b)

Figure 9. (a) Proximity of wind turbine to the town of St. Mary's (Groothuis, Groothuis, and Whitehead 2008). (b) View of St. Mary's from Pitka's Point wind turbine site (The Wind Power 2021).

- **Wildlife impacts**. Wind turbine effects on nearby wildlife are usually included in an environmental assessment for a generation project. There may be costs associated with degradation in habitat in the surrounding environment, affecting wildlife in that area. There is ongoing research attempting to evaluate the environmental and wildlife impacts from wind projects. These impacts can include wildlife fatalities, collisions with turbines, overall deterrence from the area, among others (Vaught 2014; American Wind Wildlife Institute 2014). Similar to viewshed impacts, even if wildlife impacts can be quantified, it is difficult to monetize them. Analyses would typically rely on willingness-to-pay methodologies to measure the value of wildlife and ecosystem preservation to those in St. Mary's. Due to limited data, this cost is only included qualitatively.

- **Human-environment interactions**. There may also be impacts through other human-environment interactions. This category covers costs and disruptions such as noise, shadow flicker, or other outcomes from the wind turbine. Much like viewshed and wildlife impacts, this cost can be measured through willingness-to-accept analysis. Because the St. Mary's turbine is relatively far from the village residential and commercial population, it is not expected that these costs are substantial for this project. However, more detailed analysis would need to be conducted to determine whether this is true.

2.2.8.2 Sensitivity Analyses

The discount rate used in this analysis to find the NPV of a flow of revenue or costs was 4.02%, as described in Section 2.2.3.1. If this discount rate were higher or lower by one percentage point, the results would change slightly, as shown in Table 13.

Table 13. St. Mary's Valuation Sensitivity Analysis

Value Element	Base Case	Discount Rate +1%	Discount Rate −1%
Energy Generation	$5,777,754	$5,330,252	$6,289,269
Outage Mitigation	$17,383	$17,383	$17,383
Environmental Benefits	$1,997,310	$1,830,647	$2,188,359
Economic Impacts	$7,274,164	$6,969,833	$7,623,027
Community Outage Mitigation	$255,438	$234,139	$279,854
Renewable Energy Certificates	$31,670	$29,026	$34,700
TOTAL Benefits	**$15,353,719**	**$14,411,280**	**$16,432,593**
AVEC Capital Expenditures	$107,042	$98,162	$117,172
AVEC O&M	$ 2,144,600	$1,951,636	$2,366,053
AVEC Insurance	$244,984	$223,285	$269,858
Grants and Awards	$5,626,673	$5,626,673	$5,626,673
TOTAL Costs	**$8,123,299**	**$7,899,756**	**$8,379,756**

2.3 Advanced Control and Hybrid System Design Results

2.3.1 Analysis Scenario Descriptions

For this isolated grid case study using St. Mary's and Mountain Village as reference systems, three different scenarios were analyzed to understand the relative impacts of wind and wind with advanced control on the valuation and resilience of the communities. The details of the three scenarios are described in the following sections.

2.3.1.1 Scenario 1: St. Mary’s and Mountain Village Operating on Diesel Power Only, No Wind Energy

This scenario describes the pre-2019 power system architecture of the two villages before the wind turbine and tie-line were constructed. Each village operated independently on their own diesel generators. This also serves as a proxy for most of the other remote villages that AVEC serves in Alaska. From a control perspective, this provides one possible baseline for power system performance in terms of voltage and frequency stability and diesel fuel consumption. For the HOMER analysis, the system was simplified to add the Mountain Village load to the St. Mary’s load and used only the St. Mary’s diesel generators in the analysis. This is sufficient to capture simple metrics like diesel consumption, but not sufficient to capture more transient power system parameters, such as voltage or frequency stability. This type of analysis will be performed in the coming year, once detailed historical SCADA and phasor measurement unit data are made available.

2.3.1.2 Scenario 2: St. Mary’s and Mountain Village Operating with Diesel and Wind with Basic Control, as They Are Currently in 2021

This scenario represents the current (2021) architecture of the St. Mary’s and Mountain Village power system. The wind turbine was first operational in 2019, and the tie-line connecting the villages was completed in late 2020. The general operational mode is to power both villages with the St. Mary’s diesel generators and the wind turbine, with Mountain Village acting as just a load at the end of the approximately 20-mile tie-line. The system is being operated very conservatively until sufficient operational experience is gained with the new assets; therefore, there is a requirement for 100% of wind generation spinning reserve to be provided by the diesel generators.

2.3.1.3 Scenario 3: St. Mary’s and Mountain Village Operating with Diesel and Wind with Advanced Control, as Represented by Improved Forecasting

AVEC is currently in the process of specifying and bidding out a project to install a grid-bridging system that incorporates electrical energy storage and a grid-forming inverter to enable more wind and less diesel fuel while maintaining system stability. This will effectively take the place of a portion of the spinning reserve requirements currently provided by diesel generators. Another possible way to reduce spinning reserve requirements is to use advanced control for the wind turbine, such as improving wind resource forecasting 5 or 10 minutes out. This would provide an estimate of the “firm wind” that could be relied on, and the spinning reserve requirement could be reduced, enabling diesel generators to operate higher up on their efficiency curve. It could also potentially allow AVEC to turn some units off. Additional advanced wind turbine control features will be explored in the coming year, such as frequency and voltage regulation services that could provide improvements to power system performance.

2.3.2 Results

2.3.2.1 Advanced Control at St. Mary’s

For this preliminary study, the advanced control analysis considered the three scenarios as presented using the HOMER microgrid analysis tool. The parameters and assumptions presented in the St. Mary’s and Mountain Village overview section (Section 2.1) were incorporated into the power system model in HOMER, and the three scenarios were analyzed. The primary output metric from the modeling was total diesel fuel consumed as a measure of the value that the wind turbine and wind turbine with advanced control (forecasting) bring to the system. HOMER is not capable of assessing power system performance according to metrics like voltage and frequency stability, but these will be assessed in future research using a MATLAB Simulink model that has been built for the St. Mary's and Mountain Village power systems. Additional detailed historical power system performance data will be provided by AVEC to support this more detailed research. The results in Table 14 are summarized according to the three scenarios. As a reference, there are some actual summary power system performance data available to compare against. A report from AVEC (AVEC 2020b) provides a summary of the wind energy generated at St. Mary's (11 months of operation) plus the diesel generation at both St. Mary's and Mountain Village as well as the total load at each location during 2019.

Table 14. Summary of Actual St. Mary's and Mountain Village Generation and Load for 2019 (AVEC 2020b)

2019	**Generation by Source (kWh)**			**Load (kW)**	
	Diesel	**Wind**	**Total**	**Peak**	**Average**
St. Mary's (including Pitka's Point)	1,891,432	1,342,374	3,233,806	702	370
Mountain Village	2,644,906		2,644,906	522	302
Total	4,536,338	1,342,374	5,878,712		

Note that at the time of this reference report, there was no tie-line between the villages, and so the wind turbine was curtailed above about 400 kW to 500 kW of power to not exceed the load demand of St. Mary's and Pitka's Point. With the additional data provided in the future, a more precise validation effort can be made.

Scenario 1: Baseline, No Wind Turbine

The HOMER analysis for a single year of operation with only diesel generators showed a diesel fuel consumption of 375,643 gallons for an electrical output of 5,507,850 kWh. For comparison, the available data in Table 14, which show 5,878,712 kWh of total generation from diesel and wind, and using the AVEC-published 2019 Annual Report (Northwest Power and Conservation Council 2010) value of 13.69 kWh sold per gallon of diesel fuel consumed, equates to 429,416 gallons of diesel fuel equivalent. Some of that discrepancy is likely a result of the assumption that 13.69 kWh were sold per gallon of diesel fuel consumed from AVEC, which is a fleet average. However, HOMER will select the most efficient generator and optimize the operation to minimize fuel consumption, which is how it arrives at an average of 14.6 kWh generated per gallon consumed. The load from 2019 also does not perfectly match the HOMER simulated load, so there is about a 5% difference in load as well. The following analyses are all done on a relative basis to Scenario 1, so the simulated load and fuel consumption data are internally consistent.

Scenario 2: Baseline Plus Wind Turbine with Basic Control

For this scenario, the wind turbine is added to the system and a spinning reserve of 100% was added under the HOMER constraints tab as operating reserve as a percent of wind power output. The results indicate that 230,283 gallons of diesel fuel are consumed, a savings of 145,360 gallons, or 61% compared to the baseline in Scenario 1. The HOMER model also results in 2,454,057 kWh of electricity generation from the wind turbine. It is difficult to compare the wind turbine power output to the data in Table 14 because of the unknown amount of curtailment of the turbine and the shorter operating window, but it is conceivable that with another month of operation and the doubling of load and removal of any curtailment, the turbine could produce twice as much energy. Again, with actual full operational data from 2020 provided by AVEC in the near future, this can be validated with more precision.

Scenario 3: Baseline Plus Wind Turbine with Advanced Control (Wind Forecasting)

For this scenario, a hypothetical wind resource forecasting data source is incorporated by reducing the spinning reserve requirements from 100% to 0%. As used in Scenario 2, 100% spinning reserves for the wind turbine implies zero knowledge of the future wind production so the system can recover even if the wind turbine stops producing any power. This is the most conservative operation and results in the least benefit from the wind turbine. A spinning reserve requirement of 0% would imply both a perfect knowledge of the future wind resource and the ability to instantaneously increase the power generation from the diesel generators, even if they are off. It is reasonable to assume that a relatively certain forecast of wind resource could be provided 5 to 10 minutes out using existing commercial data services, which is enough time to start up a generator. A typical system comprising just diesel generators would likely operate with a minimum of 10%–20% operating reserve even without a wind turbine. The HOMER results of diesel consumed for various operating reserves are shown in Table 15.

Table 15. Fuel Consumption with Different Operating Reserve Requirements

Operating Reserve as % of Wind Production	Total Diesel Fuel Consumed (gal)
0	202,152
10	202,739
25	203,768
50	206,567
100	230,283

As can be observed from the trend, just reducing to a still conservative 50% spinning reserve offers significant fuel savings; reducing beyond that has diminishing savings.

One additional simulation was performed by adding in battery storage to assess the potential for capturing all the produced wind energy. The battery was sized at 47,295 kWh of storage, which is quite oversized, the spinning reserve was set to 0%, and the ability to turn diesel generation off was enabled. The resulting fuel consumption was reduced to 156,054 gallons. This is roughly the scenario where the grid-bridging system is installed; however, the battery is much larger than what would be economically sized. This provides a reference of the maximum technical fuel reduction due to the wind turbine.

In summary, simulated diesel fuel consumption for the various scenarios is:

- Diesel-only operation: 375,643 gallons
- Diesel plus wind with basic control: 230,283 gallons (61% of baseline)
- Diesel plus wind with forecasting (50% reserve): 206,567 gallons (55% of baseline)
- Diesel plus wind plus grid-bridging system (minimum potential fuel use): 156,054 gallons (42% of baseline).

2.3.2.2 St. Mary's Advanced Control Scenario

As Figure 10 shows, the St. Mary's wind turbine, as modeled, does not have a benefit-cost ratio greater than 1 when considered only from the perspective of the electric cooperative. Greater energy generation benefits could be possible if the diesel generators were not providing 100% spinning reserves for the wind energy generation. One way to do this is through improved wind forecasting. With 5 to 10 minutes of forecasting, the electric cooperative could gain a sense of the "firm wind" available and might be able to operate their diesel generators more efficiently or even shut units off from time to time.

Sandia modeled this scenario in HOMER by changing reserve requirements as a percentage of the wind generation (Section 2.3.2.1). Modeling revealed the fuel consumption from a year of operation at each level of operating reserve requirement. Gallons of fuel saved were then multiplied by the fuel price for each year, and the NPV was calculated as before. We found that, if only a 50% operating reserve was needed for the wind, the NPV of energy generation would total $6,720,424. However, the value of energy generation plateaued after reducing the operating reserves further than 50%, as observed in Figure 10.

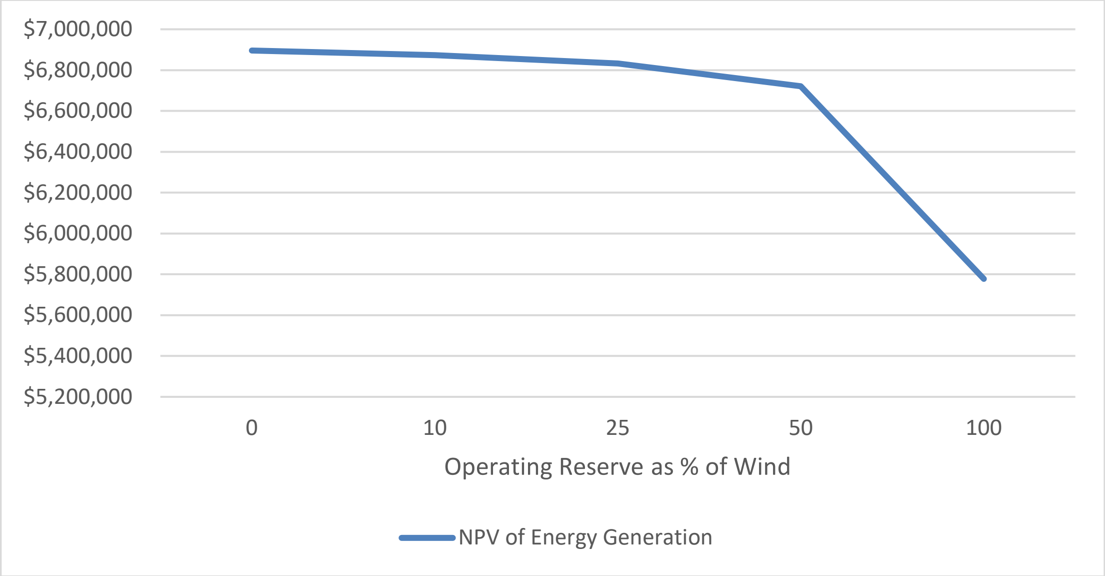


Figure 10. Net present value (NPV) of energy generation with diesel operating reserves as a percent of wind

2.4 Resilience Framework Results

The St. Mary's reference system is studied from a resilience planning perspective. Although the wind turbine in St. Mary's has already been installed, the resilience benefits that the turbine provided were not well defined. It was installed with the main objective of generating electric power from a renewable resource to reduce the local dependency on diesel fuel as the sole source of electric power generation. That is a resilience goal on its own, but there are other ways the turbine can add resilience to the system as well as scenarios of interest to analyze how resilient the wind turbine is against different hazards. In this case study, we analyze the operation of the St. Mary's power system—both with the wind turbine installed and without the wind turbine installed—during different resilience hazards of interest. This allows us to compare the performance with and without distributed wind energy and to quantify the resilience benefits provided by wind energy. As a planning exercise, this methodology could be used to assess or motivate the installation of a new distributed wind asset. As a post-installation exercise, this methodology can be used to better understand the full value provided by a distributed wind asset and to motivate future upgrades or expansions of the distributed wind asset.

2.4.1 Identify System Characteristics

The first step in the resilience framework is to identify the system characteristics and qualities to define the boundaries of stakeholder roles and evaluate the consequences of certain events. Refer to Section 2.1 for the relevant electric power system information.

2.4.2 Define System Resilience Goals and Metrics

The resilience goals are derived from the community goals defined in Section 2.1.3.

2.4.2.1 Reduce Dependency on Diesel

Prior to the wind turbine installation, these remote communities had a single source of fuel for electric energy—diesel fuel. Dependency on this single resource, and the uncertainty of fuel transportation and availability, result in a higher risk of interruption of EEDS operations. Consequences from this potential risk include underserved or unserved electrical load leading to loss of life and severe economic impact to the remote community. Hence, possible mitigations for this risk include reducing dependency on diesel fuel; the mitigations should also be carbon neutral or at least result in a reduction in carbon emissions. This risk establishes the first resilience goal.

This resilience goal can be evaluated with the resilience metrics presented in Table 16.

Table 16. Metrics for Evaluating Fuel Dependency

Indirect Metric	Source
Generation available	Simulation
Wind generation	Adjusted airport wind data + wind turbine power curve
Fuel needed	Diesel generator efficiency curves
Fuel stored/available	Storage tank capacity + simulation
Fuel displaced (when wind is installed)	Simulation
Load	HOMER modeling based on summary report

2.4.2.2 Improve Power Quality

As an isolated microgrid, the system does not interconnect to adjacent electrical systems that can provide frequency and voltage support via inertia and injection/absorption of real and reactive power. Therefore, a second resilience goal is to improve power quality. The commissioning of the intertie-line between St. Mary's and Mountain Village is a step toward making the combined systems more reliable and more resilient because they can now use generators in both villages to provide backup generation as needed. In this study, we are interested in analyzing the resilience added by distributed wind, so we consider the impacts to power quality both with and without the wind turbine, but we assume the intertie-line to be present. This goal can be evaluated using the resilience metrics noted in Table 17.

Table 17. Metrics for Evaluating Power Quality

Metric	Source
Outage duration	Assumption
Load lost during outages	Simulation
Failure rate	Simulation

2.4.3 Analysis of Resilience Hazards

Full details of the modeling and simulations performed for the hazard analysis can be found in the detailed resilience case study by (Culler et al. 2022b). In this section, we will walk through key results for each of the hazards analyzed—forecasted fuel shortage, immediate fuel shortage, severe winter weather, and communications outage. These hazards were selected after a preliminary assessment of relevant hazards. We assume that Year 1 of analysis starts on July 1, that this is also when a barge shipment has been received, and that fuel storage tanks are at full capacity. This makes it easier to analyze the fuel use and diesel reserves with respect to storage capacity throughout the year and under different hazard scenarios. The synthetic data is arbitrarily assigned the year of July 1, 2007, to June 30, 2008. For the resilience analysis, only Scenarios 1 and 2, as described in Section 2.3.1, are used. Namely, with wind operating, diesel must still provide 100% operating reserves for the portion of the load served by wind.

It is possible to adjust the source of the wind data to look at different potential wind production outputs. We obtained real wind data from the St. Mary's airport, collected at hourly intervals from 2005 to 2018 (Iowa State University 2021). We adjusted these data to account for hub height and added an additional correction factor to account for the change in location. The airport may be more protected from wind than the wind turbine site, which was selected to have maximum output. We also have synthetic wind data, generated by a HOMER model using monthly parameters for wind at the wind turbine location, again with a correction factor applied to account for the difference in wind readings and hub height. For these simulations, the airport data from 2008 were chosen as the wind source. We chose a single year rather than the average of all years because the average smooths out the variability of wind, but we wanted to preserve that variability. We chose the adjusted airport data rather than the synthetic data because we felt it represented the most realistic scenario, even though the measurements were collected at a different location than the turbine site.

In a base-case year, wind is used to serve as much of the load as possible, and diesel generators serve the remainder of the load. There is no unmet load in this base-case year.

2.4.3.1 Forecasted Fuel Shortage

The barges bringing diesel to St. Mary’s are operated by AVEC and have been operated reliably for many years. However, there are some possible scenarios where a fuel shortage could occur. We consider two fuel shortage scenarios: a forecasted fuel shortage and an immediate fuel shortage. First, we describe the forecasted fuel shortage scenario.

An unusual summer storm delays delivery of the fuel shipment. As a result of tight scheduling constraints, the delivery is rescheduled for 6 weeks later. Then one of the following three events occurs:

- The second attempted delivery is successful.
- The second attempted delivery (planned by end of summer) is also delayed by low water on the Yukon River. The villages must wait an additional 3 weeks for a shipping barge to be sent to St. Mary’s with fuel.
- The second attempted delivery (planned by end of summer) is also delayed by storms that cause an early freeze on the Yukon River. The villages must rely on air delivery of diesel via multiple shipments to last throughout the year.

Although these scenarios may seem unlikely, we note the probability is not negligible because a similar scenario was experienced by other remote Alaskan villages in 2012 (D’Oro 2012). The consequences depend heavily on the fuel reserves after the first year. If there are not sufficient reserves, the system will not tolerate many delays, and if fuel runs out, the villages will experience health and public safety consequences as well as economic impacts. This risk can be improved by ensuring there is greater storage capacity and more reserve fuel or by using more types of energy generation, like wind, to offset diesel use.

For the full analysis, refer to the resilience case study. Results are summarized below.

At the end of the first year, the fuel storage tanks have 20,289 gallons remaining in the no-wind case, and 190,151 gallons remaining in the with-wind case. With no extra provisions, the fuel storage remaining in the no-wind case is sufficient to last 21 days and 10 hours while continuing to serve the total load. The fuel storage remaining in the with-wind case is sufficient to last 184 days and 18 hours, continuing to serve all the load until January 1.

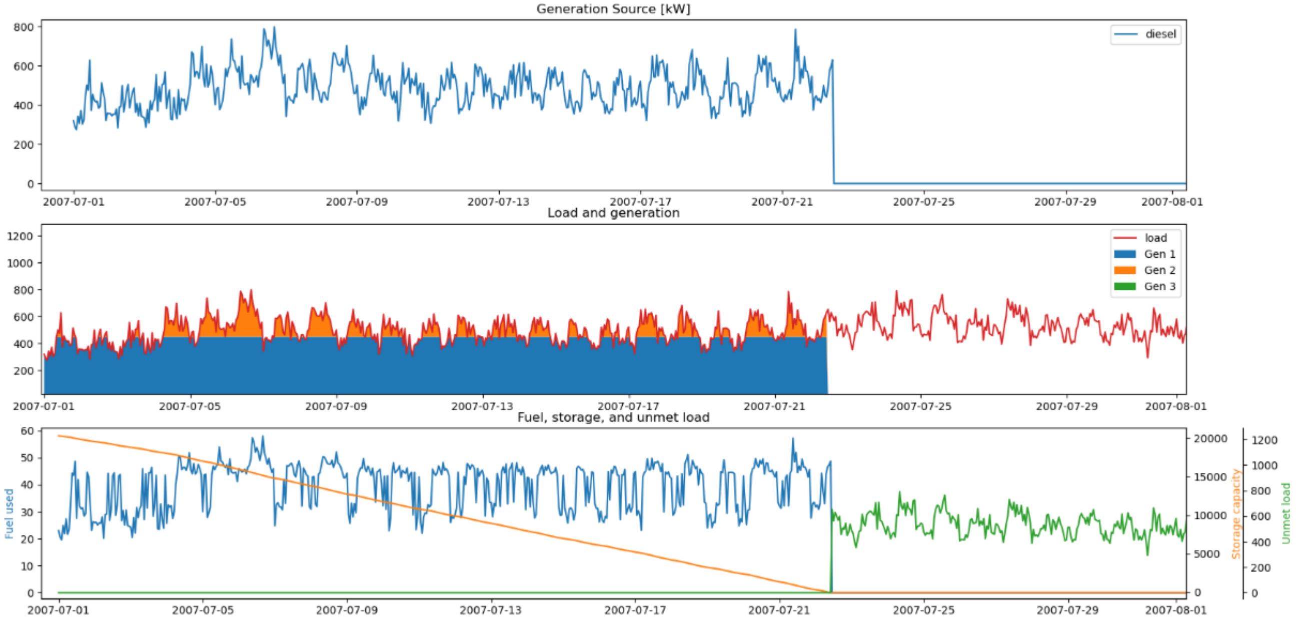


Figure 11. No wind, Year 2, missed fuel shipment (Culler et al. 2022b)

Figure 11 shows that the first 3 weeks of the second year are covered by the remaining stored fuel. However, after July 22, there is no fuel remaining to serve any of the load. There are no alternate sources of generation, so the entire load is dropped. In this case, the system would not be able to operate at full capacity until the rescheduled barge delivery reached St. Mary's. If that rescheduled barge delivery was further delayed, the St. Mary's and Mountain Village communities would continue to be without power until a barge or an airplane could reach them. With wind energy installed, the system can survive without a fuel shipment in Year 2 until January 1. This is because wind energy offsets significant diesel use in Year 1, leaving greater fuel reserves for Year 2—and wind energy continues to offset diesel needs in Year 2, making those fuel reserves last even longer. However, one full storage tank farm's worth of diesel is only sufficient to last 18 months, so additional imports of fuel, whether by delayed barge shipment at the end of the summer or by plane at some point in the fall, are needed for the system to survive the full second year.

How much wind can offset diesel usage is heavily dependent on wind production and, therefore, wind speeds. Running this analysis using different years of wind resources reveals the system would likely survive without fuel imports until at least January, potentially into February or March. If a fuel shipment was not possible in the fall, the Yukon River becomes passable again in May, so flying in the fuel needed until May and then scheduling a barge shipment may be a more cost-effective way to deliver the needed fuel.

In response to the fuel shortage hazard, the villages will be unable to meet their demand for very long without wind energy installed. They do not have sufficient tank capacity to serve the load for more than 13 months.

With the wind turbine installed, however, the villages can offset their diesel usage significantly, meeting one of their resilience goals, as shown in Table 18. Additionally, with wind energy installed, the system will not immediately or necessarily lose load, especially if they are able to get a fuel shipment in May instead of July. If the fuel shortage is minor (e.g., barges are delayed by 1 month), the villages may be able to ration their remaining fuel and rely on the maximum wind production possible. These improved power quality results are quantified in Table 19.

Table 18. Fuel Dependency Metric Evaluation for Forecasted Fuel Shortage

Metric	Performance Without Wind	Performance With Wind
Generation available	Diesel generation available for 21 days, 10 hours	Diesel generation available for 184 days, 18 hours
Wind generation All of Year 2	0	3,241,790 kWh
Fuel needed Diesel import needed to serve full load for all of Year 2 (On-time shipment)	428,215 gal	130,486 gal
Fuel needed Diesel import needed to serve full load for all of Year 2 (4-weeks-delayed shipment)	400,349 gal	130,486 gal
Fuel needed Diesel import needed to serve full load for all of Year 2 (6-weeks-delayed shipment)	385,124 gal	130,486 gal
Fuel needed Diesel import needed to serve full load for all of Year 2 (9-weeks-delayed shipment)	362,217 gal	130,486 gal
Fuel stored/available Reserves available at end of Year 1	20,281 gal	176,246 gal
Fuel displaced (when wind is installed) Diesel offset by wind in Year 2	N/A	155,934 gal
Load	Baseload profile (refer to report by Culler et al. 2022b)	
Carbon emissions	N/A[a]	N/A[a]

[a] We can evaluate the carbon emissions during different fuel shortage scenarios, but we would expect a decrease in carbon emissions from a standard year if there are outages, which could be misleading. Power outages are a more severe consequence than increased carbon emissions.

Table 19. Power Quality Metric Evaluation for Forecasted Fuel Shortage

Metric	Performance Without Wind	Performance With Wind
Outage duration With fuel delivery 4 weeks after first scheduled	6 days	None
Outage duration With fuel delivery 6 weeks after first scheduled	20 days	None
Outage duration With fuel delivery 9 weeks after first scheduled	41 days	None
Load lost during outages With fuel delivery 4 weeks after first scheduled	92,300 kWh	None
Load lost during outages With fuel delivery 6 weeks after first scheduled	283,266 kWh	None
Load lost during outages With fuel delivery 9 weeks after first scheduled	572,241 kWh	None
Failure Rate	n/a	n/a
Voltage level variation	Not simulated	Not simulated

If diesel fuel could not be delivered after 9 weeks, the two villages would find a way to fly fuel in. It is unrealistic to predict that, upon missing the shipment after the first year (on July 1 of Year 2), the villages would be rescheduled for a barge delivery of fuel 6 weeks later if they knew they would likely run out of fuel before then; it is entirely possible that a delivery could be made within the first 3 weeks of Year 2, before the fuel runs out, or at least by the fourth week, resulting in a shorter duration outage. Although a 4-week-late delivery was not part of our original hazard assessment parameters, it seems a more likely outcome, so we present the results from that case, too.

Valuation Results

The value of wind accrues to different stakeholders in these different event types. Because the forecasted fuel scenario would be very unlikely to lead to an actual outage, it would therefore most affect AVEC, which would pay to fly in additional fuel. However, in the immediate fuel shortage scenario, an outage could occur, affecting AVEC customers. The forecasted fuel shortage scenario is described in Figure 12.

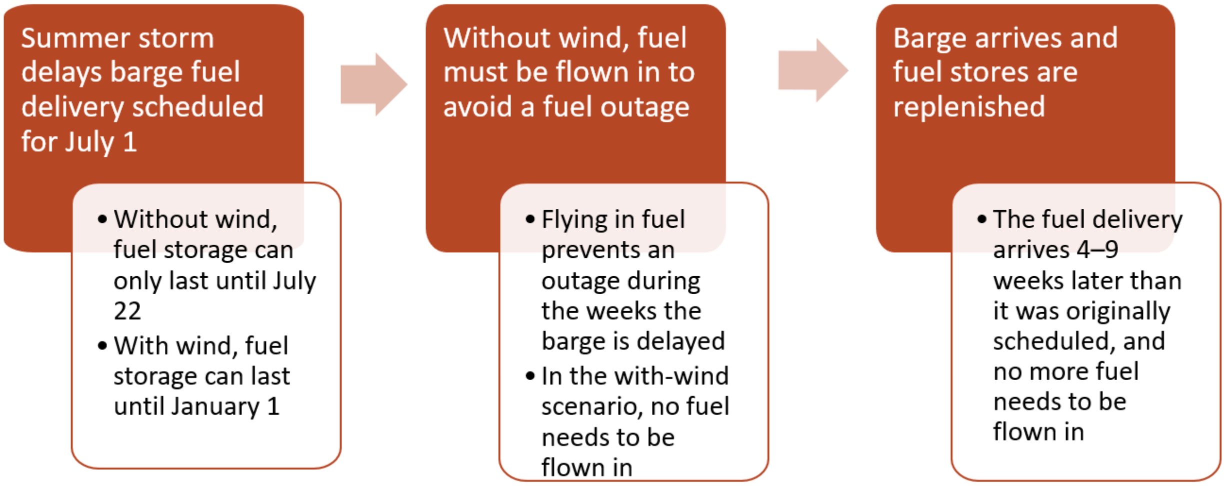


Figure 12. Forecasted fuel shortage scenarios

With wind present, no fuel would need to be flown in because fuel reserves would last until the delayed delivery arrives. Thus, the outage mitigation value of wind to the utility is estimated as the avoided costs of flying in fuel. The added cost of flying in fuel is estimated to be at least $1.25 per gallon per 100 air miles, according to data collected by the University of Alaska-Anchorage in 2010 from Everts Air Cargo, a charter airline company based out of Anchorage (Szymoniak, Fay, and Villalobos-Melendez 2010). Costs are even higher for villages with airports that can't accommodate the 4,900-gallon DC-6 transport planes that Everts Air Cargo uses. Because St. Mary's is approximately 513 miles away from Anchorage, this means the cost per gallon is approximately $7.52 after adjusting to 2019 dollars (U.S. Bureau of Labor Statistics 2021b). The amount of fuel needed in this forecasted fuel shortage scenario depends on how long the barge is delayed. Fuel amounts were calculated by INL for 4-week, 6-week, and 9-week delays, shown in Table 20, and PNNL calculated the additional cost of flying in that fuel.

Table 20. Fuel Flown in for Different Delay Durations

Delivery Delay	Load Lost (until fuel shipment received) (kWh)	Fuel Needed (gal)	Cost of Flying In Fuel (delivery adder)
4 weeks	92,300.1	7,504.30	$56,408
6 weeks	283,265.9	22,729.30	$170,850
9 weeks	572,240.9	45,635.40	$343,029

We then discounted the fuel-flying costs by the annual probability of such a shortage occurring to find the annual outage mitigation value to AVEC. We selected an annual probability of 0.75% for the 4-week outage, 0.5% for the 6-week outage, and 0.25% for the 9-week outage, as shown in Table 21. The average of these expected values was treated as the annual value of outage mitigation, and the NPV of these annual values was included in the St. Mary's valuation results in Figure 8.

Table 21. Expected Values of Outage Mitigation for Forecasted Fuel Shortage

Delivery Delay	Selected Annual Probability	Expected Value of Outage Mitigation
4 weeks	0.0075	$423
6 weeks	0.0050	$1,281
9 weeks	0.0025	$858

Because it is uncertain how likely such a scenario would be, we also calculated expected values for a range of probabilities, as shown in Figure 13.

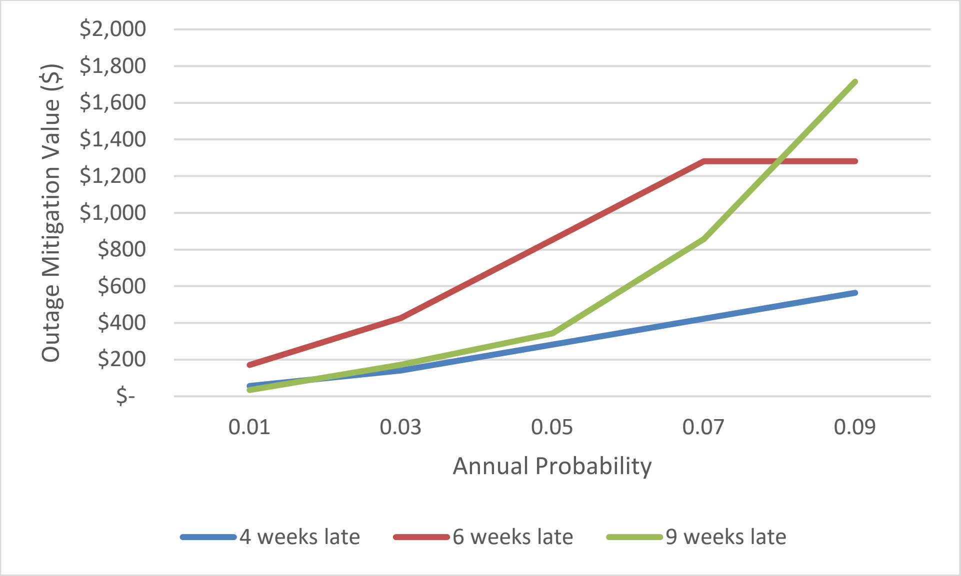


Figure 13. Outage mitigation expected values for a range of probabilities

2.4.3.2 Immediate Fuel Shortage

An immediate fuel shortage can occur if access to the local diesel supply fails. This could happen because of tank failures, fuel spills, or pipeline ruptures that prevent the power plant from receiving fuel. We consider these two examples with the following consequences:

- 2-day outage: A pipe ruptures. It takes two days to repair the pipe.
- 2-week outage: A tank ruptures. Ensuing fires cause damage to other tanks. It takes 2 weeks to get a plant to deliver backup fuel to the intact tanks.

The likelihood of an immediate fuel shortage is very low. For this to be a high-consequence event, the pipe rupture would have to prevent all fuel from reaching the power plant, and we are assuming that the Mountain Village generators are not capable of providing backup. For the tank failure scenario to cause a full halt on diesel power production, it would have to damage all tanks that have fuel remaining. This is unlikely when the fuel reserves are near full capacity. However, if a tank failure occurred on the one to two remaining tanks shortly before a new shipment was expected, it is more likely that this scenario would fully halt diesel power production.

It is impossible to identify every possible combination of failures and the types of repairs or lengths of outages associated with each. We focus on the high-consequence scenarios in this resilience analysis so that we can analyze the worst-case outcomes and find ways to mitigate the risk of these high-consequence events.

Overall, the probability of a fuel shortage is low. However, the consequences of a fuel shortage may vary depending on whether wind energy is installed or not.

In an immediate diesel shortage due to a pipe rupture or tank failure, we assume there is no diesel production available, which means the load lost is equivalent to the load expected to be served by diesel. In the no-wind case, this is all the load. In the with-wind case, this is whatever load is not served by wind production. We consider this scenario at a variety of times of the year. Results show that over any 2-day period throughout the year, the wind will serve at least part of the load, so a diesel outage will result in more lost load if wind is not installed.[5] We can observe this graphically in Figure 14. Note that the size of the load dropped without wind energy installed generally increases in the winter during any 2-day outage, but the size of the load dropped with wind energy installed is highly variable, which makes sense given the highly variable wind speeds.

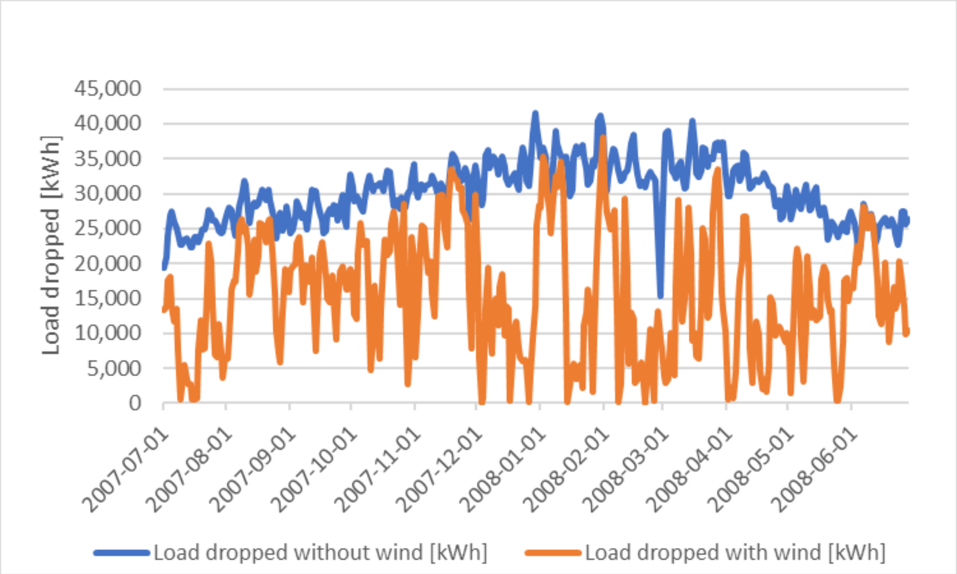


Figure 14. Load dropped during a 2-day outage starting any day in the year (Culler et al. 2022b)

We also consider a diesel outage of 2 weeks (Figure 15). Simulating diesel outages of this duration shows more load is dropped during longer outages, as expected, but the trend of the with-wind case dropping less of the load than is dropped in the without-wind case remains the same.

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[5] Note that we assumed the wind inverter has grid-forming capabilities. Therefore, in the case of a diesel outage, wind turbines can still participate.

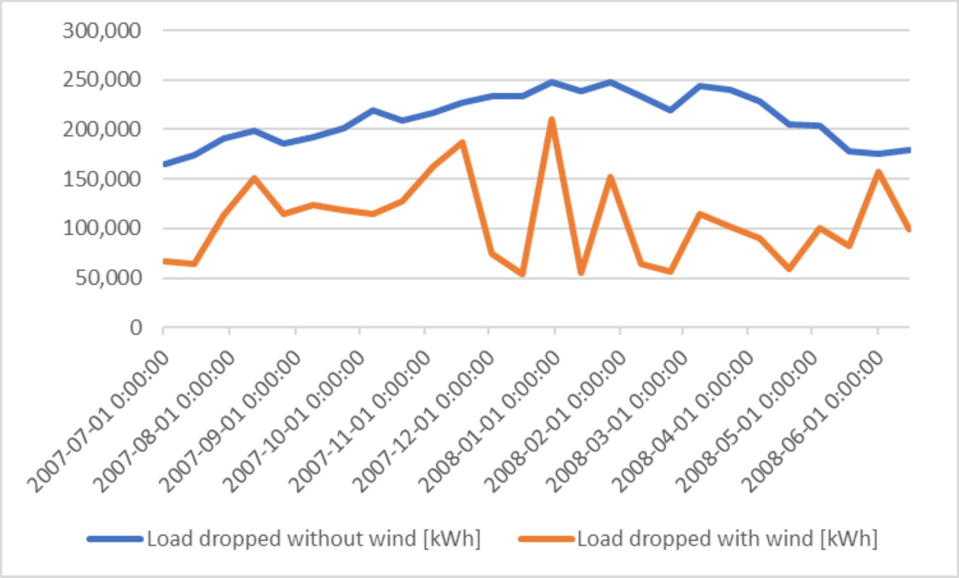

Figure 15. Load lost during 2-week diesel outage during different times of the year (Culler et al. 2022b)

The primary consequences of an immediate diesel shortage are load lost in amounts equivalent to the load expected to be served by diesel generation during the outage period. Although the wind turbine has the capacity to serve the load throughout most of the year, the variability and average wind speeds mean that the generation from wind is not sufficient to always cover the demand.

If the immediate outage was caused by multiple tank failures, then it may be necessary to import diesel to serve the remainder of the year until the annual shipment is received. The amount of fuel needed for the remainder of the year after outages occur on different dates is presented in Table 11 of the detailed case study by (Culler et al. 2022b). The time of year would dictate whether this diesel would need to be flown in or whether it could potentially be delivered by barge.

In this simulation, we did not consider the fuel storage capacity of St. Mary's and Mountain Village separately. Although future plans call for a new tank farm to serve a new power plant in St. Mary's that will serve both communities, there is existing fuel storage and generation capacity in Mountain Village. It is entirely likely that the villages would keep some fuel reserves in the old fuel storage system at Mountain Village and keep some of their generators operational. In that case, the assumed root cause of the immediate fuel shortage, a pipe failure or tank failure, could affect one village but likely not both. In that case, the numbers presented above represent the worst case—but it is possible that the reserves in the second village are sufficient to serve both villages. The cost associated with this hazard would then be the cost of lost fuel and repairs, not the lost load.

Valuation Results

The immediate fuel shortage was modeled under two different scenarios: a pipe rupture that takes 2 days to repair and a tank failure that takes 2 weeks to repair. In both scenarios, it is assumed that the event makes it impossible for the diesel generators to run, and that the generators at Mountain Village are not able to supply backup energy. The flow of these events is shown in Figure 16.

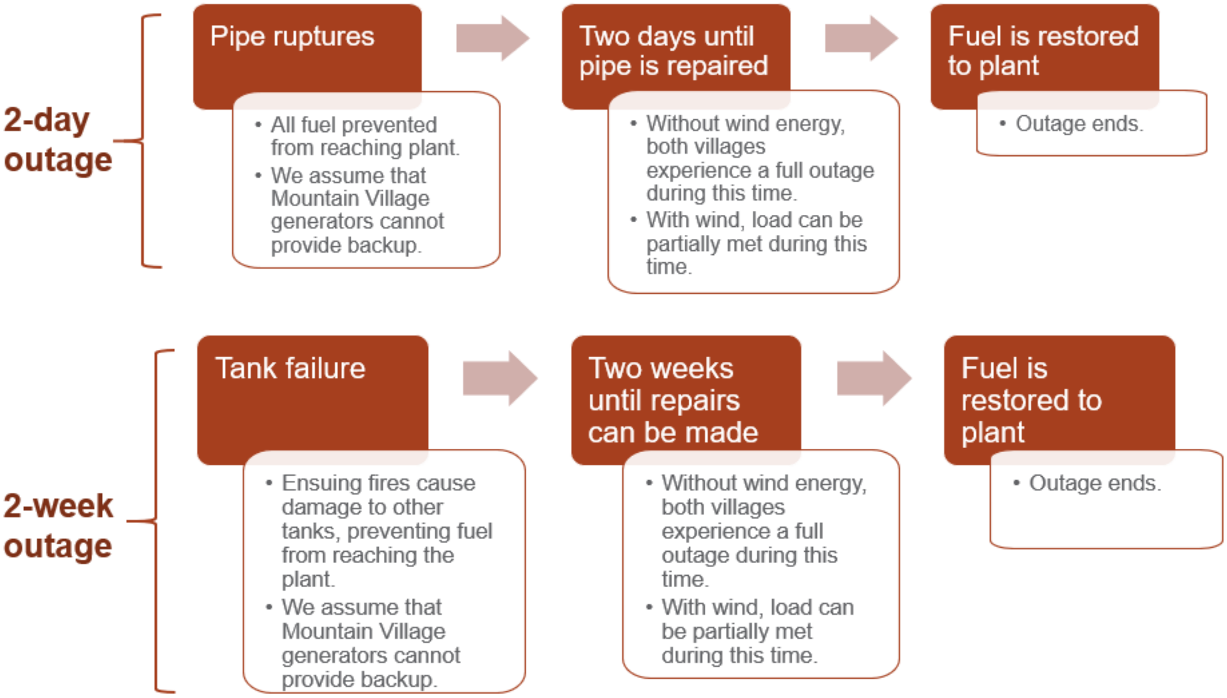

Figure 16. Immediate fuel-shortage scenarios

In these scenarios, we estimate the value of wind energy to the community as the avoided customer costs of an outage (value of load not dropped due to wind production during that time) and the value to the utility as the lost revenues to the utility. Due to scope and data availability, we did not include regional economic impacts or costs to health and safety during these outages. Results will have a lot of variances because each analysis requires numerous assumptions.

Methods have been developed and adopted for investigating the direct or avoided costs of momentary or short-term interruptions (i.e., those less than 16 hours) through customer surveys (Vaught 2014); however, there are no standardized methods for finding the impacts of long-duration outages. The impacts of long-duration outages can be very different from short-duration outages, especially when considering the regional economy. Although regional economic models have been developed to estimate the losses associated with long-duration outages, these models are location- and event-specific and do not generally yield standardized measures that could be used by utilities (Sullivan, Schellenberg, and Blundell 2015). They also require extensive regional economic data, which, in the case of St. Mary's, would be difficult to acquire because of business confidentiality concerns in such a small region.

It is unsurprising, then, that researchers only find a limited number of examples of utilities using avoided costs in formal cost-benefit analyses of power interruptions lasting more than 24 hours (Zamuda et al. 2019). In these examples, the utilities simply took data from short-duration outage impact surveys and extrapolated them to longer time periods. These analyses likely understated the economic impacts of long-duration outages because they did not include the indirect impacts on the regional economy. No utilities have included regional economic impacts in their analyses of long-duration outages (Sanstad et al. 2020).

Gathering data for the customer impacts of long-duration outages is also difficult because customers are unfamiliar with long-duration power interruptions (Bukowski et al. 2021). However, two recent papers use surveys to estimate the willingness of residential customers to pay for avoiding long-duration interruptions of service of 24 hours and 10 days in an urban area where some backup services are still functioning (Baik et al. 2021). In Baik et al. (2018), the residential customers surveyed were willing to pay $1.20/kWh to maintain high-priority residential loads, and $0.35/kWh to maintain low-priority residential loads. In Baik et al. (2020), residential customers were willing to pay $0.17–$2.30/kWh for private critical loads and $19–$29/day to support critical community services during a 10-day outage.

For the 2-day outage, we use the values from (Baik et al. 2020), assuming the 24-hour costs would be somewhat close to 48-hour costs to estimate the residential customer impacts and adjusting to 2019 dollars. We then assumed that 40% of residential loads are high priority and 60% are low priority in the St. Mary's community. We added these residential results with small commercial and industrial (C&I) customer costs for 16-hour outages from Sullivan, Schellenberg, and Blundell (2015), extrapolating to 48 hours, and assuming there are approximately 12 small C&I customers in the community. Using estimated loss of load in wind and no-wind scenarios during this 2-day outage, we calculate 2-day outage costs (the estimated value to the customers of not losing power) average approximately $447,592, though there is some variation in costs depending on the time of year, as shown in Table 22.

We also calculated lost revenues for the utility during an immediate fuel outage, taking 2021 AVEC rates for St. Mary's, adjusting them to 2019 dollars, and applying them to the lost load in these scenarios, weighted by customer type. We assumed that 8% of the load is from small C&I customers and the remaining 92% is from residential customers. We found utility lost revenues for a 2-day outage to be $4,240 on average, though this value was higher in winter months and lower in the summer, as shown in Table 22.

Table 22. Outage Costs for 2-Day Outage Scenario

	Community Outage Cost	Utility Lost Revenues
Jan	$449,218	$4,770
Feb	$449,344	$4,811
Mar	$448,655	$4,587
Apr	$447,600	$4,243
May	$444,494	$3,232
Jun	$440,860	$2,049
Jul	$447,614	$4,248
Aug	$447,553	$4,228
Sep	$448,085	$4,401
Oct	$448,606	$4,571
Nov	$448,993	$4,697
Dec	$450,080	$5,051
Average	**$447,592**	**$4,241**

We then multiplied these outage costs by the annual likelihood of the outage occurring, which we assumed to be 0.75%. The expected values of $3,356.94 for the community and $31.80 for the utility were treated as the annual values of outage mitigation, growing at a constant 2%. The NPVs of these annual values were included in the St. Mary’s valuation results in Figure 8 for society and the utility, respectively.

Because there is uncertainty about the likelihood of such an event, we also found expected values for community outage costs and utility lost revenues for probabilities between 0.25% and 5%, as shown in Table 23.

Table 23. Two-Day Outage Mitigation Expected Values

Annual Likelihood	Expected Value of Community Outage Mitigation	Expected Value of Utility Lost Revenues
0.0025	$1,118.98	$10.60
0.005	$2,237.96	$21.20
0.0075	**$3,356.94**	**$31.80**
0.01	$4,475.92	$42.41

To estimate 2-week outage mitigation values for residential customers, we used average values from (Sullivan, Schellenberg, and Blundell 2015), adjusted to 2019 dollars, and assumed the adult population to be 80% of the 1,660 residents in the St. Mary’s/Mountain Village/Pitka’s Point community. We used INL’s calculations of load dropped with wind energy versus without wind energy during a 2-week outage, with outage starting dates occurring at each week of the year, to find the value of private load. To find the value of maintaining critical public services, we multiplied the value of public services from Baik et al. (2020) by 14 days and the adult population. To find outage costs for small C&I customers, we used values from Sullivan, Schellenberg, and Blundell (2015), extrapolated to 2 weeks, assumed there are approximately 12 small C&I customers in the community, and then added this to the value of maintaining critical public services calculated earlier. The value of lost load from Sullivan, Schellenberg, and Blundell (2015) is for outages of up to 16 hours. Although extrapolating their values to 2 weeks likely does not yield highly accurate numbers, we could not find a better data source for these outage costs, and we decided it would be better to include these numbers than to leave them out entirely. In an alternate methodology to calculating outage costs based on customer type, we calculated the outage costs for high-priority and low-priority loads using values from Baik et al. (2018) multiplied by the avoided lost load, assuming 20% of the load is low priority and 80% is high priority. For our analysis, we average the values calculated using customer type with those calculated from priority of load. We find average outage costs to be approximately $4,406,281, though the costs vary slightly depending on the time of year of the outage, as shown in Table 24.

We calculated lost revenues for the utility using the same assumptions we used in the 2-day outage scenario. We found utility lost revenues for a 2-week outage to be $29,682, on average, though this value was higher in winter months and lower in the summer, as shown in Table 24.

Table 24. Two-Week Outage Mitigation Values

	Value of Community Outage Mitigation	**Value of Utility Lost Revenues**
Jan	$4,416,179	$ 31,983
Feb	$4,456,169	$41,280
Mar	$4,444,521	$38,572
Apr	$4,455,946	$41,228
May	$4,402,423	$28,785
Jun	$4,339,633	$14,188
Jul	$4,408,090	$30,103
Aug	$4,359,507	$18,808
Sep	$4,372,376	$21,800
Oct	$4,394,158	$26,864
Nov	$4,336,623	$13,488
Dec	$4,489,752	$49,088
Average	**$4,406,281**	**$29,682**

We then calculated the expected value of the outage by multiplying by the probability of its occurrence during the project's lifetime, which we estimated to be 0.25%. The expected values of $11,015.70 for the community and $74.21 for the utility were treated as the annual values of outage mitigation. The NPVs of these annual values are included in the St. Mary's valuation results in Figure 8 for society and the utility, respectively.

Because of the uncertainty of the likelihoods, we also give expected values for probabilities between 1.25% and 7% in Table 25.

Table 25. Two-Week Outage Mitigation Expected Values

Annual Likelihood	Expected Value of Community Outage Mitigation	Expected Value of Utility Lost Revenues
0.001	$4,406.28	$29.68
0.0025	$11,015.70	$74.21
0.005	$22,031.41	$148.41
0.0075	$33,047.11	$222.62
0.01	$44,062.81	$296.82

To find the overall community outage mitigation values for the project, we summed the 2-day and 2-week community expected values, and calculated the NPV of these annual values, assuming it grew at a constant 2% growth rate. This resulted in a lifetime value of $255,438 to the community in 2021 dollars. Overall utility avoided lost revenues were found by summing the 2-day and 2-week values and treating this as an annual value that also grew at a steady 2%. This showed lifetime benefits to the utility of $1,920 in 2021 dollars. For the utility, avoided lost revenues were also summed with avoided fuel flying costs from the forecasted fuel-shortage scenario, giving an overall resilience benefit of $17,383 to the utility in 2021 dollars. Although this project lifetime expected value of resilience to the utility and the community may seem quite low, it must be remembered that (1) regional economic impacts were not included in these numbers, (2) health and social costs were not included, and (3) the St. Mary's region has a small population, which means the outages will have less impact than in more populous regions.

2.4.3.3 Severe Winter Weather

Any decrease in temperature, particularly in the winter, is likely to drive up heating demand. Any winter weather scenario analyzed needs to also consider the expected higher load. Diesel generators would be able to continue operating as normal. Load would have to be extremely high to exceed the diesel generation capacity. The St. Mary's wind turbine is outfitted with a cold-weather package, which means that the turbine remains operational to −40°C. The turbine blades are black, to better absorb sunlight, causing the blades to emit heat and reduce the buildup of ice. The system is also outfitted with ice-detection sensors.

Extreme winter weather is a probable scenario, but, because the wind turbine is weatherized for cold winters, it is unlikely it would cease to operate. The consequences of this event would primarily be increased fuel use because of the higher heating load and, potentially, the wind turbine ceasing to operate at very low temperatures. Unless this hazard is combined with a fuel shortage or other failure, it is expected that the system could continue to meet the full load. This event is labeled as a mild risk hazard. However, just because it is a mild risk hazard does not mean it should be ignored. The comprehensive risk analysis still needs to be performed, and stakeholders must decide if it is an acceptable business risk or if other mitigations need to be put in place.

We modeled different scenarios in which the temperature dropped by varying amounts and for varying periods of time. The cold snaps are all centered around December 21, the beginning of winter. Although we ran the hazard analysis for all temperature changes for all durations, we acknowledge that the most extreme cases, a 12-week cold snap with temperatures 20°C below normal, would be highly unlikely. We use synthetic data to estimate the average correlation between temperature and load and use this correlation to shift the synthetic load data from the HOMER model by an appropriate amount in response to the temperature changes. The load, diesel production, and wind production may all be affected by the severe winter weather. We also note the temperature-load correlation model loses fidelity at very low temperatures, forecasting loads that continue to rise rather than leveling off or rising linearly as temperatures reach levels below −35°C (for details, refer to Appendix A in Culler et al. [2022b]). However, these models are still useful because they show the trends of different types of cold snaps. Additionally, it is useful to examine cases where the temperature reaches −40°C or lower because that is the point beyond which the wind turbine ceases to operate. In future work, we will analyze not only the impact of temperature, but the impact of blizzard-like wind speeds, which may exceed the immediate or 10-minute average wind cutoff speeds for the turbine.

Individual trials with temperature drops (changes compared to a normal year) of −10°C, −2°C, −5°C, −10°C, −15°C, and −20°C were performed. Each of these temperature drops was considered for durations of 1 week, 2 weeks, 3 weeks, 4 weeks, 6 weeks, 8 weeks, 10 weeks, and 12 weeks, leading to 48 separate studies. For each of these, we recorded the annual fuel used in a regular year with wind energy, a regular year without wind energy, the cold year with wind energy, and the cold year without wind energy. We took the corresponding with-wind and without-wind cases and compared the regular year to a cold year to find the difference in fuel used. These results are shown in Figure 17.

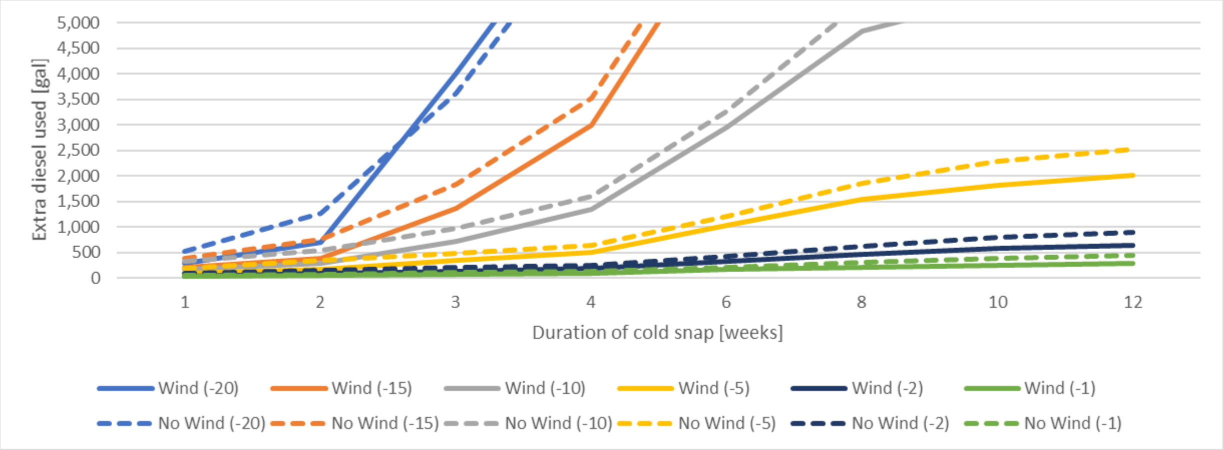

Figure 17. Increase in fuel used by scenario due to cold snap (temperatures in °C), zoomed-in view (Culler et al. 2022b)

It would have been valuable to also model extreme wind scenarios corresponding to the blizzard or high-wind criteria from the National Weather Service. However, because the simulations were at the hourly level of granularity, it was difficult to model gusts of wind. We could have modeled higher hourly wind scenarios, but we would have needed to put reasonable limits on hourly averages for wind speeds, and if these did not meet the wind turbine cutout speeds, this exercise would not have represented the hazard scenario well. We leave the task of more granular wind speed modeling and effects on power production to future work.

It may seem counterintuitive that the “with-wind” case results in higher fuel use compared to the base years than the “without-wind” case. However, we note that each line is a difference compared to the corresponding base year; namely, the solid lines represent the difference between fuel used in a cold year without wind and a normal year without wind, and the dotted lines represent the difference between fuel used in a cold year with wind and normal year with wind. The fact that the −20°C change from normal case creates a larger fuel difference with wind than without wind is explained because that temperature difference pushes the temperature below the turbine operating point and it ceases energy production. Now, not only is the load higher because of the cold temperatures, but the system is receiving less support from wind than it did in the regular temperature year (with wind installed). The “no-wind” −20°C change from normal case has a smaller change in fuel usage because the change is only due to the increased load; there is no wind to consider in either the hazard year or the base-case year.

The 1-week and 2-week cold snaps result in an increase in diesel use because of the increased load and potential loss of wind power, but this increased diesel use is not significant compared to the annual fuel use, even under extremely cold scenarios. Temperature changes of 2°C or less result in very small changes of diesel use, even when this cold period lasts for up to 12 weeks. Larger temperature drops for longer periods of time begin to result in significant changes in diesel use. In the most extreme scenarios, and without wind energy installed, the extra fuel used is enough that an early shipment of diesel would be required because the system would not last on its existing reserves. In particular, drops in temperature of 20°C for 8 weeks or more would require a shipment of diesel to arrive prior to July 1 because the extra fuel used in the cold snap exceeds the reserves that would normally be left at the end of the year. We note again that the temperature-load correlation model is not highly accurate for very low temperatures, so this fuel-use consequence may be exaggerated in our model for large temperature changes.

For large temperature drops, the without-wind case has a smaller change in fuel use than the with-wind case. This is because the wind turbine ceases to operate at actual temperatures below −40°C, meaning that diesel must fulfill extra energy needs anyway. However, for smaller temperature drops, there is a smaller change in fuel use for the with-wind case than the without-wind case. This is because there are points during the period examined where wind generation exceeds load during a normal year. With the increased load at lower temperatures (but not below −40°C), the extra load can be fully or partially served by the wind production that was curtailed in a normal year.

The system uses less fuel annually with wind installed than without wind installed during the cold snap hazard for any severity and any duration, in part, because of the fuel savings from wind during the remainder of the year outside of the cold snap. However, the wind turbine still faces the risk of shutting down for very low temperatures. There are no predicted power outages for the load, but with the current temp-load correlation model, extreme temperature drops for long periods of time result in very high loads for long durations. If no wind energy is installed, these high loads are solely served by diesel, and the extra diesel use may tap a significant portion of the fuel reserves. If enough extra fuel is used during this extreme winter scenario, an early shipment of fuel may be required because the system may not have enough diesel reserves to last until the year ends and the next regular shipment is expected on July 1.

Valuation Results

Additional fuel savings are possible from the wind turbine in a severe winter weather scenario. When temperatures are below average in the winter, loads are increased and, as a result of the wind turbine's large capacity, it is sometimes able to displace more diesel consumption, depending on the wind resource. However, at −40°C, the wind turbine loses operability, which means that at extremely cold temperatures, the wind turbine does not provide fuel savings. Multiplying INL's modeled fuel savings in situations in which temperatures are below normal by −1°C, −2°C, −5°C, −10°C, −15°C, and −20°C, for periods of 1–12 weeks centered around December 21, we found that annual fuel savings are, on average, about $407,684–$447,277 in comparison to normal annual savings of about $444,708, as shown in Table 26. The lower range of values occurs in the −20°C scenario. In this case, the temperature change of −20°C means the actual temperature drops below −40°C, so the wind turbine is no longer operable—and the low temperatures mean more fuel is consumed than normal, which removes the fuel savings.

Table 26. Annual Fuel Savings With Wind During Cold Snap

Duration (weeks)	−20°C	−15°C	−10°C	−5°C	−2°C	−1°C
1	$445,414	$445,210	$445,120	$444,987	$444,856	$444,778
2	$446,379	$445,771	$445,433	$445,175	$444,897	$444,799
3	$443,580	$446,022	$445,448	$445,094	$444,923	$444,819
4	$443,402	$446,207	$445,446	$445,122	$444,906	$444,828
6	$442,169	$445,989	$445,586	$445,234	$445,025	$444,839
8	$425,550	$444,212	$446,303	$445,643	$445,204	$444,983
10	$414,443	$445,090	$446,979	$446,034	$445,332	$445,127
12	$407,684	445,828	$447,277	$446,146	$445,452	$445,177

To find the expected value of fuel savings, we weight by the probability of the cold temperatures occurring for that duration of time. These values were estimated by INL and are provided in Table 27. The longer-duration outages (4 weeks, 8 weeks, and 12 weeks) were estimated by analyzing 50 years of monthly average minimum temperature data (1960–2010) collected in Bethel, Alaska, and shown in **blue**. We assumed that regional trends would be similar and would apply to St. Mary's. There were no examples in the data set of the larger temperature changes (−10°C to –20°C below normal), so these were estimated with a Gaussian distribution, shown in **red**. The mean and standard deviation for the Guassian distribution were taken as the mean and standard deviation for each month across the 50 years. Then, to fill in the shorter-duration likelihoods, we used the airport data from St. Mary's that was collected in hourly intervals from 2005 to 2018. We calculated weekly averages for each year and followed a similar process to estimate likelihoods for 1-week, 2-week, and 3-week cold snaps around December 21. We could have used this data for all the outage durations, but we believe that 51 years of monthly data were more representative of different conditions than the 13 years of more granular data.

The **green** is calculated with actual data; the **purple** is based on the Gaussian distribution estimates. These numbers do not align perfectly between the two data sets, nor do they align well between the Gaussian estimates and the actual fractions, but this was identified as the best way to assign actual numeric probabilities to the different weather scenarios.

Table 27. Ranges of Annual Probabilities for Temperatures Below Normal

		Degrees Celsius below normal temperatures					
		−20	**−15**	**−10**	**−5**	**−2**	**−1**
Weeks	1	0.00085	0.0093	0.154	0.077	0.154	0.077
	2	1.215E-11	1.464E-07	0.00016	0.01788	0.1091	0.1709
	3	1.033E-15	4.753E-10	5.6E-06	0.0033	0.0391	0.0732
	4	0.0002	0.00067	0.039-0.978	0.176-0.235	0.157-0.215	0.039-0.059
	8	3.77E-09	1.88E-06	0.00016	0.059-118	0.039-0.078	0
	12	3.38E-14	09.27E-10	1.37E-06	0.019-0.039	0.019-0.039	0

Multiplying by the average of these probability ranges, we find an average annual fuel savings of $1–$226,509, as shown in Table 28. These values are quite low, which suggests that the wind turbine does not add a significant amount of fuel savings value during severe winter weather. However, it does generally displace fuel during periods of increased load, except in cases where the temperature is at least −20°C below normal.

Table 28. Expected Values of Annual Fuel Savings with Wind During Cold Snap
(average of likelihoods used)

Duration (weeks)	−20°C	−15°C	−10°C	−5°C	−2°C	−1°C
1	$379	$4,140	$68,548	$34,264	$68,508	$34,248
2	$0	$0	$71	$7,960	$48,538	$76,016
3	$0	$0	$2	$1,469	$17,396	$32,561
4	$89	$299	$226,509	$91,473	$82,753	$21,797
6	$-	$-	$-	$-	$-	$-
8	$0	$1	$71	$39,439	$26,044	$-
10	$-	$-	$-	$-	$-	$-
12	$0	$0	$ 1	$12,938	$12,918	$-

2.4.3.4 Communications Outage

In this hazard, we consider a scenario in which remote communication to the wind tower is out of service. There is a fiber-optic link attached to the distribution line poles that provides communication between the wind turbine and the control switchgear of the St. Mary's prime power plant. Using that link, the wind turbine can be manually or automatically controlled at both the power plant and from AVEC headquarters in Anchorage.

The probability of such an event is low. It would take a strong storm to take out the distribution line infrastructure, and, even then, if the fiber link remained intact, it may still be operational. The biggest threat may be wildlife damaging the line, which is unlikely. If the fiber-optic line goes down, operators will be unable to receive live data from the turbine or send new commands, but the power production capability of the turbine remains unhindered. There would be a measurable impact if an alarm occurred while the link was down, and no operator noticed it. In the worst case, the turbine could shut down due to an alarm and it would be unable to contribute to the village generation. We can consider three potential alarms that are missed during the communications outage and their associated consequences:

- **Internal trip**: A breaker in the turbine flips and production ceases. It takes 2 days to discover the alarm and for a technician to get to the turbine and reset it.
- **Equipment malfunction requiring repair**: A part in the wind turbine breaks, requiring repair. Due to weather and supply chain conditions, getting the right part could take up to 2 weeks. Hub, blades, generator, and electric failures were most common among direct-drive turbines (Ozturk, Fthenakis, and Faulstich 2018).
- **Temperature warning**: This is a low-level warning. There is no change in production during a communications outage while this warning occurs.

Many of the potential consequences of a communications outage depend on the assumptions made about the outage and other potential alerts that happen during the communications outage. To evaluate the consequences, detailed data about the wind turbine production and assumptions about the outage scenario are needed.

If the fiber-optic line is out of service, operators from St. Mary's and AVEC will not be able to monitor data from the wind turbine or send commands. We assume that power curtailment is automatic, so the wind turbine can continue to operate and produce an appropriate amount of power to give to the system.

The major outcome from a communications outage would be that status messages and alerts would not be visible. An agent would have to be sent to the wind turbine to check on it regularly. The tower is about 4 miles from the prime power plant in St. Mary's. There is a 0.3-mile access road connecting the tower to the main road. The main road and the access road are both made of gravel and dirt. This could make the turbine difficult to access, especially during winter months.

Depending on the severity of the outage and the cost or time to repair it, the decision may be made to remove the wind turbine from service if it cannot be safely operated. In this case, the system loses all power production from the turbine for the duration of the outage.

The first missed alert that we consider is an internal trip, which takes 2 days to be discovered and for a technician to get to the turbine and flip the breaker back on. Sampling 2-day outages throughout the year reveals there is a high level of variability depending on which 2-day period is selected. Not much additional fuel is used if the wind turbine is out of service for 2 days, provided the wind during that period would have been low anyway. However, if wind speeds were high, then the loss of wind production results in additional diesel used to serve the load.

The second outcome we consider for the loss of wind turbine communications is a missed equipment failure alarm. We assume that the wind turbine is out of commission for 2 weeks, although the actual repair time is highly dependent on the availability of spare parts. We consider these 2-week outages for 12 potential time periods throughout the year. Like the 2-day outage scenario, there is a high level of variability correlated with the variability in wind speeds.

However, the largest increases in fuel used during the turbine outage will come in the winter, when wind speeds are at their highest.

In the worst case, the communications outage can lead to missed alert messages, which, if left untreated, can result in loss of power production from the wind turbine. However, there may be many low-level alerts that do not result in loss of power production at all, but simply make it more difficult to make operational decisions because of the loss of visibility into live wind turbine data.

Although equipment failure is not directly caused by a communications outage, it is possible that low-level alerts may have warned operators to the status of the part before it totally failed, and they may have been able to take action to avoid the complete failure and, thus, the loss of wind power production. We acknowledge that there are multiple failures required to make the event of a communications outage a high-consequence alert, but these scenarios are worth considering.

The intent of this exercise was to assess the resilience benefits of distributed wind energy. The wind turbine communications outage hazard only applies to the scenarios where wind energy is installed, so we cannot compare the resilience for with-wind and without-wind cases. Instead, the purpose of analyzing this hazard is to demonstrate that there are resilience considerations for the wind turbine itself in addition to the resilience considerations of the entire system. In the next step of the framework, mitigations for each hazard are discussed. Mitigations for the wind turbine communications outage scenario can help make the turbine operation itself more resilient, which will enhance resilience benefits for the entire system.

Valuation Results

In INL’s model, the difference between the fuel usage in a system that includes wind energy assets and the fuel usage in a system without wind energy assets depends on the time of year and the wind resource available during that time. In the 2-day outage scenario, a range of $12–$6,088 is lost from normal fuel savings while the turbine is out of service, depending on the time of year of the fault, as shown in Figure 18. Average lost fuel savings are $2,436.

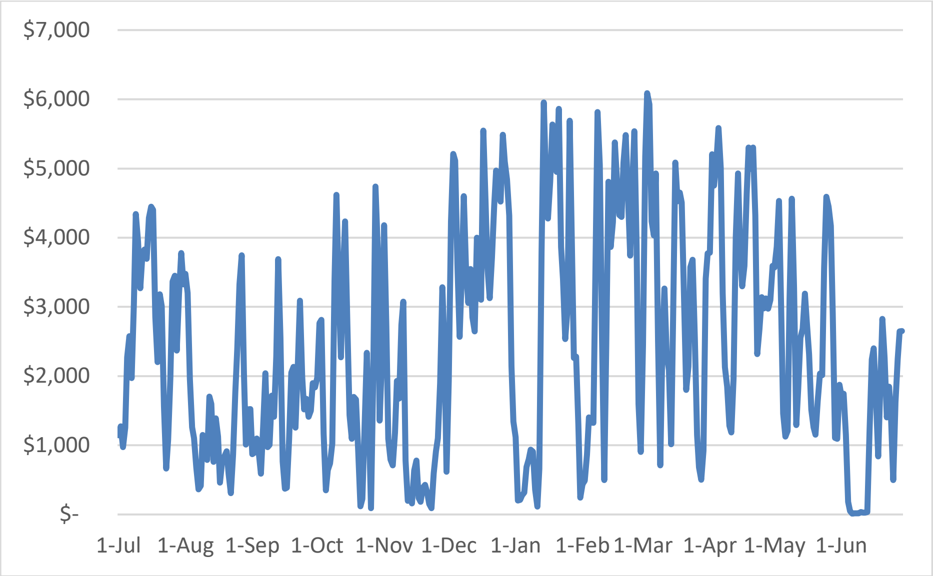

Figure 18. Fuel savings lost the during 2 days that the wind turbine is out of service

Adjusted for the annual likelihood of this occuring, which we assume to be between 0.3% and 3%, we find expected values of average lost fuel savings for the 2-day communications outage to be between $7.31 and $73.07.

In INL's 2-week communications outage scenario, lost fuel savings range between $3,225 and $30,674 while the turbine is down, depending on the time of year that it happens, as shown in Figure 19. Average lost fuel savings are $17,037.

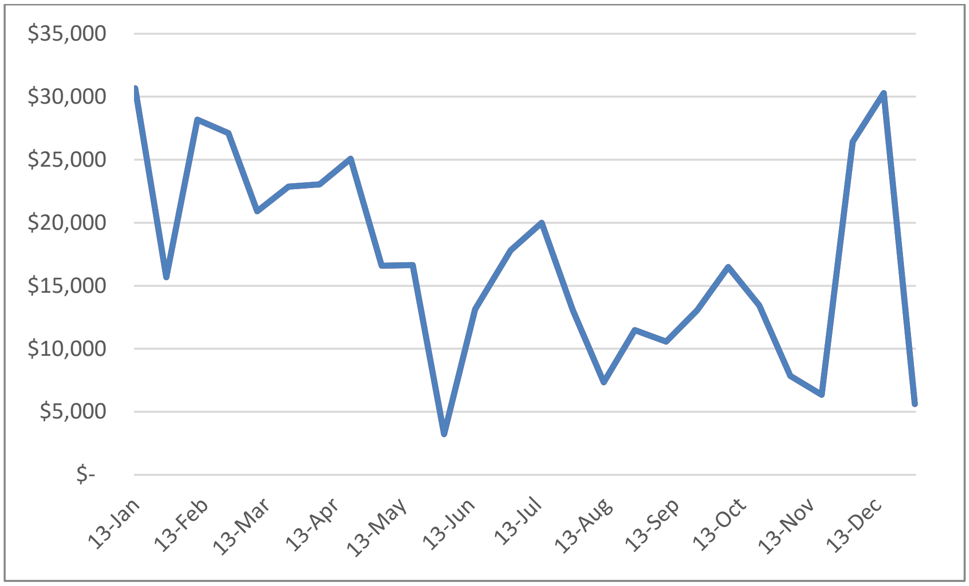

Figure 19. Fuel savings lost during the 2 weeks that wind turbine is out of service

Adjusted for the annual likelihood of this occurring, which we assume to be between 0.3% and 3%, we find expected values of average lost fuel savings for the 2-week communications outage to be between $51.11 and $511.10. The expected values of lost fuel savings are relatively low, which suggests that these scenarios are not of great concern to the system.

2.4.4 Risk Mitigation Measures

Based on the outcomes of the modeling, risk-mitigation measures should be prioritized. Perhaps the system performed well against the highest priority scenario, but additional measures are needed to protect the system against the third-highest priority scenario. A single risk may have multiple mitigation options, and those options may mitigate multiple risks. Risk-mitigation measures should include cost estimations and effectiveness metrics that evaluate the efficacy of a mitigation measure against a given risk.

Hazard 1: Fuel Shortage

- Install more diesel storage; be sure tanks are full well before winter begins
- Install more wind capacity to offset impact of fuel shortage
- Install battery storage system so overproduction of wind can be captured and returned to the system.

Hazard 1 was the hazard of greatest concern. Fuel shortages could have an impact on power quality and amount of load served, even with the wind turbine installed. Analysis showed the impact would be greater without the wind, highlighting the resilience added by the wind turbine, but there was still room for improvement on the current system. The mitigations listed above would help reduce the impact and/or likelihood of a fuel shortage, but they would all require large investments.

Hazard 2: Severe Winter Weather

- Ensure maintenance on wind and diesel power plants is kept up so they operate at peak performance under difficult conditions.

Hazard 2 had the lowest risk after all hazards were assessed. The probability of a severe winter weather event extreme enough to put the wind turbine out of service is very low and, even then, diesel generators can cover the total expected load, even when it is at its peak levels.[6] Still, there were negative outcomes associated with Hazard 2, including increased diesel fuel use, but there is little that can be done to mitigate this scenario.

Hazard 3: Wind Communications Outage

- Install redundant communications lines
- Ensure roads are maintained to make access to turbine easy.

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[6] Note: there are operational concerns with diesel generators at extremely low temperatures. Continuous operation of diesel generators (as opposed to start/stop operation) can maintain diesel fuel stability but has resilience and cost/benefit ramifications if this is a requirement of the system. Additionally, this continued operation may have ramifications, such as keeping the peaking units running continuously, even if you have wind.

Hazard 3 had mild risk. The probability of a communications outage, particularly the fiber-optic line going out of service, is low but not impossible; the consequences would likely be minimal but had the potential to be severe.

3 Reference System 2: Iowa Lakes Electric Cooperative

ILEC owns and operates two 10.5-MW wind turbine deployments in the Iowa towns of Superior and Lakota. These systems were deemed to be strong reference systems for grid-connected distributed wind analysis because of their location in a regulated energy market, co-location with a large commercial and industrial load, and existing partnerships between DOE, NREL, the National Rural Electric Cooperative Association, and ILEC.

ILEC serves 12,950 farms, homes, businesses, and industries and sells about 650 million kWh annually. Of this, about 63% is commercial and industrial, and the remainder is residential and agricultural. ILEC is a member of two generation and transmission providers: Corn Belt Power Cooperative (Corn Belt) and Basin Electric Cooperative. Corn Belt became a member of Basin Electric in 2009. This arrangement means that ILEC sells power directly to Basin Electric but uses the Corn Belt transmission system (National Rural Electric Cooperative Association 2021).

ILEC's territory is on the eastern slope of Buffalo Ridge in Iowa. It offers some of the best wind resources in the country. In fact, Iowa ranks first in the nation for having the highest share of wind energy in the state's portfolio at 58%, as of May 2021 (American Clean Power Association 2021). ILEC also has just over 3 MW of distributed generation consisting of small wind and solar arrays dispersed throughout their eight-county system that ILEC members have installed behind the meter to help offset their usage. Solar accounts for the bulk of those 3 MW because it has become less expensive and less maintenance-intense to operate for ILEC members.

ILEC began discussing wind installation in 2004, but no final plans were made until 2007. Iowa was the first state in the country to pass a renewable portfolio standard and, at the time, wind was the most feasible renewable generation technology (U.S. Energy Information Administration 2021b). By 2007, additional incentives had come into play, including the federal Energy Policy Act of 2005, which introduced an interest-free, clean, renewable energy bonds program and state policy that adopted a \$0.01/kWh production tax credit for qualified wind facilities placed into service between 2005 and 2015 (Provus n.d.). This led to the installation of two distributed wind farms in 2009, with a combined capacity of 21 MW, making it the largest wind project to be designed, financed, and owned by any distribution electric cooperative at that time. Because of this, ILEC received DOE's Wind Cooperative of the Year award in 2011 as part of the Wind Powering America Initiative (Hussong 2012).

3.1 System Description

The two ILEC 10.5-MW wind power plants each comprise seven GE 1.5-MW wind turbines on 80-m towers. ILEC owns and operates the two wind plants and sells the power to Corn Belt, which ultimately sells power to Basin Electric Power Cooperative through a PPA. A 20-year PPA was established in 2009. ILEC financed the \$43-million project with 0% interest, clean, renewable energy bonds. This PPA was negotiated in 2009 and renegotiated in 2012. In comparison to current PPA rates, ILEC's PPA with Corn Belt is quite favorable to ILEC. When the PPA expires, it is unclear how ILEC will proceed to obtain energy generation revenues if another PPA is not negotiated. However, under an assumption of a 20-year life span, the period of uncertain revenues is likely to be quite short.

Together, the two wind power plants generate about 77,000 MWh each year, which is about 12% of ILEC's electricity supply. The max output was 84,000 MWh in 2014. The annual capacity factor of the wind plants is approximately 40%, with a high of 42%.

Each 10.5-MW wind power plant is sited next to, and primarily serves, an ethanol plant that uses about the same amount of energy that is produced by the wind turbines annually; these wind plants have peak loads of 7 MW and 8 MW, and their combined annual generation is approximately 125 gigawatt-hours (GWh). The plants tend to consume a constant amount of energy year-round and, even when offline, use ~1 MW. One wind farm is adjacent to the Green Plains ethanol plant near Superior, Iowa, while the other is installed next to the Global Ethanol facility near Lakota, Iowa.

3.1.1 Technical Parameters

Each wind power plant connects to its respective distribution system through roughly 2-mile underground three-phase lines to Corn Belt-owned substations. Each substation has up to 15 MW of transformation available. Within the Corn Belt substations, the wind plants connect to the same 12.47-kV bus that serves the associated ethanol plant. The substations connect to the external grid through transformer and 69-kV subtransmission line. Most of the generation flows through the low-voltage side of the substations and is used by the ethanol plants; any excess wind production flows through the substation and into the 69-kV transmission system. Energy needs of the ethanol plant not met by the wind turbines are imported through the substation.

The turbines are equipped with voltage and power regulation, which is not currently used. They are also equipped with voltage and frequency ride-through capabilities, which are static in the turbine, but there if needed. Reactive power features are also available but not used. The turbines are outfitted with a cold-weather package, which includes heaters for the oil and gear box, control boxes, and nacelle. With this package, the turbines experience derated production at approximately −10°C, and the turbines cease operation at −20°C. There is no deicing or ice-detection mechanism installed. The sites are small enough to be Federal Energy Regulatory Commission qualifying facilities and are, therefore, not subject to curtailment (National Rural Electric Cooperative Association 2021).

Fiber-optic lines tie the wind turbines back to the SCADA at the substations. Servers at the substations allow for remote access to data, and there is dedicated communication from the substation to ILEC facilities. The wind turbines are protected by access points with role-based access control providing different levels of tiered access. Corn Belt can monitor the plant production at the substation level and open breakers on the outgoing side, if necessary, but cannot see at an individual turbine level. Only a handful of ILEC employees have full access to the wind turbines. Virtual private networks are in place, and multifactor authentication is needed to get into the administrative control room. There are physical locks on the control box of the wind turbine, on the turbine door, and on the substation server house. The server house is also secured by a password-protected alarm system.

3.1.2 Market Parameters

Currently the ILEC wind farms in Lakota and Superior are producing and selling to the market at their capacity (full generation as per available resource). In this report, we explore the possibilities for ILEC to expand into the ancillary service market as well. As part of their future market initiatives, the Southwest Power Pool (SPP) has stated they are anticipating broader DER participation to deliver various ancillary services; some examples are shown in Figure 20. The flexibility of DERs in the market is noted as being an essential component given the changing nature of the grid (SPP 2021a). Although the ILEC distributed wind asset is not a direct participant of the SPP market, there are some market services that they may be able to receive remuneration for if they were able to meet the market participant criteria under the SPP's open-access transmission tariff (SPP 2018). These criteria include financial requirements, such as minimum net worth and credit rating, as well as operational requirements, such as the technical ability to respond to the SPP communications and directions promptly and adequately.

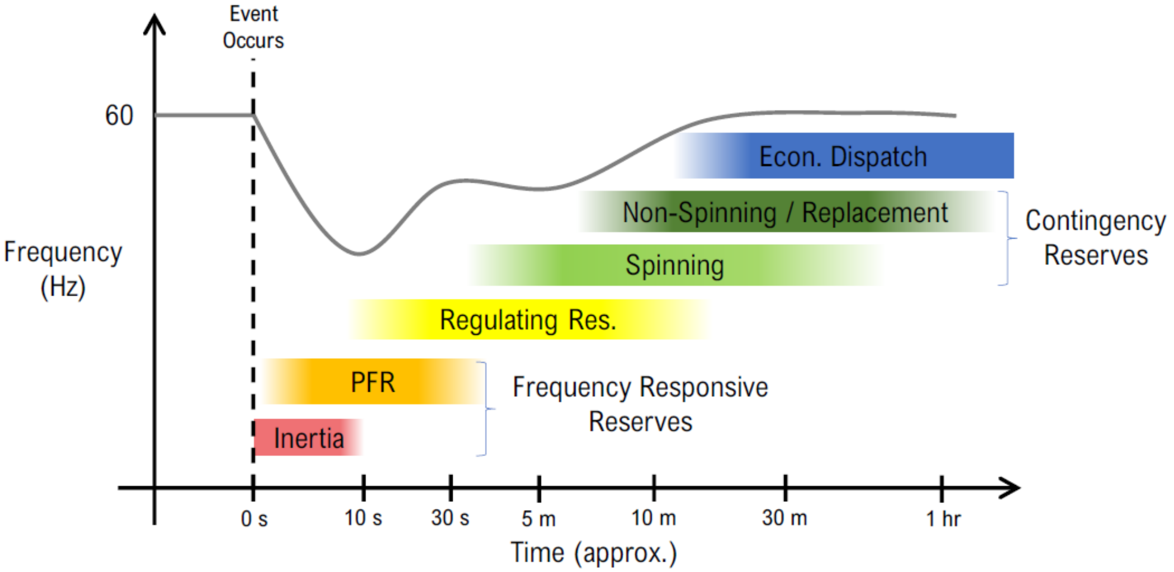

Figure 20. Main services procured in the U.S. power system (Denholm, Sun, and Mai 2019)

3.2 Valuation Framework Results

Following the distributed wind valuation framework, we used the reference system details outlined in Sections 3 and 3.1 to determine which valuation chart sections were relevant to our analysis (grid-connected, front-of-the-meter, and cooperative-owned) (Mongird and Barrows 2021). After meeting with ILEC and gaining an understanding of the system, it was possible to determine which value elements were most important and how to value many of them. The narrowed list of value elements is provided in Table 29. The green cells indicate value elements that are quantified in this report, and the yellow cells indicate value elements that can be explored through further modeling and assumptions. These yellow value elements are not currently revenue streams for ILEC but could be explored in future scenarios when their PPA expires.

Table 29. Iowa Lakes Electric Cooperative Selected Value Elements

🟩 Quantified here

🟨 For future analysis

		System Connection Type	**Grid-Connected Assets/Microgrids**		
		System Location of Assets	**Front-of-Meter**		
		Ownership Structure	**Cooperative-Owned**		
		Value Perspective	**Electric Cooperative**	**Customer**	**Society**
		Distribution System Operator/Provider	✓		
		Energy Generation Owner/Operator	✓		
		Retail Energy Purchaser		✓	
Category	**Value Elements**	**Quantifiable?**			
Bulk Energy Services	Energy Generation	Yes	🟩 ✓		
Ancillary Services	Regulation	Potentially	🟨 ✓		
	Frequency Response	Potentially	🟨 ✓		
	Load Following	Potentially	🟨 ✓		
	Voltage Support (providing reactive/active power)	Potentially	🟨 ✓		
Distribution Services	Distribution Upgrade Deferral	Potentially	🟨 ✓		
	Power Reliability/Resilience/Outage Mitigation	Potentially	🟨 ✓	🟨 ✓	
	Job Creation	Potentially			🟩 ✓
	Environmental Benefits	Potentially	🟩 ✓		🟩 ✓

Following the valuation framework guide, we decided the valuation would be conducted from the perspective of the electric cooperative, ILEC, and that value elements impacting society would also be included. Other perspectives, such as the transmission provider and balancing authority, would be difficult to include because of data confidentiality and the scope of the valuation. Equations for each of the relevant value elements were then constructed, considering the ownership structure, project configuration, and other business elements.

3.2.1 Value Element Calculation Methodology

Value elements were calculated across a 20-year project lifetime, and the NPV of each value element stream was found using a nominal discount rate. To find this discount rate, we followed methodology used by the Northwest Power and Conservation Council (2010) and assumed that electric cooperatives can finance at about 100 basis points above 30-year Treasury rates. Using the median annual 30-year Treasury rate between 2009 and 2021, we calculated a nominal discount rate of 4.02%. Sensitivity analyses were conducted for higher and lower discount rates, as shown in Section 3.2.6. If this analysis was applied to the existing facility starting at the end of its current PPA, the resulting financial assessment would be different.

NPV benefits and costs were organized by entity and presented in detail in Section 3.2.6. Qualitative value elements that are potentially significant—namely, added resilience to the electric cooperative and to society—were presented simultaneously with the benefit-cost figures. The equations used in calculating each value element are provided in the following sections.

3.2.2 ILEC Value of Energy Generation

The value of energy generation for ILEC is very straightforward. It sells all its energy to Corn Belt, its generation and transmission provider and, ultimately, to Basin Electric Cooperative (of which Corn Belt is a member) through a 20-year PPA. ILEC was also a recipient of a $0.01/kWh production tax credit through Iowa Code Chapter 476B from 2009 until 2020 (Iowa Legislature 2021). Additionally, loss-factor credits of $0.0015/kWh were in place from 2009 to 2015, and of $0.0004/kWh between 2015 and the present.

The value of energy generation for ILEC is simply the megawatt-hours generated, multiplied by the PPA rate, plus any relevant adders, such as the production tax credit and loss-factor credits. We estimated PPA rates using wind PPA prices for the SPP region from a Lawrence Berkeley National Laboratory (2021) database. To reflect the renegotiation of the PPA, we used a 2009 estimate of $50/MWh until 2012, then began using an escalator from 2012 onward. Values from 2009 were first adjusted to 2012 values using annual values from the U.S. Bureau of Labor Statistics (2021a), then escalated at a constant 2% growth rate. The equation for the value of energy generation for a given year is shown in Equation 3, where the PPA, production tax credit, and loss-factor credit are specific to each year, and the MWh is constant because it is an average value.

$$NPV\ of\ Energy\ Generation\ =\sum_{t=0}^{20}\frac{MWh\ \times\ (PPA_t\ +\ PTC_t\ +\ LFC_t\ )}{(1+i)^t} \tag{3}$$

where

PTC = production tax credit
LFC = loss-factor credit.

Energy generated was calculated using 10-minute production data from the two ILEC sites over a 3-year time frame from 2018 to 2020. The average production across the 3 years was calculated as 71,521 MWh—very close to ILEC's annual target of 72,000 MWh.

3.2.3 ILEC Economic Impacts

Job creation benefits and regional economic impacts for ILEC's distributed wind project were calculated using NREL's JEDI models, specifically the JEDI Distributed Wind Model rel. DW12.23.16 model, as was done in Section 2.3.1.3 for St. Mary's (National JEDI: Jobs & Economic Development Impact Models. n.d.).

To implement the JEDI model, we input project data and used JEDI default inputs, which came from wind industry averages, where project data were not available. For example, total project costs were submitted as $43,000,000, but default JEDI values were used to determine the proportion of this capital expenditure that went to each cost category (such as the turbine, tower, foundational materials, electrical wiring, and labor as well as the balance of systems costs). Similarly, ILEC provided ongoing operational costs as $200,000—as well as the schedule of major replacements and repairs. Using the NPV of these O&M costs, we calculated annual O&M costs to be $642,182 in 2009 dollars. We used the default JEDI breakdown of these costs by labor and material type.

The region being analyzed was defined in the model as the state of Iowa, meaning that economic impacts are calculated across the state's industries and workers. Economic impacts are the sum of on-site earnings, supply chain impacts, and induced impacts in Iowa.

3.2.4 ILEC Environmental Benefits

The environmental benefits of the wind turbines at ILEC are calculated using marginal emission factors from the AVoided Emissions and geneRation Tool (AVERT), as shown in Equation 4, as being 7.09 x 10^{-4} metric tons CO_2/kWh (EPA n.d.[b]). For the purposes of this valuation, we limited the scope of the benefits calculations to avoided CO_2.

$$NPV\ Env.Benefits\ =\sum_{t=0}^{20}\frac{Fuel\ Savings_t\ \times\ 7.09^{-4}\ \times\ 76}{(1+\ i\ )^t} \tag{4}$$

where

Fuel Savings$_t$ = Energy generation$_t$ × marginal emission factor
t = year
i = discount rate.

The discount rate for society is assumed to be 2%, consistent with Drupp et al. (2018). Annual energy generation was calculated to be 71,521 MWh, as described in Section 3.2.2. The social cost of carbon is estimated to be $76 per metric ton of CO_2 (EPA n.d.[b]). The social cost of carbon value used in this analysis is the 2020 value calculated at a 2.5% discount rate, deflated to 2019 dollars using the CPI-U (U.S. Bureau of Labor Statistics 2021a).

3.2.5 ILEC Costs

Initial project costs were funded through interest-free, clean, renewable energy bonds introduced by the federal Energy Policy Act of 2005, which has since been eliminated under the Tax Cuts and Jobs Act of 2017 (Provus n.d.). These clean renewable energy bonds were both issued and sold by CoBank, allowing ILEC to avoid costs associated with issuing bonds and uncertainty about how much interest the market will bear when the bonds are sold. This means that the project's financing was 0% interest, which is highly unusual. Annual bond payments are about $2.9 million over 15 years.

Several impact studies were conducted to allow the project to move forward. One is an impact study to determine the maximum capacity that could be connected to the substations, costing $8,000–$10,000. Additionally, the Mid-Continent Area Power Pool required a system impact study on the regional grid, costing $100,000.

Annual land-use costs are approximately $5,000 in 2021 dollars. Annual taxes are almost $200,000, and annual insurance is about $140,000 in 2021 dollars. We used the CPI-U to adjust these values to previous years and assumed a 2% inflation rate for years after 2021.

Routine O&M costs were brought in-house for ILEC as soon as wind turbine warranties allowed, enabling the cooperative to budget $200,000 annually for O&M, including labor and parts, in 2009 dollars. We used an O&M escalation rate of 2.5% to find the cost for subsequent years of the project.

Occasionally, major repairs and replacements have been needed as parts wear out and faults occur. Using data from ILEC about timing and type of major replacements, along with cost estimates for parts and labor from Table 4-3 in an NREL report by Martin-Tretton et al. (2012), we found that NPV costs of major replacements and repairs were almost $6.5 million in 2021 dollars.

3.2.6 ILEC Valuation Results

We find overall benefits to costs to be extremely favorable, at a ratio of 4.19, when considering societal and electric cooperative benefits together. When considering just the benefits to the electric cooperative, the ratio is still quite high at 1.84. Results are shown in Figure 21.

Acronyms: Mid-Continent Area Power Pool (MAPP); Operations & Maintenance (O&M)

Figure 21. Iowa Lakes Electric Cooperative valuation results

Net present energy generation benefits are almost $104 million, largely due to the favorable PPA that is in place with Corn Belt. Costs to ILEC are relatively low because of the 0% bonds that were obtained through the Energy Policy Act of 2005. The NPV of annual bond payments is $39 million, much lower than the initial $43 million required for the project. Tax and insurance NPVs are $3 million and $2 million, respectively, and the NPV of land-use costs is $87,383. The NPV of major repairs and replacements represents the single largest cost besides annual bond payments. This $6.5 million cost is a result of replacing gearboxes and other expensive turbine components. Routine operations and maintenance NPV was $4.3 million, in comparison, and system impact studies cost $135,000 at the outset of the project.

There are also large benefits to society, which, taken together, sum to more than the energy generation benefits to the cooperative. Economic impacts to the state of Iowa from turbine-related construction and O&M came to an NPV of $62 million. Environmental benefits in the form of avoided CO_2 emissions sum to an NPV of $69 million. As other pollutants were also likely avoided, the real environmental benefit is likely to be larger.

As demonstrated, the ILEC project has a very high overall benefit-to-cost ratio, even without societal benefits. In the absence of a PPA and interest-free bonds, it is unlikely the project would have had such a favorable rate of return. The current PPA is set to expire in 2029 and it is clear the system will have more than paid for itself by then. However, additional market services might be worth investigating to capture some additional value.

Sensitivity Analyses

The discount rate used in this analysis in finding the NPV of a flow of revenue or costs was 4.02%, as described in Section 3.2.1. If this discount rate was higher or lower by one percentage point, the results would change slightly, as shown in Table 30.

Table 30. Iowa Lakes Electric Cooperative Valuation Sensitivity Analysis

Value Element	Base Case	Discount Rate +1%	Discount Rate −1%
Energy Generation	$103,629,215	$94,886,397	$113,647,738
Economic Impacts	$62,224,751	$60,236,167	$64,504,320
Environmental Benefits	$69,154,229	$63,381,252	$75,771,953
TOTAL Benefits	**235,008,195**	**$218,503,816**	**$253,924,010**
Annual Bond Payment	$39,495,844	$36,873,084	$42,405,427
System Impact Study	$11,166	$11,166	$11,166
MAPP[a] System Impact Study	$124,062	$124,062	$124,062
Land-Use Costs	$87,383	$79,828	$96,094
Annual Taxes	$3,191,257	$2,898,535	$3,528,738
Annual Insurance	$2,312,039	$2,099,965	$2,556,542
Major Repairs and Replacements	$6,469,282	$6,194,295	$6,761,309
Operations & Maintenance	$4,342,213	$3,935,146	$4,812,224
TOTAL Costs	**$56,033,245**	**$52,216,079**	**$60,295,561**

[a] MAPP = Mid-Continent Area Power Pool

3.3 Advanced Control and Hybrid System Design Results

3.3.1 Analysis Scenario Descriptions

To understand the opportunities that may be present for a grid-connected distributed wind deployment in the future, the team identified three scenarios for the ILEC wind turbines. These are outlined in more detail below, but we aim to provide an understanding of the system as it exists today and evaluate hypothetical future scenarios. The three scenarios investigated under this effort include:

1. Baseline PPA: 2009 to 2029
2. Post-PPA: wind only
3. Post-PPA: wind-hybrid opportunities.

3.3.1.1 Baseline PPA

To understand the system as it is deployed today, the MIRACL team established a representative baseline of the ILEC wind turbine deployments under its current PPA, which is active from 2009 until 2029. This is not a perfect representation of the actual deployment, because of sensitivities around some aspects of the project, but enables us to compare future opportunities more closely for similar distributed wind turbine deployments.

3.3.1.2 Post-PPA Wind Scenario

This first hypothetical scenario investigates additional sources of revenue that might be available after the current PPA expires in 2029. This scenario investigates use of the existing wind turbine's advanced control functionality, enabling functions that are currently not being utilized within the turbines. We evaluate existing market opportunities in the Basin and Corn Belt territory, within the SPP, and propose further evaluation for future markets that may exist. This scenario is intended to propose future opportunities for the ILEC system as well as comparable distributed wind deployments in regulated markets. The following ancillary service opportunities were investigated to determine the likelihood or feasibility for the ILEC turbine deployments in the future:

1. Operating reserves (regulation)
    a. Regulating reserves (regulation up and regulation down)
    b. Contingency reserves (spinning and nonspinning reserves)
2. Voltage support at the local distribution level
3. Black-start support
4. Transmission congestion rights market.

3.3.1.3 Wind Hybrid Scenario

The second hypothetical scenario investigates adding a PV or utility-scale BESS to the existing wind plants. This scenario builds on the post-PPA wind scenario by adding generation of an undefined system capacity to investigate technical and market opportunities that may be enabled—in addition to the advanced control opportunities outlined in the post-PPA scenario. We evaluate existing market opportunities in the Basin and Corn Belt territory within the SPP and propose future opportunities that could be developed. This scenario is intended to propose future opportunities for the ILEC system as well as the opportunity to add energy storage to comparable distributed wind deployments in similar regulated markets. The following ancillary service opportunities were investigated to determine the likelihood or feasibility of adding energy storage to the ILEC turbine deployments in the future:

1. Capacity resource
2. Operating reserves (regulation)
3. Voltage support
4. Black start
5. Peak shaving or demand management.

3.3.2 Advanced Control Analysis

3.3.2.1 Post-PPA Wind With Advanced Control Scenario

For this scenario, we investigated the various control capabilities of the existing wind plants at ILEC to provide ancillary services to the local distribution system or regional energy market. The largest limitation placed on this hypothetical scenario is the use of existing hardware within the wind plants, except for minor software, firmware updates, and recapitalization.

Operating Reserves

Operating reserves are quick responses by generators used to rapidly help restore system frequency during or after an event—often, a large change in generation or load. These reserves may be used to address normal, random, short-term fluctuations in load that can create imbalances in supply and demand (Denholm, Sun, and Mai 2019).

Regulation Reserves

Regulation reserves are the highest-paid service in the reserves market. This does not require significant curtailment but requires maintaining the ability to ramp turbine power up or down as required by the market operator. In general, regulation is used to meet very short-term variability (seconds to a few minutes). This variability can result in either changes in frequency or unscheduled flow of power into or out of the region in which local generation is not matching load. Utility systems monitor these imbalances and signal generators in that area to modify their output as needed via a signal from the system operator. Under these conditions, regulating reserves require generators to both increase and decrease output (Denholm, Sun, and Mai 2019).

Regulation up is an ancillary service during which the generation is set below maximum capability to provide room to increase generation in response to regulation needs (Denholm, Sun and Mai, 2019). Wind is often not considered as a regulation-up resource because of its variable nature and a lack of confidence that the resource will be available when called upon. However, it is believed that improved forecasting could help increase confidence. Variable energy resources, such as distributed wind turbines, are traditionally not allowed to participate in any "up" products in the SPP because of the inherent variability of the wind resource. In February 2020, a concept called "SIR36: Reg-Up For VERS" was proposed to be included in future road map efforts to investigate allowing variable energy resources to participate in regulation-up services in the SPP (Southwest Power Pool 2020c). This will become increasingly important as the contribution of renewables to the grid increases.

SIR36 is an initiative to "modify the DVER (Dispatchable Variable Energy Resource) design to allow DVERs to clear and be deployed for Regulation-Up, Spinning, and Supplemental Reserve" (Southwest Power Pool 2020c). This initiative was proposed in March 2020, and the analysis is tentatively scheduled to begin in 2022. At this time, no determination has been made by the SPP whether to allow wind to participate in regulation up, spinning reserves, or supplemental reserves (or nonspinning reserves) (Southwest Power Pool n.d.).

Regulation down provides the same service in the opposite direction; that is, generation is set at some level above minimum so that it can reduce output in response to a signal (Northwest Power and Conservation Council 2010). These responses in output allow the SPP to smooth out fluctuations in supply and demand on the grid, ultimately making the corrections on a subinterval basis. Based on rules outlined in the SPP's compliance filing to the Federal Energy Regulatory Commission, wind is currently not allowed to participate in regulation-down services (Southwest Power Pool 2018).

The regulation-down market clearing price in the real-time market has increased the past 5 years and is projected to continue this trend in future years (Southwest Power Pool 2021b). To complement the potential revenue source and protect the overall system, there are penalties if a generator is called on to provide regulation and is unavailable. The risk of receiving a penalty may outweigh any benefits realized from the above revenue opportunities. The details of this penalty are outlined in Section 4.2.1.1.1 of the SPP Market Protocols document (Southwest Power Pool 2016).

If there is a future market opportunity or power system need, the ILEC GE wind turbines could provide regulation services to the SPP or Corn Belt. The existing power electronics of the GE 1.5-MW wind turbines currently deployed at ILEC have the capability to support regulation, but this capability is not currently utilized because ILEC is incentivized through its PPA to sell the maximum kilowatt-hours to the market. Participation in the regulation-up market would require curtailed production from the ILEC wind turbines, which would impact their annual production. A cost-benefit analysis should be performed to understand whether the participation in this market would outweigh future PPA payments. IEEE 1547-2018 requires all new DERs and wind turbines to be capable of operating with frequency-droop settings, but does not require operation with droop settings, because only utilities can require this. These settings can be adjusted to reduce the operating bands, ultimately increasing the response of the wind turbine or wind plant based on the need of the system (IEEE 2018).

Regulation services could be provided by the ILEC turbines in two ways—active or passive regulation control:

1. In active participation, the SPP would send a signal to the ILEC wind plants to change their static output or vary existing droop curves to increase output in response to the event.
2. In passive participation, the wind turbines could employ onboard inverter control logic, such as droop curves or a filter, to change the active power response of the wind turbine or wind plant.

A wind turbine control system with a droop curve can allow for participation in primary frequency control if measurements of grid frequency are available. This allows primary frequency control power commands to be synthetically generated and passed to the control system, enabling an automatic response to changes in grid frequency in addition to active power set points requested by the grid operator—as long as there is sufficient power available from the wind and the turbine stays within the designed power limits (Ela et al. 2014). Figure 22 is an example of wind turbines improving grid frequency following an event by employing five different styles of droop curves—two static droop curves and three dynamic droop curves. The wind baseline scenario outlines 15% penetration of wind on a bus with no active power control (Ela et al. 2014).

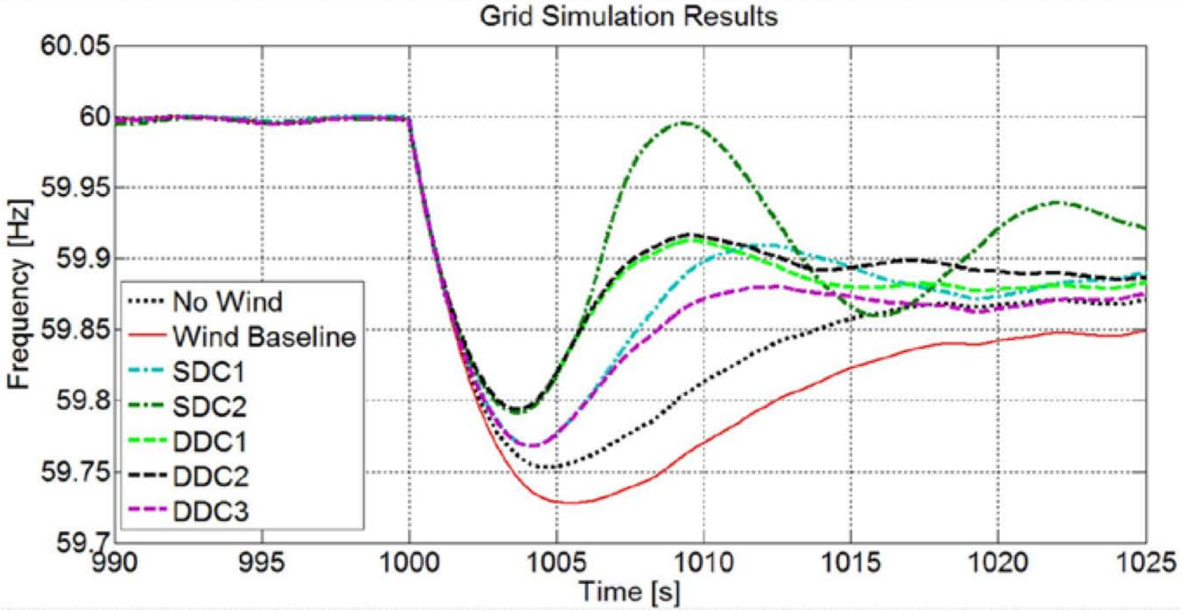

Figure 22. Example of wind turbines providing regulation services (Ela et al. 2014)

Contingency Reserves

Contingency reserves are used to address power plant or transmission line failures by increasing output from generators. These include spinning reserves, which respond quickly and are then supplemented or replaced with slower responding (and less costly) nonspinning/replacement reserves (Denholm, Sun, and Mai 2019).

Spinning Reserves. The SPP categorizes spinning reserves as “Operational Reserves—Spinning” and defines them as “generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or load fully removable from the system within the Disturbance Recovery Period following the contingency event.” Spinning reserves would require a higher curtailment in the wind energy generation, and they ensure the utility has a promised delivery of power available whenever required. This service is an ensured backup supply of power in case of contingency or increase in load. The challenge that a wind energy plant faces in this case is constant availability of the wind resource and for “how long” the spinning reserve is required to operate (Southwest Power Pool 2021a).

Nonspinning reserves. The SPP categorizes nonspinning reserves as “Operational Reserves—Supplemental” and defines a generation source providing this service as “fully available to serve load within the Disturbance Recovery Period following the contingency event.” Utilizing a wind plant as a nonspinning reserve resource would require significant curtailment and a risk-based capacity valuation of the resource, because the wind resource may not be present when the plant is called upon (Southwest Power Pool 2021a).

Where regulation services are provided on a subinterval basis, spinning and supplemental reserves are used for contingency situations. This ancillary service maintains grid stability by requiring assets to be operable and ready to respond within 10 minutes. Assets providing this service are typically responding to a grid outage or generation shortfall event. Spinning reserves are synchronized to the grid, although supplemental reserves are offline but capable of being brought online just as quickly. Figure 23 shows the market clearing prices for spinning and supplemental reserves for 2019 in the SPP, averaging approximately $6/MW and $2/MW, respectively (Southwest Power Pool 2020b).

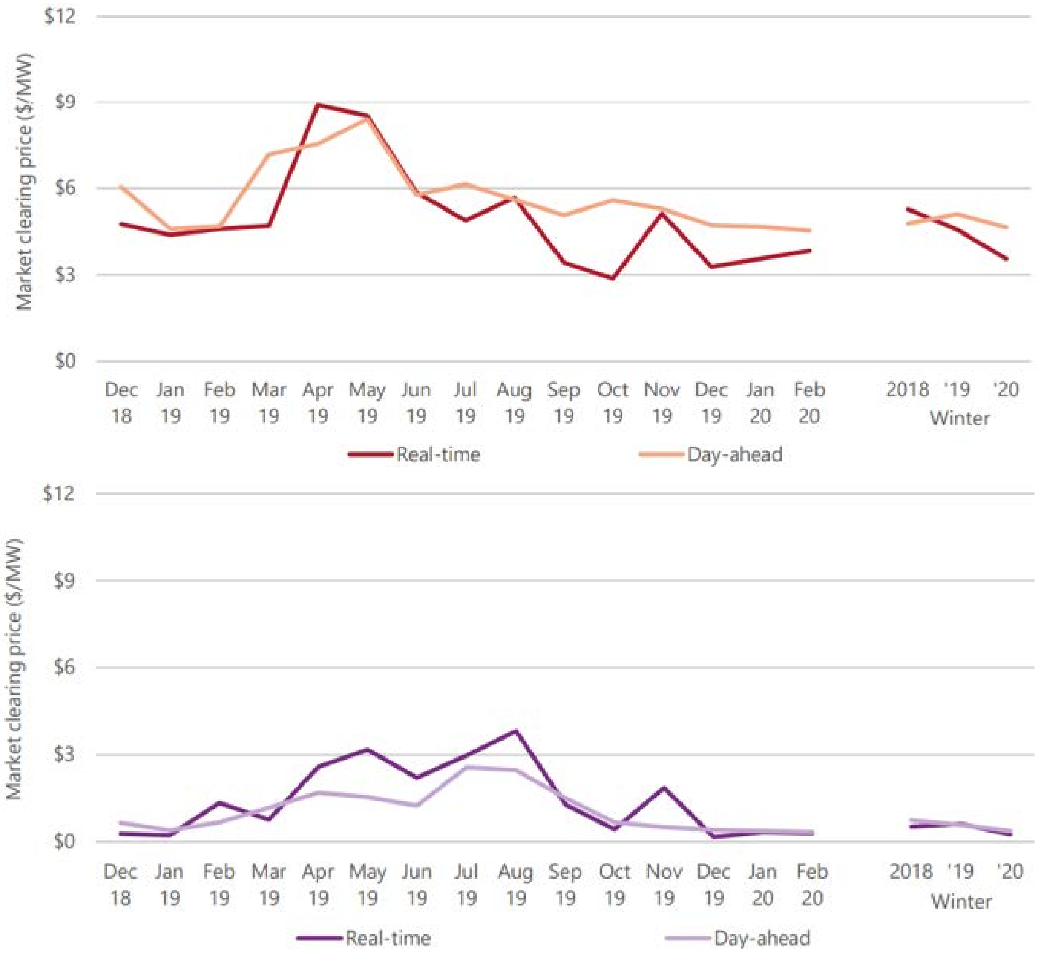

Figure 23. 2019 market clearing prices for spinning reserves (top) and supplemental reserves (bottom) in the Southwest Power Pool (Southwest Power Pool 2020b)

Serving as a contingency reserve resource is likely not a viable option for a distributed wind plant in Iowa to pursue. Based on the variability of the wind resource, current wind penetration levels, and the ability to provide "near-zero-cost" energy to the grid to offset conventional fuel sources, it is unlikely that a wind plant would be requested to curtail and be used as a contingency reserve. This responsibility will continue to fall to conventional sources of spinning and nonspinning reserves, and energy storage will play an increasing role as a contingency reserve as well.

Voltage Support at the Local Distribution Level

To maintain electric system reliability, both frequency and voltage must be carefully balanced. Frequency is constant throughout the grid, but voltage must be managed at a more localized level. Voltage is typically managed and controlled at the point of generation, at the transmission level, and at the distribution level. On the distribution system, capacitors or voltage regulators are often used to manage voltage and it is increasingly common for distributed generation, such as distributed wind, to support voltage as well.

Wind has the capability to provide voltage support because, in 2016, the Federal Energy Regulatory Commission (FERC) removed exemptions from front-of-the-meter wind generators for providing reactive power (FERC 2016). Independent system operators (ISOs), regional transmission organizations (RTOs), and some nonmarket areas compensate generators for their ability to provide reactive power. The SPP does not currently offer reactive rates, though variable payments based on opportunity cost are available to qualifying generators when they are dispatched to provide reactive power outside of a standardized power factor requirement range (Solar Energy Industries Association 2020).

In addition to these variable payments, PJM Interconnection (PJM), Midcontinent ISO, New York ISO, and ISO-Nebraska all offer fixed payments to qualifying generators (Solar Energy Industries Association 2020). For PJM and Midcontinent ISO, fixed payments are based on the reactive power capability of each resource, although there is some current uncertainty about aspects of the methodology, and the Federal Energy Regulatory Commission will be issuing further guidance (FERC 2016). For New York ISO and ISO-Nebraska, these fixed payments are based on system needs, and the rate is within an RTO-wide stated range, which means it is unlikely to yield payments as high as those in PJM and Midcontinent ISO. A summary of reactive power compensation is provided in Table 31, which is taken from (Solar Energy Industries Association 2020).

If the SPP were to adopt a fixed payment, market compensation could be possible for reactive power. If this fixed payment was based on the reactive power capability of each resource, payments would likely be higher than if they were based on system needs.

Table 31. Reactive Power Compensation in Regional Transmission Organizations

RTO	Fixed Payment	Variable Payment	Revenue Potential
PJM	Yes	Yes	High
Midcontinent ISO	Yes	Yes	High
New York ISO	Yes	Yes	Moderate
ISO-Nebraska	Yes	Yes	Low
Southwest Power Pool	No	Yes	Low
California ISO	No	Yes	Low
Electric Reliability Council of Texas	No	Yes	Low

This opens a possible research opportunity to explore hybrid energy resources by combining wind with storage and/or PV, as discussed in the next scenario.

Although there is no market opportunity in the SPP for voltage support, there are examples of voltage support in other markets, such as PJM (Denholm, Sun, and Mai 2019). There are qualitative resilience benefits that could be realized by local utilities and cooperatives to provide this service if voltage deviations are a concern. As renewable energy penetration increases, voltage fluctuations could become more likely, and the ability to provide this service from multiple sources, such as DERs, may become increasingly beneficial.

When a wind turbine is providing voltage support, the reactive power is prioritized over the real power, which may need to be curtailed and thus offsets the turbine's typical revenue source of energy (watt-hour). The reactive power can be controlled independently of real power in Type 4 wind turbines by using the power electronics of the wind turbine system. Moreover, this reactive power requirement can be dynamically commanded to the wind turbine, or the wind turbine can be set to operate at a constant power factor (at, say, 0.9 or 0.95 leading or lagging), thereby delivering some reactive power all the time. These concepts are outlined in Sections 5 and 6 of IEEE 1547-2018 (IEEE 2018).

Another way that new DERs can have a positive impact on voltage is by ensuring they ride through certain power system faults and do not negatively contribute to the voltage or event. Based on the 2018 revision to IEEE 1547, distribution-connected wind turbines and other DERs are required to ride through certain voltage and frequency events—and even provide some limited voltage support (IEEE 2018).

Black Start

Black start is an emergency service that supports restoration of a local power system after an outage. Some generators can start with the help of a small on-site battery or diesel generator (to start up local auxiliary loads), then sequentially pick up loads, transformers, distribution lines, and other larger generators, eventually stitching the entire grid together for normal operation. Such a gradual restoration of power is called a black start. A wind turbine can provide black-start capability by employing a grid-forming inverter (i.e., voltage source converter) and an integrated battery storage system.

This capability is not currently required for DERs and is likely not a viable option for the ILEC turbine deployments with wind as the only generation resource on the local distribution system. If ILEC or Corn Belt is interested in investigating this further, there is a possibility that wind could be used to supplement other black-start sources in the area once the grid local to the wind plants has been energized.

Transmission Congestion Rights Market

In addition to the energy and ancillary services market services, the SPP also has the transmission congestion rights market. Participants in this market can hedge against future transmission congestion by purchasing transmission congestion rights and reducing their risk of taking on high market prices along specific lines (Southwest Power Pool 2021a). Figure 24 shows the marginal congestion cost in the day-ahead market for the SPP in 2019 by region (Southwest Power Pool 2020a).

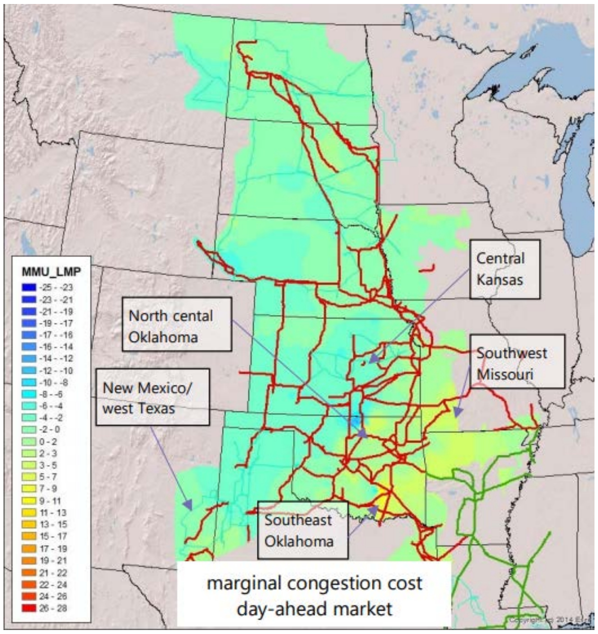

Figure 24. Marginal congestion cost (USD 2019) in the day-ahead market (Southwest Power Pool 2021b)

Although not a direct benefit that the distributed wind asset can participate in, the presence of the distributed wind generation could provide an avoided cost benefit. In a scenario in which purchasing transmission congestion rights can be alleviated through local generation, the distributed wind asset could provide value.

3.3.2.2 *Wind Hybrids (Solar and Storage)*

This scenario investigates the various control capabilities that could be enabled by adding a BESS and/or PV to the existing ILEC wind turbine deployments. The capacity of these would be limited by the existing hardware—or upgrades to the collection system and substation may be required. As discussed in 3.1.1, the common substation transformer serving the wind plant and ethanol plant is rated to 10 megavolt-amperes.

For a BESS, both the charging and discharging of the BESS would be limited based on the substation's capacity, net load, and generation behind the substation. During times of low wind production and high ethanol plant load, the ethanol plant could be consuming up to 8 MW; only 2 MW of the transformer's capacity could be available to charge the BESS. During times of high wind production and low ethanol plant load, the wind plant may be exporting 3–10 MW of power through the substation, limiting the amount of available transformer capacity to discharge from the BESS and participate in the services discussed below.

If PV is added to the wind plant, the capacity of the substation would likely need to be increased if the combined capacity of the plants exceeds the rated capacity of the substation components. An exception could be made if the wind and solar production will be coordinated and curtailed to ensure that their combined production will not exceed the rated capacity of the substation, but this may not be the most economical way of operating. There are benefits of this coordinated curtailment scenario that could be investigated. If the wind and solar resource in this region are complementary, one expected qualitative benefit is that the output between the two sources could be smoother from the perspective of the external grid—and any additional capacity could be reserved for grid-support functions. Clark et al. (2022) introduce an approach to analyzing complementarity on a spatial scale to identify opportunity areas in the United States. When including a BESS in a wind plant as a hybrid energy system, stacking revenue sources for both the wind plant and, primarily, the BESS should be considered. Revenue stacking is the prioritization and scheduling of grid-support functions from a BESS based on the technical and economic desires of the system owner. Figure 25 is an example of revenue stacking from various system owner and customer perspectives (Fitzgerald et al. 2015).

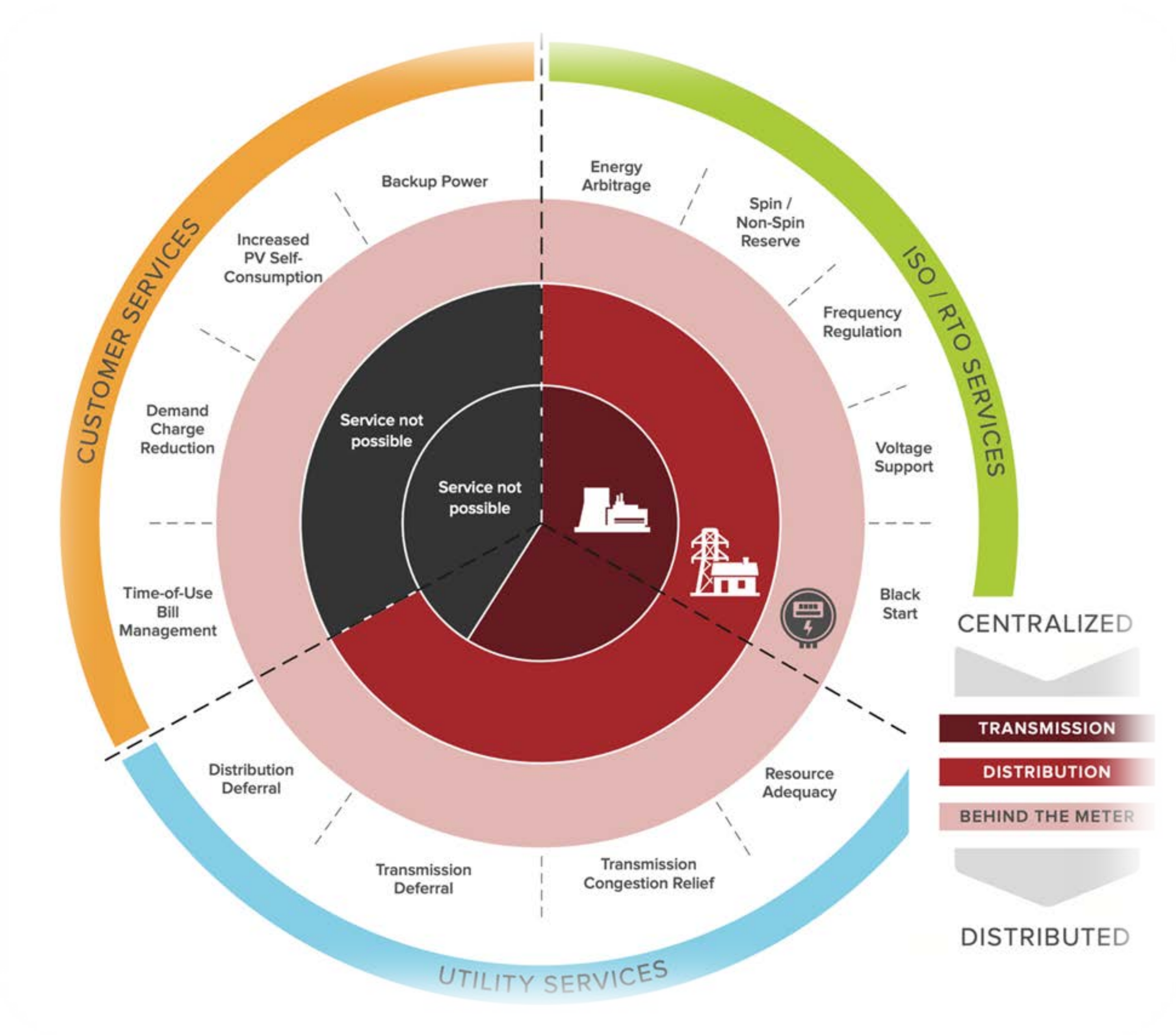

Figure 25. Revenue-stacking examples for battery energy storage systems (Fitzgerald et al. 2015)

Capacity Resource

One significant consideration of power system planning and operation is the ability to ensure that adequate generation capacity exists to meet load, with additional capacity to account for contingencies. The resources used to meet this capacity are often referred to as capacity resources, and there is some level of certainty that these generation sources will be available to deliver that generation capacity when called upon. Valuing the capacity of a variable renewable energy resource, such as distributed wind, can be challenging because of the variable nature of the wind resource. Each market region has a different way of valuing and compensating resources for their ability to serve as a capacity resource. In the SPP, the estimated peak capacity requirement in 2020 was 58.8 GW, which is largely served by natural gas and coal. The total installed capacity is 95 GW, and wind is approximately 29% of this installed capacity with 24 GW installed as of early 2021 (Southwest Power Pool 2021b).

There is a considerable amount of literature on methods to estimate generation capacity credits, and the various approaches to estimating capacity credits differ in complexity by market or region. They generally assess the probability of a plant being available during periods of highest net demand, which is typically during hot summer afternoons throughout most of the United States (Southwest Power Pool 2021b). In the SPP, the average capacity factor for wind is higher in the winter than summer. The SPP is one of three markets as of 2021 that does not have a capacity market, but it does have penalties that are applied to its members if they don't have adequate resources. The SPP values the capacity of a wind resource as 5% of capacity for the first 3 years, until the load-serving entity chooses to perform the net capability calculation during the first 3 years of operation (North American Electric Reliability Corporation 2017).

With this context around how the SPP may value wind as a capacity resource, there is a possibility that Corn Belt could value wind as a capacity resource, but the opportunity would be extremely limited for a wind plant of the capacity deployed at the two ILEC sites. One opportunity that could benefit both ILEC and Corn Belt is the addition of capacity, such as a BESS, to the wind plants, which may be fully eligible for this credit. By adding energy storage to the wind plants, the capacity (megawatts) of the energy storage system may be eligible to serve as a capacity resource for Corn Belt.

Operating Reserves

As discussed in Section 3.3.2.1, operating reserves are used to quickly help restore system frequency during or after an event, often a large change in generation or load. The addition of a BESS to the ILEC wind plants will likely enable opportunities for the storage system to participate as both a regulation reserve and a contingency reserve resource. The BESS included in the wind and storage hybrid would employ fast, power-electronics-interfaced technologies that can serve a valuable role in providing services, such as frequency regulation, contributing to grid reliability. Sandia investigated this possibility in a 2018 technical report on "Revenue Opportunities for Electric Storage Resources in the Southwest Power Pool Integrated Marketplace" (Concepcion, Wilches-Bernal, and Byrne 2018). The results of this report concluded that offering capacity of a BESS for regulation-up and regulation-down services can produce significant amounts of revenue for the electric storage resources. This shows a promising opportunity for ILEC to further investigate the addition of a BESS in their region, and the opportunity is likely improved by co-locating with the existing wind plant and leveraging the existing interconnection hardware at the site. This presents an opportunity for the MIRACL team to investigate in future efforts.

1. **Voltage support at the local distribution level**. As discussed in Section 3.3.2.1, a wind turbine can be used to support voltage at the local distribution level. The addition of a local BESS could improve the wind plant's ability to support voltage at a proportional level to the increased system capacity. But, due to the configuration and short length of the distribution line at the two ILEC deployments, this is not a strong example for simulation of this scenario. It does introduce an opportunity for future analysis into a wind-hybrid solution's ability to support long- and short-duration voltage deviations on radial distribution lines. For other systems where this would be more relevant, the BESS could include a set amount of available capacity, which could be called upon as part of the revenue-stacking prioritization. Depending on the specific technical and economic needs of ILEC, Corn Belt, and the SPP, the amount of energy storage capacity available

to support voltage could be a static amount or be set dynamically. The amount available could range from a small percentage of the energy storage system's capacity up to the full capacity based on a schedule and instantaneous power system conditions.

2. **Black start**. The addition of generation or a utility-scale BESS to the two ILEC wind plants could enable several additional benefits beyond selling kilowatt-hours into the system or to local loads. For example, ILEC could use the wind plant to support black-starts in the region. The team does not have enough information on nearby loads or sequence of operations to bring the system online to perform an in-depth analysis on this potential opportunity.
3. **Peak shaving or demand management**. One significant benefit that the ILEC configurations have is the common connection points between the wind plant and the ethanol plant behind the ILEC-owned substation. If wholesale prices for generation or other costs, such as demand charges on the market are high, a BESS could inject additional stored power to offset consumption costs for the ethanol plant or increase the amount of power sold into the market by ILEC. This introduces an opportunity for future investigation that will be pursued in future stages of the MIRACL project.
4. **Wind-solar hybrid complementarity**. As discussed in the previous section, adding storage and/or PV to a wind plant can help overcome the variability of the wind resource and provide adaptive capacity and ramping services. An NREL study of wind and PV complementarity shows how we can use the wind and solar hybrid for this effort. Figure 26 shows an example graphic from this complementarity work (Clark et al. 2022).

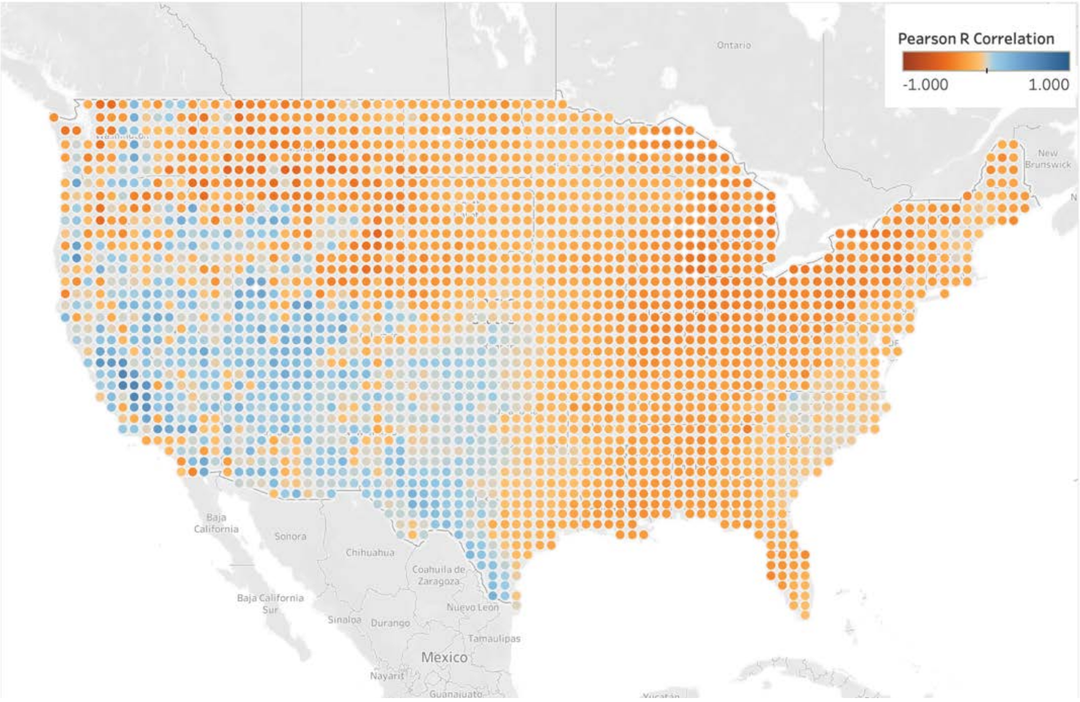

Figure 26. Daily-averaged complementarity of wind and solar resource (Clark et al. 2022)

Figure 26 depicts the wind and solar complementarity, measured over daily averages, for the contiguous United States, using the Pearson correlation coefficient. Regions in blue represent positive correlation (i.e., both wind and solar resources occur in the same space and time). The regions in orange represent negative correlation (i.e., wind and solar resources are occurring at offset times, so they are complementing one another).

The benefits of complementarity can be explored further in Figure 27 through Figure 29, which depict an optimally sized, off-grid hybrid plant at the ILEC location. This system comprises wind, solar, and storage components and is designed to supply an 8-MW load continuously at a critical load factor of 0.999. Figure 27 shows the optimal system component sizing, while Figure 28 shows the battery charge and discharge sources, as well as the state of charge, and Figure 29 shows the curtailment and shortfall of this system.

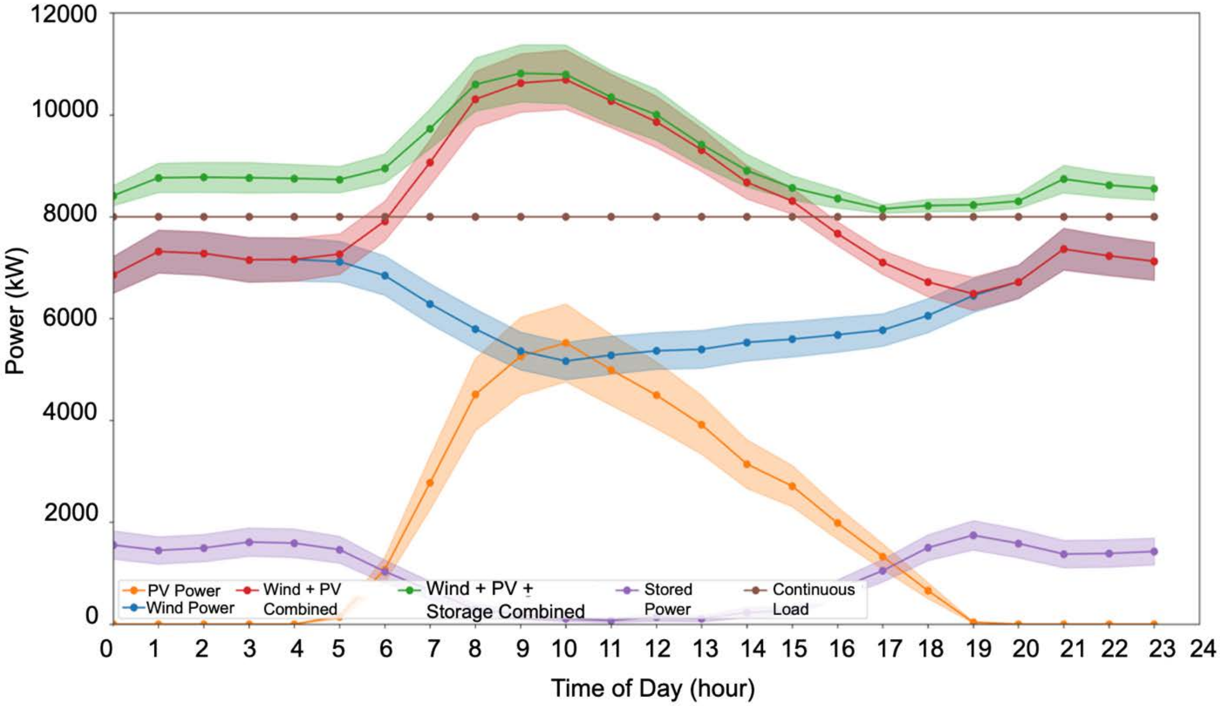

Figure 27. An optimal hybrid power plant design at Iowa Lakes given a constant 8-MW load demand

Figure 27 shows the benefit of a hybrid power plant and complementary resources over a wind-only or a solar-only plant. The daily average profiles show that solar energy generation is at a maximum when wind energy generation is at a minimum, resulting in a total system generation profile that is more consistent and better able to serve the needs of a continuous load than a wind- or solar-only plant. By adding solar PV generation, the system is better able to serve the load across time. The addition of 16 MW and 168 MWh (~10-hour duration storage) helps the system provide for load overnight, from 4 p.m. to 6 a.m., when solar energy is less available or unavailable, and to do so without necessitating additional wind energy capacity.

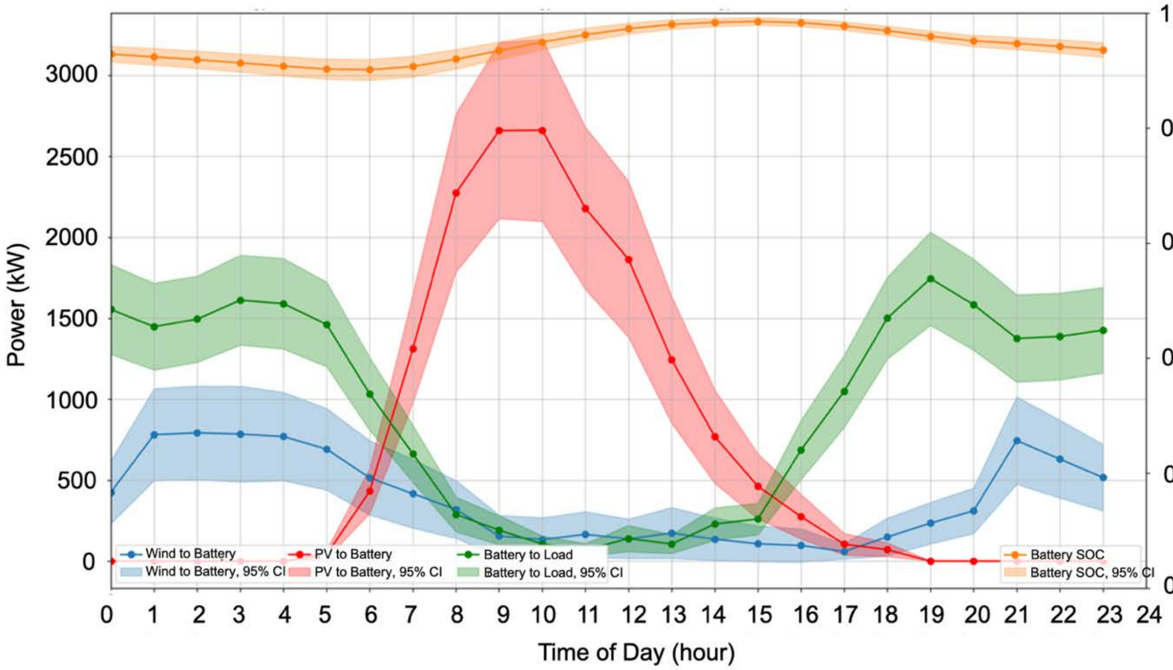

Figure 28. Battery state of charge and charge source for the Iowa Lakes site

Figure 28 shows that the state of charge for the battery remains fairly constant between 3 MWh and 3.5 MWh. The battery charges mostly from wind during the night, from 5 p.m. to 6 a.m., and from solar mostly during the day. The battery discharges mostly at night. Figure 29 shows the high curtailment required of the system to achieve 0% energy shortfall. Solar is curtailed during the day (peaking at noon), and consistently high curtailment of wind occurs across all hours.

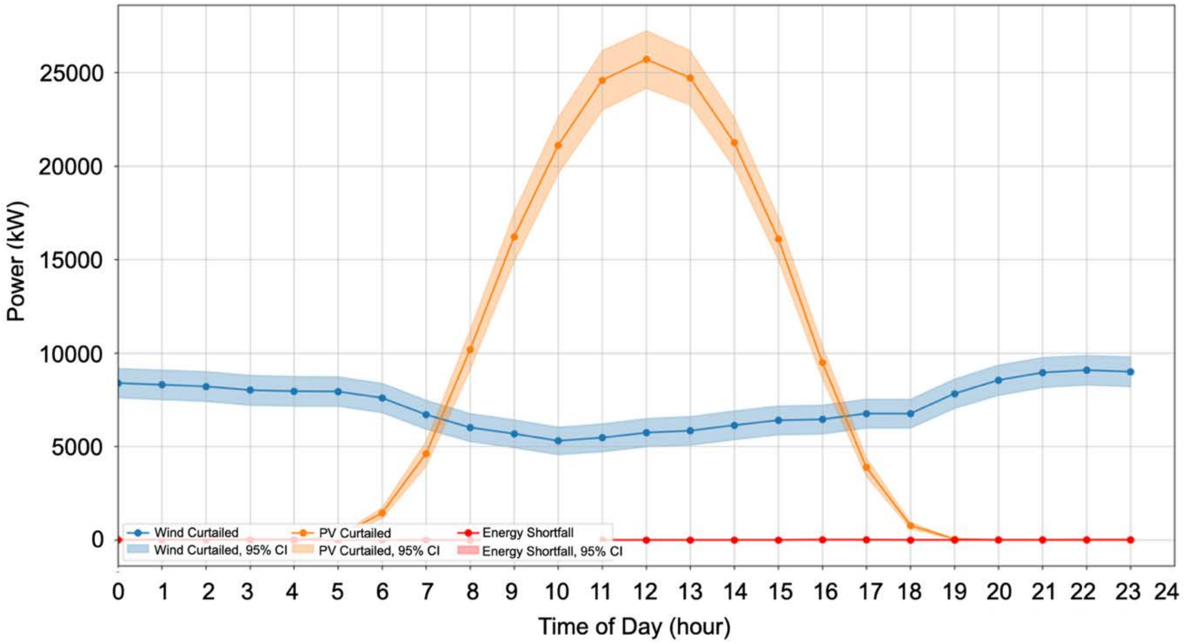

Figure 29. Curtailment and energy shortfall at the Iowa Lakes site

The installed wind and solar capacity of 25 MW and 69 MW, respectively, are high relative to the 8-MW continuous load. This overbuilding is due to the requirement of meeting a continuous load using variable renewable generation resources without buying or selling back to the grid. High amounts of curtailment in wind and solar result from this overbuilding as well as high battery state of charge. Two more realistic scenarios might be:

- Reducing the critical load that must be met by the renewable generation portion of the system to 95% or 90% (with the shortfall being handled by diesel generation or flexibility in the load)
- Maintaining a grid connection that allows for excess energy to be sold at times of over-production and purchased during times where the renewable generation is unable to meet the load.

These strategies would drastically reduce the installed capacity of renewable generation required and further enhance the robustness of the system, but a crucial takeaway is that it is possible to economically drive continuous load with renewable generation.

3.4 Resilience Framework Results

The ILEC distributed wind system is used to demonstrate the use of the INL resilience framework for evaluating cybersecurity hazards. We demonstrate scenarios in which having a distributed resource to serve local load can add resilience to a cybersecurity hazard and ways in which the distributed wind resource can still be affected by, or even contribute to, a cybersecurity hazard. The purpose is to demonstrate the resilience value of having the distributed wind as well as discuss mitigations to ensure that the distributed wind system itself is as secure as possible against potential threats.

3.4.1 Identify System Characteristics

The relevant system characteristics are described in Section 3.1.

3.4.2 Define Resilience Goals

3.4.2.1 Increase Renewable Energy Production

Iowa was the first state in the United States to adopt a renewable portfolio standard. It enacted the Alternative Energy Production law in 1983, which requires its two investor-owned utilities (MidAmerican Energy and Alliant Energy Interstate Power and Light) to own or contract for a combined total of 105 MW of renewable generating capacity (NC Clean Energy Technology Center 2018). As of May 2021, Iowa has more than 11,778 MW of wind, solar, and energy storage capacity (American Clean Power Association 2021). Although ILEC is member-owned, not investor-owned, using renewable resources for electric power generation is a high priority in the state.

The Iowa state goals for renewable energy were not necessarily developed as a resilience goal. However, diversifying energy sources reduces the dependency on any single resource, which increases resilience. As we consider long-term renewable energy mandates, including the executive order for carbon-free energy production by 2035 and net-zero emissions by 2050, increasing renewable energy production also prepares for the necessary energy transition to meet these mandates (Exec. Order No. 14008 2021). If this transition is made too suddenly, the infrastructure and processes will be barely equipped to operate under normal conditions, let alone resilience hazards. Instead, focusing on using the existing renewable sources to the greatest extent possible, better prepared the system for future reliance on these resources when other nonrenewable energy resources are retired. This resilience goal can be evaluated via the indirect metrics of wind production (sourced from ILEC) and imported generation (sourced from synthetic data).

3.4.2.2 Reduce Impact on Local Loads in the Presence of Cyber Threats

For the substations of interest, the loads of interests are the two ethanol plants. These plants run at a nearly constant output 24/7, and interruptions in service can be very costly. Thus, the second resilience goal that we consider for the distributed wind subsystems is to reduce the planned and unplanned outages for the ethanol plants. This may sound more like a reliability goal rather than a resiliency goal. However, the North American Electric Reliability Corporation (2007) defines reliability as two core concepts—adequacy and operating reliability.

- **Adequacy**—ability of the electric system to supply the aggregate electric power and energy required to the electric consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components
- **Operating reliability**—ability of the system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

This definition of reliability speaks to the ability to plan for scheduled or expected outages. It does not account for the high-impact, low-frequency events typically considered under the resilience domain. For this analysis, which focuses on cybersecurity hazards, we note that the definition of reliability does not address hard-to-predict events, such as cyberattacks that can vary significantly in their impact. It is impossible to anticipate all types of cyberattacks and impossible to predict exactly when they might occur. This goal can be evaluated with the resilience metric of outage duration, sourced from ILEC data.

3.4.3 Bow-Tie Analysis of Specific Hazards

As previously mentioned, it is impossible to classify every possible cyberattack, but it is useful to consider a few common types of cyberattack, particularly those that have become more frequent in the energy infrastructure. For hazard analysis, we consider the ransomware and denial-of-service attack scenarios, which are referred to in the “DOE Roadmap for Wind Cybersecurity” (Office of Energy Efficiency and Renewable Energy [EERE] 2020).

All organizations are at risk of being targeted by ransomware, but there is an increasing threat of ransomware to operational technology (OT) assets and control systems. Although historically energy management networks were fully separated from business networks, modern technology makes it more difficult to make technological advances while maintaining security and separation. OT components are often connected to information technology (IT) networks, allowing a malicious actor to pivot from IT to OT networks (Cybersecurity & Infrastructure Security Agency 2021). The energy sector can be a particularly valuable target for adversaries because the highest security priority for electric energy systems is availability. The electric utility sector is experiencing an increase in ransomware attacks, and examples are prevalent across the world (Walton 2020; Seals 2021). Recent attacks in related sectors indicate that ransomware can influence operations in addition to compromising IT systems and payment infrastructure (Turton and Mehrotra 2021). If ransomware can compromise the availability of an electric energy OT system, attackers will have strong leverage against their victims to demand swift and large payments.

Full details of the bow-tie analysis can be found in (Culler et al. 2022a).

3.4.3.1 Corn Belt Operational Technology Ransomware

The first scenario we can consider is ransomware that hits the Corn Belt transmission and distribution cooperative rather than ILEC directly. If the ransomware infects the OT system of Corn Belt it could cause inefficient or imprecise generation dispatch, leading to a lack of resources where they are needed. If the ransomware infects the IT system such that operators feel it is unsafe to continue operating their systems, then ILEC could lose access to the power imports it relies on to supplement the wind power at the ethanol plant substations. The risk associated with this scenario is moderate because the wind turbines can still provide some power to the ethanol plants, but without the supplementary power from the transmission system, the ethanol plants will not likely be able to run at full output. Additionally, any excess power will have to be curtailed. This scenario could cause the system to fail in its achievement of both resilience goals, maximizing renewable energy output and providing constant and continuous power to the ethanol plants. These consequences are severe, but the likelihood of ransomware impacting the operational functionality of a transmission operator remains low. The combination results in a moderate risk.

We consider three different outage durations caused by the ransomware attack on Corn Belt:

- **10-hour outage**. The ransomware affects the power production, but quick incident response from Corn Belt allows them to verify that their OT systems are not infected and can be safely operated.
- **3-day outage**. The ransomware infects parts of the data historian. Corn Belt can load data backups onto the servers and safely restart the system.
- **7-day outage**. This is a more severe attack that Corn Belt is not well-prepared for. With support from governmental agencies, Corn Belt pays the ransom and can restart their systems after a weeklong halt on power production.

Without wind. All the load is served by the Corn Belt transmission system. The loss of Corn Belt means all power to the ethanol substations is lost. They will have to shut down or run at minimum levels with on-site backup generators. The average load lost (taken as a rolling average throughout the year) is shown in Table 32.

Table 32. Load Lost With No Wind

Outage Duration	Lakota Substation (load lost) (kWh)	Superior Substation (load lost) (kWh)
10 hours	65,921	75,925
3 days	474,554	546,584
7 days	1,107,041	1,275,117

Basic wind. If the wind turbine inverter has basic grid-forming capabilities, the ethanol plants can be served by the immediate power output provided by the wind farms. The variability of wind may not be acceptable to the ethanol plants—they may not be able to vary their output based on the current power available—but we can still look at the power that could be provided in this case. *We can also consider that, in this scenario, the plants could cut their output so only 50% or 25% of typical power consumption is used.* If the load were more residential, this may be a more acceptable case. If the inverters do not have grid-forming capabilities, this is equivalent to the first scenario. All loads will be dropped.

Advanced wind. If there is a combined wind-storage option with advanced grid functions available, including grid-forming capabilities, additional benefits can be provided by any wind overproduction charging the battery, and the battery helping to keep the power production constant for a period. *We can consider multiple battery capacities. We can also consider in this scenario that plants could cut their output so only 50% or 25% of typical power consumption is used.*

Our base case for battery storage is 32,000 kWh for each substation, which is 4 hours of storage for an 8-MW load, so it should serve each power plant for 4–6 hours with a full charge. This is equivalent to about 138 Tesla Powerpacks, which is a very large amount and would be extremely expensive. We also consider 16,000 kWh and 8,000 kWh of storage for each substation. It takes about 35 Tesla Powerpacks to store 8,000 kWh, which is more reasonable for a grid-scale storage installation.

With the power production data we have, we assume the power needed as imports from Corn Belt is not served; thus, this is the amount of load dropped during each 10-minute interval (matching the granularity of the data). We enter a start time and end time for the Corn Belt outage. We assume the battery starts at full capacity, if the battery is in place, and begin by serving all the load unmet by wind power with battery power until the battery is depleted. If there is wind overproduction, the excess charges the battery. We calculate the amount of time until the combined battery/wind production cannot serve the entire load. However, we assume the plants will not fully shut down the first time the full demand cannot be met. We calculate the percentage of time during the Corn Belt outage that the full load is met (i.e., there is no unmet demand). This percentage can change as we examine cases in which the plants can curtail their power usage in response to the Corn Belt outage, using only 50% or 25% of their typical consumption. Finally, we calculate the unmet energy demand, in kilowatt-hours, of the plants during the Corn Belt outage.

Summary. Although the ethanol plants have slightly different loads, the overall results are similar. For that reason, we choose to plot only the Lakota substation results for the following graphs, which summarize the data.

First, in Figure 30, we examine the time until any load is first dropped. This is especially important for this system because the ethanol plants may not be able to tolerate the variability in available power. This metric may represent the time the plants remain operational if they choose to fully shut down after their load (or reduced load) can no longer be fully served.

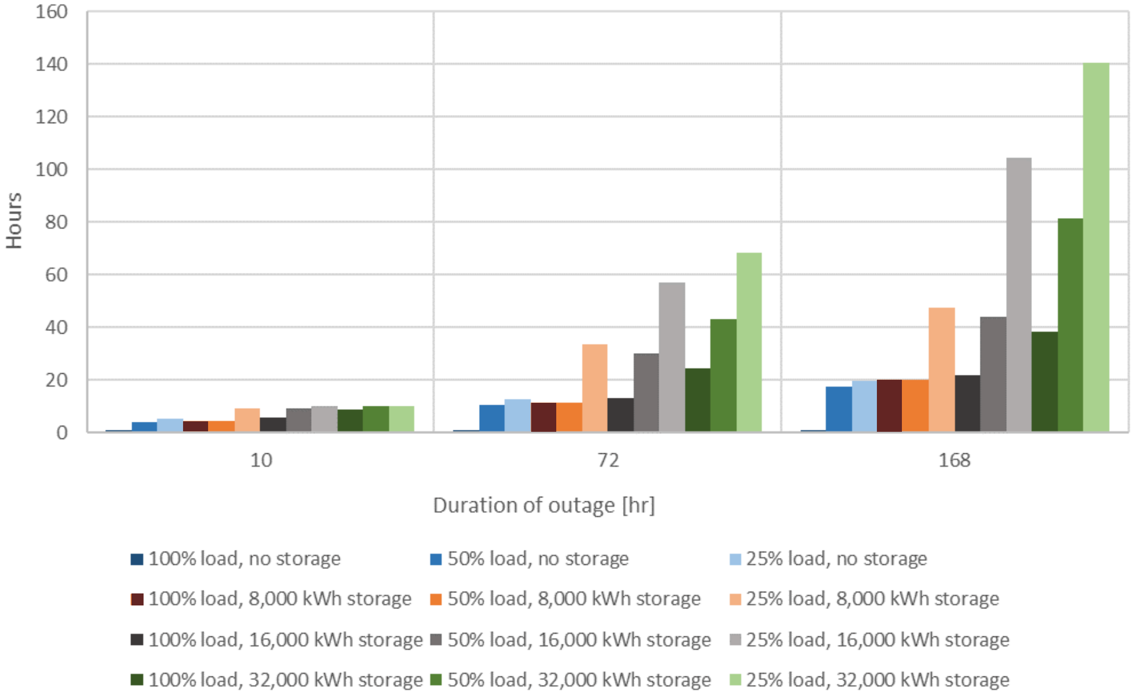

Figure 30. Summary of cases: time until load is first dropped (Culler et al. 2022a)

The results change more based on the percentage load that is used rather than the change in storage capacity. Figure 31 shows the percentage of the outage duration when the load (or reduced load) is fully served. If the ethanol plants can tolerate multiple startups and shutdowns in a short duration, then this metric represents the maximum output that the plants can have during the outage.

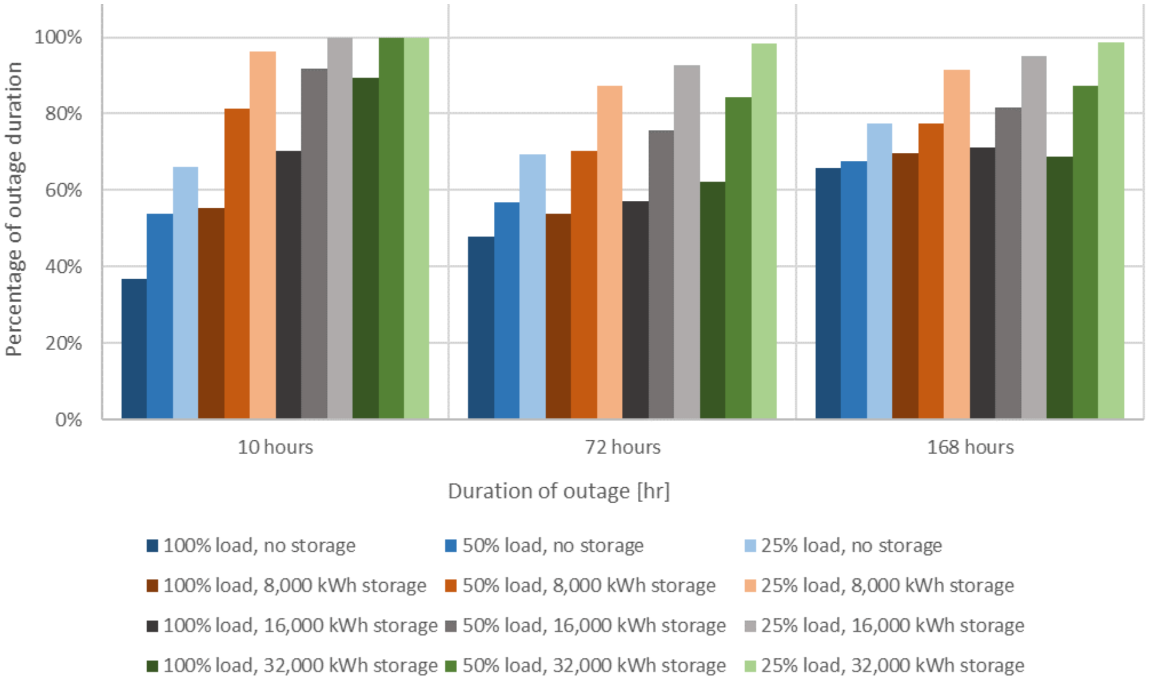

Figure 31. Summary of cases: percentage of time when load is fully served using different storage capacities (Culler et al. 2022a)

Changing the storage capacity has a more dramatic effect on the percentage of time that load is served than changing the load for the short-duration outage—but changing the load is the most effective mitigation measure for all outage durations.

Again, we note that adjusting the load via demand response measures has a greater impact on the ability of the system to serve the load than does additional storage capacity. This trend is even more pronounced for the dropped load analysis in Figure 32, which makes sense because this is the variable most directly correlated to the adjusted demand.

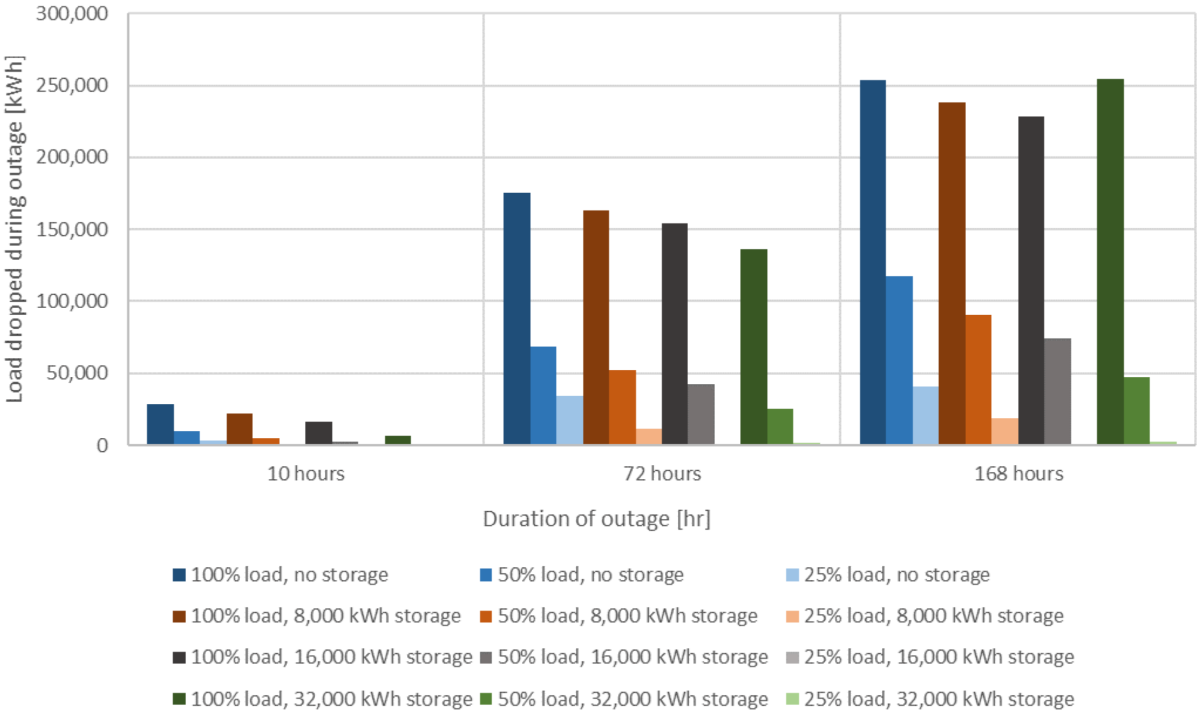

Figure 32. Summary of cases: total load dropped during an outage (Culler et al. 2022a)

In response to the Corn Belt OT ransomware attack, ILEC wind provides some power to the ethanol plants. Wind and storage combined can keep full power supplied to the plants for longer durations with less variability. Increased storage provides increased capability of the system to serve a constant load at the plants for a longer duration. Additional measures that decrease variability in load served include curtailing ethanol plant output so the plant uses 50% or 25% of normal power. If it is feasible to run at these lower power levels, a full plant shutdown can be prevented, thereby avoiding a costly and difficult restart.

Corn Belt Ransomware Impacts on Value

The wind turbines provide some outage mitigation value for the ethanol plants in the Corn Belt ransomware scenario. PNNL calculated outage mitigation values for the two ethanol plants using value-of-lost-load estimates from Sullivan, Schellenberg, and Blundell (2015). Outage mitigation values were determined following the same methodology as described in Section 2.4, discussing the outage mitigation methodology used in St. Mary's, Alaska. In future analyses, it may be possible to determine more specific economic impacts to the ethanol plants using the plants' production functions, but such an analysis requires extensive proprietary data from the ethanol plants or thorough investigation of similar ethanol plants' output and costs, which may be difficult to obtain.

Outages for 10, 72, and 168 hours were modeled with 0 kWh, 8,000 kWh, 16,000 kWh, and 32,000 kWh of storage present in addition to the wind turbines. Outage mitigation values for each of these scenarios are shown in Table 33. The costs of the energy storage were not evaluated in the ILEC valuation performed in Section 3.2.5.

Table 33. Iowa Lakes Electric Cooperative 100% Outage Mitigation Scenarios With and Without Energy Storage

	Outage Duration (hours)					
	10		72		168	
Storage (kWh)	**Hours Mitigated**	**Outage Mitigation Value**	**Hours Mitigated**	**Outage Mitigation Value**	**Hours Mitigated**	**Outage Mitigation Value**
0	1.94	$59,066	1.94	$59,066	1.94	$59,066
8,000	4.83	$115,231	6.57	$151,184	6.57	$151,184
16,000	6.23	$144,033	9.42	$213,542	9.42	$213,542
32,000	8.04	$182,810	13.82	$318,273	13.82	$318,273

Based on the analysis conducted, it was determined the wind turbine alone can only mitigate up to 1.94 hours of an outage; however, the wind turbine in combination with the storage assets can vastly increase the duration of outages mitigated. The maximum amount of outage mitigation value the wind turbines can provide independently is $59,066 in 2021 dollars for a 1.94-hour outage. Much higher value is provided in almost all cases of the wind-plus-storage scenarios, reaching as high as $318,273 with the 32,000-kWh storage when outages can be mitigated for up to 13.82 hours.

Outage mitigation values do not increase from the 16,000-kWh energy storage case to the 32,000-kWh energy storage case because the outage duration is the same. However, because the 32,000-kWh energy storage case allows additional load to be served during the outage, it may be adding value that is not captured in this analysis. If future analysis is conducted using the ethanol plant production data, it may be possible to calculate the additional value this scenario brings.

3.4.3.2 ILEC Information Technology Ransomware

If ILEC is directly compromised by ransomware, which could have many points of origin—including phishing, improper USB use, known vulnerability, or zero-day exploit—we assume that, at the very least, their enterprise systems will be compromised (Fruhlinger 2020; Cybersecurity & Infrastructure Security Agency 2019). In many cases, this can cause consequences, including email servers being unavailable, web-based bill-paying systems being unavailable, and potential loss of sensitive data (Cybersecurity & Infrastructure Security Agency 2019). This may not impact the ability of ILEC to operate its power systems if the IT and OT systems are well segmented. In this case, the consequences will be more business-oriented than power-system oriented. However, ILEC may still have to meet mandatory reporting requirements and may have a duty to report such a breach to its members. Consequences may include long-term loss of trust in the board, expensive overhaul of IT equipment, and increased potential for a more severe cyberattack if the exfiltrated data is sold or used to mount a more targeted campaign. These consequences point to an important difference between the short-term reliability impacts that consider only the power system, and the resilience impacts, which consider the lifetime of the system. Although the consequences are tolerable, both in terms of short-term and long-term impacts, the likelihood of such an attack is increasing. Many utilities across the United States have already experienced similar attacks. If firewalls and demilitarized zones are properly implemented, IT ransomware may not affect OT systems, including control rooms, power system hardware, or networks connecting the two.

Without more specific information about the company's internal networks and server infrastructure, it is difficult to perform a detailed simulation analysis as we have done with the cases that affect power system operation. In this section, we discuss common attack paths and outcomes of ransomware that affect the business infrastructure for an electric utility.

The most common points of origin for ransomware include phishing, exploits of known vulnerabilities, and unintentional back doors left open. An example of the latter type is the Colonial pipeline hack, which took advantage of a virtual desktop application accidentally left running. It also used spear-phishing techniques to get the password needed to access the virtual desktop. Two-factor authentication was not used for the application.

After ransomware has infected one computer in a system, it uses automated techniques to spread throughout the network and may intelligently search for critical applications or data before executing the payload. When the payload is executed, ransomware traditionally encrypts all the files it has access to and sends a message to the company demanding payment in return for access to the decryption key. Although there may be a concern that the decryption key will not be delivered on payment, it is poor business for ransomware hackers not to provide this key. If there is no trust that the key will be delivered upon payment, fewer victims will pay. Not all victims will pay the attackers. Some companies may use internal professionals or external consultants to break down the malware and recover files without getting the decryption key from the attackers. Depending on what data were compromised, some companies may also be able to restore the system and files using backups stored in a secure location, potentially only losing changes made since the last backup.

More recently, ransomware attackers have not just encrypted the files they have access to, but also extracted that data prior to encrypting it. They attempt to further motivate victims to pay the ransom rather than remove the encryption themselves by threatening to publish or sell sensitive data that were extracted. This can be especially damaging for utilities. If customer information is compromised, they may have mandatory data-breach-reporting requirements, which damages corporate reputations. Customer data breaches may also require payment of identity-theft tracking services for customers affected. Additionally, if data describing the power system are extracted, this could potentially be used by bad actors to mount more targeted and damaging attacks against the utility.

If the cyberattack impacts customer-facing services, a utility may suspend shutoffs and late fees until its payment infrastructure is restored. This could affect short-term finances for the utility because most customers will wait until the electronic infrastructure is restored rather than paying by cash or check. It may also negatively affect customers' views of the utility, but effects from the loss of the bill-paying infrastructure may not be long term. Beyond customer interactions, it may be difficult to conduct other regular business operations for the duration of the ransomware attack.

Consequences will be highly dependent on the strain of ransomware, the defenses, network segmentation, employee training, and response ability of ILEC. Potential consequences were discussed in the previous section, but key takeaways are the assumptions that the ransomware is limited to enterprise systems and does not compromise the OT network. However, utilities need to be aware of the potential long-term impacts of this type of attack.

We assume that the IT ransomware does not affect the immediate ability to operate the power system. There is no change in power production or distribution during the attack.

Using the metrics deemed most important for resilience early in the framework, this hazard does not pose a huge threat, and having distributed wind does not affect the resilience of the system under this hazard.

3.4.3.3 ILEC Operational Technology Ransomware

This scenario considers what would happen if ILEC was directly hit with a targeted ransomware attack that impacted OT systems or created significant instability on the IT side, forcing operators to choose to shut the power system down to protect its integrity and security. The consequences of this attack are more immediate and more directly measurable on the power system. In the worst case, we assume the wind turbines are shut down. The ethanol plants would be served entirely by power imported from the transmission system, which would negatively affect the goal of using renewable energy. Corn Belt is fully capable of meeting this load, but the energy would come at a higher cost to ILEC.

In both ILEC ransomware cases, the cooperative would be responsible for deciding whether to pay the ransom or not, repairing or replacing equipment compromised in the attack, performing forensic analyses to determine if data were exfiltrated and, if so, how it might be used or sold, and adding security to systems to ensure it doesn’t happen again.

For the purposes of this analysis, we assume the ransomware attack affects the Superior and Lakota wind turbines. We consider two cases: one in which the turbines may be the first target of the attack, and one in which they may be affected by propagating ransomware that originated elsewhere in the system. As with the previous case, we discuss potential attack paths and outcomes, but without knowing more about the communications infrastructure, defenses and segmentation, and many assumptions, we cannot say with any amount of confidence what the most likely outcome would be.

Wind turbines as point of entry. One of the unique characteristics of distributed wind systems is their physical isolation. In general, wind turbines are often installed where the resource capacity is greatest, which may be in remote locations. Because of this, remote connectivity is needed for monitoring and control and is relied on more than a typical generation asset, where control centers may be on-site. If these remote access points are not properly secured, they can provide entry for an adversary into the system.

Because turbines tend to be located remotely and not visited often, it is possible that an adversary could physically access the turbine itself and use local access points to load malware into the system. In the worst case, this malware could then propagate to the substations and back to the main control room or even just compromise the local hardware.

Another possibility is that a technician or other service person could accidentally infect their own hardware then compromise the wind turbine when servicing the machine. This exact scenario has happened, not with ransomware, but with other malware that caused turbines at a wind power plant to stop working one by one (Davidson 2018).

Finally, the turbine communications could be compromised directly if they are not properly secured. In a brief search by Forbes, 50 devices manufactured by wind and solar companies with known vulnerabilities were found using Shodan, a search engine for internet-connected devices (Brewster 2015). These devices were found more than 6 years ago and, although general security practices may have improved since then, the number of turbines installed is growing very rapidly and there are no requirements readily available to installers or integrators to prevent this kind of access.

After the ransomware compromises the turbines, it is likely that the turbines will be shut down. It is possible that the ransomware could spread to the substations, potentially locking systems there and, in the worst case, shutting down the connection to Corn Belt. The ransomware may spread even further into ILEC's systems, potentially compromising more OT devices or working its way into the enterprise system.

Wind turbines compromised after alternate point of entry. Although we want to highlight the threat of ransomware infecting a system via the distributed wind turbines, this is not the only way that ransomware could affect ILEC's OT system. Similar methods of entry could be used at other points in the system and the ransomware could spread, eventually affecting the turbines. The effects on the power system, particularly on the Lakota and Superior turbines, may be similar. However, the different attack paths may need different mitigations to best ensure resilience against this hazard.

As discussed previously, the ransomware could have a direct and limited effect on the wind turbines only. In this case, all power needed to serve the ethanol plants load could be imported from Corn Belt. There may be increased costs to ILEC compared to the base case, but there would be no load lost.

It is also possible that the ransomware could affect the substations as well. If the breakers have a fail-open condition, power from Corn Belt may be cut in addition to the wind turbines being compromised. In this case, all power sources for the ethanol plants are lost and the load is dropped. Table 34 shows the average amount of energy consumed by each substation over different durations. This is the amount of load that would need to be imported from Corn Belt, if available, or that would be dropped.

Table 34. Average Energy Consumed at Each Substation

Duration of outage	Lakota Substation (kWh)	Superior Substation (kWh)
10 hours	65,921	75,925
3 days	474,554	546,584
7 days	1,107,041	1,275,117

In response to the ILEC OT ransomware, the system may still be able to serve the two ethanol plants if the Lakota and Superior substations are not substantially compromised. In this case, although wind production may be halted, sufficient power may be imported from Corn Belt. Alternatively, if the substation is compromised and breakers are flipped, the ethanol plants may be cut off from any production sources, in which case all the load from the ethanol plants will be dropped. In either case, the wind asset does not add any resilience through properties of its power production. It is possible the wind turbines could be used to help compromise the system, in which case, the turbines are a vulnerability rather than a mitigation tool against the ransomware hazard.

3.4.3.4 Denial-of-Service Attack

In a denial-of-service (DoS) attack, the attacker floods systems, servers, or networks with traffic to exhaust resources and bandwidth. This attack can occur against any resource the attacker can communicate with, such as servers, firewalls, or other network end points.

In 2019, a DoS attack occurred against wind and solar provider, sPower. This attack caused Cisco firewalls to reboot in 5-minute intervals over a 12-hour period. During the reboots, operators lost visibility and communications with the solar and wind resources, although it did not affect the generation itself or the transfer of power (Sobczak 2019). This attack was not believed to be targeted, and the attackers may not have even known who the victims of their attack were (Lyngaas 2019).

We imagine a similar scenario happening on the ILEC system. Depending on exactly which resource is compromised by the DoS attack, it is unlikely the attack would cause impacts on the ability of the turbines to produce power. However, loss of control and monitoring could affect the dispatch of the generators and could potentially have more significant consequences if important alerts or alarms went unnoticed by operators during the attack. Hackers employed a DoS attack against call centers in Ukraine during the infamous attacks on the Ukrainian power grid in 2015, which interfered with operators' ability to identify outage areas quickly (Korolov 2016). In this way, DoS attacks could be part of a larger campaign, or they could simply unintentionally mask other issues in the system's operation.

We assume that the DoS attack affects equipment that is between the wind turbine and the ILEC control center. This hazard is modeled on an attack that affected a firewall at Salt Lake City-based sPower (Davidson 2018). However, this hazard could affect equipment other than firewalls. Although the sPower attack is one of the most notable because of its direct effect on operations, NETSCOUT, which maintains a Cyber Threat Horizon tracker in real time, recorded 1,780 distributed DoS (DDoS) attacks against utilities worldwide between June 15 and August 21, 2020, representing a 595% year-over-year increase (Jenkins 2020). This is an unprecedented increase in DDoS attacks. In addition to the increase in frequency of attacks, the DDoS attacks are happening at higher speeds, with more than four times as many data packets being sent in the same amount of time.

Traditionally, DoS attacks send repeated packets to a device at high speeds with the goal of filling up all the available ports so that legitimate traffic cannot get in. However, a lot of devices have basic DoS protection built in. When the device notices there are a lot of packets coming in from an unknown source, or even a known source if the internet protocol is spoofed, it may block that internet protocol or drop packets from that source for a period. DDoS attacks are more advanced because the attacker spoofs many different internet protocols so the attack does not appear to be coming from a single source. This can trick many filters looking for attacks coming from a single source.

However, even a next-generation firewall that claims to have DoS protection built in cannot deal with all types of attacks. Firewalls cannot handle volumetric DDoS attacks. At best, a firewall may overload, freeze up, and shut off all inbound traffic—including good customer traffic along with the bad attack traffic. At worst, a firewall may go into bypass mode and allow all traffic, good and bad, to flow. This puts the rest of the IT infrastructure, as well as its data, at risk (Newman 2019).

An additional component to consider for DoS attacks is that the barrier of entry is low. It is not difficult to configure a program to send packets to a target at high speed. Slightly more advanced attacks will use botnets, private devices infected with command-and-control malware and controlled as a group without owners' knowledge, to increase the volume of packets send to a target during an attack, but even these attacks are widely available for purchase. This means anyone, from hacktivists to cyber criminals to nation states, may use DoS attacks.

A DoS or DDoS attack may hit different parts of the ILEC infrastructure. It can impact the IT networks, taking out websites, payment infrastructure, or internal networks. In this case, the attack acts somewhat like the ILEC IT ransomware, but with less threat of the information being extracted and no ransom demanded. Like the sPower attack, the attack may also impact the OT infrastructure. In the best case, this could just limit operators' ability to receive data from the system, blocking their visibility. In the worst case, the DDoS attack could affect infrastructure, like switches critical to the automated control and communication of the system. The physical power lines will not be affected, but if data cannot be shared throughout the system, no changes to settings may be made. It could affect the ability of the wind turbines to properly curtail their output or to provide ancillary services.

IT infrastructure is typically better protected against DoS and DDoS attacks, making it less likely that ILEC would be impacted by this type of attack. The most likely place where an IT DoS attack would have an impact is on a public-facing website, which may include payment systems.

A DoS attack on OT infrastructure that just blocks visibility into the system would have limited impacts, although it reveals the vulnerability of power systems to attacks and the importance of making sure devices are not publicly accessible—they should be hidden behind virtual networks and only accept traffic from known sources.

In the worst case, a DoS attack could impact the control and communications infrastructure of the automated power system. Some devices might have fail-safe mechanisms that turn them off if communications are lost. This could include the wind turbines.

DDoS threats are constantly evolving, and many hackers now use them as a smoke screen to launch a more sophisticated attack. These threats may be designed to knock a firewall or intrusion-prevention system offline, opening the system for the delivery of more sophisticated malware or exfiltration of corporate data. Given that most companies now take more than 190 days to detect a data breach on their networks, this can give attackers a significant head start for their exploits. Application-layer and domain name system-based DDoS attacks can also cause significant outages and may go undetected by security staff and mitigation devices (Fimia 2019).

In response to the DoS or DDoS attack, there may not be an immediate effect on power system performance, but, in the worst-case scenario, wind assets could shut down if the communication is blocked as a fail-safe mechanism.

3.4.4 Risk Mitigation Measures

Based on the outcomes of the modeling, risk mitigation measures should be prioritized. A single risk may have multiple mitigation options, and those options themselves may mitigate multiple risks. Risk mitigation measures should include cost estimations and effectiveness metrics that evaluate the efficacy of a mitigation measure against a given risk. Return-on-investment metrics should be calculated.

Potential mitigations to address the cybersecurity hazards for ILEC are described below.

Hazard 1 (Corn Belt Ransomware)

- Ensure network segmentation in substations connected to Corn Belt
- Ensure wind-storage hybrid system is appropriately sized to support loads.

Hazard 2 (ILEC IT Ransomware)

- Segment enterprise networks
- Use two-factor authentication, especially on any remote-access applications
- Require mandatory employee phishing training and testing
- Install demilitarized zones where appropriate.

Hazard 3 (ILEC OT Ransomware)

- Install backup generation for ethanol plants
- Create security plans for third parties, including maintainers and technicians
- Confirm fail-safe operations are enabled and programmed correctly.

Hazard 4 (DoS Attack)

- Ensure communications devices are not publicly searchable
- Install filters on all firewalls (easy-to-detect DoS and DDoS attacks)
- Use virtual private networks where appropriate
- Perform active and regular patching.

After further analysis, the ILEC OT ransomware and the DoS attack have the worst possible consequences but low probabilities of occurrence. The ILEC IT ransomware has the highest likelihood of occurrence but lower potential consequences. It is difficult to rank these hazards against one another without performing more detailed simulations and analysis, which would require more network and security information about the system and more assumptions about the attack. With the Corn Belt ransomware analysis, we showed that the distributed wind assets, when combined with battery storage, can help keep the ethanol plant loads fully powered for short durations, which may be sufficient for Corn Belt to bring its transmission system back online.

4 Conclusions

In this report, we apply methods developed through the initial three years of the Microgrids, Infrastructure Resilience, and Advanced Controls Launchpad (MIRACL) project to two real-world distributed wind reference systems: an electrically isolated grid in St. Mary's, Alaska, and a distributed grid system with two front-of-the-meter, 10.5-megawatt wind deployments owned by Iowa Lakes Electric Cooperative (ILEC) in Iowa. Through the application of these methods to the two reference systems described in this report, we intend for the results to serve as referenceable case studies, available to stakeholders interested in additional value-added capabilities of distributed wind systems and to facilitate the technology transfer of the theories, methods, and technologies developed under the MIRACL project. The main methods we demonstrated include:

1. A valuation framework to comprehensively value the services distributed wind can provide
2. Advanced control and hybrid system design methods to enable microgrids to provide greater market and resilience value to distributed grid operators and owners
3. A resilience framework to systematically characterize a distribution system's resilience and compare investment options for improving resilience in their system.

Through the application of these methods, we demonstrated the additional opportunities, beyond bulk energy supply, that distributed wind can provide to a power system as well as ways to value these opportunities.

We analyzed the opportunity of distributed wind in St. Mary's, Alaska, to improve electrical distributed system resilience in varying outage-duration cases due to fuel shortages, severe weather events, or communications outages. The results showed that distributed wind alone can provide significant resilience benefits during likely resilience hazards. Namely, the local generation of energy with renewable sources provides significant resilience against supply chain hazards associated with imported fuel sources. These benefits may require advanced control capabilities, such as grid-forming inverters, and are enhanced by other advanced controls, such as advanced forecasting. Additionally, the resilience benefits at St. Mary's could be quantified when considering a specific instance of a hazard, but we found that they were most effectively described by evaluating a range of severity and timing of each hazard. Some of the benefits, while quantified, were best explained qualitatively, such as how in a severe cold snap, wind added resilience if previously curtailed generation could instead be used to serve added heating needs, but these benefits disappeared if the hazard was so extreme that temperatures dropped below the turbine's operating limit.

The valuation analysis identified three major value streams associated with the wind project: energy generation, economic impacts, and environmental impacts. In scenarios with advanced control, the value of energy generation increased by 16%, showing that more efficient operation of the turbine can result in greater savings. While the costs of the project were higher than the benefits to just the electric cooperative, the societal benefits more than doubled the overall benefits when combined with the electric cooperative benefits for a total of $15 million in net-present-value benefits across all the value elements considered when compared to its costs, which are $8 million.

Additionally, we presented preliminary results of distributed wind in a hybrid system with solar and battery storage, optimized for the ILEC system using simplified economic and load assumptions. We analyzed the impact that including distributed wind has on the ILEC system, such as economic impacts, environmental impacts, resilience and cybersecurity implications. The lifetime economic benefits of the project are $235 million, with costs of $56 million. The local nature of the turbines allows them to serve the local load (two ethanol plants) during a projected cybersecurity incident that limits power production on the transmission system. Analysis of potential scenarios using battery hybrids and demand response showed that the resilience benefits from wind are enhanced when solar, battery storage, and advanced control are added to the system, compared to wind alone. The resilience benefits evaluated were most useful when they considered specific stakeholder input, such as the need of the ethanol plant loads to receive constant power without steep ramping. This analysis also showed that the ILEC system, due to it being a grid-connected system and participating in the regional energy market, could potentially provide additional grid services and market value.

Future Research and Validation Opportunities

While this report makes significant progress toward developing and demonstrating tools to quantify and improve value and resilience in distributed electrical energy systems through distributed wind assets, the work could be advanced through analysis updating, data archiving, stakeholder engagement with a larger variety of system configurations, greater integration of the MIRACL toolsets, and physical demonstration.

Although the analysis with ILEC is complete, the Alaska Village Electric Cooperative (AVEC) will be providing access to historical and ongoing operational data, financial data, and other power system information for both St. Mary’s and Mountain Village. These data will be used to validate power system models, improve assumptions used in the valuation and resilience analysis, and statistical analysis on the power system performance over multiple years. This will facilitate the exploration of more advanced control methods and power system benefits, such as voltage and frequency regulation, which can, in turn, be added to the valuation framework as benefits. Detailed historical data can provide additional insights into modes of failure encountered in the past that might inform additional resilience scenarios. The outputs of this framework will provide AVEC with a more accurate picture of opportunities to help inform future investments and operational methods to meet its goals in the various communities in which it operates.

The real data provided by AVEC may enable more realistic analysis, but real data are often incomplete. Meters may not always be recording, specific values of interest may not be captured, and it can be difficult to align data collected across multiple sources. To help address these issues and make clean data sets available for researchers, further development of the MIRACL Data Hub is recommended. The Data Hub development should focus on improved accessibility for researchers and the addition of more diverse data sources, and it should host data from partnering communities and physical assets on the national laboratory campuses.

Additionally, the MIRACL project would benefit from more direct engagement with stakeholders, and a more cohesive approach to the valuation, resilience, and hybrid analysis of systems. Initial work for this project focused on developing the core capabilities in each of these areas, but as highlighted in key findings, the benefits of distributed wind are enhanced by using hybrid resources and advanced controls for resilience, and by wholistically considering all value streams, including those provided by hybrids and resilience. To that end, the project team is developing a relationship with Algona Municipal Utility (AMU) in Iowa. AMU has a distributed wind system, and they are currently looking to upgrade the system with advanced controls and hybrids. Timely collaboration with the MIRACL team will help AMU determine the optimal sizing, location, and configuration for their planned upgrades.

In future work, we will apply this hybrid system design and optimization approach and leverage the valuation and resilience frameworks to identify the added benefit of hybridizing distributed wind systems with solar and storage components. Additional future work also includes the validation and testing of the advanced control scenarios and power-hardware-in-the-loop methods developed under the MIRACL project described in this report. These advanced control and power-hardware-in-the-loop methods advance the ability for distributed wind and hybrid systems to provide the ancillary services or resilience benefits outlined by both the valuation and resilience frameworks detailed in this report.

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