Use of Operating Agreements and Energy Storage to Reduce Photovoltaic Interconnection Costs: Technical and Economic Analysis

Joyce McLaren,[1] Sherin Abraham,[1] Naïm Darghouth,[2] and Sydney Forrester[2]

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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-80556
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Suggested Citation
McLaren, Joyce, Sherin Abraham, Naïm Darghouth, and Sydney Forrester. 2022. *Use of Operating Agreements and Energy Storage to Reduce Photovoltaic Interconnection Costs: Technical and Economic Analysis*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-80556. https://www.nrel.gov/docs/fy22osti/80556.pdf.

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National Renewable Energy Laboratory
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Golden, CO 80401
303-275-3000 • www.nrel.gov

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Foreword

This analysis was conducted as part of the Solar Energy Innovation Network (SEIN). SEIN is a collaborative research effort led by the National Renewable Energy Laboratory and supported by the U.S. Department of Energy's Solar Energy Technologies Office. SEIN supports teams across the United States that are pursuing novel applications of solar and other distributed energy resources by providing critical technical expertise and facilitated stakeholder engagement, giving them the wide range of tools necessary to realize their innovations in real-world contexts. Teams are composed of diverse stakeholders to ensure all perspectives are heard, key barriers are identified, and the resulting solutions are robust and ready for replication in other contexts.

This analysis was conducted in support of the efforts of a team from Rhode Island that participated in Round 2 of SEIN, led by the Rhode Island Office of Energy Resources and joined by National Grid and the Clean Energy States Alliance. The team sought to elucidate the potential value of adding battery energy storage to solar projects to reduce distribution upgrade costs and optimize solar hosting capacity.

The technical and economic analyses presented in this report support the team efforts. This is the companion report to *Use of Operating Agreements and Energy Storage to Reduce Photovoltaic Interconnection Costs: Conceptual Framework* (Gill et al. 2021).

Acknowledgments

The authors would like to thank those who provided valuable input to this project and who reviewed this report, including Carrie Gill and Shauna Beland (Rhode Island Department of Energy Resources), Ryan Constable, Caitlin Broderick, Tim Roughan, and Stephen Lasher (National Grid), Anthony Teixeira (Rocky Mountain Institute), Caroline McGregor (U.S. Department of Energy), Michael Ingram and other colleagues at the National Renewable Energy Laboratory.

List of Acronyms

ANSI	American National Standards Institute
DER	distributed energy resources
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
ISA	interconnection service agreement
NREL	National Renewable Energy Laboratory
OEA	Operating Envelope Agreement
PV	photovoltaic
p.u.	per unit
SEIN	Solar Energy Innovation Network
TMY	Typical Meteorological Year

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Table of Contents

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

List of Figures

List of Tables

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Introduction

1.1 Background and Literature Review

Utility spending on the electricity distribution system in the United States has been increasing dramatically. Annual expenditures were 64% higher in 2020 than in 2000 (U.S. EIA 2021). Much of the cost increase is a result of the need to replace aging equipment and modernize the grid to integrate new technologies and increase resilience. Solar photovoltaics (PV) can have both positive and negative cost impacts to the distribution grid, depending on many factors (Horowitz et al. 2018). In some cases, PV adds value by producing zero carbon electricity while reducing net load on the system. In other cases, PV can negatively impact voltage, loading, and protection equipment (Horowitz et al. 2018; Jothibasu, Dubey, and Santoso 2016).

Horowitz et al. (2018) conducted a meta-analysis on distribution system costs associated with PV deployment. They found that the impacts of PV integration on the grid, the level of PV penetration when issues arise, and the costs associated with avoiding negative impacts are highly variable. Analyses on specific PV integration scenarios also yield a wide range of results, but a few common themes emerge. Hosting capacity[1] and subsequent upgrade costs depend on factors such as the length of the feeder, where on that feeder the PV system is placed, whether the PV generation is spread out or clustered, the load profile and its flexibility, the grid configuration, and the equipment in use (Horowitz et al. 2018). A separate analysis observed a wide range of impacts across only three representative feeders, with PV hosting capacity ranging from 15.5% to 100%+ of median daytime peak load (Jothibasu et al. 2016).

The diversity of factors influencing hosting capacity results leads to cost uncertainty when interconnecting PV. The cost challenge is exacerbated by the fact that the individual PV project that triggers the need for a distribution system upgrade is typically responsible for the upgrade cost, although future projects may also benefit from those upgrades.

Depending on the nature of the grid violation[2] that a proposed PV system is found to induce, there are several possible mitigation strategies that vary in cost. A review of PV interconnection in several western states found that voltage violations were the most common, followed by loading violations (e.g., thermal loading), which was one of the costliest issues to correct. The need for network expansion was the most expensive mitigation found, and the least commonly undertaken (Bird et al. 2018).

Traditional strategies to mitigate violations include uprating lines and equipment, installing on-load tap changers or other voltage regulation devices, or volt-VAR control (Horowitz 2019; Jothibasu et al. 2016). Additional strategies include using some level of communication and

[1] Hosting capacity is the amount of PV that can be added to the distribution system before control changes or system upgrades are required to safely and reliably integrate additional PV.
[2] A grid violation is any instance where actual grid conditions are not within predefined operating parameters. For example, a thermal violation occurs when the temperature of a conductor exceeds a range specified by the American National Standards Institute (ANSI).

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control to engage smart inverters, demand-side resources, dynamic curtailment, and/or battery storage (Babak et al. 2020; Horowitz et al. 2018; Jothibasu et al. 2016).

Battery storage is well equipped to increase distribution circuit (feeder) hosting capacity, mitigating the voltage and loading issues in addition to reducing backfeed, which can abate protection issues (Horowitz et al. 2018; Jothibasu et al. 2016). However, interconnecting PV-with-battery systems can be more complex. By its nature, the combined PV and battery system has a wide variety of autonomous configurations and dispatch strategies, and the combined system acts both as a generator of electricity and as a load (McAllister et al. 2019). In many cases, system impact studies of these hybrid systems are based on a worst-case scenario in which the battery is discharging at full power during peak PV production (McAllister et al. 2019). This worst-case scenario may induce grid violations such as local high voltage, but it is completely avoidable. As such, states have begun to change policies and practices for studying PV and battery systems, with the goal of tapping their benefits while avoiding negative grid impacts.

Battery adoption continues to increase as procurement costs fall, wholesale market rules evolve, and new tariffs are set (Wood Mackenzie/ESA 2021). In addition, policies and standards are being set to mitigate negative grid impacts of distributed energy resources (DERs), including the provision of certain performance capabilities unique to energy storage, to allow for continued growth. On a national level, IEEE 1547-2018 requires device interoperability, communication functions, and other capabilities in inverter-based DERS (IEEE Standard Association 2018).[3] Several states are also taking action to realize the benefits of DERs.

California aims to increase the value of DERs using advanced inverter functionality. The state's Rule 21 describes how a distributed PV and battery system can use inverter settings to set maximum export parameters that can be bid into the market as system capacity. It goes further to describe a future in which the generation profile from the system could be dynamically set in response to real-time conditions using enhanced communications and controls (CPUC 2020). Other states have made steps to incorporate storage into interconnection rules. Nevada's interconnection standards allow combined PV and battery systems to have a "net nameplate rating" that is achieved using a control system, power relay, or other settings (McAllister et al. 2019). New York has implemented the concept of a flexible interconnection solution that offers developers an option to avoid interconnection upgrade costs by signing onto "principals of access" that specify when and for how long generators will be curtailed to avoid system violations (NY PSC 2019; Horowitz 2019).

Even with recent battery cost reductions and the policy evolution, battery systems are still relatively expensive. In cases where storage can serve as an alternative to an especially expensive upgrade (e.g., replacing a transformer), it may be cost-effective (Horowitz et al. 2018). However, in many cases, paying for system upgrades may still be cheaper than using a battery to mitigate violations, unless the battery can produce additional value (Horowitz et al. 2018; Jothibasu et al. 2016). The introduction of FERC Orders 841 (FERC 2018) and 2222 (FERC 2020) will shift organized wholesale market rules to be more technology agnostic, providing

[3] For educational materials on IEEE 1547 see NREL's resource page at: https://www.nrel.gov/grid/ieee-standard-1547/.

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more opportunities for batteries and aggregated DERs, respectively, to provide value to system owners. Additionally, some wholesale markets (CAISO n.d.) have begun to address the role of solar-plus-storage resources, specifically. Research on these systems shows that value can vary locationally (Gorman et al. 2020).

There are multiple factors that affect the cost-effectiveness of a battery system that is deployed with a primary function of mitigating violations from a PV system and, secondarily, providing wholesale market services. These factors include battery-specific economics, the obligations of the battery to integrate the paired PV system, market restrictions and payments available to PV and battery systems, and the comparative cost of traditional distribution grid upgrades or other strategies to integrate PV.

1.2 Scope and Purpose of This Analysis

This report presents an analytical methodology to identify alternative options to manage interconnection costs and streamline interconnection timelines for distribution system-connected PV systems not co-located with load. It details a technical analysis methodology to identify time-based operational parameters for a DER system (an "operating envelope"), to mitigate violations on a utility distribution feeder. It then explores the economic feasibility of the technical options identified.

The technical analysis presented here begins like, but goes beyond, standard interconnection studies conducted by utilities. In a standard interconnection study, a utility model identifies the potential grid violation(s) induced by a proposed PV system and the infrastructure upgrades or reduced PV size that would be required to mitigate the violation. We take this process further to explore the feasibility of using battery energy storage in combination with the PV system to mitigate identified grid violations and reduce interconnection costs. Furthermore, the analysis supports the ongoing evolution of interconnection standards for combined PV and energy storage systems by providing a methodology to define allowable maximum export limits during each hour.

As battery technology costs continue to decline, the use of batteries in the electricity sector is becoming more commonplace. The two most prevalent types of battery projects are: (1) behind-the-meter applications that are deployed with the goal of bill savings or resilience, and (2) utility-scale batteries that are deployed to enhance grid reliability or achieve system cost savings (i.e., peak shaving, regulation services). In contrast to those applications, the primary driver for this analysis is the mitigation of violations induced by distribution-connected PV.

There are several reasons to explore the addition of battery energy storage as a means of mitigating violations from distributed energy resources. The overarching driver is to enable the interconnection of larger PV systems. Solar developers faced with high interconnection costs typically choose to reduce PV system sizes, rather than pay for expensive infrastructure upgrades. But this solution fails to capture several benefits of larger PV system sizes. Larger systems facilitate higher levels of clean energy on the electricity system to address state and regional goals; they reduce the land-use impact associated with many smaller-scale ground-based PV systems; and they allow developers to take advantage of economies of scale during construction, which reduces the societal cost of clean energy development.

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This report details the methodology and results of an analysis that:

- Identifies potential grid violations that would be induced by a PV system requesting interconnection to a distribution circuit
- Identifies multiple technically viable options for mitigating the potential violations, including infrastructure upgrades, downsizing the PV system size, curtailment of PV, and addition of battery energy storage
- Defines the required technical operating parameters of the system in order to mitigate all potential violations (the "Operating Envelope")
- Compares the economics of each option, from the PV developer's perspective.

Overarching requirements for acceptable solutions are:

- The solution will not induce violations on the distribution feeder over the course of the test year, based on an 8,760 (hourly) time-series analysis[4]
- The solution makes use of technology that is readily available (e.g., industry standard PV size increments, battery system size increments, standard infrastructure upgrade options)
- The solution is designed in a way that would reasonably be expected to reduce time and cost to a system developer (e.g., slightly reduce the PV system size in a paired PV and battery solution, rather than significantly increasing battery size).

This analysis provides a foundation upon which others in the field may build proof of concept. The methodology presented could be used by utilities as part of the interconnection study process, to inform negotiations with DER developers and the drafting of mutually acceptable interconnection agreements. It is envisioned that the technical operating parameters defined through the method detailed in this report would be included as part of the interconnection service agreement (ISA) between the system owner and the utility company. We call this addition to the ISA an "Operating Envelope Agreement" or OEA. The companion report to this analysis, Gill et al. (2022), details the expansion of an ISA to include the time-based technical parameters and the associated terms and conditions.

[4] An 8,760 time-series analysis models generation and load on the distribution feeder over each hour of a typical year to identify the potential of grid violations induced by a new generation source on the feeder.

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Operating Envelope Agreement (OEA): A contractual agreement between the utility and the system owner that defines a mutually agreeable set of time-based technical operating requirements (an "Operating Envelope") for a PV and storage system that limits risk to neighboring customers and the utility's infrastructure and provides certainty to both the utility and PV system owner.

The Operating Envelope is a principle of access in addition to those mentioned by Horowitz et al. (2019a), which essentially dictates export over time rather than specifying when generators will be curtailed. There are two key benefits of the Operating Envelope principle of access: granularity and predictability. An Operating Envelope provides a specific boundary for export, rather than curtailing all generators equally depending on current grid conditions. This allows developers to predict and optimize project revenues more accurately. An Operating Envelope is more predictable than a last in/first out principle of access (the last project to interconnect is the first to be curtailed) because the chance of curtailment is not dependent on other systems coming online.

Figure 1 outlines the workflow undertaken in this techno-economic analysis. Sections 3 and 4 detail the methodology and results of the analysis.

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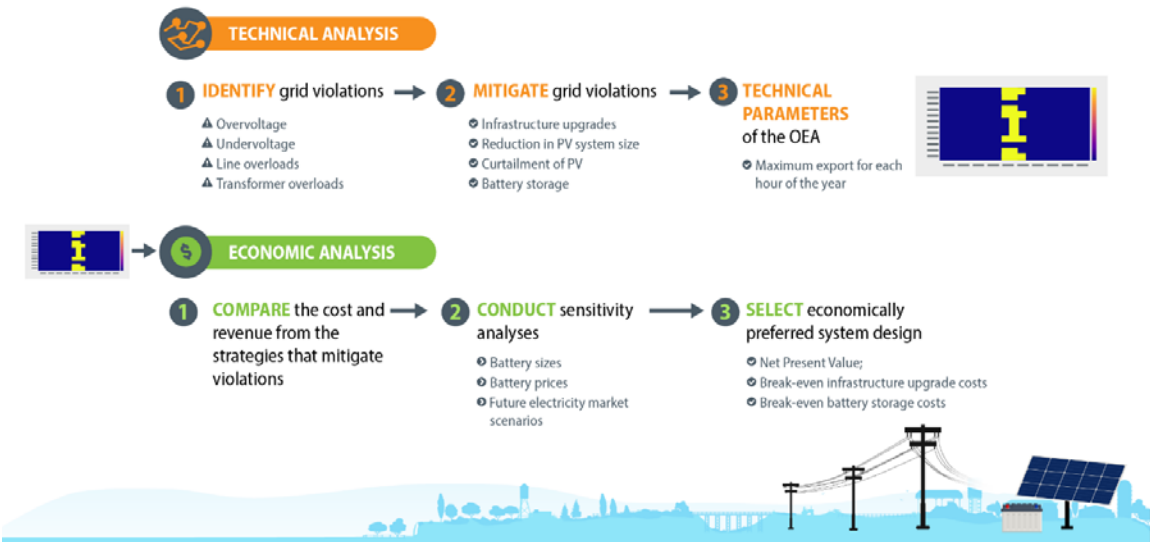

Figure 1. Overview of the analysis

The scope of this analysis is limited to distribution system-connected solar PV systems not co-located with load with installed capacity roughly between 1 and 5 megawatts (MW). However, the concept and analysis method may be applied to a range of solar PV project sizes, use cases, projects interconnected at the transmission system, and/or other renewable energy technologies. The applicability of the analysis to other situations is a recommended area for future research.

2 Technical Analysis

2.1 Tools and Methodology

This section details the tools and methodology used to develop the technical parameters of the OEA (i.e., the Operating Envelope). It covers the software used to conduct a distribution system power-flow analysis, and the inputs and outputs of the technical analysis, which feed into the economic analysis.

2.1.1 OpenDSS Software

For this analysis, OpenDSSDirect was used to perform the distribution system power-flow analyses. OpenDSS Direct is an open-source Python wrapper on the power distribution system simulator OpenDSS. For this work we developed a quasi-static time-series analysis module that can perform an 8,760 time-series power-flow simulation on a distribution feeder model in OpenDSS format.

2.1.2 Inputs to the Time-Series Power-Flow Analysis

Time-series power-flow analysis requires the following inputs:

1. A distribution **feeder model** representing the configuration of the distribution feeder
2. A time-series **load profile** representing the existing load on the distribution feeder

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3. A time-series **generation profile** for the DER being tested.

Feeder Model

Our original goal was to conduct the analysis using a model that represents a feeder in Rhode Island on which interconnection applications for PV systems have been denied, and where the concept of an OEA might have been applied to reduce interconnection costs. Rhode Island National Grid selected a feeder and shared data with the National Renewable Energy Laboratory (NREL) under a non-disclosure agreement. However, after significant challenges in converting the chosen feeder model from Cyme to the OpenDSS format, we ultimately used an open-source IEEE test feeder for the analysis. An advantage of using the IEEE feeder is that the data is openly available, so the results may be replicated by others, if desired.

The IEEE 34-bus test feeder that was selected is an existing feeder with a nominal voltage of 24.9 kV. It has long and lightly loaded overhead distribution lines, regulators, shunt capacitors, and a transformer for a short 4.16-kV section. There are no observed violations in the base case and the lines are very lightly loaded in the original data set. Hence, for this analysis, the ampacity of feeder lines are reduced such that two lines are severely overloaded. This is to mimic the violations seen on the National Grid feeder and better test the viability of the OEA concept.

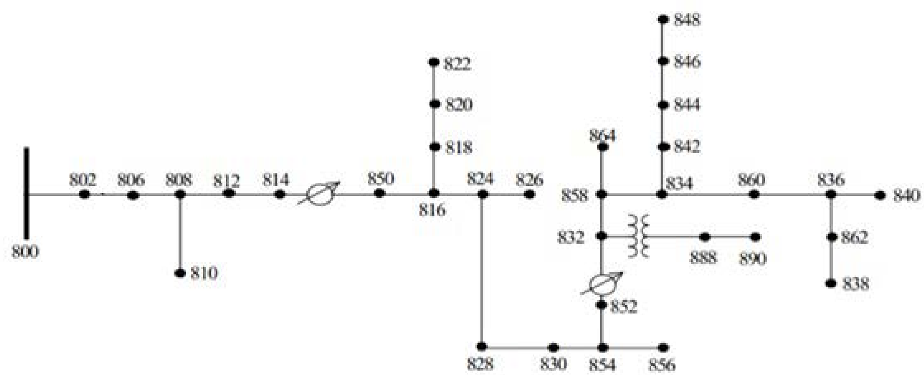

Figure 2. IEEE feeder model used in the technical analysis

Feeder Load Profile

After exploring multiple open-source feeder load profiles, we selected a domestic load profile for the year 2020 that represents a typical residential profile. The data are publicly available at: https://www.sce.com/regulatory/load-profiles. Two critical network loading condition days in the year are shown below. These represent the day with the maximum feeder load (Figure 3), and the day with the highest PV generation and lowest feeder load (Figure 4).

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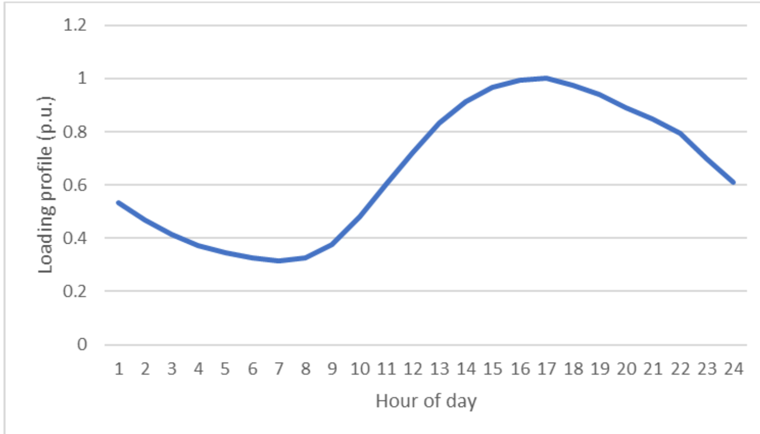

Figure 3. Maximum load day feeder load profile

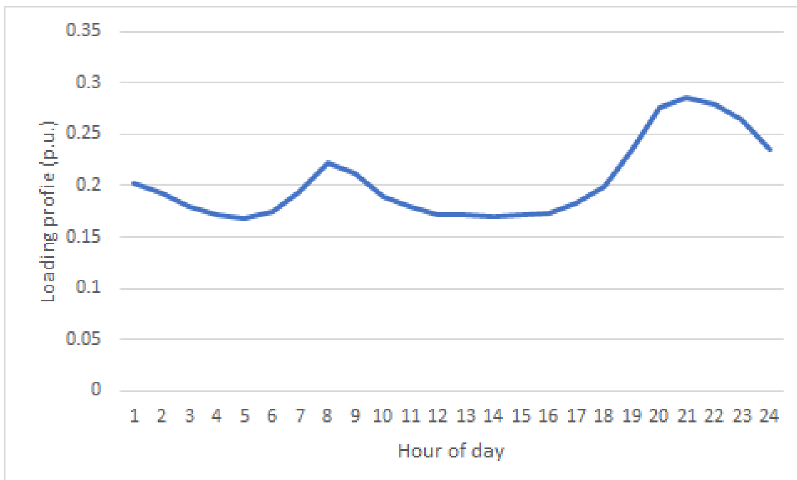

Figure 4. Feeder load profile for high PV, low loading day

Solar Generation Profile

The PV generation profile for the same geographical area as the loading profiles (Los Angeles) and the same year (2020) was used to represent PV generation used in this analysis. The PV profile (as shown in Figure 5) was generated using pvlib, an open-source PV model Python library developed by Sandia National Laboratories (Holmgren, Hansen, and Mikofski 2018). Irradiance profiles for a clear sky were used because they represent the highest PV generation and create the “worst-case” scenario, from the perspective of distribution network operations.

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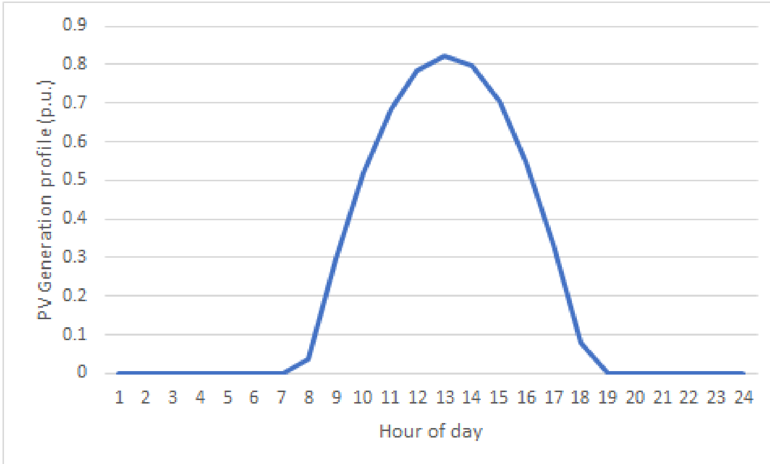

Figure 5. Sample clear sky PV generation profile

2.1.3 Outputs From the Time-Series Power-Flow Analysis

Using the above inputs to the time-series module, we determine the violations induced by a DER at any location on the distribution feeder during every hour of the year. The analysis identifies overvoltages, undervoltages, line overloads, and transformer thermal overloads induced by the distributed energy system under consideration. Table 1 details the output metrics from the time-series analysis.

Table 1. Output Metrics From OpenDSS Direct Quasi-Static Time-Series Analysis

	Time-Series Output Metrics	Description
M1	Maximum voltage (per unit)	Maximum voltage magnitude across all nodes in the network that experience overvoltage violations
M2	Minimum voltage (per unit)	Minimum voltage magnitude across all nodes in the network that experience undervoltage violations
M3	Maximum transformer loading (per unit)	Maximum loading observed across all transformers in the network that experience overloading
M4	Maximum line loading (per unit)	Maximum loading observed across all lines in the network that experience overloading
M5	Duration of occurrence of violations for each month in a year	This metric gives the total number of hours that the system experienced different kinds of violations for every month
M6	Duration of occurrence of violations for each week in a year	This metric gives the total number of hours that the system experienced different kinds of violations for every week
M7	Duration of occurrence of violations by hour of day	This metric gives the total number of hours that the system experienced different kinds of violations for every hour of the day, across the whole year

Acceptable limits to define a violation for this analysis are based on conversation with utility partners. The goal is to represent limits that are generally used in utility interconnection studies. In this case, we use ANSI Range A voltage limits with a lower bound of 0.95 per unit, and an upper bound of 1.05 per unit. These Range A limits represent normal operating conditions. A

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thermal violation is defined by conditions in which a line or transformer is loaded over 100% of its capacity (NEMA, 2016).

2.1.4 Methodology (Workflow of the Power-Flow Analysis)

This section outlines the workflow and methodology undertaken, using the tools and data described above. Utility companies typically use commercial grid modeling software, such as Cyme and Synergi, to conduct analyses for interconnection studies. Depending on the size and complexity of the PV interconnection, different levels of studies are performed, ranging from a simple analysis at the point of interconnection to a detailed study (Bird et al. 2018).

Figure 1 provided an overview of the entire technical and economic analysis methodology. Figure 6 shows the workflow for developing the OEA technical parameters using the power-flow analyses. Table 2 lists the scenarios conducted as part of the workflow and their purpose in the technical analysis. An 8,760 time-series power-flow analysis is conducted for each scenario in Table 2 to identify grid impacts and violations. The outputs are used to determine the grid export limit at the point of interconnection that is necessary to avoid violations; these injection limits form the basis of the Operating Envelope. All scenarios have the same feeder model and load profile as inputs. The only change across scenarios is the generation profile that represents the PV (or stored PV generation) that is injected into the feeder over the 8,760 time period.

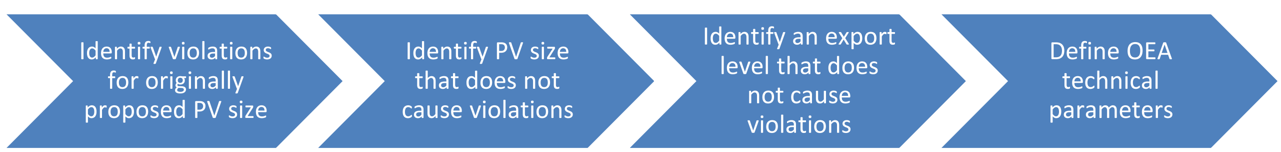

Figure 6. Power-flow modeling workflow to develop technical parameters of the OEA

Table 2. Power-Flow Modeling Scenarios

	SCENARIO	Description/Purpose
S1	Load-only	Tests the feeder model to ensure that there are no pre-existing violations or errors prior to beginning scenario analysis.
S2	Originally proposed PV size	Tests for violations due to the originally proposed PV system size, which represents the system as originally proposed by a PV developer in the interconnection request. For the purposes of this analysis, this scenario is designed to result in violations.
S3	Originally proposed PV size with smart inverter controls	Tests for violations due to the originally proposed PV system size, with advanced inverter controls enabled (volt-VAR), in accordance with IEEE Standard 1547. For this analysis, this scenario is designed to result in violations. The goal is to quantify the impact of advanced inverter controls in alleviating violations.

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	SCENARIO	Description/Purpose
S4	Downsized PV system	This scenario is used to identify and verify the PV system size that does not cause violations on the feeder. A downsized PV system size is estimated, based on the violations from scenarios 2 and 3. An iterative process is used to identify and confirm the system size that does not cause violations in any hour of the year.
S5	Constant injection of generation to simulate a battery energy storage discharge to the grid	This scenario is used to ensure that the addition of a battery to mitigate PV violations will not cause additional violations by discharging to the grid (e.g., in hours of low PV production). It determines the maximum allowable constant injection at the point of interconnection. An iterative process identifies and confirms the battery size that does not cause violations in any hour of the year, despite when the battery is discharged.

The technical parameters of the OEA are developed based on the outputs of the time-series scenarios and define the operating parameters to which a PV system must adhere to avoid causing violations on the feeder. We generate them by taking the *maximum* of the generation from the downsized PV that does not cause violations (S4) and the constant export that does not cause violations (from S5), for each hour of the day in a single month.

To make the parameters easier to use, we specify one maximum injection value for each hour of the day, during each month of the year. The maximum injection limits are visualized in a 12-month x 24-hour table, as a heat map (see Figure 12). This heat map represents the technical parameters of the OEA and is the final output of the technical analysis. A simpler version of the heat map can be generated through rounding (see Figure 13), which could simplify system operators' planning and automatic controls. The heat map is then passed to the economic analysis to determine a PV system size and configuration that adheres to the requirements. Our economic analysis is detailed in Section 4.

If this process were being completed in the field, the technical parameters would be passed by the utility conducting the interconnection study to the PV developer. The PV developer would then conduct their own economic analysis to determine the preferred PV system size and configuration to adhere with the Operating Envelope.

A time-series analysis may be computationally intensive for a utility to perform. Instead of an 8,760 time-series analysis, a less intensive approach is to identify the worst-case day for every month and run power-flow simulations on these 12 days (instead of the whole year). The maximum grid export for those 12 days could then be used to create the required operating parameters in the OEA.

The following section presents the outputs of the 8,760 time-series power-flow modeling we undertook and the resulting technical parameters of the OEA for our example case.

2.2 Results of the Technical Analysis

2.2.1 Violations for Feeder With Originally Proposed PV Size

In this case study, there are no violations observed in the feeder in the base load-only case (Scenario S1). On running Scenario S2 (feeder with the originally proposed PV size of 3.3 MW),

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the PV causes overvoltage and line overloading violations. Figure 7 and Figure 8 show the magnitude and number of violations in the feeder over the year due to the originally proposed PV system. Figure 7 shows a maximum voltage of 1.09 p.u. and a maximum line loading of 2.44 p.u. in the feeder. Violations are higher in March and April, which are the months when PV generation is high and loads are low. Figure 8 shows the number of hourly voltage and loading violations. Because the two lines that make up the feeder are (intentionally) extremely overloaded in our example case, violations occur during every hour of the year.

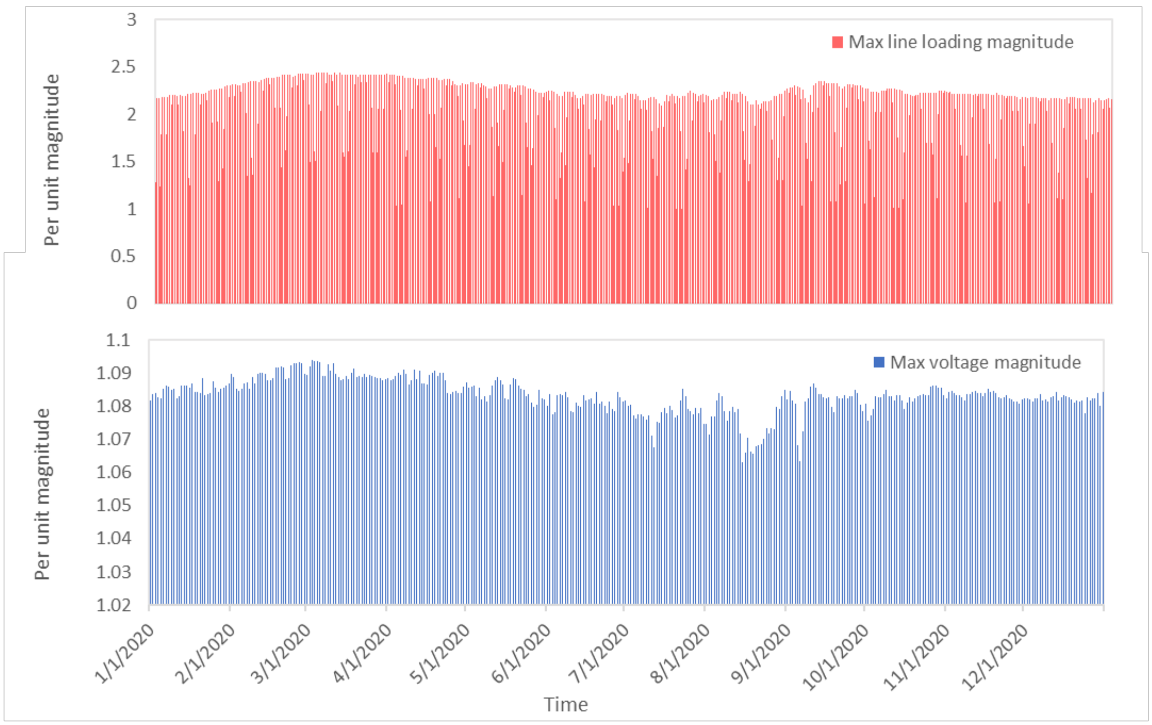

Figure 7. Maximum per unit line loading and voltage magnitude for the feeder with 3.3 MW of PV installed.

Line loading greater than 1 p.u., and voltage greater than 1.05 p.u. is considered a violation. The originally proposed PV size (3.3 MW) causes violations during every hour of the year. The maximum voltage is 1.09 p.u. and the maximum line loading is 2.44 p.u.

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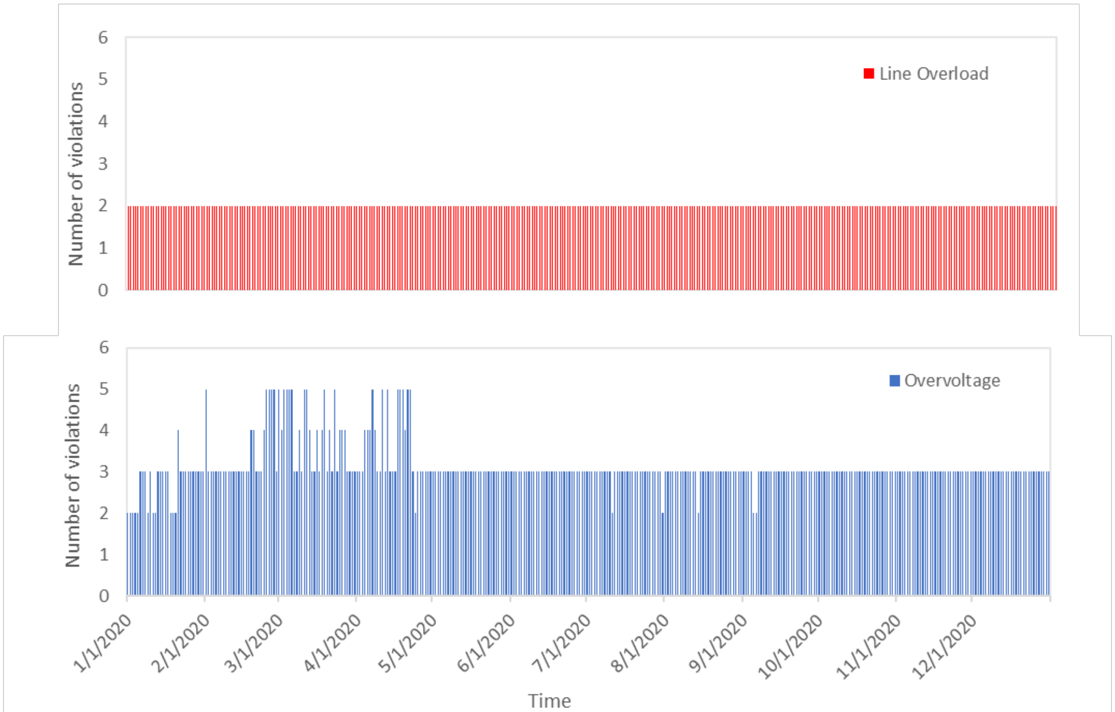

Figure 8. Number of hourly violations for the feeder with 3.3 MW of PV installed.

Overvoltages and line overloads are observed during all months in the year.

Scenario 3 (S3) is a sensitivity analysis to investigate the impact of smart inverter controls and understand the impacts of volt-VAR controls implemented at the PV location. Volt-VAR control is a feature of smart inverters that supports grid voltage stabilization during overvoltage and undervoltage conditions by automatically absorbing or injecting reactive power in response to grid voltage measurements. A volt-VAR curve illustrates a particular volt-VAR control setting that dictates the inverter behavior. Figure 9 shows the volt-VAR curve used in this analysis.

The comparison of the results of time-series analysis with and without smart inverter controls is shown in Figure 10 and Figure 11. Smart inverter controls help solve some overvoltage violations. But in some instances (e.g., at 8:00), the volt-VAR controls increase overloading on lines while decreasing the overvoltage violations (as seen in Figure 11). The controls reduce the overvoltage magnitudes across the feeder, but they do not mitigate all the overvoltage violations due to the magnitude of these violations in our test case.

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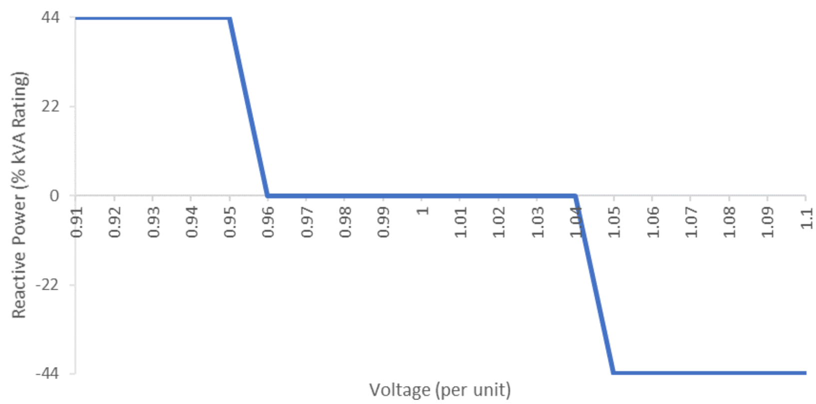

Figure 9. Volt-VAR curve used in the analysis

If grid voltage drops below the lower limit of 0.96 p.u., the inverter will inject reactive power to maintain the desired nominal voltage levels. If the voltage continues to fall to 0.95 p.u. or below, the reactive power injection is held constant at 44% of nameplate apparent power rating. If grid voltage exceeds an upper limit of 1.04 p.u., the inverter will begin to absorb reactive power, increasing linearly until voltage reaches 1.05 p.u., at which point reactive power is held fixed.

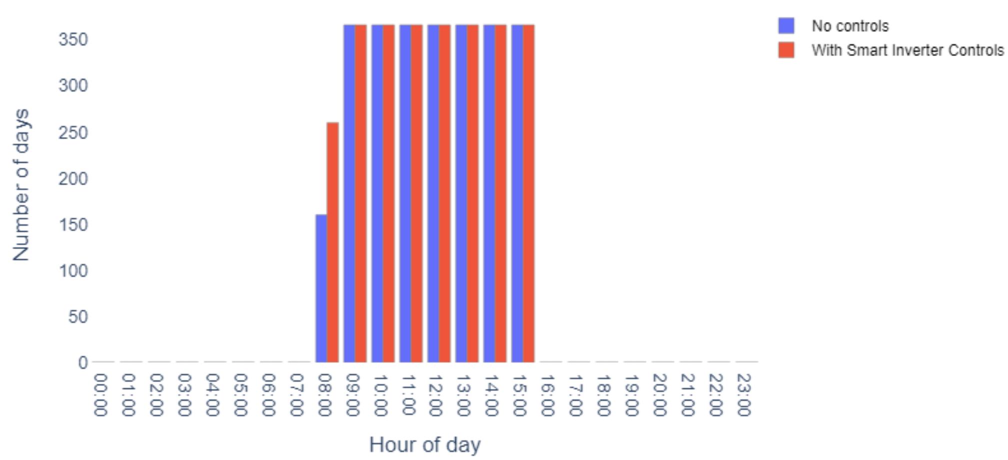

Figure 10. Comparison of occurrence of line overloading violations with smart inverter controls for the whole year, by hour of day

In some instances (for e.g., at 8:00), volt-VAR controls increase overloading on lines while decreasing the overvoltage violations (as seen in Figure 11).

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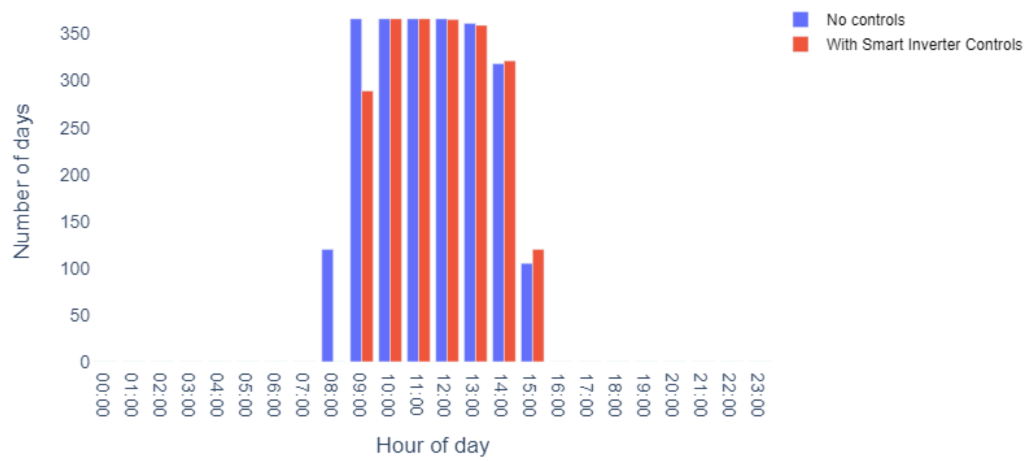

Figure 11. Comparison of occurrence of overvoltage violations with smart inverter controls for the whole year, by hour of day

Smart inverter controls resolve some instances of overvoltage violations, reducing the overvoltage magnitudes across the feeder. They do not mitigate all overvoltage violations, due to the magnitude of these violations in our test case.

The grid violations remaining in the smart inverter control scenario (S3) can be avoided by reducing the size of the interconnected PV system. The reduced system size that avoids all violations (S4) is found to be 1.32 MW. This downsized PV system size is one of the technically viable options considered in the economic analysis below.

Next, to inform the design of a system that includes a battery to mitigate violations from PV injection (but does not induce additional violations from battery discharge), we determine the maximum allowable constant injection limit across the year (S5). For our example case, a maximum injection of 990 kW does not cause violations at any time during the year. The outputs of all the time-series analysis scenarios are used to determine the OEA technical parameters, as specified next.

2.2.2 OEA Technical Parameters

Results from the power-flow scenario analyses are processed and combined to arrive at the OEA technical parameters (i.e., Operating Envelope). It is computed by taking the *maximum* of the generation from the downsized PV that does not cause violations (S4) and the constant export that does not cause violations (from S5), for each hour of the day in a single month. As such, the Operating Envelope is the maximum allowable export (in kW) for every month/hour combination, as show in Figure 12. The maximum allowable output from the distributed energy system ranges between 990 kW and 1088 kW, with higher outputs allowable in midday. These outputs are computed directly from the analysis results and are what the developer would have to limit their export to at each hour for every month. It can be further simplified (as seen in Figure 13) by rounding, which could make it simpler for the developer to implement or the utility to verify for compliance purposes.

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	0:00–10:00	11:00	12:00	13:00	14:00– 23:00
January	990	990	1004	991	990
February	990	1015	1067	1034	990
March	990	1045	1088	1049	990
April	990	1042	1072	1023	990
May	990	1016	1041	995	990
June	990	990	1010	990	990
July	990	990	1017	990	990
August	990	1003	1037	995	990
September	990	1038	1062	1005	990
October	990	1009	1021	990	990
November	990	991	996	990	990
December	990	990	990	990	990

Figure 12. The Operating Envelope indicates the maximum allowable export (in kW) for every month/hour combination

	0:00–10:00	11:00	12:00	13:00	14:00– 23:00
January	950	950	1000	950	950
February	950	1000	1050	1000	950
March	950	1000	1050	1000	950
April	950	1000	1050	1000	950
May	950	1000	1000	950	950
June	950	950	1000	950	950
July	950	950	1000	950	950
August	950	1000	1000	950	950
September	950	1000	1050	1000	950
October	950	1000	1000	950	950
November	950	950	950	950	950
December	950	950	950	950	950

Figure 13. A simplified Operating Envelope is obtained by rounding the raw parameters obtained from the technical analysis.

This simplified version can make it easier for developers to implement system controls or for utility compliance verification.

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3 Economic Analysis

In this section, we look to explore how an Operating Envelope may impact the economics of a solar project for a developer. We consider the traditional distribution system upgrades and multiple technically viable options for abiding by the technical parameters in an OEA, without causing the violations identified in the analysis above.

The OEA gives developers more flexibility in deploying solar in distribution feeders that are nearing their hosting capacity. In the past, a developer looking to install a solar system on a distribution feeder that is at or near its hosting capacity had two principal options: either reduce the system size to avoid any grid violations or pay (sometimes substantial) distribution upgrade costs that would accommodate higher levels of solar on the distribution feeder. However, as indicated by the results of the technical analysis in Section 3, the violations resulting from solar can be mitigated through multiple means. From the developer's viewpoint, there may be more cost-effective ways to manage these violations than upgrading the infrastructure to accommodate PV generation during relatively limited hours of the year that cause grid violations. The OEA is a mechanism by which utilities can set limitations on injections of power to the grid, to protect system reliability while allowing a developer flexibility in the design of their system. As long as the Operating Envelope is adhered to, the developer can size and operate the system as they wish.

To ensure exports are within the limits specified in the Operating Envelope, a developer can either (a) co-install a storage system to absorb any PV generation in excess of the specified limits, to be discharged during hours allowed by the Operating Envelope to maximize revenue, or (b) curtail the PV system as needed to abide by the Operating Envelope. Sizing of the PV (or PV + battery) system is freely determined by the developer, as long as the technical specifications in the Operating Envelope Agreement are met.

If the present value of the additional revenue from arbitrage of electricity on the wholesale market using a battery storage system is greater than the cost of adding the battery to the system, a developer may choose to add the battery rather than curtail excess PV generation. This depends on the cost of storage and the potential additional revenues from the storage.

In this economic analysis, we demonstrate the economic impact of an Operating Envelope, from the developer's perspective. We simulate the expected revenues and cash flow for a developer looking to install solar on a solar-constrained distribution feeder in Rhode Island. We use the technical specifications in the Operating Envelope from the technical analysis above for our example case.

We describe the data in Section 4.1, methods in Section 4.2, and main results in Section 4.3 before discussing conclusions and implications of the analysis in Section 5.

3.1 Data and Price Assumptions

In the field, the utility would provide the developer with an Operating Envelope. The specifications are likely be different for each distribution grid and interconnection point, so the specifications would likely vary for each project. For this economic analysis, we use the output of the technical analysis above as the Operating Envelope for this economic analysis (Figure 12).

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The PV system is assumed to be connected to the distribution system "in-front-of-the-meter," which means there is no self-consumption of PV generation; all PV generation is either exported to the grid, curtailed, or used to charge a battery, if available. The PV (or PV + battery) system is assumed to be a merchant plant, with all income based on revenue from the wholesale market spot prices and no long-term power purchase agreements are signed. Revenues are therefore dependent on future wholesale electricity prices.

In this analysis, we use energy and capacity prices developed by NREL's Cambium tool, which builds on NREL's Regional Energy Deployment System (ReEDS) model and the PLEXOS model to simulate hourly wholesale electricity prices for nodes in the United States through 2050. Details on the Cambium tool can be found in Gagnon et al. (2020). We used the "Mid-Case" scenario as our central case, but also considered the "Low Battery Cost" and "Low Renewable Energy Cost" as sensitivity cases. The data was downloaded from the Cambium viewer (https://cambium.nrel.gov/), and the Rhode Island node was used.

Simulated PV generation was generated using the System Advisor Model (Blair et al. 2018), with typical meteorological year (TMY) data for Rhode Island using an optimal fixed orientation and default values for all other inputs.

3.2 Methodology of Economic Analysis

We simulate revenues resulting from four PV and PV + battery options that do not result in grid violations:

Option (1) Downsized PV system: The developer originally proposed a 3.3-MW PV system, but to avoid grid violations, the PV system is downsized to 1.32 MW.

Option (2) 3.3-MW PV with infrastructure upgrade costs: The developer installs the originally proposed 3.3-MW PV system and pays infrastructure upgrade costs to mitigate grid violations associated with the PV system.

Option (3) 3.3-MW PV with curtailment to adhere to Operating Envelope: The developer installs the originally proposed 3.3-MW PV system and agrees to adhere to the Operating Envelope, doing so by curtailing PV.

Option (4) 3.3-MW PV, using battery and curtailment to adhere to Operating Envelope: Developer installs the originally proposed 3.3-MW PV and agrees to adhere to the Operating Envelope, doing so by charging a battery and/or curtailing PV during the hours when the PV system generation is above the specified limits. Different battery sizes are explored.

We use the hourly simulated PV generation from the System Advisor Model and hourly prices from Cambium to calculate revenues from solar alone (options 1 and 2). For the hours where the PV generation is greater than the allowable as per the Operating Envelope, compensated PV generation was limited according to the Operating Envelope, simulating partial curtailment (option 3).

For combined solar and storage (option 4), we first determined storage dispatch to maximize revenues, using a linear optimization model implemented in MATLAB. The optimization model,

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loosely based on the underlying model from Sandia National Laboratories' [QuESt tool](), outputs hourly storage charge and discharge levels in order to maximize revenue from wholesale electricity market, charging only from solar (to retain the full Investment Tax Credit) and curtailing solar generation when needed, while ensuring that the Operating Envelope limits are respected at all hours.

The objective function f(x), which we are looking to maximize, represents the total annual revenue from the solar + storage system:

$$\max f(x) = \sum_{i=1}^{T} \lambda_i \ * \ \left(qS_{d,i} + qPV_{inj,i}\right) \qquad (1)$$

subject to:

$$s_i \geq Q_s \cdot \delta_{S,min} \qquad i = 1,2,\ldots,8760 \qquad (2)$$

$$s_i \leq Q_s \cdot \delta_{S,max} \qquad i = 1,2,\ldots,8760 \qquad (3)$$

$$qS_{PV,i} + qS_{d,i} \leq P_s \qquad i = 1,2,\ldots,8760 \qquad (4)$$

$$qS_{d,i} + qPV_{inj,i} \leq OEA_i \qquad i = 1,2,\ldots,8760 \qquad (5)$$

$$s_{i-1} + \eta_c \cdot qPV_{inj,i-1} - qS_{d,i-1} - s_i = 0 \qquad i = 1,2,\ldots,8760 \qquad (6)$$

$$qS_{c,i} + qPV_{inj,i} + qPV_{curt,i} = gPV_i \cdot Q_{PV} \qquad i = 1,2,\ldots,8760 \qquad (7)$$

$$qS_{d,i} \geq 0 \qquad i = 1,2,\ldots,8760 \qquad (8)$$

$$qPV_{inj,i} \geq 0 \qquad i = 1,2,\ldots,8760 \qquad (9)$$

$$qPV_{curt,i} \geq 0 \qquad i = 1,2,\ldots,8760 \qquad (10)$$

$$s_i \geq 0 \qquad i = 1,2,\ldots,8760 \qquad (11)$$

Variables:

$qS_{d,i}$: Storage discharged and injected into the grid at hour i (MWh)

$qS_{PV,i}$: Storage charged from PV at hour i (MWh)

$qPV_{inj,i}$: Solar generation injected into the grid at hour i (MWh)

$qPV_{curt,i}$: Solar generation curtailed at hour i (MWh)

s_i : State of charge of the battery at hour i (MWh)

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Constants:

λ_i : Electricity price at hour i ($/MWh)

Q_s : Battery capacity (MWh)

P_s : Battery power rating (MW)

Q_{PV} : Solar nameplate capacity (MW)

$\delta_{S,min}$: Minimum state of charge (%)

$\delta_{S,max}$: Maximum state of charge (%)

OEA_i : Maximum power injected at hour i as per OEA rules (MWh)

η_c : Roundtrip efficiency (%)

gPV_i : Total PV generation at hour i ($/MWh)

In words, Equation (1) is looking to maximize revenue from discharging the storage and PV injected into the grid. Equation (2) ensures that the state of charge is always above a minimum level, and Equation (3) ensures that the state of charge is always below a maximum level, assuming a depth of discharge. Equation (4) ensures that the rate of charge/discharge is not larger than its power rating. Equation (5) ensures that the electricity injected into the grid abides by the limits set by the Operating Envelope in any given hour. Equation (6) makes the state of charge of any hour dependent on the state of charge the previous hour, the charge or discharge rate, considering any roundtrip efficiency losses during charging. Equation (7) ensures that the PV generation must either be injected into the grid, used to charge the battery, or curtailed. Equations (8)–(11) ensure that all the variables are greater than or equal to zero.

The output of the optimization specifies the output variables for each hour of the year, which defines for each hour of the year the charging or discharging of the battery, solar generation injected into the grid (if any) and curtailed (if any), as well as the state of charge of the battery.

A sample output of the optimization model is shown in Figure 14. During the hours where PV generation is higher than the Operating Envelope limits, the PV generation is either used to charge the battery during hours when prices are low or it is curtailed, or both. The dispatch algorithm is indifferent between charging and curtailing, as long as the battery is fully charged before the high-priced hours when it discharges to maximize revenue. An example of this behavior is seen in hour 10:00. The battery is charging at 9:00, PV is curtailed at 10:00, and the battery charges again at 11:00. There is no revenue impact to this behavior since the battery charges to full capacity by 16:00.

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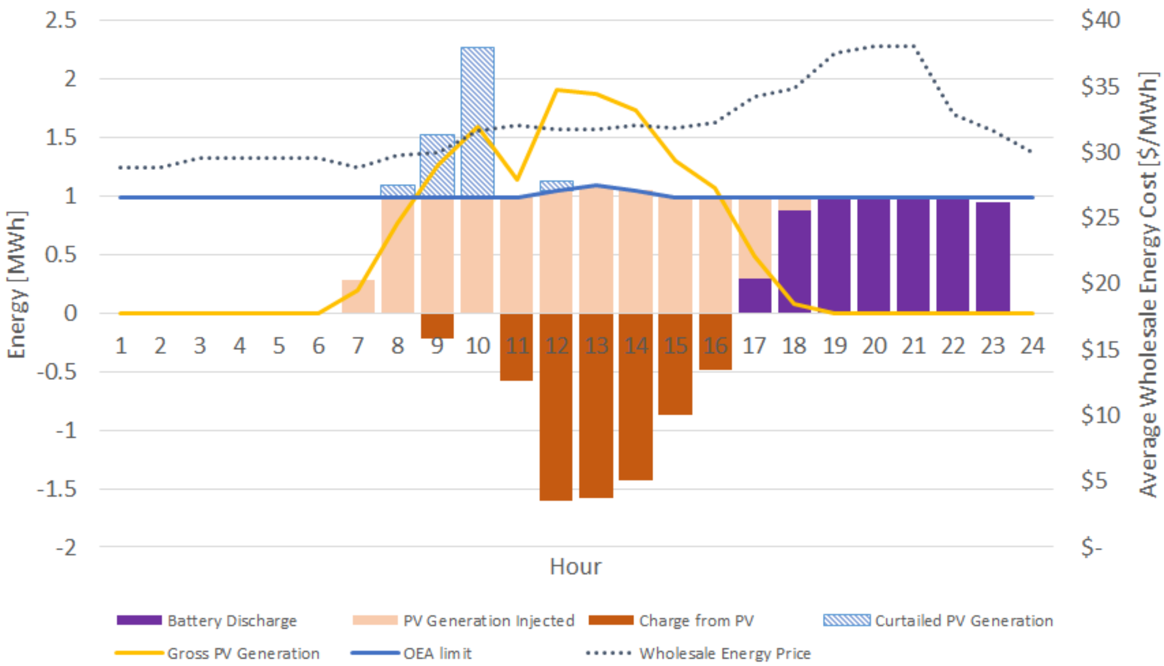

Figure 14. Example output from the optimization model (March 25, PV system size = 3.3 MW, storage rated power = 1.6 MW, storage rated capacity = 6.4 MWh)

The optimization was run for years 2020 through 2030 using the energy and capacity busbar costs from Cambium (biannually, as per Cambium output). The annual revenue from each of the system design options (options 1–4 above) is calculated each year, taking into account all the electricity injected into the grid. For options 3 and 4, we assume that the OEA holds for the full lifetime of the project. For option 4, we assume that after the storage is retired, the annual revenue for the remainder of the solar system lifetime is equal to that of the case where the Operating Envelope is adhered to through solar curtailment alone (option 3).

The costs in year 1 are calculated by adding the upfront costs for PV, storage, and interconnection distribution upgrade costs, as applicable. The net present value for each option is calculated using the cash flow over the lifetime of the project. Assumptions are summarized in Table 3. Note that this is a relatively simple cash flow analysis to understand some of the high-level cost trends and dynamics between the upfront investments and revenues over time. A developer would use a more sophisticated cash flow model, using costs that are specific to the project and financial parameters appropriate for the developer (including debt and equity considerations that are not present in this analysis).

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Table 3. Economic Analysis Assumptions

Variable	Base Case Value
Solar PV system size	*Option 1*: 1.32 MW *Options 2–4*: 3.3 MW
Storage size	*Option 4 only* Rated capacity: 0–2.4 MW Rated Power: 4x rated capacity (4-hour duration)
Solar PV capital costs	$1/W (DC STC)
Incremental storage costs	$1,250/kW (ATB 2021 battery storage CAPEX, 4-hour, advanced)
Discount rate	5%
PV degradation rate	0.5% per year
Battery degradation rate	3% per year
Battery depth of discharge	95%
Battery roundtrip efficiency	90%

3.3 Results of the Economic Analysis

Whether the OEA is an attractive option to a solar developer depends on the revenue that can be realized, given the injection restrictions defined in the Operating Envelope, as compared to the cost of infrastructure upgrades that would be required without the OEA. When minor upgrades are needed to accommodate a PV system on the distribution grid, the interconnection costs that are passed on to the developer may be acceptable, obviating the need for an OEA with the utility. However, as distribution feeders become saturated with PV, these interconnection costs increase and the OEA becomes a more economically attractive option. This case study of a generic distribution feeder demonstrates the economic feasibility of the OEA, as compared to paying traditional infrastructure upgrade costs.

To evaluate the economics of a project, we first consider the upfront costs for each of the options included. For the four options described in Section 3, the lowest upfront cost is associated with the smaller PV system (1.32 MW, option 1) that requires neither upgrades to the distribution feeder nor an OEA agreement because there are no grid violations associated with the PV system, as per the technical analysis results. The next lowest upfront cost option is the originally proposed PV system with curtailment to abide by OEA rules (option 3). In this case, there are no infrastructure upgrade costs and no capital costs for a battery system. The relative cost of the two other options (2 and 4) are dependent on the required infrastructure upgrade costs and the size of the storage installed by the developer. Figure 15 shows the upfront costs for two different battery sizes for option 4 (0.4-MW and 2.4-MW storage with a 4-hour duration).

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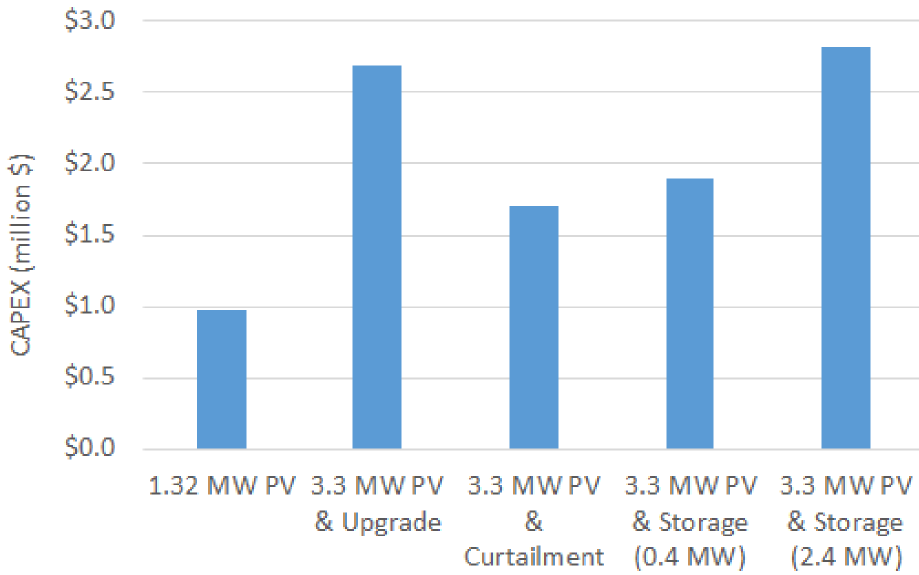

Figure 15. Upfront costs for each PV system configuration considered

Figure 16 shows the annual revenues for each of the options considered, including systems with two different battery sizes.

Option (1) Downsized PV system: The revenue is dependent on the wholesale prices and the PV generation profile alone. This option results in the lowest revenue.

Option (2) 3.3-MW PV with infrastructure upgrade costs: All the PV generation sold directly into the wholesale market for the lifetime of the PV system.

Option (3) 3.3-MW PV with curtailment to adhere to Operating Envelope: During hours of peak PV generation, curtailment as required by the Operating Envelope reduces the compensated output of the PV system by 37%.

Option (4) 3.3-MW PV, using battery and curtailment to adhere to Operating Envelope: Storage increases the revenue as compared with option 3, depending on the size of the storage. Storage avoids the need to curtail electricity by charging using PV generation that would have otherwise been curtailed, but also provides additional revenue by discharging during hours when wholesale electricity prices are highest—which may occur outside PV generation hours, a form of price arbitrage.

The annual revenues from the 3.3-MW PV system + 2.4-MW storage system adhering to an Operating Envelope (option 4) is greater than the annual revenues from the 3.3-MW PV system that curtails power to adhere to the Operating Envelope (option 3). However, this is only true for the lifetime of the storage system (assumed here to be 10 years, based on a standard manufacturer's warranty). Starting in year 11, PV generation must be curtailed to avoid violating the injection limits, and the annual revenues of option 4 (PV with battery) are equivalent to those of option 3 (curtailment only). An additional option is to continue to use the batteries beyond

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year 10, account for the additional degradation and curtail as needed—a scenario that is explored in our sensitivity analysis below.

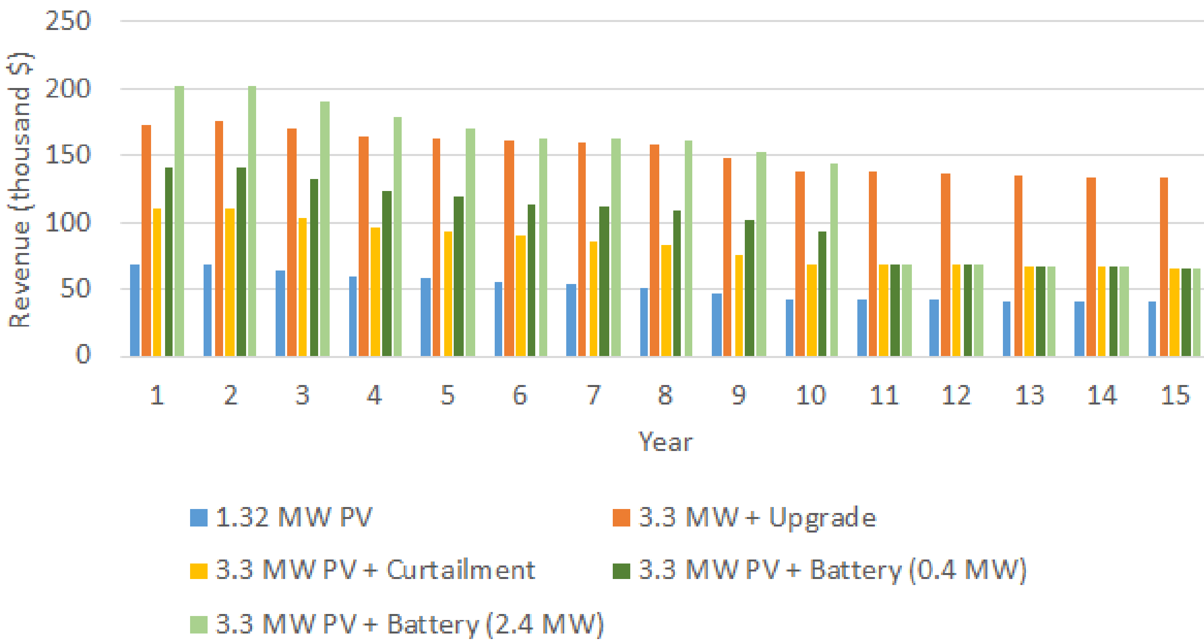

Figure 16. Annual revenues for years 1–15 for each PV system configuration considered

To better understand the relationship between battery size and revenues in the options with an Operating Envelope, we can look at the curtailment of PV generation and the marginal value of storage for various battery sizes.

Figure 17 shows how curtailment of electricity decreases as the size of the battery system increases. The mean value of the electricity sold from the discharging of the battery system is greater than the mean value of the curtailed electricity, but this ratio decreases with increasing battery size as the marginal value of energy storage falls (ratio of 1.7 for battery size of 0.4 MW falling to 1.56 for battery size of 2.4 MW). Small storage systems are able to discharge only during the highest price hours, but larger systems must spread the discharging over several hours (some lower priced) to ensure that the discharge levels remain lower than the grid injections allowable by the Operating Envelope, leading to a diminishing return to scale.

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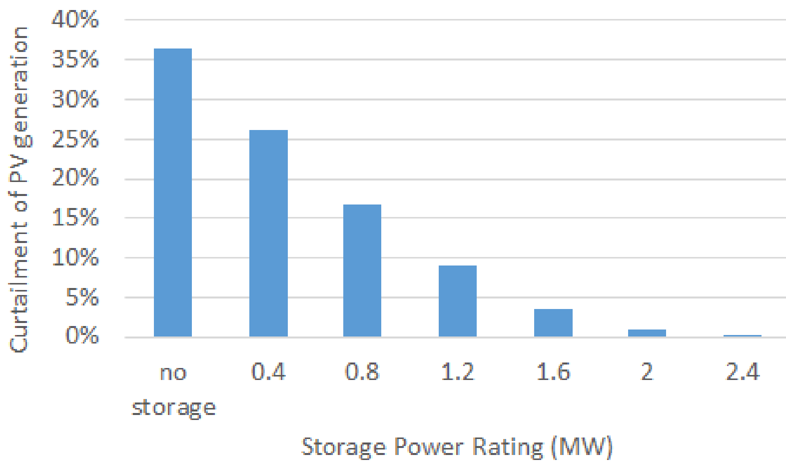

Figure 17. Curtailment of PV generation resulting from the OEA with increasing storage sizes

For our case study, assuming battery costs of $1,250/kW for 4-hour storage duration, the net present value of the PV and battery system with an OEA (option 4) is lower than the net present value of the PV curtailment with an OEA (option 3), regardless of the size of the battery system selected. Hence, the additional value from adding storage over its lifetime is not sufficient to warrant the additional costs at its current price in our case study. But as storage prices fall, the solar plus battery option becomes increasingly attractive. Figure 18 shows the break-even price for the battery option—the price at which solar with batteries becomes as attractive as the solar plus curtailment—for each of the battery sizes considered in this analysis. The break-even battery price is highest for smaller storage systems because the incremental value from the batteries is the highest, as shown in the secondary axis of Figure 18. Smaller storage systems can capture the highest value arbitrage. The incremental value from storage is directly proportional to the breakeven cost.

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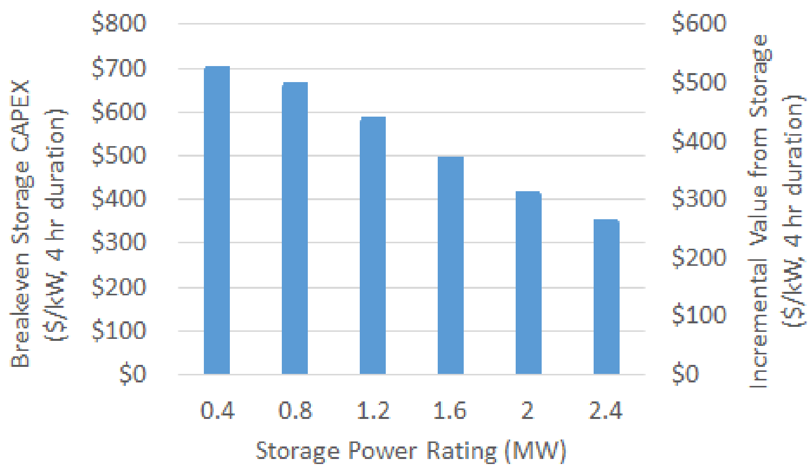

Figure 18. The breakeven storage costs and incremental value from storage with increasing storage sizes

The break-even storage cost is the battery price ($/kW) at which solar with batteries becomes as attractive as the solar plus curtailment (left y-axis). The incremental value from storage (right y-axis) is directly proportional to the breakeven cost. Smaller storage systems capture the highest value arbitrage. The break-even battery price is highest for smaller storage systems because the incremental value from the batteries is the highest.

Assuming infrastructure upgrade costs of $148,500, option 2 (3.3-MW PV + infrastructure upgrade) has a greater NPV than option 3 (3.3-MW PV with OEA + curtailment), but the interconnection costs will differ depending on local conditions. In our analysis, we find a break-even interconnection cost of $650,000, or about a quarter of total installed costs for the 3.3-MW system. As battery prices fall below their break-even costs (from Figure 18), the break-even interconnection costs will fall to lower levels.

3.3.1 Sensitivities

We consider two other future electricity market scenarios from the Cambium output: a low-battery-cost scenario and a low-renewable-cost scenario (which represents lower prices paid on the wholesale market for renewable energy generation), both described in Cole et al. (2020). For each of these scenarios, we re-ran the simulations and battery dispatch optimization to evaluate how different wholesale price series may impact the customer economics of solar (and storage) under the four options.

With the low renewable cost scenario, we see reduced revenues in 2030 for all options, a result of lower wholesale electricity prices across most hours. Figure 19 shows the 2020 and 2030 revenues from each of the options considered in this analysis. Table 4 provides the values for each scenario.

The lower wholesale prices make the investment less attractive overall, regardless of the option, which translates into lower net present values. For a 0.4-MW battery system, the break-even costs fall from $706/kW under the mid-case scenario to $680/kW under the low renewables scenario and for the larger 2.4-MW system, the break-even costs fall marginally from $355/kW to $345/kW. The break-even interconnection costs (between options 2 and 3) fall from $654,000

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to $610,000. The low-storage-cost scenario leads to minor differences, with only small changes in the break-even storage and interconnection costs.

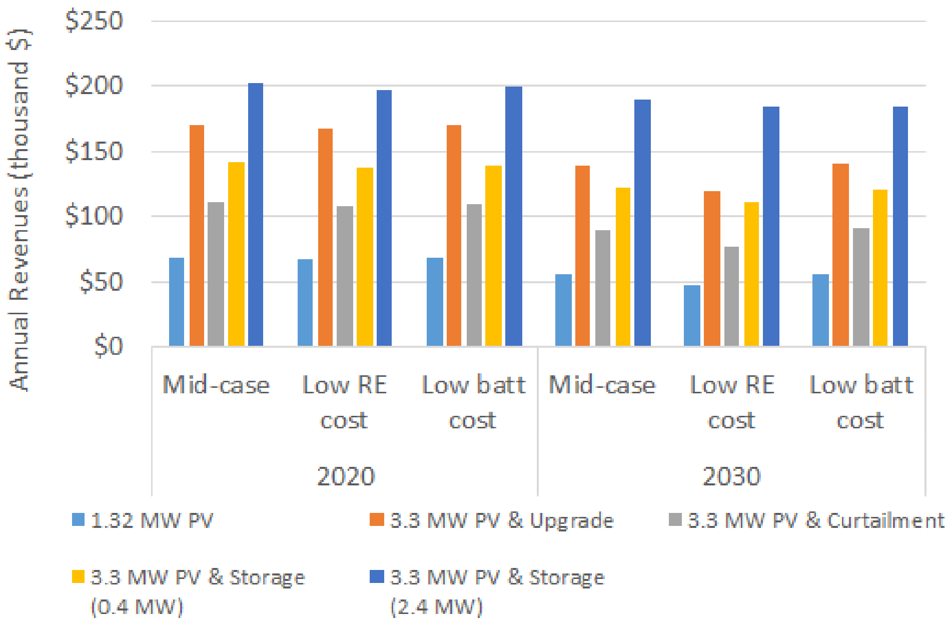

Figure 19. Annual revenues for each of the five options considered under three wholesale price scenarios

Another assumption that influences the economic outcomes is the battery system lifetime. In our base case we assume a 10-year lifetime in accordance with the manufacturer warranties for smaller storage systems. However, if the battery system were not retired after the warranty period ends, it could continue to provide arbitrage value (even if degradation deteriorates capacity levels further). With a continued degradation of 5% per year beyond the 10-year warranty period for another 5 years, the net value from storage increases, as does the break-even storage costs, as shown in Figure 20.

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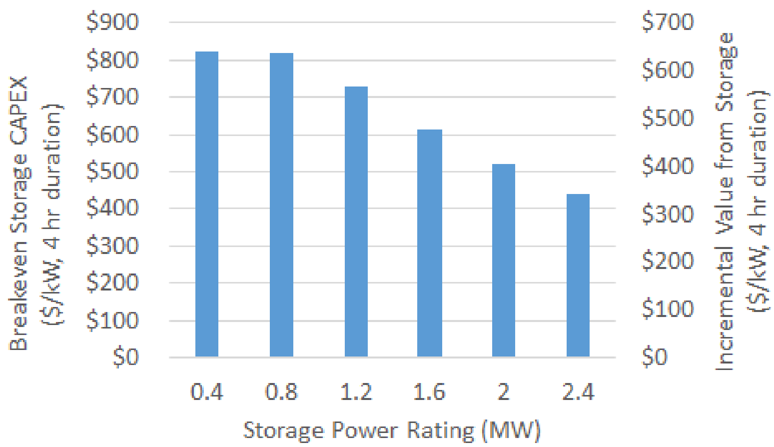

Figure 20. The breakeven costs and incremental value from batteries with increasing battery sizes, assuming a 15-year battery system lifetime

Additional value can be obtained from the battery when it is used past the manufacturer's warranty period of 10 years, which makes the PV + storage option economically attractive at higher battery prices.

If the economically preferrable solution includes the addition of a battery to the PV system, a final power-flow analysis could be conducted to confirm that the system does not cause violations. It is important that the battery is both sufficiently sized to soak up the PV generation that induced violations in the base case and can discharge sufficiently to be ready for the next required charging period, without causing additional violations. If violations are found in the PV and battery system, the battery discharge rate may be further restricted through adjustments to the technical parameters specified by the Operating Envelope.

4 Conclusions and Implications

Our analysis suggests that an OEA that specifies technical parameters by which a developer can avoid downsizing a proposed PV system and avoid paying expensive infrastructure upgrade costs can be an economically attractive option under select conditions. While viable solutions will differ substantially depending on the context, our analysis shows that implementing technical parameters derived from thorough analysis may enable larger PV systems, while reducing curtailment and increasing the net present value of the investment.

As storage costs continue to decrease, adding storage to reduce curtailment levels while abiding by grid injection limits will prove to be viable investments for developers. In addition to avoiding curtailed PV generation, storage can also capture higher priced hours by discharging when electricity prices are at their highest. With increasing PV, those peak-priced hours are likely to shift away from peak PV generation hours, but our analysis shows that when wholesale prices are generally depressed, the economics of solar (and battery storage) can deteriorate for developers relative to scenarios with higher wholesale price levels.

The process of developing the technical parameters of the OEA can be integrated into the existing interconnection study process. Providing developers with the technical parameters early in the interconnection process reduces the number of iterations needed to arrive at a system

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design that satisfies both the developer's economic objectives and the utility's requirements for reliability of the system.

Table 4. Revenues for each of the five options considered under three wholesale price scenarios

		CAPEX (million $)	Base Case		Renewable Cost Sensitivity		Storage Cost Sensitivity	
Option #	Description	PV cost $1/W 4 hr storage cost $1,250/kW	Revenue 2020 (thousand $)	Revenue 2030 (thousand $)	Revenue 2020 (thousand $)	Revenue 2030 (thousand $)	Revenue 2020 (thousand $)	Revenue 2030 (thousand $)
1	1.32-MW PV, downsized to avoid grid violations	0.98	68	55	67	47	68	56
2	3.3-MW PV + infrastructure upgrade costs of $148,500	2.69	171	139	167	119	170	140
3	3.3-MW PV + curtailment to avoid violations	1.71	111	90	108	76	110	91
4a	PV + 0.4-MW / 4-hour battery	1.89	141	123	137	111	140	121
4b	PV + 2.4-MW / 4-hour battery	2.82	203	190	197	185	200	185

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