FAASSTeR

SOLAR +

CLEAN ENERGY STRATEGIES FOR THE SUNSHINE STATE

2021

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d. Principal Investigator	Rick Meeker, P.E. President / Principal Engineer, Nhu Energy rmeeker@nhuenergy.com 850-757-0100
e. Business Contact	Rick Meeker, P.E. President / Principal Engineer, Nhu Energy rmeeker@nhuenergy.com 850-757-0100
f. Recipient Organization	Nhu Energy, Inc.
g. Project Period	**Start:** 1/1/2017 **End:** 12/31/2020
h. Submitting Official Signature	Rick Meeker

The Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) was formed in 2016 to conduct a collaborative multi-year initiative to provide foundational research and assist in developing strategies for successful expansion of grid-integrated solar, energy storage, and other distributed energy resources ("solar+") in Florida in a way that maximizes value and reduces risk.

Cover Photo: 20 MW_{AC} solar farm, located adjacent to Tallahassee International Airport, Tallahassee, FL, and supplying energy for City of Tallahassee Electric Utility's community solar program, one of the first large municipal utility solar projects to come online during the FAASSTeR project period. Photo credit: City of Tallahassee Electric & Gas Utility.

SOLAR+
CLEAN ENERGY STRATEGIES
FOR THE SUNSHINE STATE

Final Technical Report

for

Office of Energy Efficiency and Renewable Energy
Solar Energy Technologies Office
U.S. Department of Energy

Prepared by:

FAASSTeR

THE FLORIDA ALLIANCE FOR ACCELERATING SOLAR AND STORAGE TECHNOLOGY READINESS

Nhu Energy
1736 W. Paul Dirac Drive
Tallahassee, Florida 32310

Principal Authors:

Rick Meeker (*corresponding author*, rmeeker@nhuenergy.com)
Anna Brinck
Nhu Energy, Inc.

Andrew Mills, Maria (Pia) Rodriguez Ortega
Lawrence Berkeley National Laboratory

Elaine Hale, Paritosh Das, Ella Zhou
National Renewable Energy Laboratory

2021

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Additionally, the FAASSTeR initiative was made possible with contributions to the effort and regular engagement and support throughout the project from a core group of Florida municipal utilities: City of Tallahassee, Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA, Lakeland Electric, and Orlando Utilities Commission. Also crucial to the project effort were the other team member organizations, including the Florida Municipal Electric Association (FMEA) connecting all 33 Florida Municipal utilities to FAASSTeR, helping to lead the project and providing outreach; the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL), providing much of the research; the Southern Alliance for Clean Energy (SACE), contributing to the research, providing data and information on solar in the Southeast, and providing outreach; and the State of Florida Office of Energy, part of the Florida Department of Agriculture and Consumer Services, providing outreach and connection to related activities and groups at the State of Florida.

FAASSTeR Core Team member organizations and individuals from those organizations who participated regularly in the project are listed below. In addition, significant contributions were made by others in the form of presentations at in-person workshops and project team web-meetings and related content included in this report. We acknowledge and extend our appreciation to Joachim Seel, Naim Darghouth, Galen Barbose, and Andy Satchwell from the Electricity Markets and Policy Group at LBNL for contributions related to Utility-Scale Solar Trends, and Financial and Rate Design Analysis related to Behind the Meter Storage and Net Metering. We also acknowledge and extend our appreciation to Manajit Sengupta, Caitlin Murphy, Eric O'Shaughnessy, Kevin McCabe, James McCall, and Nick DiOrio from NREL for contributions in the areas of solar forecasting, resiliency, PV curtailment, solar-agriculture dual-use, distributed generation forecasting, and utilizing the NREL System Advisory Model (SAM).

FAASSTeR Core Team Members

FAASSTeR Organization	Key Contacts
Nhu Energy, Inc.	Rick Meeker, Anna Brinck
Florida Municipal Electric Association (FMEA)	Amy Zubaly, Nicole Albers
Florida Municipal Power Agency (FMPA)	Ann Beckwith, Susan Schumann
JEA	René Brown, Mary Moran, Melinda Fischer, Steve McInall
Orlando Utilities Commission (OUC)	Justin Kramer, Paul Brooker, Rubin York
Lakeland Electric	Scott Bishop, Paul Shipps, Willie Mathis, Phuong Nguyen
City of Tallahassee Electric & Gas Utility (TAL)	Ben Cowart, Ella Isfahani, Michael Ohlsen, Paul Clark, David Byrne
Gainesville Regional Utilities (GRU)	Milvia Hidalgo, Tom Boyer
Southern Alliance for Clean Energy	Bryan Jacob, George Cavros, John Wilson
Florida Office of Energy	John Leeds, Sean White
Lawrence Berkeley National Laboratory	Andrew Mills, Pía Rodriguez
National Renewable Energy Laboratory	Elaine Hale, Paritosh Das, Ella Zhou

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ACRONYMS

AC	Alternating Current
ACE	Area Control Error
ADR	Automated Demand Response
AGC	Automatic Generation Controls
AEU	Altamonte Electric Utility
AMI	Advanced Metering Infrastructure (in grid technology context)
AMI	Area Median Income (in economic analysis context)
APPA	American Public Power Association
BA	Balancing Authority
BESS	Battery Energy Storage System
BOL	Beginning of Life
BOS	Balance of System
BLM	Bureau of Land Management
BTM	Behind-the-Meter
CCGT	Combined-Cycle Gas Turbine
COD	Commercial Operation Date
CoS	Cost of Service
CPP	Critical Peak Pricing
CPS	Control Performance Standard (part of NERC reliability standards)
DA	Day-Ahead
DC	Direct Current
DEF	Duke Energy Florida
DER	Distributed Energy Resources
DEP	Department of Environmental Protection
DG	Distributed Generation
dGen	Distributed Generation Market Demand Model (developed at NREL)
DHS	Dept. of Homeland Security
DOD	Dept. of Defense
DOE	Dept. of Energy
DPV	Distributed Photovoltaics
DR	Demand Response
DSM	Demand Side Management (typically includes DR and EE)
E3	Energy and Environmental Economics, Inc.
EC	Energy Conservation
EFOR	Equivalent Forced Outage Rage
EE	Energy Efficiency
EERE	Energy Efficiency & Renewable Energy
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EOL	End of Life

ES	Energy Storage
ESA	Energy Storage Association
EV	Electric Vehicle
FAASSTeR	Florida Alliance for Accelerating Solar and Storage Technology Readiness
FAASSTER	Florida Alliance for Accelerating Solar and Storage Technology and Energy Resilience
FERC	Federal Energy Regulatory Commission
FIT	Feed-in-Tariff
FDACS	Florida Department of Agriculture and Consumer Services
FMEA	Florida Municipal Electric Association
FMPA	Florida Municipal Power Agency
FMPP	Florida Municipal Power Pool
FOA	Funding Opportunity Announcement
FOR	Forced Outage Rate
FPL	Florida Power and Light
FPV	Floating (Solar) PV
FRCC	Florida Reliability Coordinating Council
FRSG	Florida Reserve Sharing Group
FPSC	Florida Public Service Commission
FTM	Front-of-the-Meter
GMI	Grid Modernization Index (published by the GridWise Alliance)
GRU	Gainesville Regional Utilities
GW	Gigawatts ($1x10^9$ or one billion Watts)
GWh	Gigawatt hours ($1x10^9$ or one billion Watt-hours)
HA	Hour-Ahead
IBR	Inverter-Based Resources
ILR	Inverter Load Ratio
InSPIRE	Innovative Site Preparation and Impact Reductions on the Environment
IOU	Investor-Owned Utility Independent Power Producer
IPP	Independent Power Producer
ITC	Investment Tax Credit
JEA	Jacksonville Electric Authority (former, now "JEA")
kW	kilowatts ($1x10^3$ or one thousand Watts)
kWh	kilowatt hours ($1x10^3$ or one thousand Watt-hours)
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
LE	Lakeland Electric
LiDAR	Light Detection and Ranging
Li-ion	Lithium ion (batteries)
LMI	Low-to-Moderate Income
LOLP	Loss of Load Probability
LSE	Load-serving Entity
MACRS	Modified Accelerated Cost Recovery System

MFOO	Multi-Family Owner-Occupied
MFRO	Multi-Family Renter-Occupied
MW	Megawatts ($1x10^6$ or one million Watts)
MWh	Megawatt hours ($1x10^6$ or one million Watt-hours)
NEI	Nhu Energy, Inc.
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NWA	Non-wires Alternatives
NWP	Numerical Weather Prediction
OCGT	Open-Cycle Gas Turbine
OOE	Office of Energy (specifically, the FDACS Office of Energy)
OUC	Orlando Utilities Commission
PEV	Plug-in Electric Vehicle
PPA	Power Purchase Agreement
PPSA	Power Plant Siting Act
PSC	Public Service Commission
PURC	Public Utilities Research Center (at University of Florida)
PV	Photovoltaic
REopt	Renewable Energy Integration & Optimization
RICE	Reciprocating Internal Combustion Engine
SACE	Southern Alliance for Clean Energy
SAM	System Advisory Model
SCADA	Supervisory Control and Data Acquisition
SEIA	Solar Energy Industries Association
SEPA	Smart Electric Power Alliance
SES	State Energy Strategies
SETO	Solar Energy Technologies Office
SFOO	Single-Family Owner-Occupied
SFRO	Single-Family Renter-Occupied
SH	Sub-Hourly
SoBRA	Solar Base Rate Adjustment
SOC	State-of-Charge (energy storage)
SUNGRIN	Sunshine State Solar Grid Initiative
TA	Technical Assistance
TECO	Tampa Electric Company
TSP	Transmission Service Provider
TW	Terawatts ($1x10^{12}$ or one trillion Watts)
TWh	Terawatt hours ($1x10^{12}$ or one trillion Watt-hours)
TYSP	Ten-Year Site Plan
V2G	Vehicle-to-Grid

VAR	Volt-Amps Reactive
VoS	Value of Solar
WACC	Weighted Average Cost of Capital

EXECUTIVE SUMMARY

This reports on a four-year effort to provide foundational research, analysis, strategies and assistance to help Florida, and other states that might learn from this work, to grow solar energy in conjunction with other distributed energy resources by addressing and overcoming existing barriers, and in way that delivers increased value. The start of this effort coincided with an inflection point of sorts into a new dawn for solar energy in Florida (Figure 1), where the Sunshine state's national ranking in total installed solar, according to the Solar Energy Industries Association (SEIA), has rose from 13th to 4th. Florida has now become the national leader in annual utility-scale solar growth as dozens of large plants have come online[1]. Also, during this time, Florida utilities have expressed a strong and growing interest in understanding the role of energy storage and how to best plan for and deploy this unique resource as part of strategies to grow solar. The utility-scale solar growth experienced has been fueled by the economics of solar cost-parity with natural gas combined cycle plants and Florida Public Service Commission's (PSC) approval of cost-recovery for the Investor-Owned Utilities (IOU's), primarily through the Solar Base Rate Adjustment (SoBRA) mechanism. This has led to gigawatts (GW's) of rate-based solar capacity additions over several years, along with fairly significant amounts of energy storage.

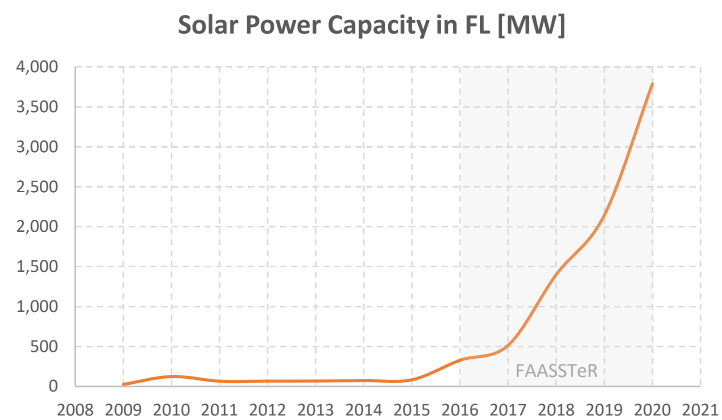

Figure 1. Growth in installed solar power nameplate capacity in Florida (graph derived from EIA data through 2020).

Meanwhile, municipal electric utilities, which, collectively, are the third largest source of power in the state, have been increasing solar considerably through power purchase agreements (PPA's) and are on track to have close to 1 GW of grid-connected solar by 2024. Florida's municipal utilities and the Florida Municipal Electric Association (FMEA) have been key partners in the Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR), formed to carry out this effort. The six largest of these have been Core Team utilities, engaging throughout the project in weekly calls, discussions, and project direction, participating in and hosting workshops and benefiting from technical assistance in several areas.

Of Florida's largest municipal electric utilities who are retail load serving entities, three are projected to exceed 10% solar PV penetration (on the basis of PV nameplate capacity as a % of total generation capacity) [2] and two are expected to be just under 10% by 2024[3] (Figure 2).

[1] Most of these new utility-scale solar plants are just under 75 MW in size to avoid additional permitting and review.
[2] Note, % of generation capacity is one solar penetration metric, and is not to be construed as the percent of net energy for load that is met by solar, which is significantly smaller due to the relatively low capacity factor of solar.
[3] based only on large solar additions publicly announced plus projected growth in customer-owned generation based on prior years.

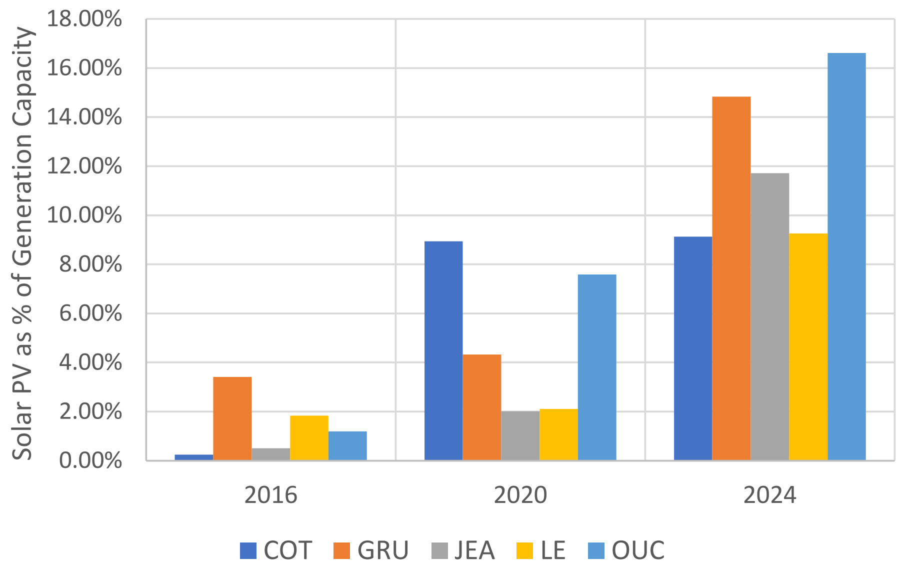

Figure 2. Florida municipal utility solar PV penetration growth, 2016 – 2024 (COT: City of Tallahassee, GRU: Gainesville Regional Utilities, JEA: Jacksonville Elec. Auth, LE: Lakeland Elec., OUC: Orlando Utilities Commission)

There is an opportunity for significant further growth in solar PV deployment, taking advantage of the remarkable cost declines in solar PV, meeting aggressive clean energy goals, and increasing its value by better defining and implementing new services.

Land Availability

Currently, the vast majority of solar PV expansion is in the form of utility-scale solar plants. These plants are being located where grid interconnection is suitable and where land is available. Land is one of the major issues in Florida. A typical size is 74.9 MW, which requires, on average, over 600 acres. Florida has large amounts of land that is already developed or has a higher value for commercial and residential development, conservation land that is preserved, and wetlands. Municipal utilities, having smaller service territory footprints, are reaching the limits of land availability for solar much more quickly than the investor-owned utilities.

Strategies for smaller utilities can, of course, include importing solar from utilities with service territories where ample land exists for the time being. However, that is a localized solution that still runs into limitations over larger areas as solar penetration increases. Attractive strategies that have broad stakeholder benefits involve solar deployment that does not require dedicated land, such as expanding rooftop solar, canopy solar for covered parking and pedestrian areas, and floating solar. Florida has the largest cumulative surface area of feasible water bodies for floating solar of any state in the country.

Ramp Mitigation

Florida municipal utilities expanding their solar portfolio identified ramp rate mitigation as a top priority, necessary to ensure continued ability to balance the electric system and meet NERC requirements. Both City of Tallahassee and JEA are nearing 10% solar PV penetration as a percentage of generation capacity. FAASSTeR project research has provided insight on sizing the power and energy capacity for batteries used for system ramp rate mitigation (whether the source of ramps is solar, load, or some combination).

The required power rating and energy capacity, and therefore cost, are found to be significantly less for ramp mitigation than for peak shaving / shifting applications, and very sensitive to how strict the requirements are for battery enforcement of ramp limits over relevant time periods. Of the numerous uses for energy storage in the value stack, ramp mitigation appears immediately beneficial and viable on a cost and performance basis.

Viability of Storage Improving

Because of its usefulness paired with solar, a fourth quarter 2020 SIEA/Wood-Mackenzie report forecasts that energy storage will be included with 26% of new solar installations by 2025, increasing from 4% in 2019. The cost of energy storage is declining, some say proceeding on a 22% learning curve, meaning that each time global volume of storage produced and installed doubles, costs decline 22%.

Strategies for System Balancing

At high system-wide levels of solar PV, balancing generation and demand in the electric power system becomes increasingly challenging. One of the existing ways utility operators is by maintaining sufficient balancing reserves. Reserves are costly and maintaining excessive reserves would undermine some of the benefits of renewables. The larger the utility service territory is, the larger the numbers of dispatchable generators and the larger the transmission and distribution network and the greater the permutations of states the system can operate. This translates to large IOU's having more flexibility in being able to handle system balancing under high penetration solar with existing reserves than municipal utilities who are also NERC balancing authorities (BA's). This is shown in the research.

Strategies are available, however, to deal with these challenges. These include 1.) moving from day-ahead to hour-ahead load forecasting, solar forecasting, and system dispatch, 2.) reducing forecasting uncertainty, and 3.) working together to collectively procure operating reserves.

Resource Adequacy and Capacity Credit

Solar's resource adequacy contribution (RAC) represents the contribution of solar photovoltaics (PV) to reliably meeting an electric power system's peak demand and has become increasingly significant in determining a system's reliability and cost-efficiency. Assessing RAC and the Capacity Credit (CC) for solar and energy storage adds significant complexity to an already complex process. Methods are needed to more efficiently explore questions concerning RAC and CC for solar and energy storage to provide basic insights necessary to guide system planning.

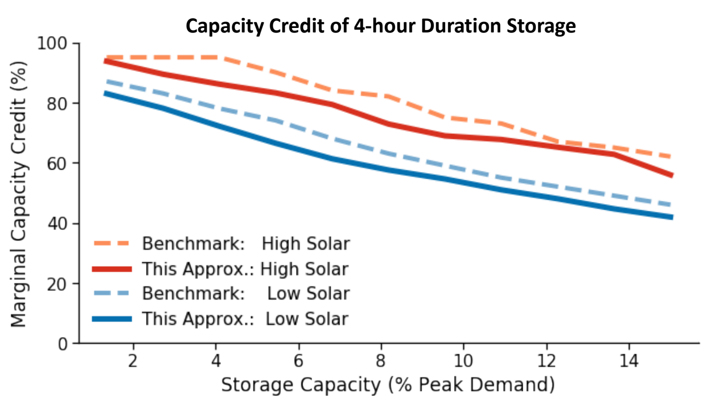

Figure 3. Comparison of probabilistic CC assessment methods to new faster approximation method. Both approaches show a declining capacity credit of 4-hour duration storage, and increase in capacity credit with high system-wide solar.

New methods have now been developed to aid in identifying the primary drivers of solar and storage systems' RAC and CC. These methods have been applied to systems in Florida, where current research is deficient. The methods compare acceptably with much more complex, involved, and sometimes proprietary methods that are often used (Figure 3). Some of the insights into gained on CC of solar and storage are, 1.) CC of solar varies by utility and weather year, 2.) average CC of solar declines with increasing solar deployment, 3.) CC of storage depends on the storage duration, declines with increasing storage deployment, and can vary with weather year, 4.) CC of storage depends on system-level solar deployment, 5.) solar+storage configuration affects CC, and, 6.) forecasting matters for storage CC, particularly with small storage reservoirs.

Resilience

It is intuitively clear that solar+storage provides a resiliency benefit due to their ability to supply local loads without requiring any fuel source when grid infrastructure has become unavailable (e.g., due to storm damage or cyber-attack). The challenge is in quantifying this value. The fact that it has value to customers is confirmed by the fact that many early participants in JEA's behind the meter energy storage incentive program were more interested in having the storage for resiliency than for the intended purpose of storing solar for peak periods rather than exporting it to the grid.

Large municipalities that provide not only electric service, but, also water and wastewater understand very well the interdependencies of these two infrastructures. In fact, in Florida, hurricanes have repeatedly caused major overflows and spills from wastewater systems due to loss of power to lift stations. JEA has examined and defined a feasible use-case for solar+storage to provide power for some of these lift stations, which would likely eliminate the need for diesel generator backups at those locations and result in year-round benefits in powering lift station pumps with clean energy not possible with diesel generators.

Towards a High-Penetration Solar Grid

In the quest to provide a spectrum of foundational research and analysis to guide expansion of solar+ for Florida and elsewhere, it has been discovered as well that the challenge and opportunity is a very large one. That is, the challenge and opportunity of aspiring for 100% clean electric power systems. Moving further along that path requires numerous strategies working together.

This effort has provided perspective, research, and new insights and tools in several important areas, however, a number of challenges remain, including increasing the overall deployment and use of customer-sited resources, co-adoption relationships and strategies for customer-sited resources (e.g. solar, storage, and electric vehicles), vehicle to grid integration, maximizing benefits of storage delivering multiple simultaneous value streams, and developing and integrating programs and systems for leveraging demand-side resources alongside solar, storage, EV's and conventional resources.

Electric power system transformation requires successful collaboration across multiple stakeholder groups. It also requires state-level engagement in order to actually effect change…

We are …

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Together …

THE FLORIDA ALLIANCE FOR ACCELERATING SOLAR AND STORAGE TECHNOLOGY READINESS

INTRODUCTION

Background

Due to efforts of the U.S. Dept of Energy (DOE), global competition in the solar photovoltaic (PV) module and hardware supply chain, and increasing demand for solar, driven by various factors, the cost of solar PV on both a levelized cost of energy (LCOE) basis and on an overnight capital cost basis has declined to a fraction of the cost of only a decade ago [1]. Utility-scale solar is now less costly than other traditional fossil-fuel generation choices in many cases. Overall, solar PV has experienced exponential growth across the U.S., although, with vast differences geographically in growth rates and penetrations levels[4], and in the growth distribution by system scale (utility, commercial, residential).

In 2016, on track to meet or exceed its goal of $0.06/kWh for utility scale solar by 2020, the DOE sought to continue to reduce the cost of solar PV by focusing efforts on soft-cost reduction, with soft-costs constituting over half of system cost. Compared to achieving hardware cost reductions, soft-cost reductions would depend much more on the geographical disparities across the U.S. Recognizing this, DOE developed and issued a funding opportunity announcement (FOA) in February 2016 that included a topic focused on “State and Regional Solar Strategies” [2]. This report summarizes the work of the Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR), one of several teams across the U.S. selected under that FOA to help directly tackle soft costs and market barrier challenges at the state and regional level by maximizing the benefits of solar electricity through energy and economic strategic planning. Like other projects, the FAASSTeR initiative represented a partnership between state and utilities/electricity sector entities and research organizations to provide analytical support to examine pathways to best increase solar deployment in the state or region (Figure 4).

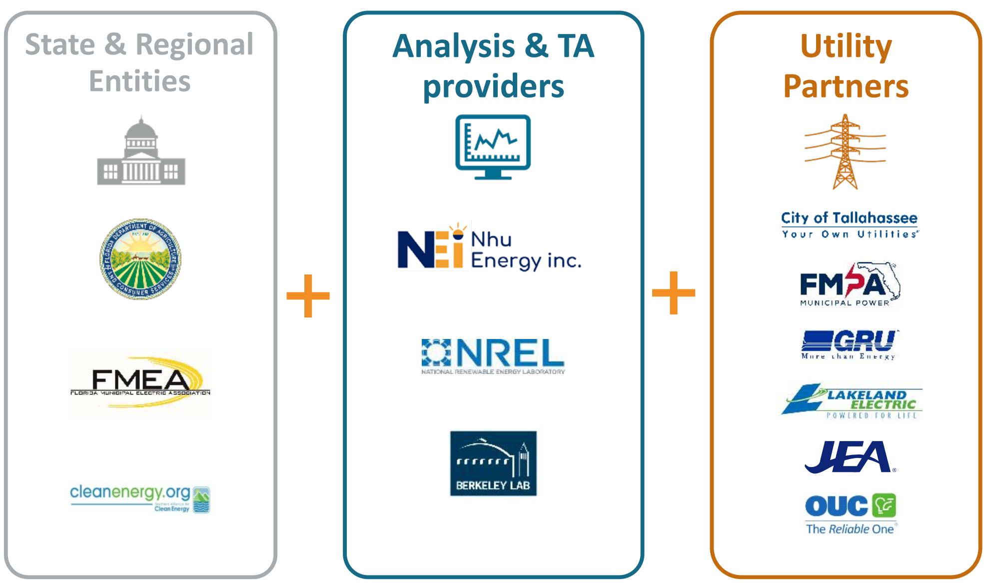


Figure 4. The FAASSTeR State Energy Strategies (SES) project include government, industry, research and other stakeholder entities working as a team to address solar growth challenges and opportunities.

[4] In 2015, solar growth was concentrated in relatively few areas within the U.S., with over 90% of solar installations located in 10 states [1].

FAASSTeR

In 2017, the Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) project was initiated with support from the U.S. Department of Energy to provide foundational research and analysis, develop strategies, and provide technical assistance to accelerate the beneficial and value-added deployment and use of solar energy in Florida. From the outset, the FAASSTeR team sought to consider future growth strategies broadly, with a long-term aim of realizing the best possible combination of technologies, policies, and project structures. The evolution of state and regional solar portfolios, as can be observed across the U.S. and around the globe, comes in the form of a broad range of programs and policies that drive and shape adoption across the spectrum, from utility-scale to commercial-industrial to distributed and rooftop solar. State and local strategies could include a range of options such as community solar, net energy metering (NEM), utility-owned solar, third-party-owned solar, low-to-moderate income (LMI) solar adoption, utility scale, front-of-the-meter (FTM) and behind-the-meter (BTM) energy storage programs, demand-side management programs that complement or incorporate solar and storage, and more.

The FAASSTeR project aimed to provide information and analysis to foster a shift from mostly ad hoc deployment of solar by Florida utilities, third party developers, and customers to smart deployment that maximizes the benefit of solar in the overall power and energy system. Considerable additional value can be unlocked by not only considering solar more strategically in how and where it is deployed, but also by examining its value at the systems level in combination with other resources.

Prior research funded by the Dept. of Energy and others has examined in considerable detail the technical and operational issues and strategies for high-penetration solar PV deployment on utility distribution circuits and the concept of hosting capacity [3]. Meanwhile, solar PV deployment has continued to increase significantly. And, as a growing number of cities [4][5] and states [4][5][6], along with large corporations [7], have set aggressive clean energy goals, the focus now is on how to successfully expand the use of solar to very high penetration levels across entire utility service territories and regions of the country. Appendix A provides information on the eleven Florida Cities that have made 100% clean energy commitments as of the date of this report [5] (Figure 5).

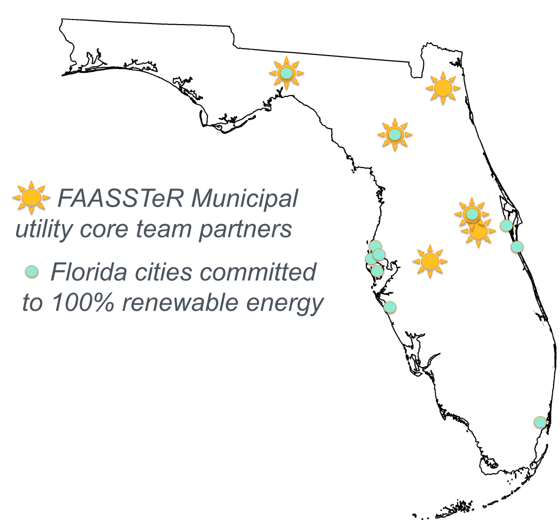


Figure 5. Eleven Florida Cities have made 100% clean energy commitments.

In 2009, Gainesville Regional Utilities (GRU), the municipal electric utility serving Gainesville, Florida (and, a FAASSTeR Core Team member), became the first utility in the U.S. to offer a broad solar feed-in tariff (FIT) program to its customers [8], inspired by and modeled after similar programs that drove early solar expansion in Germany. Since that time, a number of effective means for assigning and delivering energy value from solar have become well-established and predominant, including net energy metering (NEM), power purchase agreements (PPA's), and utility rate-based generation. These mechanisms have helped significantly expand solar in Florida. Going forward towards ever-higher penetration levels of solar over wider areas, it is necessary to more comprehensively examine the economic, environmental, and electric grid planning and operational considerations associated with utilizing the current established approaches to derive maximum value from solar, and where new strategies and approaches may be required.

With the participation of Dept. of Energy national lab partners, FAASSTeR has conducted Florida-specific studies of solar PV and net load characteristics in electric grid operations, capacity value of solar and energy storage, balancing, reserves, operational flexibility for increasing levels of solar, sizing and economics of storage with solar, resiliency value of solar and storage, and the growth trajectories of distributed solar.

The goals of the FAASSTeR project were to:

- Enable Florida Municipal Electric Association (FMEA) member utilities to increase solar energy to over 10% of power capacity by 2024 (versus the current projected total for all Florida utilities of 2.1%), and,
- Enable informed policy and regulation in the state that maximizes consumer benefit from substantial growth in solar.

Four (4) objectives were defined in support of achieving these goals:

1. Identify technical, regulatory and economic barriers to solar specific to Florida.
2. Conduct detailed analysis to define the value proposition for Florida municipal and cooperative electric utilities and their customers associated with increased deployment of solar PV and solar+.
3. Develop scenarios and strategies, with stakeholder engagement, for how best to locate solar PV and PV in combination with other DERs in Florida municipal and cooperative utility service areas to derive maximum value.
4. Provide assistance to 2-4 municipal utilities to begin incorporating study results and strategies into system planning and developing programs in their service areas.

Approach

The FAASSTeR initiative considered how other energy resources, and particularly energy storage, could play a complimentary role in improving the overall value from solar PV to enable considerably more beneficial deployment of PV in the state. The term "solar+" was adopted to describe solar in combination with any other distributed energy resources, including energy storage, demand response, electric vehicles, and more (Figure 6). This may include co-adoption where the growth and deployment of solar and one or more of these other resources are directly linked. Whether linkages are through co-adoption or otherwise, it is important to consider the technical, economic, and regulatory/policy interdependencies

Figure 6. "Solar+" includes solar in combination with other distributed energy resources.

of solar in combination with other resources, and how incorporating this into strategic planning expands opportunities to enhance value and reduce overall cost.

The project approach was also to begin without presumptions as to the solar and solar+ strategies that might be most feasible or represent the greatest value for Florida stakeholders. This means, for example, there are no presumptions about what proportions of residential, commercial, or utility scale systems should prevail. There are no presumptions about how and where storage should be deployed. And, there are no presumptions as to which value streams would be most important. However, with practical limitations on resources and time, it was necessary to focus the more detailed analysis on some specific areas, including net-load characterization and ramp analysis, capacity value and resource adequacy, system balancing and reserves, and storage for PV ramp mitigation.

The FAASSTeR project was carried out in three phases, originally planned for a period of performance of three years, later extended to four, with major activities by phase outlined in Figure 7.

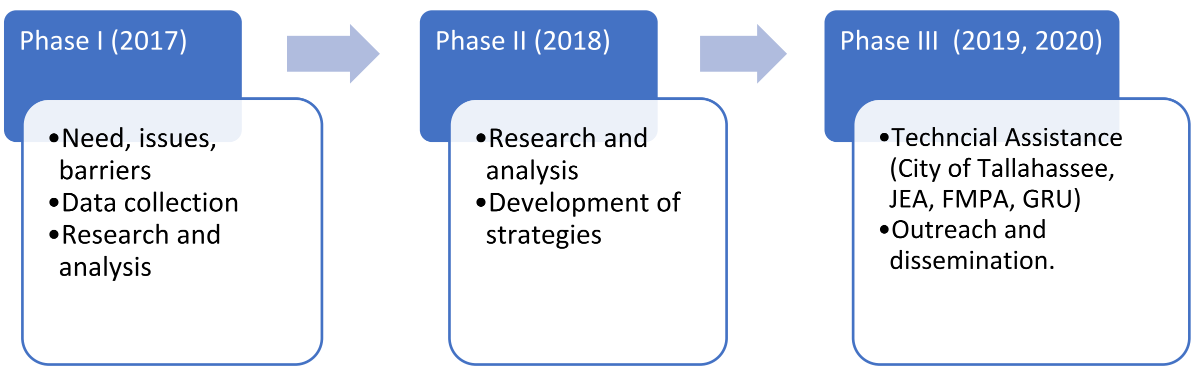


Figure 7. FAASSTeR project Phases and major activities by phase.

Structure and Roles

The FAASSTeR team included state and regional entities, analysis and technical assistance (TA) providers, and utility partners, consistent with the SES topic as described in the DOE FOA [2] (Figure 4). Utility partners were Florida's municipal electric utilities (Figure 8).

Municipal utility service territories are geographically located across the entire state of Florida (Figure 8), from the Georgia border (City of Chattahoochee electric utility) to the southernmost point of the continental U.S. in Key West (Keys Energy). Combined, Florida's municipal electric utilities would be the third largest utility in Florida, behind FPL and Duke Energy Florida. Unlike the investor-owned utilities (IOU's), Florida municipal utilities are not rate-regulated by the Florida Public Service Commission (PSC), which allows for greater flexibility in developing solar+ strategies and programs to benefit customers. However, the large municipal utilities who are also NERC balancing authorities (BA's) have less flexibility than the larger IOU's in terms of how they can operate the portions of the electric system within their respective service areas to meet reliability standards as solar penetration grows.

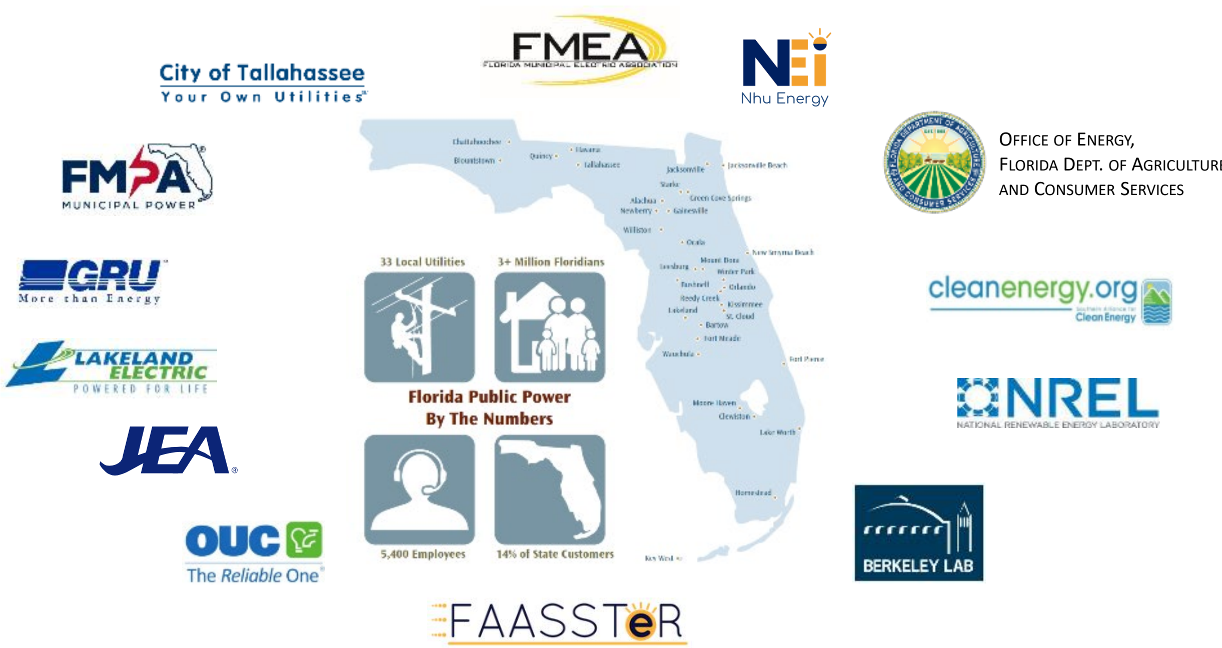


Figure 8. The FAASSTeR collaboration includes Florida's municipal electric utilities, DOE national labs, industry and advocacy groups, the state of Florida, and small business.

Project team member organizations and their respective roles are as follows:

Nhu Energy, Inc. (NEI), provided overall project management and leadership, as well as electric power systems analytical and research capabilities to provide some of the technical assistance, leveraging also prior work with Florida utilities on high penetration solar PV deployment [2].

The **Florida Municipal Electric Association (FMEA)**, as the official state trade association of Florida's public power community, represented the interests of 33 public power communities across Florida, and assisted in overall project coordination and engagement with the municipal utility community at the state and national level (through APPA), including the planning and delivery of five stakeholder workshops held in Florida on solar+.

Florida's municipal utilities were central to the FAASSTeR effort (Figure 8), including a utility core team consisting of the six largest municipal utilities in the state: The **City of Tallahassee, FMPA, GRU, JEA, Lakeland Electric, and OUC**. These utilities were engaged throughout the project effort, including through participation in weekly project team telecons and all of the five workshops, contributing data, input, and review for the research and analysis activities, and participating on the FAASSTeR Advisory Board.

The **Florida Dept. of Agriculture and Consumer Services (FDACS), Office of Energy (OOE)**, is the legislatively designated state energy policy and program development office within Florida, and acted as a liaison between various relevant state entities and activities and the project team, including engagement through the Florida Energy Summit.

Two Department of Energy National Laboratories – the **National Renewable Energy Lab (NREL)** and **Lawrence Berkeley National Lab (LBNL)** – provided technical assistance, including substantial in-depth research and analytical support in the areas of resource planning and distributed generation growth modeling, system balancing and reserve requirements, and capacity value and resource adequacy associated with solar and storage.

The **Southern Alliance for Clean Energy (SACE)**, a leading clean-energy advocacy non-profit for the Southeastern U.S., provided perspective on issues in solar deployment strategies in Florida and the southeastern U.S. along with access to data and reports and assistance with workshops, outreach, and dissemination.

The **FAASSTeR Advisory Board** was created to provide additional guidance and perspective to the project team to support goals and objectives. This group consisted of representatives from each of the **six municipal core team utilities, FMEA,** the **State of Florida Office of Energy,** the **Smart Electric Power Alliance (SEPA),** and the **University of Florida's Public Utilities Research Center (PURC)**.

STAKEHOLDER ENGAGEMENT

Fundamentally, the state energy strategies (SES) projects are about engagement, at the state and regional level, and across multiple stakeholder groups. The work reported here is informed by a high level of engagement within the FAASSTeR project team, including group discussions and special presentations during the weekly project team web-meetings over the entire duration of the effort and a series of five workshops to engage with the broader stakeholder community (Table 1).

Stakeholder Workshops

The stakeholder workshops provided an effective forum for input and discussion on strategies to grow solar+ in Florida and for the exchange of insights and experience. The workshops also provided a learning environment for attendees to expand their knowledge and awareness of relevant solar+ research from experts in the R&D community, and solar+ technologies, and of technology and real-world applications from the supplier community and industry active in developing and operating solar+. Thus, the workshops informed some of the research and findings reported here, particularly the Issues, Needs, Barriers and Solar+ Strategies sections.

Table 1. FAASSTeR Workshops

Dates	Location / Utility Host	Focus / Highlights
11/29 – 12/1/2017	Orlando, FL / FMPA	• Needs, issues, barriers to solar+ • Energy storage technologies
6/6 – 6/7/2018	Orlando, FL / FMEA	• Solar forecasting • Resource planning models • Capacity value
11/27 – 11/30/2018	Orlando, FL / FMEA	• Solar+ value streams (incl. resiliency) • Resource planning and distributed generation growth modeling • Solar and storage siting, permitting, and agricultural dual-use
6/24 – 6/26/2019	Gainesville, FL / GRU	• Storage technology and applications • D-gen growth forecasting • Demand Response • EV's • PPA's • Solar forecasting • Valuing resiliency
11/19 – 11/20/2019	Jacksonville, FL / JEA	• Utility-scale solar • Community solar • Solar+storage applications • Utility rate and revenue implications • Independent power producer insights & strategies

In addition to particular topics and themes aligned with FAASSTeR project objectives, workshops included regular updates and presentations by the state's largest investor-owned utilities (IOU's) on their respective solar+storage activities, plans, and experience, solar in the southeast updates (by SACE), and updates on the FAASSTeR project research and analysis. FAASSTeR Advisory Board meetings and in-depth project team workshops were also held in conjunction with the stakeholder workshops.

Attendance at the workshops was typical around 50. Representatives from over 100 organizations participated, including electric utilities, independent power producers, suppliers, project developers, engineers and consultants, state, local, and federal government, industry and trade organizations, and research laboratories and universities (listed in Appendix A).

From workshop survey results, Figure 9 provides some idea of how perceptions of the value of energy storage evolved over the course of the project, from year 1 to year 3.

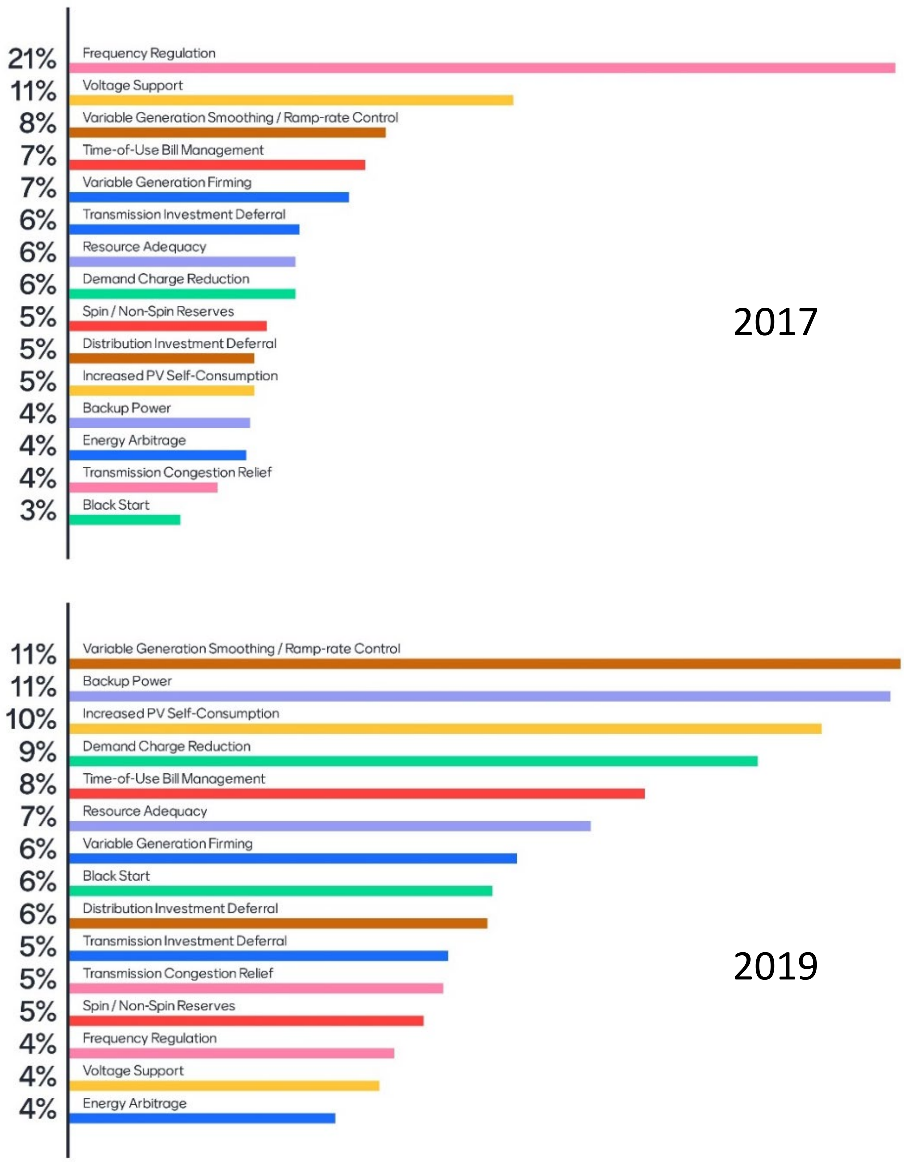


Figure 9 – Workshop participant ranking of energy storage value streams in Florida over next 5 years, illustrates the change in perception of where storage will have the most impact and value, from the first year of the FAASSTeR (2017) project to the third year (2019).

SOLAR AND ENERGY STORAGE IN FLORIDA

When examining state-specific energy strategies for growing solar+, it is important to consider Florida's unique characteristics in terms of population density, land availability and usage, the electric power system, and growth of solar.

Population and Electric Energy

Florida, with a population of 21,733,312 at the end of 2020, is the third most populous state in the U.S. The population annual growth rate has been positive every year for the last 74 years and has been growing at between 1.11% and 2.02% per year for the last 10 years, surpassing NY in 2014 to become the 3rd most populous state in the U.S. [9].

Florida is ranked first in total electric utility generation capacity (net summer capacity of 54.5 GW) and energy produced (229 TWh) [10]. Based on land area, population, and energy use, it is useful to compare the four most populous states, California, Texas, Florida, and New York, on the basis of population density and energy density (Figure 10). Florida's population density is roughly equivalent to New York's and much higher than both California and Texas. Florida's electric energy density (total energy generation divided by total land area) is significantly larger than all of the three other most populous states. With a growing population and the prospects of beneficial electrification, including electrification of transportation, this number can be expected to only grow larger. This indicates Florida, comparatively, has significantly less land relative to total energy needs, now and in the future, than the other most populous states. Florida's population has grown steadily for decades and is the only of these four states whose population grew in 2020.

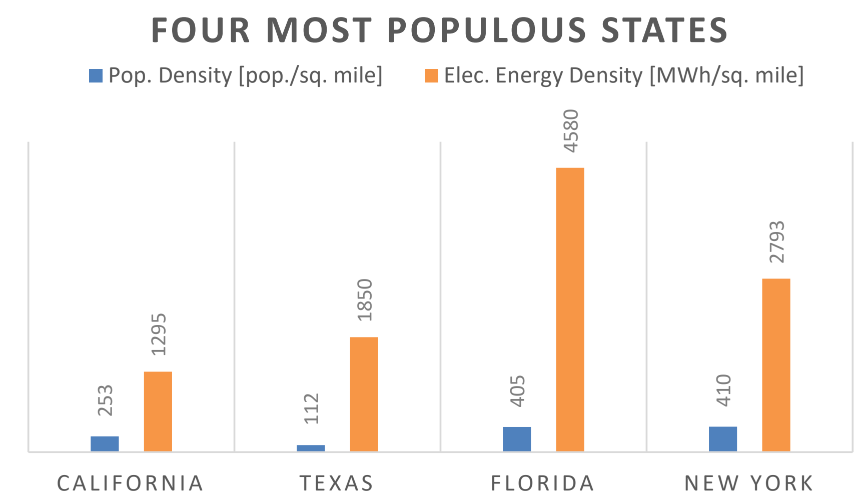


Figure 10. Comparing population density and electric energy density of the four most populous states.

Solar Growth – Recent and Forecasted

According to data published by the Solar Energy Industries Association (SEIA), through 2016, Florida had 405 MW of installed solar capacity [11], and in the first quarter of 2017, was ranked 13th nationally in installed solar and 8th nationally in projected 5-year growth in solar capacity [12]. However, more recently, through 2020, Florida ranked 4th nationally in installed solar, with 6,540 MW of installed capacity, and 3rd in projected 5-year growth [13]. And, even with a major pandemic impacting the economy, new solar capacity installed in Florida in 2020 was nearly double that of 2019 (Figure 11). In the last four years, the Sunshine State has progressed considerably in expanding solar energy capacity.

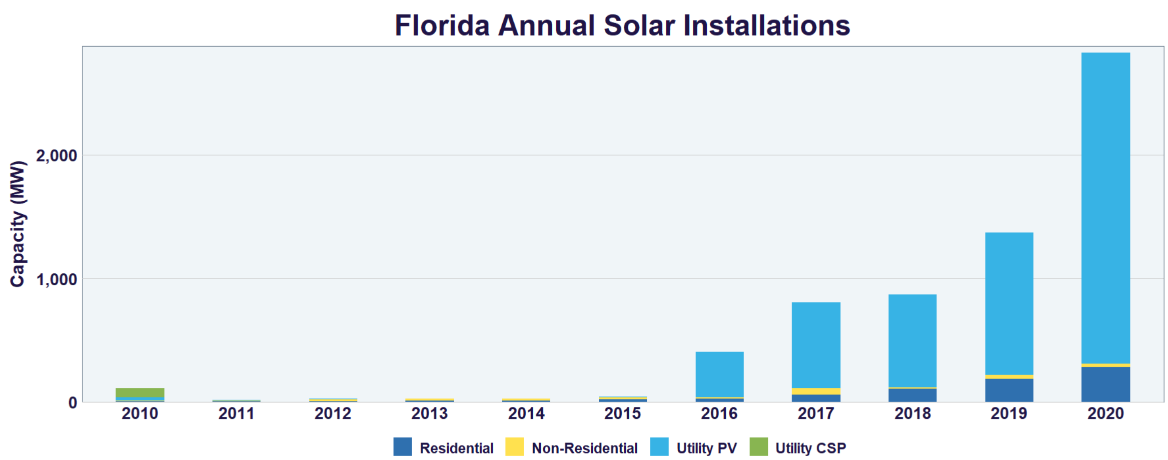


Figure 11. Solar installed capacity growth, 2010 – 2020 (source: SEIA) [13].

Florida's relative progress in expanding solar has also advanced considerably on a regional basis. The 2020 "Solar in the Southeast" report, published by the Southern Alliance for Clean Energy (SACE), shows Florida is on track to lead the Southeast in installed solar capacity, expected to surpass North Carolina in 2021 (Figure 12) [14].

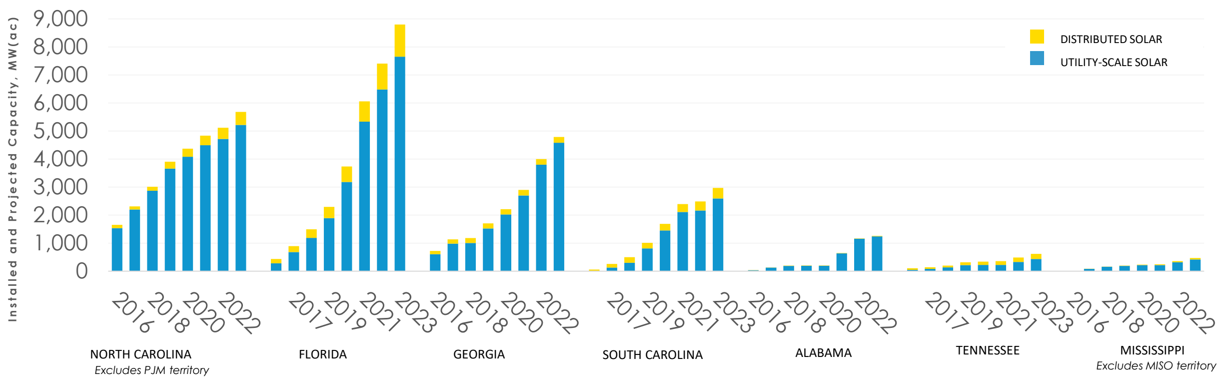


Figure 12. Solar installed capacity growth forecast for Southeast states, from SACE Solar in the Southeast [14].

Utility-scale Solar

Considerable progress in solar generation growth in Florida has come in the form of MW-scale solar PV installations, totaling 2,570 MW of capacity in 2020 (Figure 13) [15], much of that from electric-utility owned-and-operated generation. By 2019, Florida became the largest annual growth market in the U.S. for utility scale solar, as determined by the Utility-Scale Solar research team at Lawrence Berkeley National Laboratory (Figure 14) [16].

As can be seen in Figure 13, in Florida, 59% of large solar PV plants are owned and operated by electric utilities, compared to 9% for the U.S. as a whole. Nearly all of these plants are less than 75 MW in capacity. Twenty-four (24), over a third, of these plants have nameplate capacities of either 74.5 or 74.9 MWAC. In fact, a large number of utility-owned solar PV plants in Florida have been constructed at capacities just under 75 MW, to avoid certain statutory requirements, including 1.) certification under the Florida

Electrical Power Plant Siting Act [17][18][19], and, 2.) a Florida Public Service Commission (FPSC) determination of need proceeding [18][19][20].

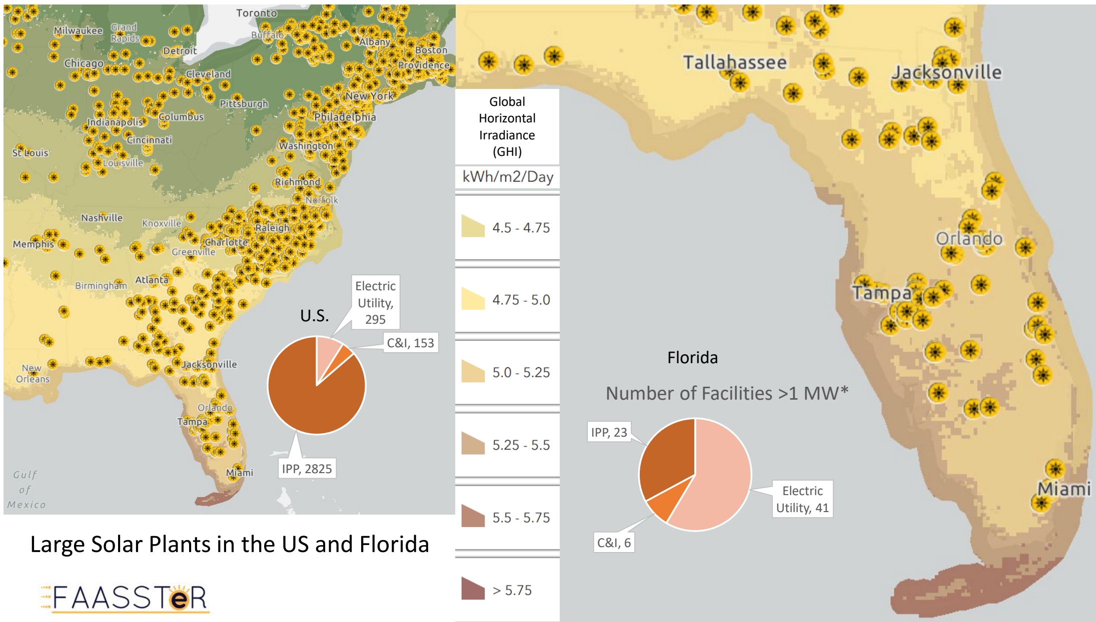


Figure 13. Solar facilities larger than 1 MW in Florida (right), along with solar irradiance (legend in center), and distribution of MW-scale plants by plant owner-operator type (Legend: IPP = Independent Power Producer, C&I = Commercial and Industrial), based on data as reported to US EIA (EIA-860, EIA-860M and EIA-923) through Jan. 2020 [15]. Note, for space limitations, left figure shows only eastern U.S., while data in the pie chart is for the entire U.S.

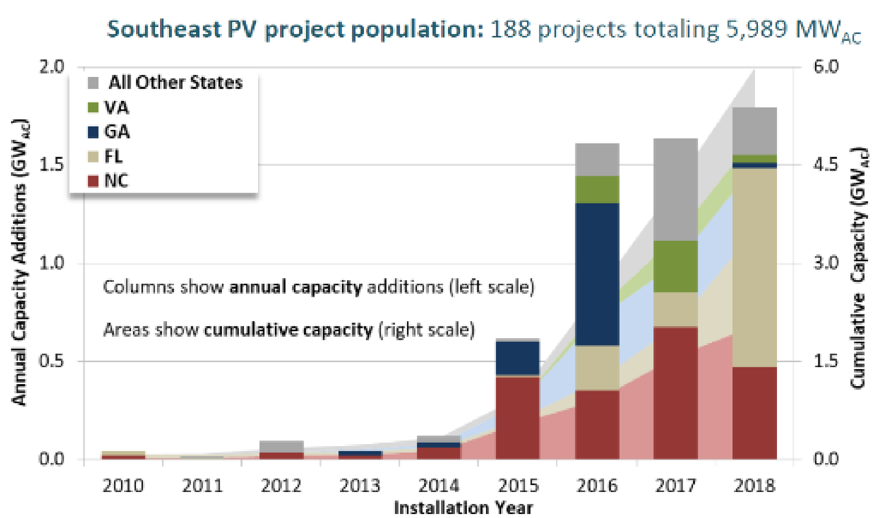
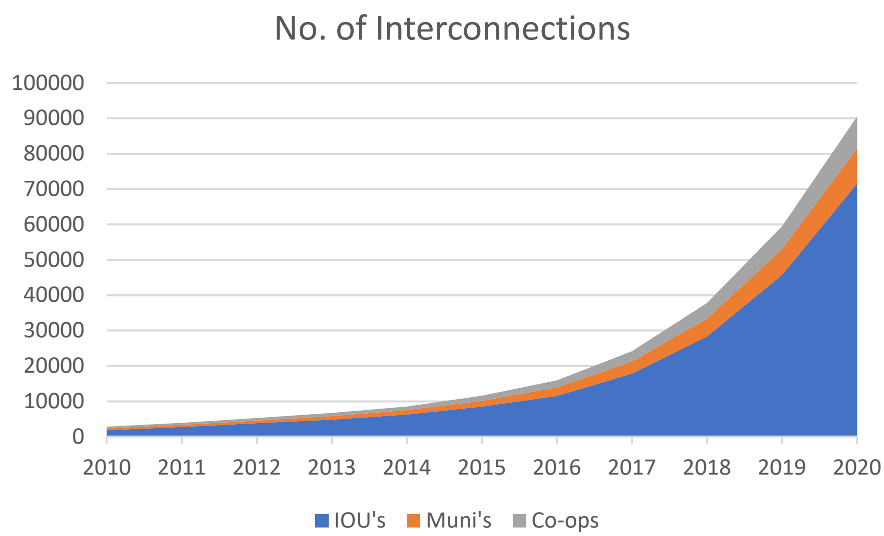


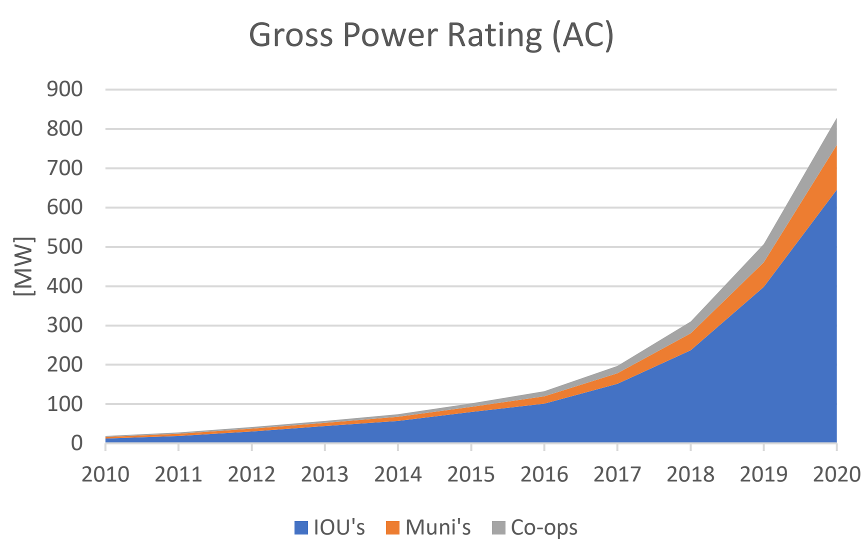
Figure 14. As of 2018, the Southeast became the new growth engine of the US utility-scale solar market, led by Florida with the largest annual market at 1010 MW$_{AC}$ or 25% of national additions [15].

Customer-Owned Behind-the-Meter (BTM) Solar

Though it remains a much smaller portion of the total solar capacity in Florida, customer-owned solar is growing exponentially, both in numbers of interconnections and installed capacity, reaching over 828 MW of capacity through 2020, with over 31,042 new interconnections that year, for a total of 90,518 grid-connected systems (Figure 15) [21].



(a)



(b)

Figure 15. Customer-owned solar in Florida, 2010 through 2020, (a) number of interconnections, (b) gross AC power rating. Figures developed from data in [21].

Forecasting Customer-Owned Behind-the-Meter (BTM) Solar

The potential for residential solar in Florida is 3rd overall nationally, after California and Texas. Rooftop PV on FL's residential buildings consist of 54 GW of capacity and 76 TWh of generation. [22][23] Unlike utility-procured solar, deployment of customer-adopted solar, is uncertain, requiring advanced bottoms-up consumer solar adoption forecasting methods. To accomplish this, NREL employed its agent-based Distributed Generation Market Demand Model (dGen), Figure 16, incorporating detailed spatial data, population-weighted sampling, and factors affecting consumer decision-making to forecast adoption of distributed (customer-owned) solar PV [22][24][25].

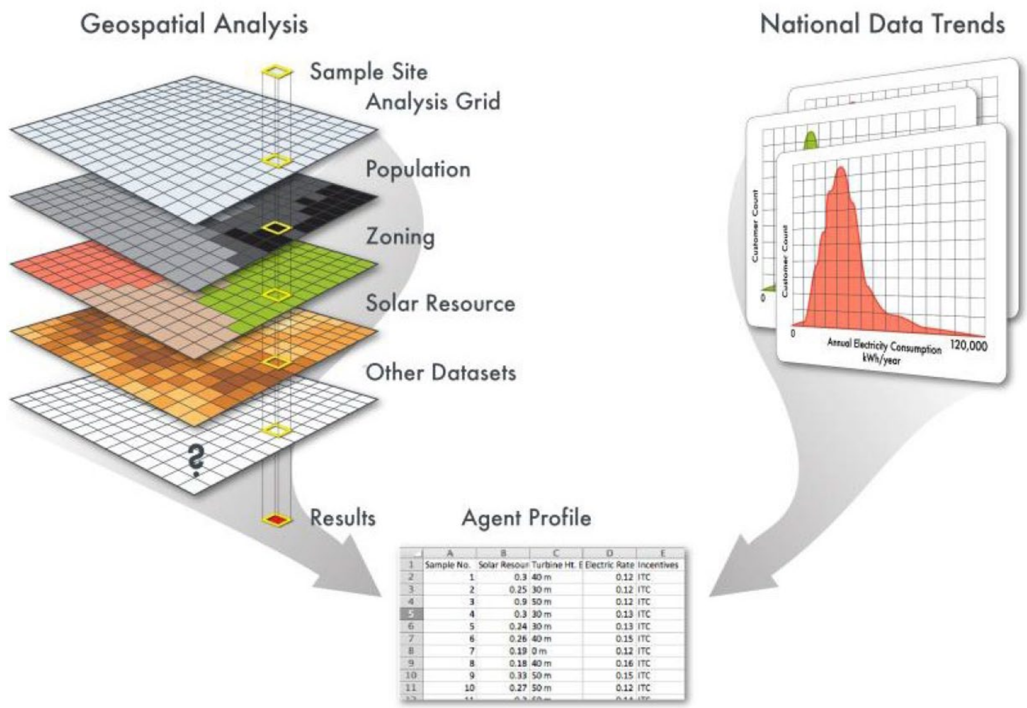


Figure 16. NREL dGen agent- based modeling and simulation tools for forecasting distributed generation growth.

The process for estimating Florida distributed energy resource solar deployment involves three primary steps [22]:

1. Estimate total rooftop solar potential for all Florida counties based on analysis of rooftops using LIDAR data
2. Determine solar capacity that maximizes agent net present value (NPV) using 4.4% weighted average cost of capital (WACC)
3. Estimate total rooftop solar deployment by applying market diffusion estimates (i.e., not all sites with economic potential will be deployed)

Examining residential rooftop solar technical potential, as shown in Figure 17, we find the total residential rooftop solar PV potential in Florida to be nearly 54.8 GW, broken down as follows: 57% of Florida's total households are Single-Family Owner-Occupied (SFOO), having a total distributed PV (DPV) potential of 30 GW; 71% of Florida households are Single-Family, including both Owner-Occupied (SFOO) and Renter-Occupied (SFRO), with a residential rooftop DPV potential of 36.5 GW; 64% are Owner-Occupied households, including both Single-Family (SFOO) and Multi-Family (MFOO), with a residential rooftop DPV potential of 36.9 GW.

Examining residential rooftop solar technical potential by income, as shown in Figure 18, we find 42% of Florida's total residential rooftop solar potential can be contributed by Low-to-Moderate Income (LMI) households, while the rooftop solar potential on non-LMI households represents 32 GW of capacity and 44 TWh of generation potential.

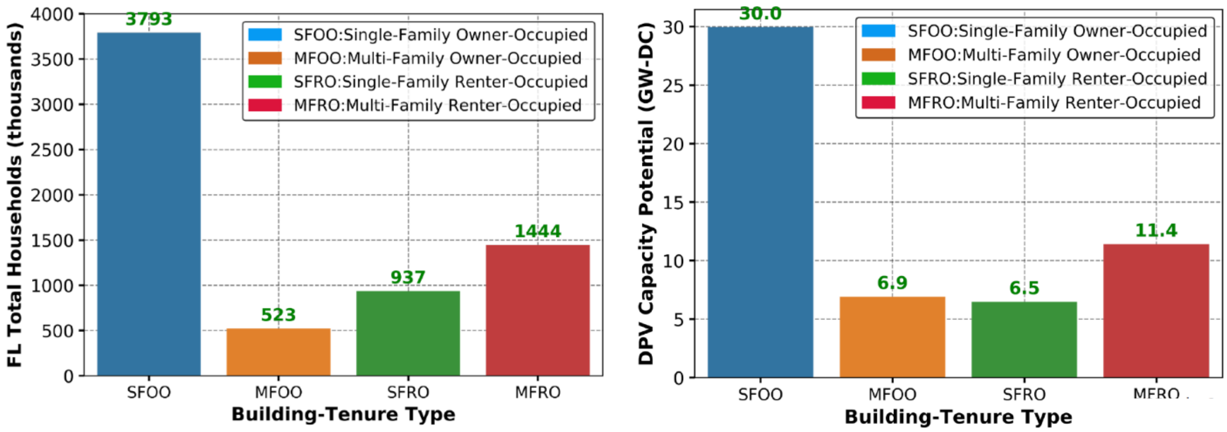


Figure 17. Florida number of households (left) and residential rooftop solar PV technical potential (right) by building tenure type (occupancy and own/rent) [22].

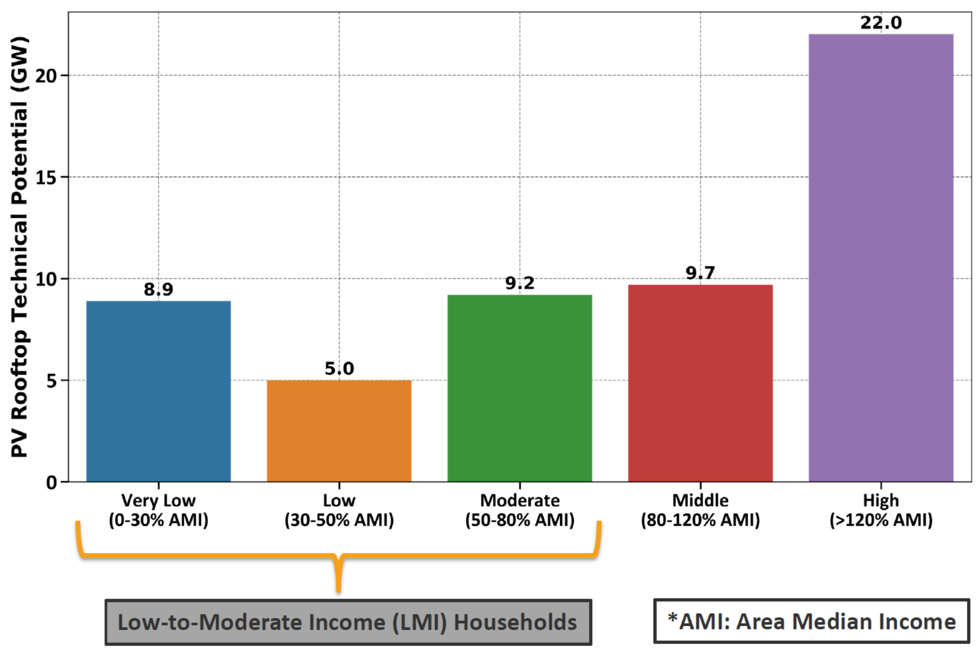


Figure 18. Florida residential rooftop solar PV technical potential by income class [22].

The next step in modeling solar adoption involves maximizing agent NPV. Using consumer surveys, we relate the system payback to the fraction of consumers that would adopt solar. Then, the optimal system size is evaluated using a 4.4% weighted average cost of capital (WACC), with an assumption that all consumers have access to financing. The Bass Diffusion model is then used to simulate adoption over time, using the “Maximum Market Share” as the terminal adoption level. Each agent completes a discounted cash flow analysis in each model year using hourly solar generation and electricity consumption profiles. Cash flows include capital and O&M costs, revenue from bill savings and the ITC, and tax considerations (i.e. MACRS). Agents are assigned appropriate tariffs (with net metering) based on geographic and energy/demand consumption constraints, and incorporating actual utility retail rate structures[5].

Using this approach, rooftop solar PV payback periods are estimated. Figure 19 shows payback periods for residential and non-residential rooftop PV for 2040.

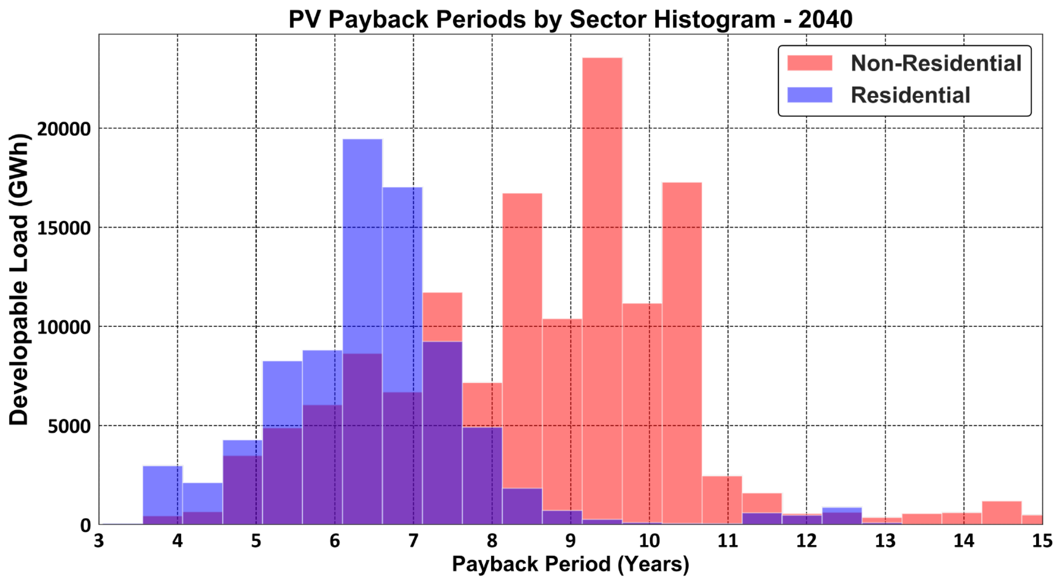


Figure 19. dGen estimate of rooftop solar PV payback periods in 2040.

Using a range of different assumptions, including solar PV cost and load growth Florida DPV adoption is forecast through 2040, shown in Figure 20. For a mid-case set of assumptions, this predicts about 2 GW-DC of cumulative residential rooftop solar PV by 2024 and just over 7 GW-DC of cumulative residential rooftop solar PV in Florida by 2030. As a check, this is fairly consistent with simple estimates of customer-owned solar PV growth extrapolated from the historical customer-owned renewable generation reports [21].

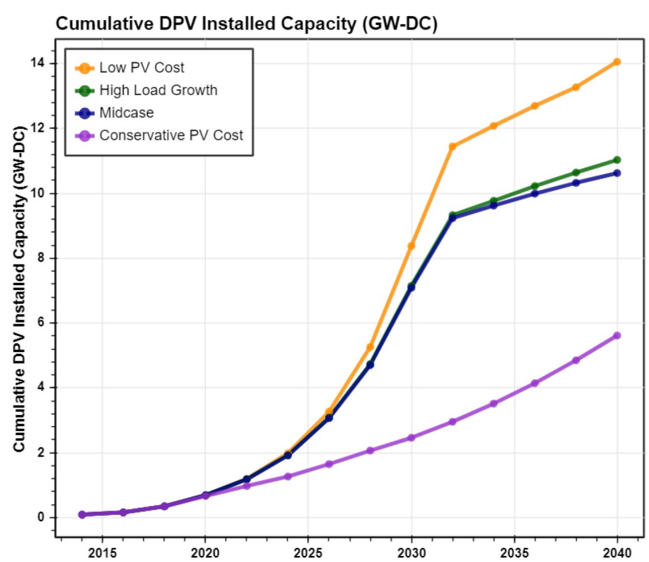


Figure 20. Estimate of residential rooftop solar PV growth in Florida through 2040 for different sets of assumptions.

Solar PV Penetration

With all of the growth in solar, however, by end of 2020, renewables, including mostly solar, make up only 3% of firm utility summer generating capacity in Florida [26]. This does not account for the load served by customer-owned solar. What is certain, in any case, is that solar energy is expected to continue to grow substantially in the Sunshine State to serve an increasingly larger percentage of the load. SEIA projects that 12,153 MW of solar will

[5] EIA AEO-2020 annual real retail price escalations were used.

be added in Florida in the next five years [27]. It may be more than that, given that eleven Florida cities have committed to 100% clean energy goals with target dates between 2035 and 2050 (Figure 5), and, solar will be a key part of the strategy for any Florida city or utility to get there. This is expected to drive solar PV penetration, particularly in those communities, to levels never seriously contemplated in the not-too-distant past. This is not fully reflected in the dGen rooftop residential solar PV forecasts, nor is it reflected yet in utility ten-year site plans which count only utility solar[6] and only include solar PV additions which utilities can confidently include in their plans.

Based on utility ten-year site plans through 2020, total solar capacity in Florida by 2024 is expected to be about 7.0% of peak summer demand excluding DR, EE and EC programs, or 7.5% of firm peak demand as reduced by the impact of DR, EE, and EC programs. All five of the largest Florida Municipal utilities serving retail customers are projected to exceed this (Figure 2). Note, as shown in Figure 21 from the Florida FRCC, the total forecasted firm solar capacity for Florida has consistently been revised upward each year in recent years [26].

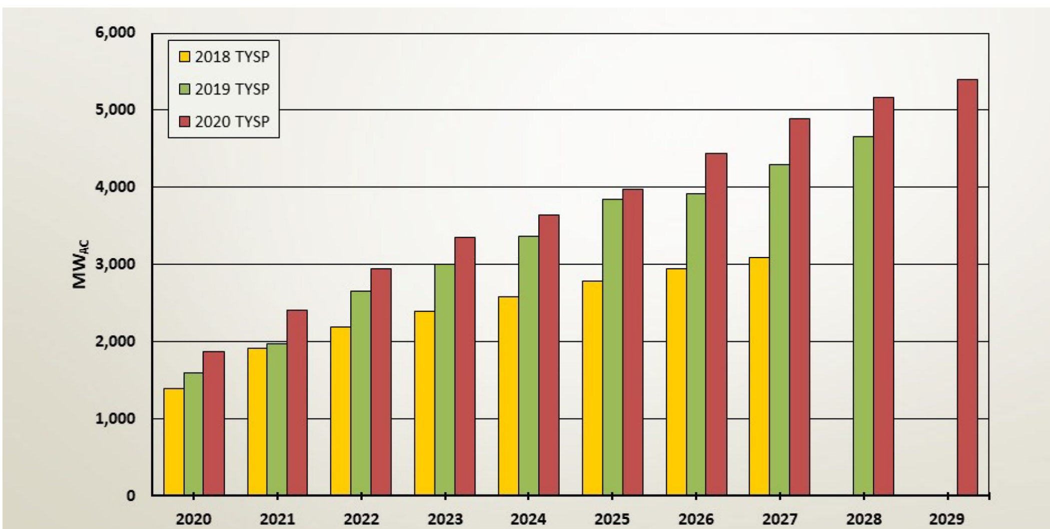


Figure 21. 2018-2020 Florida utility Ten-Year Site Plans forecasted solar, firm summer capacity (fig., FRCC) [26].

Energy Storage

Utility-scale Energy Storage

Though expected to grow in coming years, currently, utility-scale energy storage is not widespread in Florida, as utilities are having storage deployed in one-off or small numbers of installations, interested first in gaining experience and validating the business case. In most cases, the interest is in solar PV firming or ramp mitigation. Municipal utilities piloting and gaining experiencing with energy storge in various ways include JEA and OUC. JEA has a 2 MW/4 MWh lithium-ion battery energy storage system (BESS) co-located with a 5 MW_{AC} solar PV system at the SunPort Solar plant in Duval county, FL. OUC is deploying a 4 MW, 8 MWh lithium-ion BESS at a rural substation located southeast of Orlando in the general vicinity

[6] Noting that growth in customer-owned solar will show up as reduction in load growth.

of a 74.5 MW solar PV plant in order to examine use of storage for volt/VAR support, frequency regulation, handling contingency events, and PV smoothing. As part of another DOE-funded project, OUC is also installing 400 kg of hydrogen storage that can dispense hydrogen for use in OUC fleet vehicles or produce electricity through 900 kW of fuel cells. OUC also currently plans to procure 350 MW of energy storage capacity through PPA's with contract start dates in various years between 2025 and 2030. And, GRU has plans to deploy 12 MW of energy storage along with 50 MW of solar PV being procured through a PPA and expected to come online late 2022.

Florida IOU's FPL, Duke Energy Florida, and TECO are all moving forward with energy storage projects included in various rate settlements and base-rate adjustments approved by the FL PSC [28]. In 2018, FPL installed a 10 MW BESS at its Babcock Ranch Solar Energy Center, creating the largest combined solar-plus-storage facility operating in the U.S. at the time. The Babcock ranch system captures energy generated by the solar power plant and stores it for later use, helping improve reliability for thousands of local homes. FPL plans to bring 469 MW of energy storage online in 2021. In January of 2021, FPL started construction on a 409 MW / 900 MWh BESS in Manatee County, FL, which will be one of the largest in world. The FPL Manatee Energy Storage Center, first announced in March 2019, is co-located with FPL's existing Manatee Solar Energy Center ground-mounted solar PV plant and is expected to be up and running towards the end of 2021. FPL expects that the battery will be charged by solar energy. The capacity provided by the BESS will partially offset the loss of generation from the retirement of two 1970s-era natural gas generating units at FPL's neighboring power plant [29]. FPL plans to bring 300 MW of additional storage online in 2029 and 400 MW in 2030.

Customer-Owned Behind-the-Meter (BTM) Energy Storage

Customer adoption of behind-the-meter (BTM) energy storage in Florida is very low. Cost is still a barrier, and there are very few incentive programs. Notably, in 2018, JEA introduced possibly the first and only such incentive program for BTM energy storage in the state. The program is aimed at encouraging customer renewable technology adoption. It provides a $4000 rebate towards purchase of qualified BESS. Though the goal is to enable solar adoption while shifting it to align better with customer load, a major motivating factor for customers has been having the backup power during outages.

Research by LBNL's Electricity Markets and Policy Group provides some analysis and insight into how Florida's retail electricity rate design can impact customer bill savings from behind-the-meter (BTM) storage[7] [30]. The work included surveying time-varying rates and commercial demand charge rates in Florida, quantifying demand charge savings from storage using three representative customer loads, quantifying arbitrage value from time-of-use rates for residential and commercial customers, and examining a critical peak pricing example using Gulf Power and Tampa Electric Company (TECO) rates. Thirteen of Florida's largest utilities (by number of customers) were included in the analysis (five are FAASSTeR core team utility partners)[8].

- Florida Power & Light
- Duke Energy Florida
- Sumter Electric Cooperative
- Clay Electric Cooperative

[7] With support from the U.S. DOE Office of Electricity and Electricity Advisory Committee
[8] Online tariff sheets and rate information, accessed in December 2018.

- Tampa Electric
- JEA
- Gulf Power
- Orlando Utilities Commission
- Lee County Electric Cooperative
- Lakeland Electric
- Your Own Utilities (Tallahassee)
- Gainesville Regional Utilities
- Florida Public Utilities

Most utilities have optional time-of-use (TOU) rates for general service commercial customers, often with TOU demand charge optional. However, residential TOU rates in Florida are uncommon. There have been several pilots. When they are offered, they are always optional and opt-in. Available rate programs for the thirteen utilities considered at the time of the analysis (2018) are summarized in Table 2.

Table 2. Summary of TOU rates for thirteen Florida utilities (2018).

Utility	Residential TOU	Commercial TOU
FPL	Residential TOU Rider (RTR-1)	General Service, Non-demand, Time of Use
Duke Energy Florida	Residential Service (Optional Time of Use, RST-1, no new customers)	General Service, Non-demand, Time of Use (GST-1)
TECO	-	Time-of-Day General Service, non-demand (GST)
JEA	-	General Service Time-of-day (optional)
Gulf Power	-	General Service Time-of-use (GSTOU)
OUC	-	General Service Demand Time-of-Use option B Secondary
Lee County Electric Coop	-	-
Sumter Electric Coop	-	-
Clay Electric Coop	-	General Service Time (GST)
Lakeland Electric	Residential Service shift to save optimal Time-Of-Day RSX-1	General Service, Shift to Save, Optional Time-of-day (GSX-1)
Tallahassee	Nights &Weekends Pricing Plan	-
GRU	-	Non-demand Time-of-Use
FPU	-	-

All utilities considered have at least one commercial rate which includes a demand charge. JEA also had an experimental residential rate with a time-varying demand charge (JEA SmartSavings Residential Pilot). Six of the thirteen utilities considered offer a demand charge with a time-varying element – these tend to be the larger utilities. Time-varying demand charges are almost always an optional rate. Non-coincident demand charges ranged from $4.35 to $13.46 per kW. Larger utilities tended to have higher demand charges but with a number of exceptions. Commercial demand charge rates are summarized in Table 3.

Demand charge savings from BTM storage was examined for these Florida utilities, for three customer types, assuming 2-hour energy storage. The 2-hour energy storage system was sized at 20% of annual peak, assuming a $250/kWh storage cost. The selected customer types span a range of customer characteristics, with non-coincident demand charges only. Demand charge savings were dependent on demand charge level and ranged from $17-$128/kW/year across utilities and customer types (Figure 22). For peaky loads (e.g. customers with PV), even storage with shorter durations can be effective at shaving the narrow load peaks. For flatter load profiles (e.g. manufacturing), storage cannot sustain the required discharge to reduce peak demand.

Table 3. Summary of commercial demand charge rates (2018) for utilities included in LBNL BTM storage analysis.

Utility	Commercial customers	Demand charge level (non-coincident)	time-varying demand charge available?
FPL	551,967	$10.60	Y
Duke Energy Florida	199,930	$10.70	Y
TECO	83,690	$10.70	Y
JEA	55,959	$10.28	Y
Gulf Power	57,001	$7.16	Y
OUC	30,169	$9.10	N
Lee County Electric Coop	18,432	$6.99	N
Sumter Electric Coop	16,779	$5.75	Y
Clay Electric Coop	19,456	$4.35	N
Lakeland Electric	21,330	$8.04	N
Tallahassee	14,635	$13.46	N
GRU	11,132	$9.58	N
FPU	7,462	$4.86	N

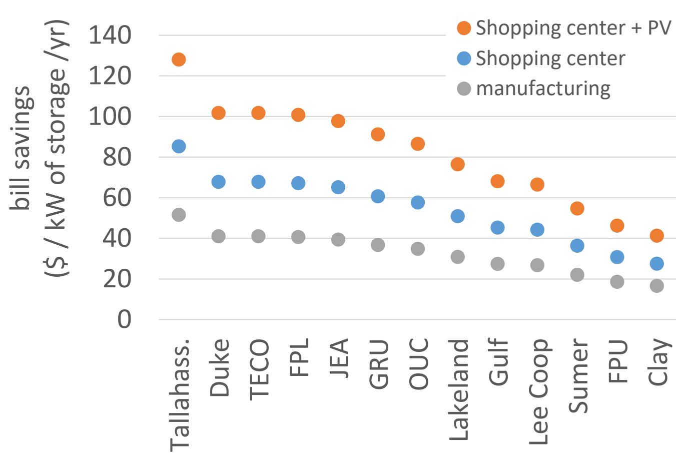


Figure 22. Commercial customer demand charge savings with 2-hour BTM energy storage cost at $250/kWh.

Payback period was also examined for the same three customer types. As with the actual savings, the analysis shows a large range in payback times across Florida utilities – a factor of three difference from shortest to longest (Figure 23).

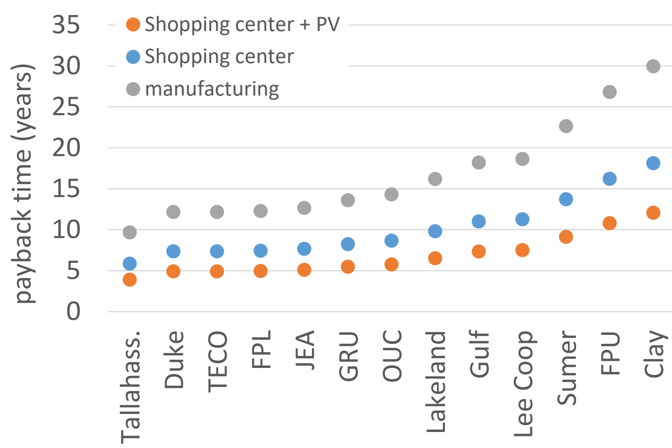


Figure 23. Commercial customer payback time for BTM energy storage based on demand charge savings, with 2-hour BTM energy storage cost at $250/kWh.

The computed value of energy arbitrage from storage was also examined across available TOU rates. In this case, bill savings are driven by the peak-to-off-peak TOU rate differential. This differential varies widely across available TOU rates across the utilities considered, from 2 to 20 cents per kWh. Arbitrage value occurs fairly evenly across the year for most Florida utilities, since peak period rates apply all year long in most cases. The results are shown in Figure 24.

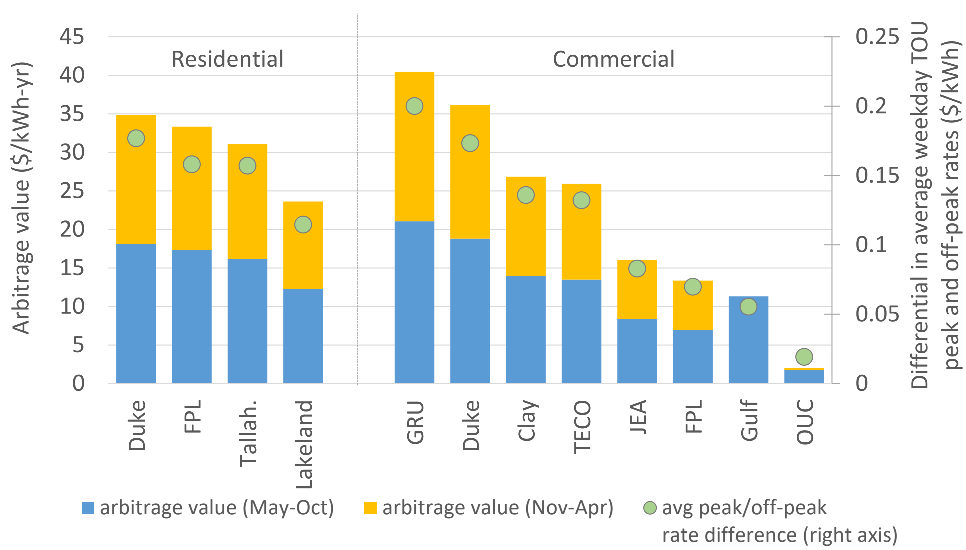


Figure 24. Value of energy arbitrage using BTM energy storage.

It is important to note that ***this analysis should be considered merely illustrative****. It is intended to show how demand charge design details can potentially be decisive in BTM storage economics and adoption.* And, it should be noted that demand charge savings are the only possible source of customer value, though they are the only once considered in this analysis. Customers may also obtain value from energy arbitrage, resilience, participating in utility demand response programs, providing ancillary services, and more.

Another possible value stream for BTM energy storage (and solar+storage) is participation in Critical Peak Pricing (CPP) programs, which consist of a high rate applied during certain days and hours declared by the utility (usually a day ahead) to be critical peak times. CPP is common in CA and to some extent elsewhere, but, rare in Florida. Two residential Critical Peak Pricing (CPP) were identified and considered, summarized as follows:

Gulf Power Energy Select

TOU rate + $0.785/kWh critical peak price

TOU differential is $0.108/kWh

Critical peak hours not to exceed 88 hours / year

TECO (Tampa) Energy Planner Program

TOU rate + $0.434/kWh

TOU differential is $0.083/kWh

Critical peak hours not to exceed 130 hours / year

The arbitrage values per kWh of energy storage employed, as well as number of event days called, are shown in Figure 25, for both the Gulf Power and the TECO programs

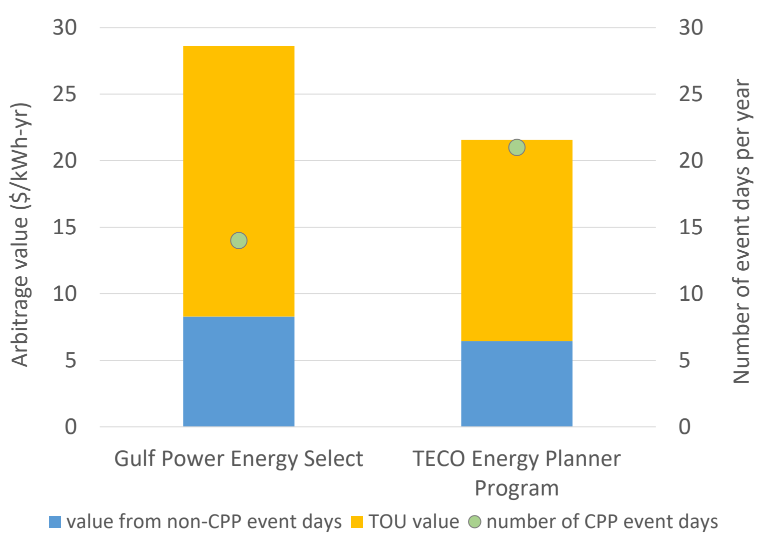


Figure 25. Value of energy arbitrage with Critical Peak Pricing program participation using BTM energy storage.

NEEDS, ISSUES, AND BARRIERS

There are significant needs, issues, and barriers to consider and address in order to successfully reach high penetration levels of solar PV across entire utility service territories and across the entire electric power system. Some, such as solar PV variability and solar-load coincidence, are similar to issues at the individual distribution circuit high penetration[9]. While others, such as system balancing and assigning capacity value, pertain mostly to wide area high penetration. On individual distribution circuits, the operational issues tend to be related to voltage regulation, PV variability and ramp rates, coincidence of solar with circuit load, circuit protection, safety, and power quality. Wide-area expansion of solar affects ability to balance power in the system, maintain frequency, and meet North American Electric Reliability Corp. (NERC) standards.

The significance of these issues and the magnitude of the challenge increases with percent solar penetration. There are a variety of definitions for solar penetration, including percent of summer firm power generation capacity, percent of annual energy generation, percent of peak load, percent of minimum daytime load, and more. For the large increases in solar PV contemplated here and anticipated in the next 10 years in many parts of the U.S., the penetration level measured by any of the common definitions, increases significantly.

Total installed solar at some Florida utilities is close to, even soon to exceed, 10% of generation capacity. Between 10% and 30% penetration across utility service areas (not just individual distribution circuits or substations), the technical and business risks introduced require significantly new approaches to electric power system planning and operation. Safely traversing into this high-solar future will ultimately require significant change from both an engineering and technology perspective as well as a business, policy, and regulation perspective. The associated challenges and opportunities affect planning, technology deployment, system operation, business economics and rates, and utility policy and regulation.

Planning and deployment

Land

Land arises as an issue associated with ground-mount solar in several ways. First, there is the consideration of land-use for solar PV development displacing agricultural land use or reducing agricultural productivity, reducing forested land and natural habitat, and having some aesthetic impact. Second, there is simply the issue of land availability, particularly large tracts required for utility-scale solar.

Most of the solar expansion in Florida currently is in the form of large ground-mount utility-scale solar. The energy density of utility-scale solar is about 0.13 MW/acre, compared to the energy density of a natural gas combined cycle (NGCC) plant, which is about 8.7 MW/acre. The average land requirement for the typical 75 MW solar PV plant being constructed is nearly 600 acres. Some issues with finding available land for solar PV in Florida are that 1.) it often has a higher value for other uses, 2.) it is often unsuitable for PV development, being wetlands or environmentally sensitive, and, 3.) it may not be in the best locations for grid interconnection or serving load.

A large number of utility-scale PV plants are being installed by IOU's, having been approved by the FL PSC under the Solar Base Rate Adjustment (SoBRA) provisions based on cost-effectiveness. Utility plants close

[9] Explored in prior DOE-funded research on high-penetration solar PV deployment [3][31]

to 75 MW in capacity coming online in 2021 are being built at installed costs as low as $1.07/watt, with plants coming online in 2020 and 2021 averaging about $1.24/watt installed cost. Based on FL utility ten-year site plans, these utility-scale plants will dominate solar expansion in Florida through at least 2023.

The area of Florida is 36,338,000 acres, roughly 1/3 that of California and 1/5 that of Texas. Much of Florida's land is either wetland, conservation lands, or high-value land used for development that would not be utilized just for solar PV. While there still exists significant agricultural and other undeveloped land in Florida, there will be continued pressure on land availability and property values from population growth. The portion of land that is developed land is expected to nearly double in the next 50 years if trends continue. Table 4 provides a breakdown of land use from 2010 and two projected scenarios for how land use may evolve by 2070 [32].

Table 4. Land usage in Florida, 2010 and 2070 projected scenarios [32].

	2010 Baseline		*2070 Trend*		*2070 Alternative*	
Classification	*[acres]*	*land %*	*[acres]*	*land %*	*[acres]*	*land %*
Developed	6,412,000	19%	11,647,716	34%	9,777,000	28%
Protected (existing agriculture)	9,950,000	29%	9,950,000	29%	15,716,000	46%
Protected agriculture	920,000	3%	920,000	3%	2,931,664	8%
Agriculture (croplands, livestock, aquaculture)	7,518,267	22%	5,520,237	16%	4,827,759	14%
Other (mining, timber, etc.)	9,742,733	28%	6,505,047	19%	1,290,577	4%
Total land	34,543,000	100%	34,543,000	100%	34,543,000	100%
Acres of open water	1,795,000					
Total including open water	36,338,000					

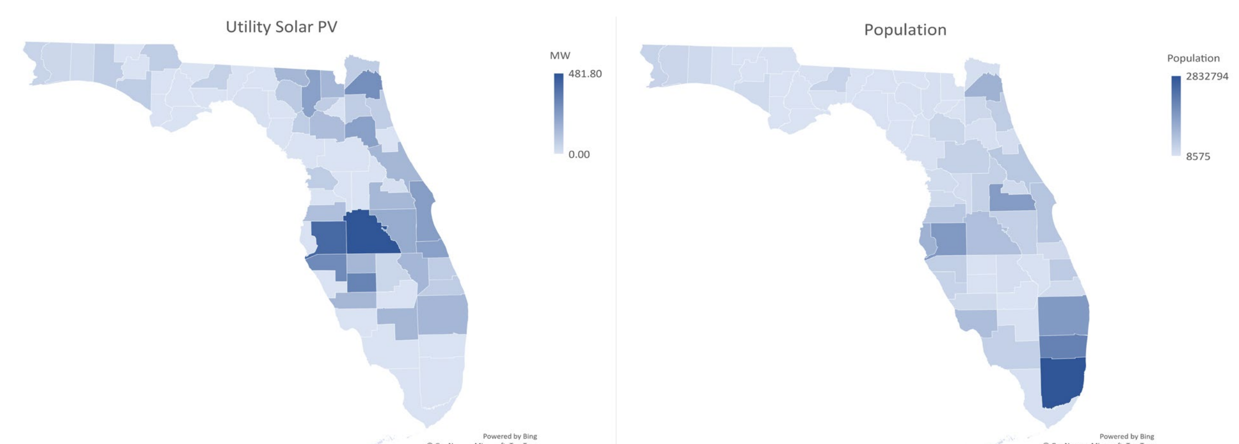


Figure 26. Utility-scale solar PV capacity (left) and population (right) by county in Florida.

Locating solar or solar+ based mainly on where the land can be acquired largely ignores the resiliency value of having distributed energy close to loads, including critical loads. Figure 26 illustrates, by county, where utility scale solar is currently being developed and where population is concentrated (which correlates with electric load).

For reasons discussed in the previous section, the typical plant size in Florida is 74.5 or 74.9 MW. Examining 54 solar PV plants[10] in this size range built, under construction, or planned by the three largest

[10] A mix of fixed-tilt and single-axis tracking systems, noting that the largest and smallest plants were fixed tilt.

FL IOU's, the average land requirement is 648 acres, or 8.5 acres/MW, with parcels ranging from a minimum of 402 acres to a maximum of 1219 acres. The land requirement varies considerably due to variation in the portion of any given parcel for solar PV placement due to presence of water bodies, wetlands, unsuitable soil or slopes, or other conservation or environmental restrictions. JEA is currently having five 50 MW plants installed through PPA's at sites varying considerably in total acreage and with the solar PV land requirement varying considerably depending on site characteristics (including presence of wetlands). Considering a larger sampling of 78 solar PV plants in Florida, ranging in size from 4 MW to 75 MW, the land requirement averages 8.1 acres/MW with a median value of 7.7 acres/MW (Figure 27).

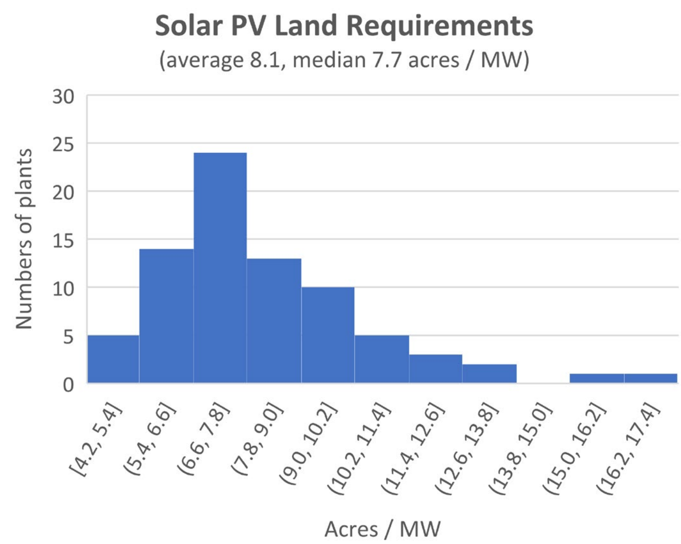


Figure 27. Solar PV land requirements, sampling of 78 FL plants, ranging in size from 4 MW to 75 MW, with average size of 64 MW.

With geographic information system (GIS) tools, it is possible to conduct detailed analysis of land availability for solar. A crucial step in the production of useful results from this kind of analysis is the development of a set of rule-based criteria for land types to exclude, in whole or in part, for PV development. Using available GIS tools and databases, NREL developed a procedure, selection criteria and very preliminary results that primarily demonstrate the effectiveness and practicality of the methodology [33]. The process was demonstrated for assessing rural and community utility-scale solar land availability. The technical exclusion categories were slope, urban classification (urban/suburban), landmarks, parks, land use (forest, wetland, and water types), Bureau of Land Management (BLM) Areas of Critical Environmental Concern (ACEC), forest inventoried roadless areas (IRA), and federal lands. Within these categories, the percentage to exclude can be specified (0-100%) for each layer within the category. Some categories, such as "federal lands" have a number of different layers (land types). Results are not provided here as they would require further refinement and vetting to be relied upon for assessing available land.

Resource Adequacy, Capacity Credit, and Capacity Value

The contribution of solar photovoltaics (PV) to reliably meeting an electric power system's peak demand – solar's *resource adequacy contribution (RAC)* – is limited owing to the inherent variability in generation from the changing position of the sun along with passing clouds. Increasingly, energy storage has been considered a leading option to improve solar's resource adequacy contribution, yet the contribution for different configurations of solar and storage is not widely understood.

Contribution to reliability is one of the value streams of solar+storage. Contribution to peak needs can defer or avoid investment in other forms of generation. Critical to this is an estimate of the "capacity credit" (CC) of solar+storage. We define ***capacity credit*** as the percentage of a generating technology's nameplate capacity that contributes to meeting utility peak load requirements, and, consequently, that can be counted toward resource adequacy. Economic value depends on the contribution solar+storage and the cost and timing of the deferred resources. We refer to this economic value as the ***capacity value*** (in monetary terms). Capacity value depends on the economic value of avoiding or deferring need to build other peaking capacity Figure 28 [34][35].

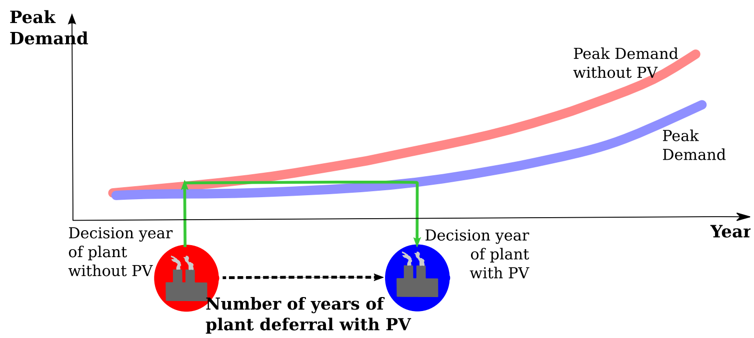


Figure 28. Generation capacity required in a system is based on peak load requirements and capacity value solar, storage, and solar+storage can be assessed based on ability to reliably contribute to serving peak demand [34].

Evaluating resource adequacy and assigning capacity value are a part of electric system planning. This involves assessment of the capability of the electric system to supply load, including determining how much generation, reserves, and interchange of power from neighboring utility service areas are required and how much are projected to be available based on the must current forward-looking plans. Methods are needed for determining the contribution of solar and storage to resource adequacy. This can be quantified by determining the capacity credit of solar, energy storage, and solar+storage. Efficient and effective methods to determine capacity value and capacity credit are needed that are sufficiently accurate to rely on for system planning and, yet, not excessively complex, costly, and time-consuming. This was identified early on in the FAASSTeR project as an issue and need for Florida utilities.

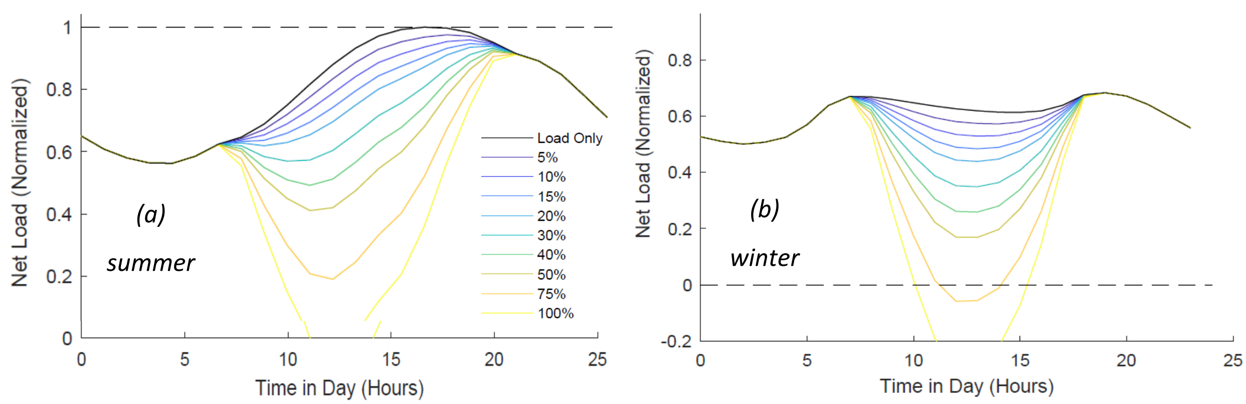


Figure 29. Seasonal mean net load curves (a.k.a. "Flamingo Curve") for a large Florida municipal electric utility shows system peak shifting later in the day in summer (a) as solar penetration as a percent of base load-only peak increases, and a dual-peaking winter load pattern in Florida (b) common in many utility service areas.

Resource adequacy assessments must now consider the effect of inherently variable stochastic resources such as solar and wind on the ability of installed generation to serve peak load. In the summer, the peak load that must be served by non-variable or dispatchable generation shifts later in the day as solar PV penetration increases (Figure 29a). As a result, the contribution of solar to resource adequacy declines with increasing penetration, because capacity value is assessed based on ability to serve peak load. More specifically, the Effective Load Carrying Capability (ELCC), declines as solar penetration increases. ELCC indicates the ability of a resource to serve load at riskiest (peak) periods and is measures the additional load that can be supplied with a generation resource of interest, with no net change in reliability [36].

Current literature on solar and storage CC is lacking, and there is a need to fill in some of the gaps to gain more insight on estimating RAC. For example, many detailed evaluations of solar's CC focus on regions that have their highest peaks on summer afternoons (e.g., much of the western United States), but solar's CC is smaller in regions with winter night peaks. Relatively few studies focus on regions with a dual-peaking pattern, where summer cooling loads are nearly equivalent to winter heating loads (e.g. southeast United States). In addition to the shortage of solar CC research in certain regions, estimates of storage's CC are sparse in the literature, regardless of the region. The papers that do estimate storage CC assume storage is dispatched to maximize its arbitrage value, and then they evaluate the CC associated with that dispatch. They do not indicate the degree to which the CC could be increased if storage's dispatch were optimized to maximize CC. Finally, solar and storage can also interact to affect the CC of both technologies, though these interactions have only been studied in a limited number of regions. Interactions between solar and storage using probabilistic reliability techniques have been investigated in California, Singapore, and Ontario, Canada.

Solar Capacity Credit in Florida Utility Planning

At the start of the FAASSTeR project, in 2017, Florida utilities with solar PV in their system were generally assigning no capacity value to solar. As of the final year of the project, 2020, Florida utilities have gradually started to assign solar a capacity credit[11] for net summer generation only (zero for winter).

For those utilities assigning a capacity credit, for individual or co-located installations, it varies from 20%[12] up to approximately 60%[13] of solar plant AC capacity rating [37][38][39]. Factors considered by respective utilities in arriving at capacity values for solar include site location, technology, design, and the total amount of solar that is operating on the utility's system.

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[11] Florida utility Ten-Year Site Plans and FRCC Presentations use the term "capacity value" to mean "capacity credit", as it is defined here and in the various DOE national laboratory research reports.

[12] City of Tallahassee, 12 MW_{AC} summer firm capacity for 62 MW_{AC} combined solar PV plant installations at Tallahassee International Airport.

[13] FPL, approximate capacity value of 43 MW_{AC} summer firm capacity planned for 74.5 MW_{AC} Cotton Creek Solar Energy Center in Escambia County, FL

Operational

Variable Generation and "Net Load"

It is well-known that the degree to which solar production coincides with actual system load on any given day varies considerably depending on the nature of the loads served (e.g. residential versus commercial) and the time of year. This has been widely conveyed in the form of the California "duck curve"[14] [40], which shows the net load at various system penetration levels of solar, the "net load" being the load that would remain to be served by non-variable generation at any instant if there were no variable generation[15]. It provides a useful starting point for examining the impact of increasing solar penetration on any given electric system.

Figures 29 and 30 are Florida "flamingo curves", the Sunshine State's version of the net load curve. They are each based on data from a large Florida municipal utility. Figure 29 shows seasonal mean net load on a basis of solar PV penetration as a percent of peak system load (*power*; with no PV), and Figure 30 illustrates net load on a basis of solar PV penetration as a percent of peak *energy* for load for a spring day and a summer day for a large Florida municipal utility that is also a NERC balancing authority (BA).

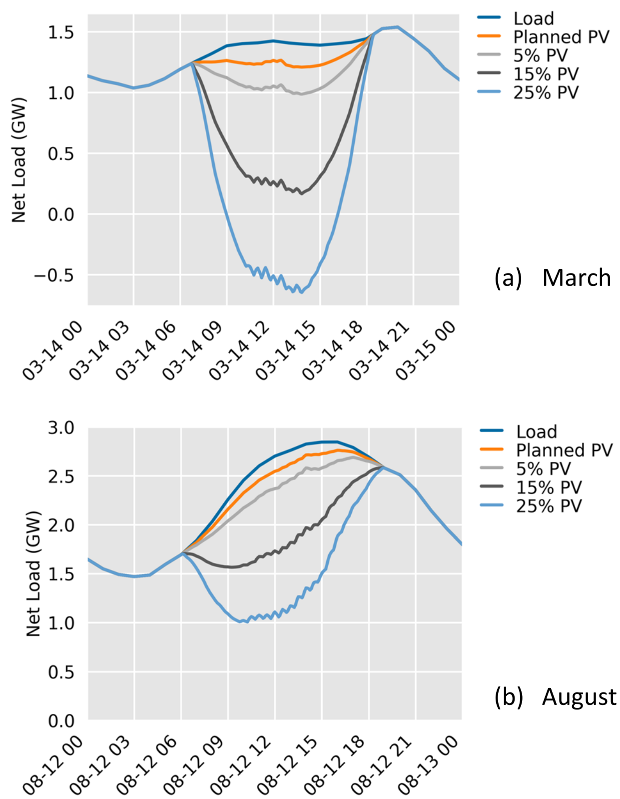

Figure 30. Spring and summer net load "flamingo" curves for a large Florida municipal utility balancing authority, a) top, March, b.) bottom, August

These figures illustrate several important characteristics of an electric system with increasing levels of solar generation: 1.) that dispatchable generation in the system will experience much larger and faster variation (ramps) than in the past due to solar variation, 2.) that the timing of the system peak in summer is shifts later in the day as solar penetration increases, and, 3.) that excess supply begins to occur at certain times of the day and year once the penetration level of solar exceeds some amount. Shifting the system peak later in the day and creating periods of excess supply cause the marginal value of each additional MW of solar capacity to decline. The "shoulder" months in the spring and fall are where the excess supply issue tends to show up, when system load is relatively light. This is evident in Figure 30(a), the top set of curves, where it can be seen that, in the month of March, at 25% PV penetration (as a percent of energy supplied), significant excess supply occurs mid-day.

[14] First published by the California Independent System Operator (CAISO) in 2013.

[15] We define "net load" as the power required to serve actual load minus the power produced by variable generation, at any instant in time. CAISO defines "Net Load" as "the difference between forecasted load and expected electricity production from variable generation resources" [40].

Solar and Net Load Ramp Rates and Variability

We define ramp rate as the change in power over some time interval. It can refer specifically to the ramp rate of an individual solar plant's output, the ramp rate of multiple solar plants combined, the ramp rate of an individual generator of any kind (solar or otherwise), the net load ramp rate, or the actual load ramp rate. Solar ramp rates manifest in the system as impact to net load. For most of the analysis in this report, net load and actual load are taken to be for an entire utility service area.

Table 5. Typical maximum ramp rates of dispatchable generation units.

Dispatchable Generation Plant Type	Typical Maximum Ramp Rates [% of rated power/min]
Coal	1-6
Nuclear	1-5
Combined Cycle Gas Turbine (CCGT)	2-11
Open Cycle Gas Turbine (OCGT)	8-50
Reciprocating Internal Combustion Engine (RICE)	>100

When referring to the ramp rate of a dispatchable generator, that is, a generator where the power output can be set by operations or automatically over a significant range, it is necessary to consider the actual ramp rate during operation and the ramp rate limits. When referring to the ramp rate limit, we are most interested in the high limit, that is, the fastest rate at which a generator can be ramped. This maximum ramp rate is limited by the physical capabilities and ratings of the generation resource and also by any environmental permit limits. Typical maximum ramp rates for the major types of dispatchable generation units are shown in Table 5 [41][42][43]. Examining data sets for Florida utilities with large solar PV plants, one-minute solar PV power ramp rates of up to 73%/min. can be observed (Figure 31).

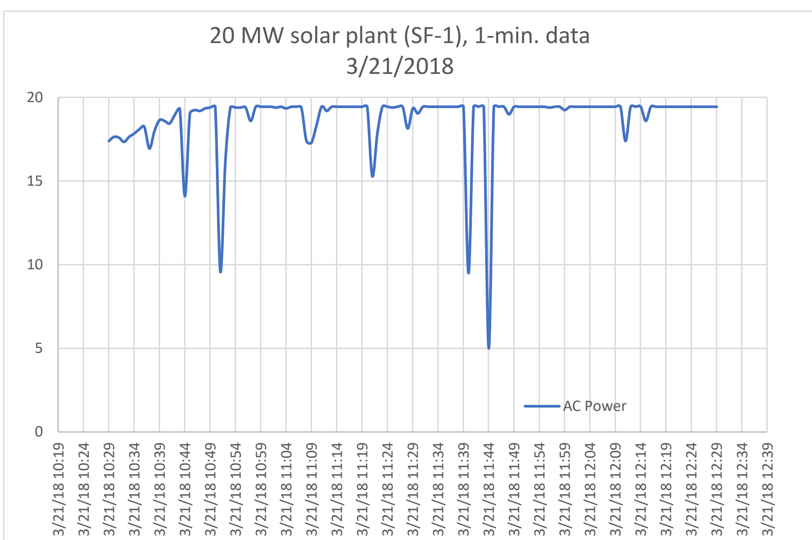

Figure 31. Steep ramps, as high as 73%/min. on a 20 MW_{AC} solar PV system.

Some studies of solar ramp rates remove the diurnal component of solar variation in order to quantify and characterize the portion of the variation that is a consequence of clouds [44]. While this has merit, it remains the case that the summed contributions to ramping are ultimately what is important to utility operations. The summed effect can be significantly different depending on the timing of cloud-induced ramps relative to the diurnal variation. Note the very steep rise in solar PV on the left set of curves in Figure 32 at around 10:40 a.m. on 3/20/2018 due to clouds clearing the system at the same time the sun is rising.

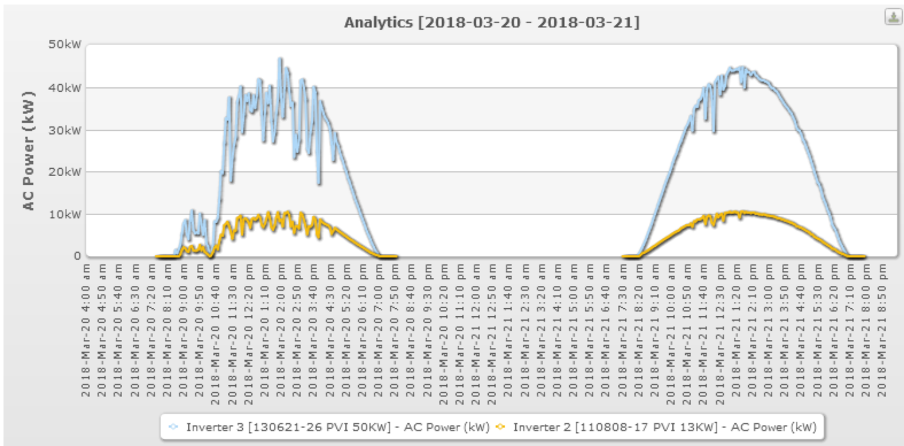

Figure 32. Solar PV power output from two of three inverters that make up a 75 kW_{AC} system on the roof of Tallahassee International Airport. Note the exceptionally steep rise in solar output on the 50 kW_{AC} inverter on 3/20/2018 (left) due to high cloud variability coincident with the steepest portion of the normal diurnal irradiance curve.

Timing of solar variations with other sources of variation in the system must considered, including load variations, unplanned outages and calls for reserves. Both COT and JEA each have a particularly large intermittent load on their system that result in rapid load changes of close to 50 MW_{AC} up and down.

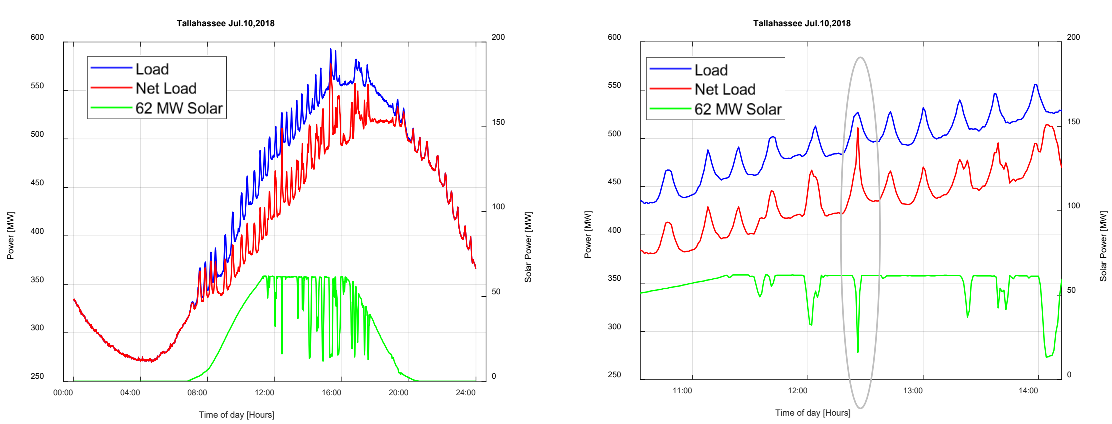

Figure 33. Effect on net load from of a highly variable solar day with highly variable load (analysis was performed with 20 MW_{AC} Tallahassee Airport solar PV data scaled to 62 MW_{AC}, the eventual total size of the utility-scale PV at that location). In the figure on the right, a more granular view of the left figure, at 12:26 pm, solar PV output (green) ramps down 45 MW_{AC}, at the same time that the load (blue) ramps up 44 MW_{AC}, combining to produce an 89 MW_{AC} ramp up in net load (red).

In the case of COT, the load comes from powering coils on large magnets at the National High Magnetic Laboratory (NHMFL) research facility. In the case of JEA, the rapid load swings come from the arc furnace of a steel mill. Figure 33 shows a day on the COT system with numerous load ramps and solar PV ramps, and cases of these ramps coinciding to increase the system net load ramp; For example it can be seen in the figure on the right at 12:26 p.m. an 89 MW_{AC} net load ramp resulting from solar and the NHMFL load ramping at essentially the same time.

System Balancing and Reserves

Physics require that generation and load in a connected electric system be in balance if system frequency is to remain constant and, ultimately, for system operation to be reliable and stable. Variation or ramping of solar that is not offset by other generation or interchange with neighboring systems will result in frequency deviations. The fastest variations are handled by governors on synchronous generators (primary control), followed by manual or automatic generation control (AGC). If generators cannot respond sufficiently in magnitude or rate, frequency deviations will show up. A utility that is a Balancing Authority (BA) tracks this relative to other control areas in terms of Area Control Error (ACE). A simple illustration of ACE excursions due to generation and demand imbalances arising in different ways is shown in Figure 34. NERC regulations prescribe that ACE be maintained within specified limits over certain time intervals.

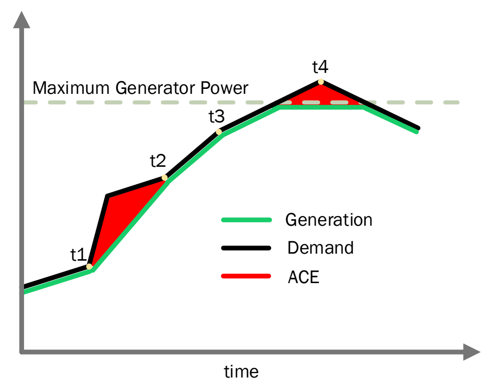

Figure 34. Operation of generator in load-following mode and possible contributions to ACE. From t1 to t2, generation does not respond fast enough to follow load; from t3 to t4, generation hits its maximum operating limit.

As mentioned, it is not only variable generation, but, other events such as large load changes or loss of generation or transmission that can make it challenging to keep the system in balance. Contingency reserves are provided for in order to maintain balance in the case of large unexpected events on the system. All of the BA utilities In the Florida Reliability Coordinating Council coordination and planning area (most of Florida) participate in the Florida Reserve Sharing Group (FRSG). The participation agreement includes binding commitments to make reserves of a specified amount, unique to each utility, available in a short amount of time when called upon to recover from a contingency event within the group[16]. For 2019, the COT had an FRSG commitment of 51 MW and JEA, 117 MW. The possibility of a reserve call on a municipal BA utility due to a contingency event somewhere in the state is an additional rapid variation in the BA's local system that must be planned for and effectively handled by grid operators along with large load changes and variable generation.

Increasing net-load variability and uncertainty on 4-second (regulating reserve) to 1-hour (ramping) timescales resulting from increasing solar PV penetration may require utilities to allocate additional operating reserves [45][46]. Balancing actions required of large system operators or neighboring systems operated cooperatively are smaller than those required of a small system when measured on a normalized basis (e.g., percent of load for a given solar penetration) due to the damping effects of aggregating many geographically dispersed solar plants [47][48][49]. Although this fact is generally known, the impacts on

[16] Notably, loss of solar output due to the loss of irradiance does not qualify for a reserve call.

reserve requirements have not been well quantified for BA utilities such as municipals, who do not have the very large widely dispersed systems that IOU's do.

Solar Observability

In Florida, most customer-sited behind-the-meter solar is net-metered and has no metering other than a utility billing meter with net-metering capability to measure power flow from or to the electric system. In this case, the meter only measures that net exchange of energy and provides the utility no information on the solar produced or the actual electric load served on the premises, as shown in Figure 35, where positive values are consumption and negative values are export [50]. Full visibility can be achieved by adding a production meter on the solar system (Figure 36) [50].

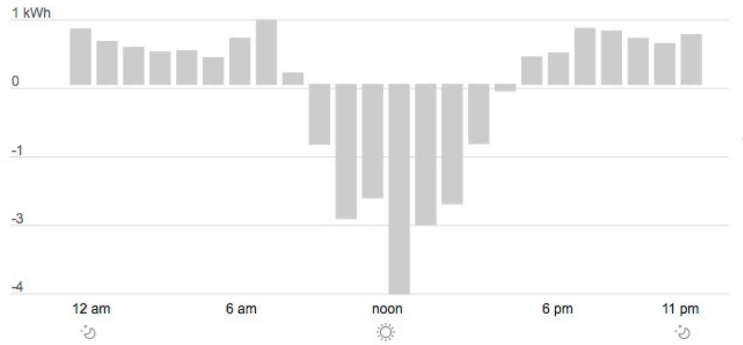

Figure 35. Visibility to utility with a net meter only (source: OUC) [50].

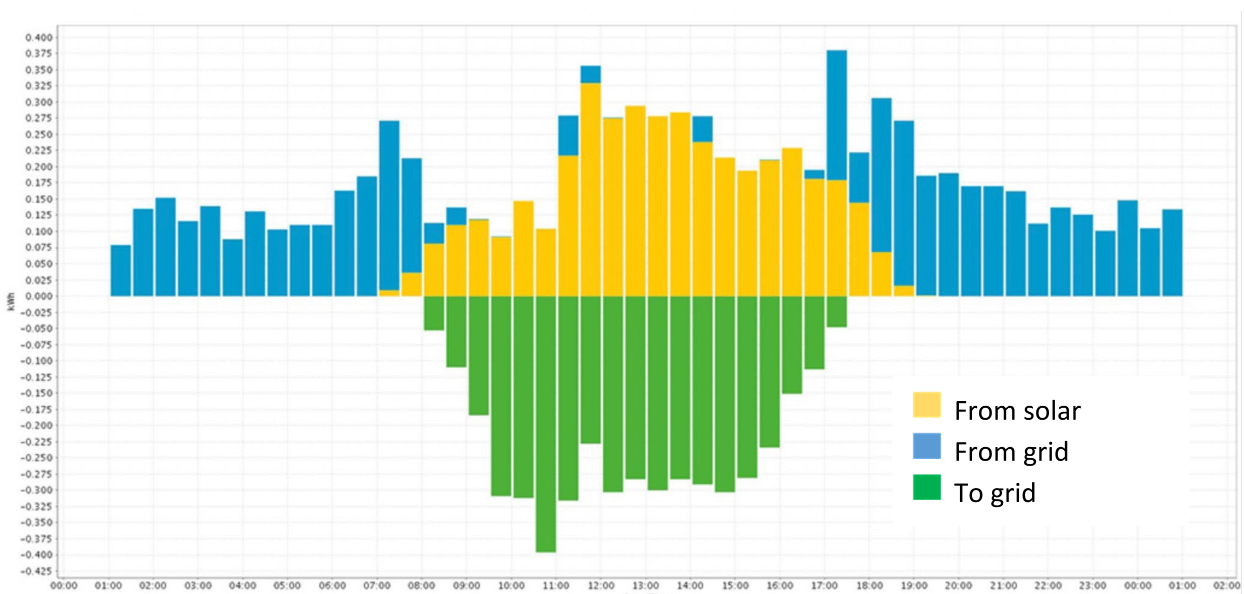

Figure 36. More complete information on solar and load possible with solar PV production meter [50].

A lack of actual measurement of the true load (or gross load) and solar PV generation (e.g. by employing a production meter on the solar PV) and a lack of reasonably good estimates and forecasts of these can lead to overscheduling of energy production and reserves, reliability constraint violations, and other operational challenges [51]. Estimating the "disaggregated" solar PV and gross load measurements from other measurements and information available is an active area of research [51][52].

Solar PV Power Forecasting

To operate successfully with increasingly high penetration levels of solar PV, there is a need for improved forecasting of solar power output from PV plants on multiple timescales. High penetrations of variable renewable energy resources increase the variability and uncertainty associated with power system operation. In the cast of Florida utilities with significant solar, the degree to which solar forecasting is incorporated into operations varies, but, the need for it as solar continues to grow, is widely recognized.

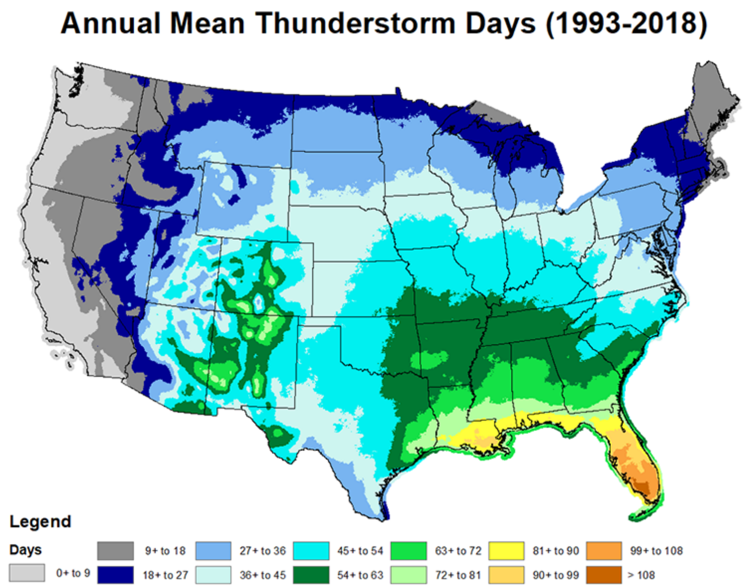

Figure 37. Annual mean thunderstorm days in the U.S., 1993-2018 [53].

Forecasting solar can be particularly challenging in Florida, in part, due to coastal effects[17] and summer weather and cloud formation patterns. As shown in Figure 37, Florida has the highest incidence of thunderstorms in the U.S. [53]. The top three cities with highest number of thunderstorms per year in the U.S. are in Tampa, Fort Meyers, and Tallahassee, FL [54].

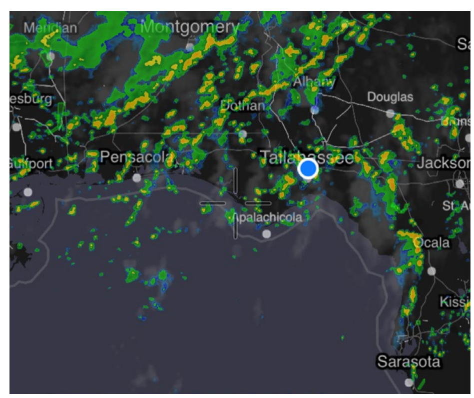

Figure 38. Scattered clouds form quickly in the summer in FL with movements difficult to predict.

Summer cloud formation patterns, including formation of thunderstorms, can cause considerable solar PV fluctuation (ramping) and can be particularly challenging to forecast at adequate spatial and temporal resolution to be useful in day ahead and real-time operations. Associated cumulus and cumulonimbus clouds form relatively quickly, especially during the summer months, and move in scattered non-uniform patterns that are difficult to predict (Figure 38).

Excess Supply

Excess supply in the electric system due to solar PV production can occur when dispatchable and load following generating units are at their minimum operating points and PV produces more power than can be used or exported ("over-production"), as illustrated in Figure 39, derived based on data from a Florida

[17] The combined land and coastal boundary of Florida is approximately 1835 miles, 1350 of it (74%), being coastline, with the Gulf of Mexico to the west and the Atlantic Ocean to the East.

municipal utility. This is more likely to occur in the “shoulder months” occurring spring and fall when total system load is low.

Traditional dispatchable generators have minimum operating limits. Governors on the generators provide primary control to keep system power and frequency stable as generation and load change. This does not maintain balance, however. To keep the system balanced, measured by frequency and Area Control Error (ACE), the output of one or more generators is changed in real-time, known as secondary control. This is normally accomplished automatically, using Automatic Generation Control (AGC) [55]. AGC cannot reduce units below their set low limits. If solar PV production plus the sum of all dispatchable generator production at their respective minimums is greater than the actual load, than PV over-production, also referred to as “excess supply”, can result, and other action must be taken to keep the system in balance.

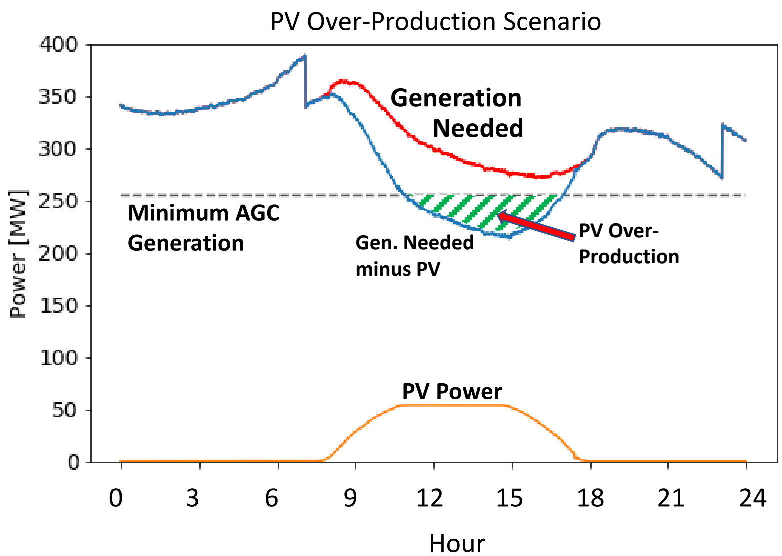

Figure 39. An example of solar PV over-production due to sum of solar PV and minimum dispatchable generation exceeding actual load.

Energy Storage

Energy storage will play a vital role in the electric grid. Though costs have declined considerably, they still currently present a barrier to widespread use. As the downward trend in cost continues due to massive buildout of a supply chain, economies of scale, market demand, and technology innovation and maturation, the cost barrier will diminish. Utilities also face issues with defining the business case for storage and in selecting and sizing storage for different applications. When charging, storage is also a high-demand load on the grid (as in the case of fast chargers for EV’s). Broadly, two major roles for storage in the future electric power grid are 1.) stationary storage for the grid and consumers, and, 2) transportation electrification (towards carbon-free mobility).

Stationary storage

Energy storage can be used to help address a number of the issues that can arise in the system with high penetration solar PV, including increased ramp rates and variability, excess supply, peak shifting and management, economic dispatch, and frequency and voltage regulation. With pumped-hydro as the exception, utility grid stationary energy storage technologies are still relatively new and evolving in both operating performance and life-cycle cost. The issues and challenges with deploying energy storage as a solution include determining life expectancy, selecting specific technologies and suppliers, understanding performance characteristics, specifying storage power and energy ratings (sizing), locating storage, and operating storage for different use cases and objectives.

Value streams, sizing, cost, asset life

Energy storage can be considered the "Swiss Army Knife" of electric grid resources, in terms of how many functions it can perform and value streams it can add. It is both an energy and a power resource. The specifications for storage, including choice of technology and sizing, depend on how it will be employed. A single storage installation can serve one or multiple value streams. The many possible functions and value streams are listed in Table 6 (a FAASSTeR project adaptation of [56] and [57]). Florida's municipal utilities on the FAASSTeR project identified *solar PV ramp rate mitigation* as a top concern, because, of the potential for solar PV variation at higher system penetration levels to impact their ability to meet NERC BAL regulations (concerning ACE and frequency).

Table 6. Energy Storage Value Streams

Utility / Electric Grid	Customer / BTM
Ramp-rate Mitigation	Backup Power (Reliability and Resiliency)
PV Firming	Increased PV Self-Consumption
Capacity / Resource Adequacy	Demand Charge Reduction
Energy Arbitrage	Time-of-Use (TOU) Bill Management
Reserves (Spin / Non-Spin)	Utility Demand Response (DR) participation
Frequency Regulation	Utility Grid Support participation
Voltage Support	
Black Start	
Distribution Deferral	
Transmission Deferral	
Transmission Congestion Relief	
Grid stability (through one or more of the above)	
Grid resiliency (through one or more of the above)	

Asset life depends heavily on the specific energy storage technology and how it is used, especially how it's state of charge (SOC) is cycled, including charge-rate (C-rate), depth-of-discharge and maximum charge, rate of cycling, and cumulative cycles. This is an active area of research, and, of the various battery applications, including consumer, electric transportation, and stationary power (electric grid), the latter has the shortest track record in terms of numbers and durations of existing deployments. Understanding and predicting battery aging, degradation and life span is an active area of research [58].

Supply chain

Battery energy storage is currently dominated by Li-ion, which has shown steady cost declines due to global economies of scale. Li-ion's dominance of nearly 100% of the electric vehicle (EV) energy storage market and the accompanying cost declines has led to Li-ion dominance in grid-scale and behind-the-meter energy storage market. While alternatives exist, such as flow batteries and a few other battery chemistries that are establishing some small traction in the market, nearly all electric grid related energy storage deployment in Florida has been Li-ion.

For the current and foreseeable future, the U.S. is heavily dependent on global supply chains for Li-ion battery energy storage materials and manufacture. In 2020, the U.S. had 8% of Li-ion cell manufacturing capacity, while China had 76%, and, current projections have this changing very little over the next 5-10 years [59][60][61]. The dominance of Li-ion batteries for EV and electric applications currently places the U.S. on a path of trading dependence on the Middle East for oil to dependence on China and other parts of the world for batteries.

The dominance of Li-ion batteries for EV and electric applications currently places the U.S. on a path of trading dependence on the Middle East for oil to dependence on China and other parts of the world for batteries.

Battery global supply chain dependencies are emerging as a national security issue[18] significant to the U.S., and significant for Florida, second in the nation in net electricity generation, third in population (over 21 million) and numbers of vehicles (almost 8 million), and home to 21 military bases. Not only are military bases dependent to a large extent on the electric grid, directly to power bases, and, indirectly, to power the communities that work on and support the bases, but the DOD is also increasingly looking at expanding the role of energy storage for installation (base) energy assurance and operational energy.

Transportation and Mobility Electrification

According to DOE data, Florida has the third-highest motor gasoline demand and the sixth-highest jet fuel use in the nation [62]. According to researchers at Rocky Mountain Institute, in order to hold global warming to a 1.5 deg. C rise in temperature, U.S. transportation emissions must decrease 45% by 2030, which translates to 70 million EV's nationwide, of which Florida's share would be about 5 million [63].

From May 2019 to October 2020, the Florida Department of Agriculture and Consumer Services' Office of Energy held a series of workshops and webinars as part of a focused initiative to develop an EV Roadmap for Florida. In December 2020, the first Florida EV Roadmap was released (Figure 40), providing the first comprehensive investigation into the status and needs of EV charging in the state looking out three to four years [64].

According to the Rocky Mountain Institute (RMI), to hold global warming to a 1.5 deg. C rise in temperature, U.S. transportation emissions must decrease 45% by 2030, which translates to 70 million EV's nationwide, of which Florida's share would be about 5 million [63].

[18] Simon Moores, Managing Director, Benchmark Mineral Intelligence, "…we have witnessed a global battery arms race and watched the world's number of supersized battery plants – known as battery megafactories or gigafactories - go from 17 to 142. China has increased its number of battery megafactories from 9 to 107, of which 53 are now active and in production. The USA has gone from 3 to 9 battery megafactories in the pipeline of which still only 3 are active, the same number as back in 2017. Lithium ion batteries are a core platform technology for the 21st century." [60]

Florida has over 3900 Level 2 charging plugs and approximately 975 DC fast chargers (267 stations) [63][64]. Florida has committed $25 million of its share of funds from the Volkswagen emissions litigation settlement to expanding EV charging infrastructure in the state, most of that for DC fast charging infrastructure along Florida's interstates and other major roads[19]. According to RMI, in order to support the roughly 5 million EV's in Florida needed by 2030 to help meet U.S. carbon reduction to limit global warming, approximately 26,000 DC fast chargers are needed in Florida by that time (a 25X increase). This represents a significant issue and opportunity for the electric power grid. These represent high demand loads scattered across the electric power system, posing new planning and operational challenges, but also a substantial potential increase in revenue servicing these loads.

Some of the important issues identified by the Florida EV Roadmap related to conversion to EV's and the required EV charging infrastructure are:

- The need for EV interoperability with charging infrastructure and the electric grid.
- Challenges forecasting EV adoption rates and patterns.
- The need for planning charging infrastructure to be resilient to extreme events such as hurricanes.
- Gaps in EV charging infrastructure for emergency evacuation.

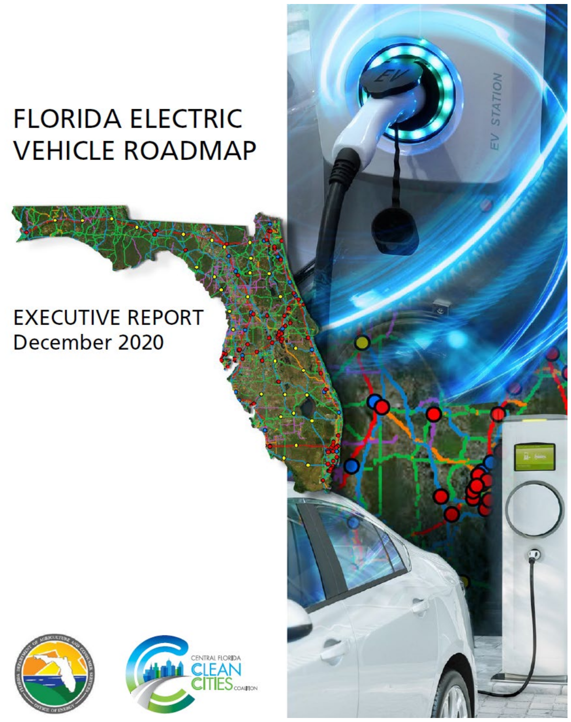

Figure 40. The Florida EV Roadmap, produced by the FDACS Office of Energy, is the first comprehensive plan addressing future EV charging infrastructure in Florida.

Grid Modernization

Extensive integration of new types of resources such as solar and energy storage to help transform to a cleaner more resilient electric power system is coupled with and dependent on grid modernization. Grid modernization involves the infrastructure, operation, business, and regulatory changes to support distributed variable resources, a secure self-healing resilient grid, grid-interactive efficient buildings, prosumer enablement, new products, services, and markets, and power quality and reliability for an increasingly digital and electronic world (Figure 41) [65][66].

[19] The state of Florida currently provides funding for the installation of EV infrastructure through funding from Florida's Volkswagen Settlement. Florida Department of Environmental Protection (FDEP) manages the state's share of the EPA's lawsuit against Volkswagen for actively falsifying emissions test results for their diesel vehicles. The state allocated $25 million (15%), the maximum amount allowable for EV infrastructure under the $167 million settlement [64].

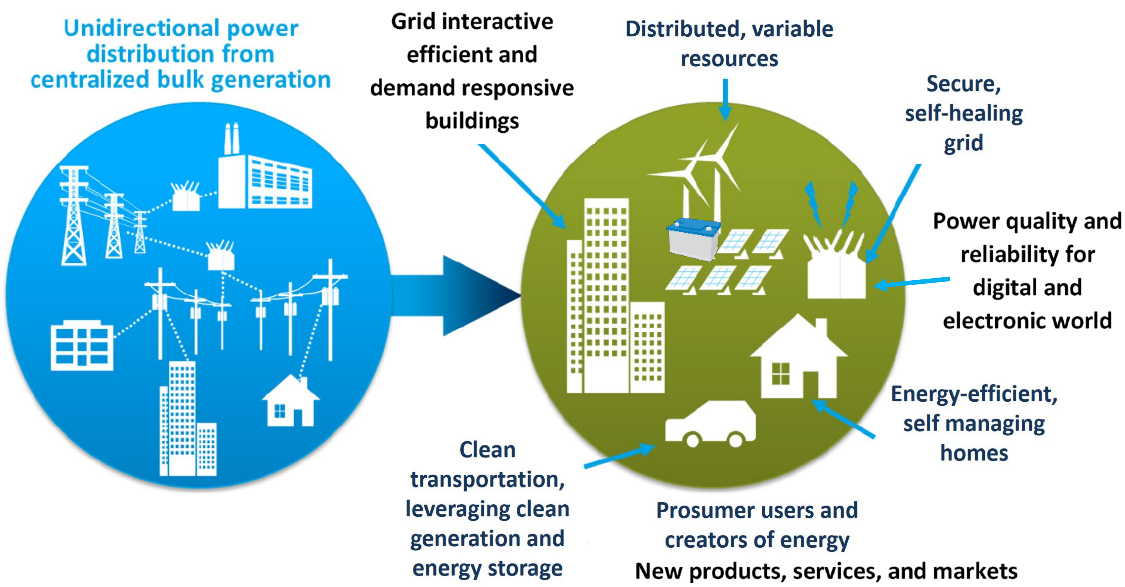

Figure 41. Grid modernization to enable a transformed electric system (R. Meeker, Nhu Energy, adapted from A. Satchwell, LBNL presentation [65]).

In 2013, the Gridwise Alliance developed a ranking system that uses a clearly defined set of criteria to evaluate and convey the progress and impacts of transformative improvements to states' electricity infrastructure [67].

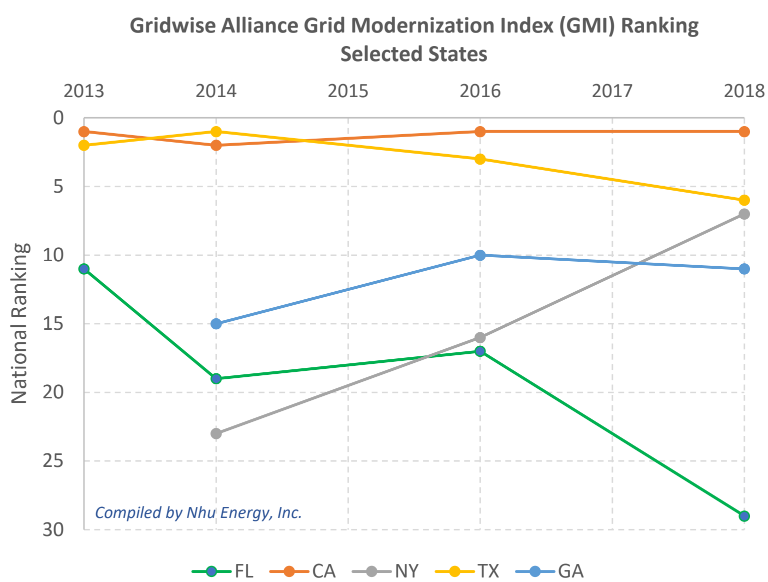

Figure 42. Grid Modernization Index trends, comparing selected states.

The Grid Modernization Index (GMI), uses metrics to benchmark states' progress in the areas of, State Support, Customer Engagement, and Grid Operations[20]. The most recent GMI, published in Dec. 2018, ranks Florida at 29, in the "beginners" grouping, described as having "exhibited promising new efforts or early-stage actions to support grid modernization, but not yet (having) comprehensive roadmaps or coordinated activity around grid modernization" [68]. Florida's scoring in each area was as follows (point score/max possible; where higher is better): State Support, 6/29; Customer Engagement, 10/34; Grid Operations, 12/37. Florida's national ranking trend compared to other selected states, through 2018, has declined overall, as shown in Figure 42.

Economic and regulatory

Rate Impact / Cost

Florida utilities have been sensitive to keeping rates low and to equitable programs and investments in solar that avoid cost shifting and provide access to all ratepayers. According to separately-funded LBNL research, evaluating retail rate impacts to all customers due to increasing solar penetration is specific to each utility and depends on the Value of Solar (Vos) to Cost of Service (Cos) ratio, the total customer-owned solar PV penetration, and the solar compensation rate that has been set by the utility. At low customer-owned distributed PV penetration levels that many states, including Florida, are at, using the VoS/CoS evaluation approach, utilities are unlikely to see any appreciable effects of customer-owned distributed PV growth on retail electricity prices (cost-shifting). [69]

Consumers have shown a willingness to pay a small premium for solar. FMPA found in a survey completed in 2016 that 72% of customers were interested in the utility further investigating solar for the community and 38% were likely or somewhat likely to pay a higher electricity price for solar [70]. Customer interest in community solar has been confirmed by strong participation in programs at the City of Tallahassee, OUC, and FMPA.

A 20 MW_{AC} solar PV plant serving the City of Tallahassee came online adjacent to Tallahassee International Airport (TLH) in December 2017 (Figure 43). When this community solar program was made available earlier in the year for customers to sign up, it was fully subscribed in just a few months. In the City of Tallahassee's community solar program, the fuel charge on the bill is replaced by a fixed charge for solar, 5 cents/kWh for residential and small-to-medium-sized commercial customers[21]. Participating customers can elect to have solar represent 25, 50, or 100 percent of the energy usage on their bill. Community solar subscription for a second, 42 MW_{AC} solar PV plant at the TLH the airport has been slower, possibly, in part, due to the timing, with the plant coming online just prior to a major economic slow-down due to the global pandemic[22]. It is unclear the degree to which other factors are contributing to this, such as the continuing decline in the cost of solar.

[20] STATE SUPPORT: plans and policies that support grid modernization, CUSTOMER ENGAGEMENT: rate structures, customer outreach, and data collection practices, GRID OPERATIONS: benchmarks the deployment of grid modernization technologies such as sensors and smart meters.

[21] The solar rate replacing the fuel charge remains fixed until Sept. 30, 2037.

[22] Commercial operation date (COD), Dec. 26, 2019.

Declining Marginal Value with Increasing Penetration

There are not necessarily major reliability-only barriers to PV deployment. The primary ceiling on PV penetration levels today is economic—at high enough penetrations, the value PV provides to the power system on its own declines. To push past that barrier, which Florida has not yet reached, system flexibility, especially the ability to shift energy use from low-solar to high-solar times, becomes an important consideration. Storage can help mitigate the declining marginal value by re-establishing temporal alignment of energy production with energy demand.

Figure 43. A 20 MW_{AC} solar PV plant located at Tallahassee International Airport (pictured above) went into commercial operation December 13, 2017. The plant production supplies the City of Tallahassee Electric Utility and its first Community Solar program, which was soon fully subscribed. A second solar PV plant, rated at 42 MW_{AC}, went into commercial operation at the airport on December 26, 2019, making the combined installation, at 62 MW_{AC}, the world's largest airport-based solar facility [37]. (photo credit: J. Kearney, Nhu Energy)

STRATEGIES FOR SOLAR+

Our objective is to inform realistic strategies that can be applied to successfully chart a path to a future electric power system in Florida that will rely heavily on clean low carbon and distributed energy resources including solar and energy storage. One approach to organize solar+ strategies for consideration is in the context of the issues and opportunities they are most aimed at addressing. To that end, the discussion that follows considers solar+ strategies having to do with Physical Deployment, and Customer/Societal Value, and Electric Grid Planning and Operation.

A project team workshop exercise provides a first high-level perception of some strategies relevant specifically to Florida municipal electric utilities, as shown in Table 7, The strategies are categorized by whether they were already being pursued ("existing/new") and according to perceived priority/viability (see also Appendix B for a version of the original list).

Table 7. Municipal strategies and near-term viability, from FAASSTeR workshop discussion.

Existing or New / Near-term Viability	Strategy
Existing[1]	• Utility-Scale Community Solar • BTM Storage + Net Billing + TOU Energy and/or Demand • Reduce Solar + Interconnection Timelines – Identify and Eliminate Bottlenecks
New[2] /Higher	• Floating Solar • Incorporate Storage in Solar PPA RFP's • PPA 2.0 – Incorporating Additional Value Streams and Services into PPA Structure • Solar Curtailment • Critical Infrastructure Resiliency Projects • Demand Response (solar + DR) • Supporting Transportation Electrification • Forecasting Improvement (solar and load); Increasing Dispatch Frequency
New[2] /Lower	• T&D Deferral / NWA Projects • Municipal reserve pooling across BA's

1. *Existing: employed at 2 or more;*
2. *New: employed at 1 or none*

Physical Deployment

Physical deployment here refers to all scales of solar PV and energy storage, from residential behind-the-meter (BTM) to utility scale and everything in between. As discussed in this report, Florida's solar growth has been dominated by utility-scale solar (Figures 13, 14), and, that is set to continue for at least the next 2-3 years according to current planned projects and initiatives communicated by Florida's electric utilities in their Ten-year Site Plans submitted to the Florida PSC [71] and elsewhere.

Addressing Land Availability

On the FAASSTeR project, researchers at the National Renewable Energy Laboratory (NREL) examined various scenarios for distributed generation growth potential specifically for Florida. Rooftop solar and floating solar are realistic options for Florida to significantly expand solar without requiring additional land.

Three strategies that can help address land availability challenges are:

1. Find alternatives to land, which would include rooftop, parking canopies, and floating solar.
2. Promote dual-use, e.g. with agriculture or co-location with industrial and mining operations
3. Increase land utilization, i.e. increase solar PV power and energy density, which can be improved through increased efficiency (e.g. advances in panels and inverters) and/or increased capacity factor (e.g. with single-axis tracking).

There are also potential benefits if the siting of distributed energy could be more integrated with state and local land-use and growth-management activities. With collaboration between energy key stakeholders (e.g. utilities, the public service commission, independent power producers and developers) and planning groups, it is possible that areas could be designated, even possibly "zoned", for distributed energy such as solar PV and energy storage.

Rooftop Distributed Solar

Rooftop solar expansion provides a path to grow solar that does not require land. While it is limited by availability of suitable roof space, rooftop development of solar PV in Florida is currently very low. Through 2020, *net-metered solar*, which is mostly rooftop, was less than 1.8% of generating capacity in Florida. According to LBNL research published in 2019 on commercial rooftop solar PV, Florida's *commercial* rooftop solar PV penetration is less than 0.4% [72].

The potential for future growth of rooftop solar in Florida is large. Based on NREL analysis of DHS LIDAR data taken from 2006-2014 for 123 U.S. cities, Florida has 76.2 GW of rooftop solar PV potential [73]. The actual potential is likely significantly larger due to the fact that 1.) the LiDAR analysis only covered areas around certain cities (Figure 44), and, 2.) the data is over 6 years old (as of the date of this report), and, there, has since been net growth in commercial rooftop potential in Florida due to continued commercial property development. According to NREL analysis on the FAASSTeR project, the residential rooftop solar PV potential in Florida is approximately 54.8 GW. For reference, the total firm net summer electric power capacity in Florida as of Jan. 1, 2021, is 57.1 GW[23] [74].

Figure 44. Florida cities considered in 2016 NREL analysis of U.S. rooftop solar PV potential [73].

Floating Solar

Deploying floating solar PV (FPV) is one viable strategy Florida can use as an alternative to ground-mount PV systems. FPV can potentially increase PV panel efficiency and can reduce evaporation losses, algae growth, the formation of waves, and coupled erosion effects [75]. According to an NREL study published in 2018, 10% of US generation needs could be provided from FPV deployed on just 27% of suitable man-made water bodies in the US [76]. According to that same study, the potential annual generation from FPV in Florida would be between 23 TWh and 120 TWh per year, enough to meet 50% to 100% of Florida's total annual energy production in 2016. Most of the suitable water bodies in Florida fall into the use-

[23] Noting, that most of solar PV's rated capacity cannot be counted as firm generation.

categories of "control, stabilization, and protection" or "water supply". The NREL study also shows that Florida has the largest cumulative surface area of feasible water bodies, on the order of 740,000 acres, and, along with California, Arizona, and New Jersey, the highest average land values, between $6,579 and $12,905 per acre (Figure 45).

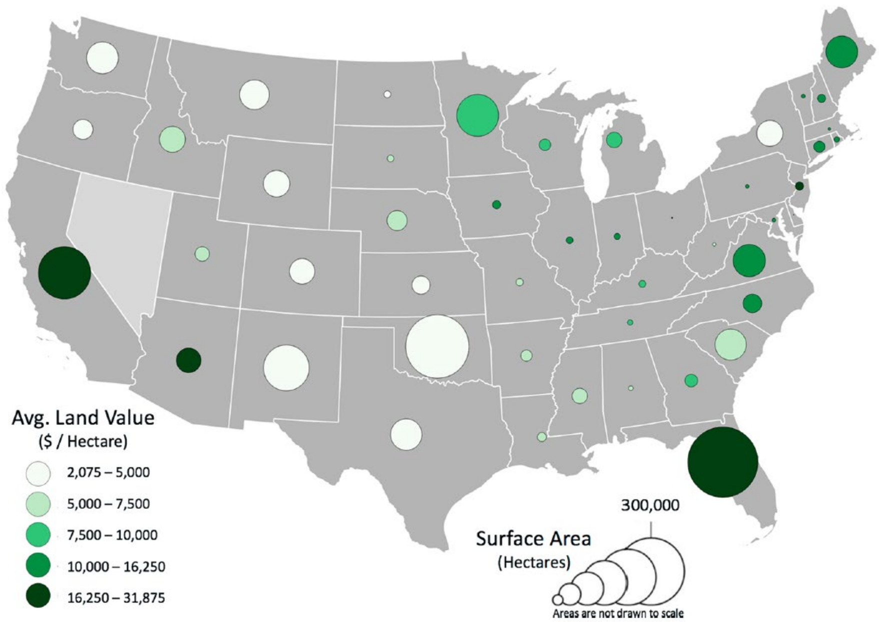

Figure 45. Cumulative surface area (dot size) of feasible U.S. water bodies for FPV installations by state and the associated land values for state (dot color). Circles are not drawn to scale of states. (Reprinted with permission from [76], Copyright 2019, American Chemical Society.

FAASSTeR utility core team partner, OUC, installed Florida's first floating solar installation, a 31.5 kW_{AC} system, at its Gardenia Operations Center in Orlando area in 2017 (Figure 46), and has since expanded the system to nearly double the capacity to 59.2 kW_{AC}. And, two additional FPV systems have been installed in OUC's service territory, a 123 kW_{AC} system at Orlando International Airport and a 249 kW_{AC} system at Universal Orlando Resort. FPL and Miami-Dade have installed a 157 kW_{AC} system at Miami International Airport. Most of these systems have been installed on retention ponds.

Table 8. Floating solar PV (FPV) installations in Florida

Location	Utility	Capacity	COD
OUC Gardenia Operations Facility, Orlando, FL	OUC	59.2 kW_{AC}	2017
Orlando International Airport, Orlando, FL	OUC	123 kW_{AC}	2020
Miami International Airport, Miami, FL	FPL	157 kW_{AC}	2020
Universal Orlando Resort	OUC	249 kW_{AC}	2021
Florida Conservation and Technology Center (FCTC), TECO Big Bend Station, Apollo Beach, FL	TECO	1 MW_{AC}	2021
Regional Water Reclamation Facility, Altamonte Springs, FL	AEU	960 kW_{AC}	2022

And, FPV installations are getting larger. Tampa Electric Co. (TECO) is having a 1 MW_{AC} FPV system installed, scheduled to come online in 2021 or early 2022, and, the City of Altamonte Springs and the Altamonte Electric Utility (AEU) have a 960 kW_{AC} system coming online in 2022 to provide resilient power for a water reclamation plant. All of these systems are supplied by Florida companies, and, one, the TECO installation, includes floatation systems manufactured in Florida. Table 8 provides a summary of these Florida FPV installations.

Figure 46. A 31.5 kW_{AC} floating solar array installed in 2017 at Orlando Utility Commission's (OUC's) Gardenia Operations Center in Orlando, FL. In 2020, the system was expanded to 59.2 kW_{AC}. (photo courtesy J. Kramer, OUC)

Dual-Use Applications and Reducing PV Land Impact

Given the continued development of large utility-scale solar PV plants, it is important to consider land impact and opportunities for co-location and dual use with agriculture. If properly considered at the development stage, large-scale solar PV plants can be designed in beneficial ways [77], including:

- Water quality protection – Perennial ground cover that reduces runoff, soil conservation, vegetated wetland and waterway buffers
- Habitat value – Pollinators, small mammals, birds, reptiles
- Agricultural opportunities – Apiaries, grazing, high-value hand-picked crops, pollinator benefits for nearby crops

Properly selected vegetation, and, possibly vegetation combined with grazing can provide benefits to solar PV, such as 1.) increasing efficiencies by lowering temperatures beneath panels, and, 2.) reducing O&M costs associated with vegetation management.

Agriculture co-location applications include:

- Pollinator habitat
- Shade to reduce water, thermal, and radiation stress on crops and vegetation

- Water harvesting and redistribution (with systems designed for that added to solar PV assemblies/structures)
- Grazing

Benefits can include increasing agricultural yields in arid conditions, providing energy, water, and food security in remote, possibly off-grid areas, providing pollinator habitat and associated benefit to crops, providing additional revenue stream (to solar plant owner/operators or to farmers, land-owners), vegetation management from grazing and nutrition and land for livestock, and more. For grazing and vegetation management, sheep are commonly employed[24] [78]. At a 7 MW solar farm in JEA's service territory in Jacksonville, FL, between 80 and 100 sheep graze the property daily (Figure 47).

The DOE-funded InSPIRE project has provided a guidebook, available online [79], that addresses up-front siting and screening, native vegetation and pollinator habitat, and agricultural co-location.

Figure 47. Solar PV sites can be compatible with sheep grazing, which provides vegetation management and revenue for livestock owners, as pictured above at a JEA 7 MW solar PV plant in the Jacksonville, FL. (photo, courtesy R. Brown, JEA).

Increasing PV Plant Power and Energy Density

Land-use can be reduced by increasing the power and energy density[25] of solar PV plants, thus reducing the area required for the same power or energy rating. There are a number of approaches to this that will not be discussed here in detail, for which there exist ample published research and reference material. These include:

- Higher efficiency PV panels
- Bi-facial PV panels

[24] "Various livestock, and sheep in particular, may be sensitive to the preexisting mineral contents of the soil, and proper soil testing should always be done prior to grazing", see [78].
[25] 'Power density' = 'peak power output' / 'land area'; 'energy density' = 'annual energy output' / 'land area'.

- Higher efficiency inverters
- Tracking systems (most often single-axis)
- Plant architecture and selection and placement of DC optimizers (MPPT's)
- Optimized Inverter Load Ratio (ILR)

Utility scale solar PV plants developed and under development in Florida are a mix of fixed-tilt and single-axis tracking. Individual utility or owner-operator experience with plant performance and lifecycle costs doesn't always match published data and expectations that particularly concerning total cost of ownership advantages of tracking. Unique to Florida and other coastal states is the need for solar PV plants to withstand hurricane force winds. Tracking systems add to the number of components and the cost and complexity of achieving the necessary wind resistance. Trackers have some advantage in hurricanes in that they allow the tilt to be set to zero, reducing wind load somewhat. However, there is still lift on the panels, even in a horizontal position, as they are always still several feet off of the ground. Tracking systems have been rendered inoperable in some cases on utility-scale solar PV systems following hurricanes.

The ratio of the installed DC power capacity of a solar PV plant to the rated AC output capacity (of the inverters), also known as the inverter load ration (ILR), has increased in recent years. Looking at 42 Florida solar plants in the 2020 LBNL Utility-Scale Solar Update database [80], the average ILR for 2009-2011 was 1.11, and the average ILR for 2015-2019 was 1.40 (Figure 48).

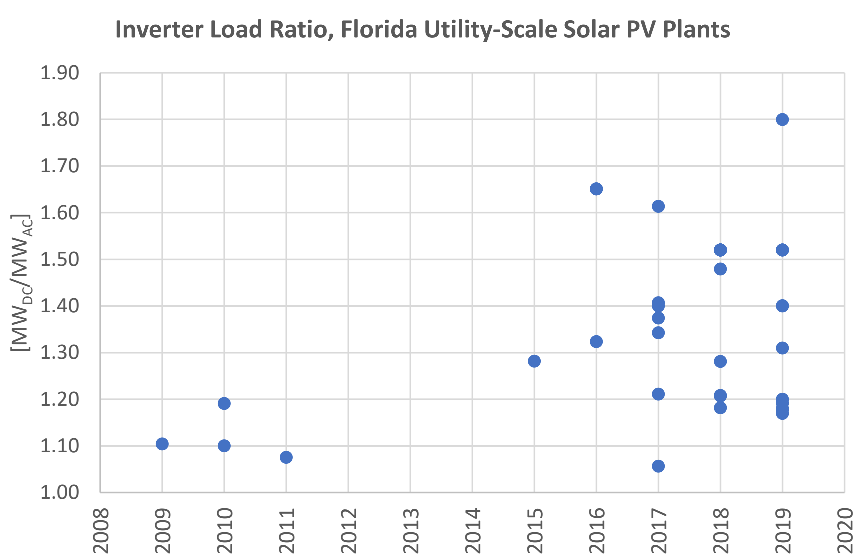

Figure 48. Inverter load ratios (ILR's) on Florida solar plants have generally increased over time, as shown here for 42 utility-scale solar PV plants in the 2020 update of the LBNL Utility-Scale Solar database (with data through 2019). (derived from data in [80]).

Increasing the ILR takes advantage of lower PV panel costs to increase inverter capacity utilization. For a fixed-tilt PV system, it has the effect of making the solar PV plant daily power output profile more resemble a single-axis tracking system. Determining the optimal ILR is somewhat complex and must consider PV irradiance profiles for the specific location, the installed costs and LCOE of the DC portion of the plant and the AC portion of the plant, off-take price (in case of PPA) or utility cost of generation (for utility-owned), and system load profiles throughout the year.

Customer/Societal Value

Utility-scale and Community Solar

Utility-scale solar plants offer the opportunity for a broad spectrum of customers to have their energy supplied by clean renewable resources, especially those who are not in a position, due to location or economics, to invest in their own solar systems. In the near-term, utility-scale community solar has provided a means for utilities to make the business case for solar and speed the deployment for customers willing to pay somewhat more than their current energy costs based on the existing generation mix. As mentioned, Florida municipals initially found robust customer interest in this approach and have had good participation. The City of Tallahassee Utilities' strategy for community, as described previously, was to offer customers a fixed cost replacement of 5 cents/kWh for the fuel charge on the bill, guaranteed to remain constant far into the future.

More recently, FPL petitioned the FL PSC to introduce the largest community solar program in the country, using an innovative rate design [81]. With this new program, known as "SolarTogether", customers subscribe to a portion of 1,490 MW of solar at 20 new 74.5 MW solar power plants across FPL's territory and receive credits that over the long run save them money on their total electricity costs. The Settlement Agreement, excerpted from the FL PSC FINAL ORDER approving the program, filed March 20, 2020, is provided in Appendix D. As part of the Settlement Agreement, FPL will allocate 10 percent of the residential capacity, or 37.5 MW, to low-income customers.

Transportation and Mobility Electrification

The degree to which conversion to electric vehicles moves transportation towards carbon-free mobility and helping to limit global warming depends on the level of decarbonization of the electric grid supplying charging infrastructure. It is also important to ensure the electric grid can absorb the demand placed upon it by a vast charging infrastructure and an increasing rate of conversion to EV's.

Figure 49. Solar EV charging canopy at the Dwellings sustainable housing development in Tallahassee, Florida (photo: R. Meeker, Nhu Energy).

Strategies to decarbonize the electric grid are already underway, and solar+ clearly will play an important role.

An additional strategy to consider specific to electric vehicle charging infrastructure is *co-locating solar and energy storage at or proximate to fast-charging locations,* which could offer several benefits:

1.) Significant potential to increase the reliability and resiliency of these charging networks[26],
2.) Reduction in the amount of investment in T&D infrastructure to support charging, and,
3.) The ability to ensure electric transportation will truly be carbon-free.

Presently, most charging stations in the state are electric grid powered and do not include energy storage. An example of a solar canopy covered parking area with solar-powered EV charging is shown in Figure 49. The solar PV installation shown in the figure is located at The Dwellings [83], an innovative low-income sustainable housing development for the financially, socially, or institutionally disadvantaged, located in Tallahassee, Florida.

Electric Grid Planning and Operation.

System Planning

There are many ways in which the significant expansion of solar+ becomes an important consideration in electric power system planning. In the context of strategies for expanding solar+, the research reported here focuses on two in particular: 1.) the ***capacity value*** of solar and energy storage, and 2.) ***reserve requirements*** with increasing solar penetration. Both of these affect "resource adequacy", which assesses if electric system resources will be sufficient to meet requirements over a time horizon according to some planning criteria, which includes ability to serve load.

Operations

Integrating solar into the electric power system at high penetration levels comes with certain technical risks and operational challenges. At system-wide[27] solar PV penetration levels above 10% of peak power generation, adjustments to operation, including solar PV curtailment, can become necessary. As penetration increases, balancing generation and load becomes increasingly challenging. NREL research finds "very high" penetration levels of 55% of energy on an annual basis are possible, but require grid operations that look very different from today [84]. This future grid, with very high instantaneous penetration of inverter-based resources (IBR's) would routinely experience high net-load ramp rates and many hours of excess supply or zero energy prices in wholesale markets. Strategies for operating this future grid would include solar PV curtailment and intelligent use of energy storage to play an active role in balancing supply and demand. This includes effective integration of forecasting. It also may include new market designs and compensation mechanisms for sources of energy that have no variable costs. Strategies for managing these potential risks and impacts include, roughly in ascending order of cost and ease of adoption (Figure 50):

1. **Adjustments to operating practices for dispatch and reserves**
2. **Greater use of forecasting / improved forecasting, particularly solar**
3. **Demand response / flexible load**
4. **Locating solar for aggregation (variability reduction) and system support and resilience benefits**
5. **Use of solar curtailment**
6. **Deployment of energy storage**
7. **Increased reserve sharing and possibly pooling reserves across balancing areas**

[26] Florida has considerable experience with impacts of extreme events such as hurricanes on transportation and fueling infrastructure and other interdependent infrastructures and has identified that as an important consideration in planning for the expansion of EV charging infrastructure.
[27] "system-wide" generally referring to an entire electric utility service territory.

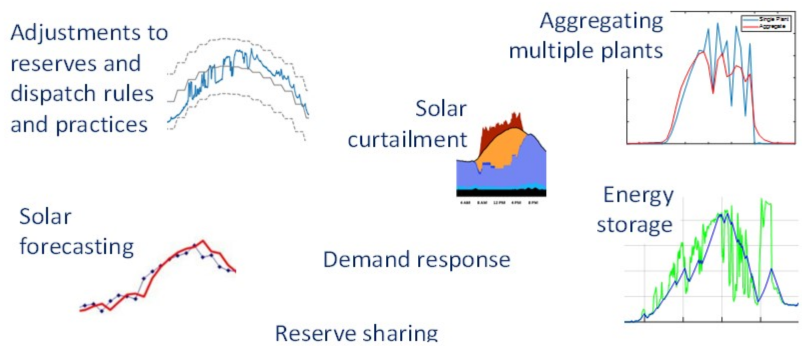

Figure 50. Strategies for system-wide growth in solar

Improving Forecasting

Electric power system variability and uncertainty both on the generation and load side are increasing. On the generation side, it is primarily from variable renewable generation such as solar. On the load side, electrification, especially conversion of transportation to electric, can be expected to increase variability and uncertainty. As daily and seasonal weather and climate factors are significantly correlated with electric load, changes in weather patterns and climate also may impact load uncertainty and forecasting error.

As solar PV penetration increases in the Florida electric system, integrating solar forecasts into scheduling and dispatch operations, or improving forecasting where it is already in use, will reduce uncertainty, helping to lower costs and improve reliability. With improved forecasting of both solar and load, economic dispatch of generation can be improved, resulting in lower cost. This includes better use of least-cost units, less generation plant cycling, and less starting of fast-start open-cycle gas-turbine (OCGT) or reciprocating internal combustion engine (RICE) units. It can also reduce regulation and load following reserve requirements.

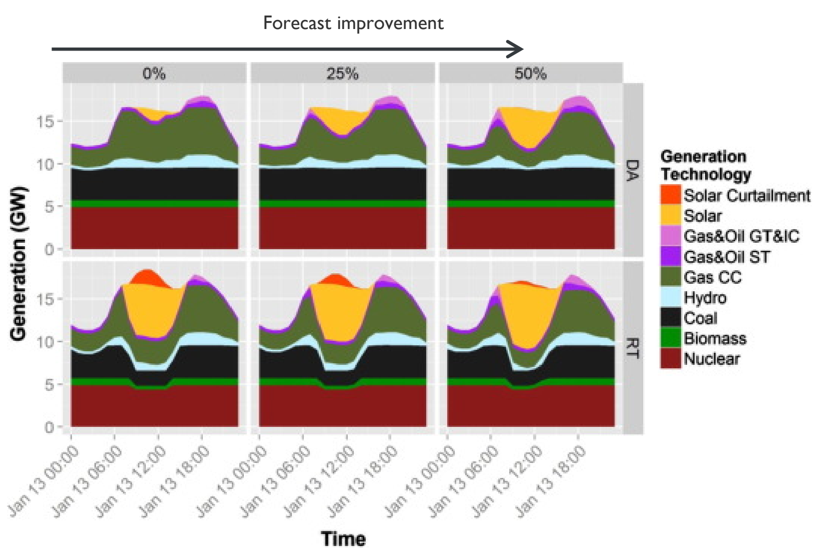

Figure 51. Generation dispatch stack for one day for the Day-ahead forecast (top row) and Real-time markets (bottom row) [85].

Increased forecasting accuracy can reduce the need to curtail solar, as shown in the dispatch stacks in Figure 51, comparing forecasts (top) and actual real-time operation bottom, for increasing forecasting accuracy, left to right. [85]

Solar forecasting is needed on different timescales. Many power plants need notice before they can be available to produce energy. A typical demand forecast is produced a day ahead of the time in question so that generators can be ready for operation the next day. As solar penetration becomes significant in the system, the forecasting process needs to include a day-ahead renewable energy production forecast. While a day-ahead forecast will not be as accurate as a shorter timeframe forecast, it can typically provide the system operator with enough information to plan for the amount of thermal generation that will be needed in the next day. Lack of forecasting or poor forecasting can lead to cost overruns and reliability issues. For example, if the system operator starts a plant today which is not needed tomorrow, it leads to needless fuel costs which could have been avoided. Conversely, if the system operator does not start a plant that will be needed the next day, generation may fall short of demand and cause reliability issues for the end-use customer.

Renewable energy forecasting is also essential to managing the intra-day economic dispatch. For example, if the system operator expects large thunderstorms forming at or moving into in the areas where solar generation is located, thermal units can be notified and ready to ramp up during those periods. While more frequent forecasts do provide greater accuracy, they are only useful to the system operator up to the timeframe in which actions can be taken in response to the forecast.

Different forecasting methods are needed for different timescales. Short-term forecasting, from sub-hourly (SH) to 1-3 hours ahead (HA) may employ sky-imagers and/or satellites. Day-ahead forecasting often employs numerical weather prediction (NWP) models. Forecast errors need to be factored in when integrating forecasting into intra-day and/or day-ahead operations.

Net PV Ramp Reduction Through Geographic Dispersion

One readily available method to mitigate extreme solar power ramping is aggregation of geographically separate solar plants. Research has shown that geographic diversity can help mitigate sub-hourly variability for sites within a utility service territory [86], [87]. This is a benefit arising naturally when power is combined from solar plants from different physical locations. Power fluctuations are smoother in the summed output of the separate plants because cloud activity is different in different locations – if it's cloudy over one PV plant, at the same instant in time, it may be sunny over another PV plant. This power smoothing due to PV plant aggregation helps reduce power fluctuations in the overall system but does not help mitigate more localized impacts on transformers and distribution feeders, and localized voltage fluctuations. So, the natural smoothing effect of solar aggregation is evaluated here, but may not necessarily be a complete solution to smooth solar power ramping.

Using data from previous years from existing PV plants in Jacksonville, Florida, we were able to study the ramping behavior of all the existing solar plants in aggregate compared to ramping behavior of a single plant.

Changes in output power of a PV plant were measured across a year's worth of data for every time interval from 1 minute to 60 minutes, in increments of 1 minute. The maximum ramp of the year at each time interval was determined for both an individual site and the combination of all existing plants in Jacksonville. The data for the individual site were taken from Jacksonville Solar and the data for aggregate

PV power were taken from Jacksonville Solar, Northwest JAX Solar, Starratt Road, Old Plank Road, Simmons, Blair, and Old Kings Solar. Resulting maximum ramps for a single versus aggregate of 5 plants are shown in Figure 52.

These figures show that the most extreme ramps seen over the course of a year are much lower for aggregated solar than for a single PV plant site. If we look at ramps that happen at the 20 minute or less time scale, the single plant most extreme fluctuations were roughly between 60% and 90% of total nameplate capacity, whereas the aggregated sites most extreme ramps were between 30% and 60%, much lower. For ramp intervals above 20 minutes, the single site most extreme ramps were in the 80% to 95% range, whereas aggregate ramps were only between 50% and 75%.

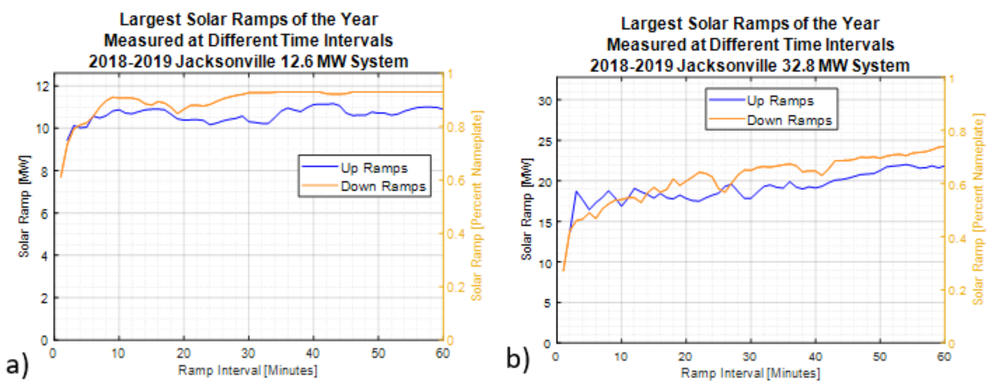

Figure 52. Comparison of most extreme ramps over a one-year period measured at time intervals from 1 to 60 minutes, in (a) single and (b) aggregated PV plants.

These figures show that the most extreme ramps seen over the course of a year are much lower for aggregated solar than for a single PV plant site. If we look at ramps that happen at the 20 minute or less time scale, the single plant most extreme fluctuations were roughly between 60% and 90% of total nameplate capacity, whereas the aggregated sites most extreme ramps were between 30% and 60%, much lower. For ramp intervals above 20 minutes, the single site most extreme ramps were in the 80% to 95% range, whereas aggregate ramps were only between 50% and 75%.

We also measured how frequent ramp events were in a year for aggregate and single-site solar PV power output, shown in Figure 53. Each line represents a ramp of a given magnitude expressed in percent of nameplate capacity. We see that the frequency of extreme ramp events is drastically lower in the aggregated site power for all ramp intervals and magnitudes. In the 20 minute or less time scale for the single site, ramps exceeding 50% occurred on almost 200 days over the course of a year, whereas for the aggregated plants, ramps of more than 50% nameplate capacity happened only 10 days of the year at most.

Another illustration of the drastic difference in rampling is that in the 10 minute range, we see that ramping of over 80% of nameplate capacity occurs for a single plant, whereas we see only a handful of ramps over 50% for aggregate plant.

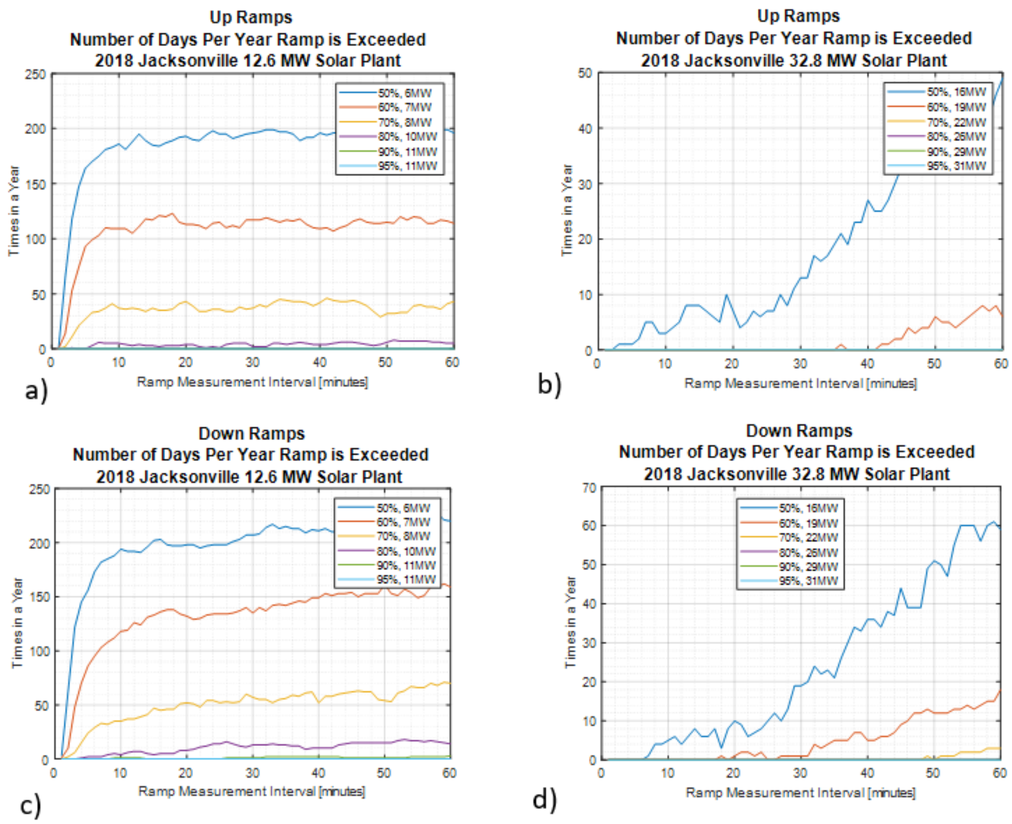

Figure 53. A comparison of number of up-ramps per year measured at time intervals from 1 to 60 minutes, in (a) single and (b) aggregated PV plants. A comparison of down ramps in (c) single and (d) aggregated PV plants.

To further illustrate the point that significant smoothing happens with aggregation of PV plants, in the aggregate solar data, a change in solar of more than 60% of nameplate is never seen in 18 minutes or under, and a solar ramp of 50% nameplate capacity happens less than 10x per year. These ramp-rate studies confirm that aggregating solar output from several plants results in significant smoothing of the output power.

Note that up ramps and down ramps are considered separately because down ramp tend to have different behavior than up ramps. Down ramps tend to have a steeper slope.

Energy Storage for Ramp Mitigation

As discussed, energy storage has many applications and multiple possible value streams related to integrating solar, including peak shifting and energy arbitrage to address power capacity and energy production timing issues, and ramp rate mitigation for rapid solar and load variation, along with ancillary services such as reserves and voltage and frequency regulation, resiliency, and providing black-start capability.

Florida municipal utilities expanding their solar portfolio identified ramp rate mitigation as a top priority, necessary to ensure continued ability to balance the electric system and meet NERC requirements. Both City of Tallahassee and JEA are nearing 10% solar PV penetration as a percentage of generation capacity. FAASSTeR project research has provided insight on sizing the power and energy capacity for batteries used for system ramp rate mitigation (whether the source of ramps is solar, load, or some combination). The required power rating and energy capacity, and therefore cost, are found to be significantly less for ramp mitigation than for peak shaving / shifting applications.

A methodology was developed for evaluating battery energy storage sizing, both the power and energy rating, for solar PV ramp mitigation. Provided as part of FAASSTeR technical assistance, the method was utilized to examine ramp sizing for several realistic scenarios Florida municipal electric utilities are facing.

Ramp control algorithm

A ramp control algorithm from the literature was chosen to implement to represent the cycling of the battery. The choice of algorithm was based on choosing an effective algorithm that meets the ramp smoothing objective with minimal use of the battery and minimal battery size when compared to other control algorithms. It is shown in [88] that moving average and filter-based control algorithms over-use the storage and result in a larger battery capacity requirement, and that ramp-based control algorithms are more effective. A ramp-based control algorithm uses a specified ramp-rate limit, and then only smooths solar output when ramping exceeds the imposed limit.

Of the ramp-based control algorithms, one was chosen that was easy to implement. However, other algorithms were shown to result in a battery size with 20% less energy capacity [88]. These other, more efficient algorithms were not used because of difficulty of implementation, so it should be kept in mind that the resulting battery sizes here are somewhat conservative. The chosen algorithm is from a method described by authors Marcos et al [89], hence forth referred to as the Marcos algorithm. The basic objective of the algorithm is to smooth solar ramps to within a specified rate in MW/min while simultaneously driving the state of charge of the battery to 50% between ramps. The reason for always driving the SOC to 50% after a battery charge or discharge is so that the battery is ready to provide smoothing for either a ramp up or a ramp down at any time. The algorithm was slightly modified in this study to have a battery setpoint of 58% because the battery capacity had more of a tendency to drain too low than to fill too high.

The block diagram in Figure 54 shows the operation of the Marcos control algorithm. Both the error of the ramp rate and the error of the SOC are accounted for in the control action to cause a result that strives to meet both objectives. This algorithm was implemented in MATLAB.

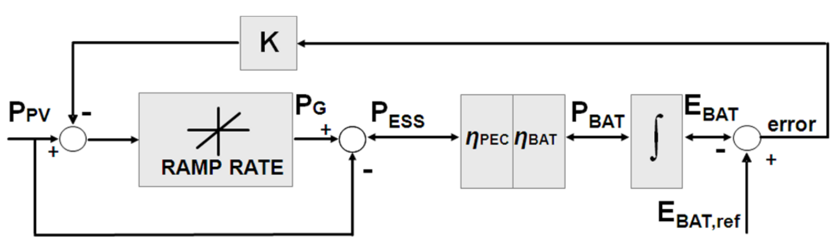

Figure 54.. Marcos ramp-rate control algorithm block diagram [89].

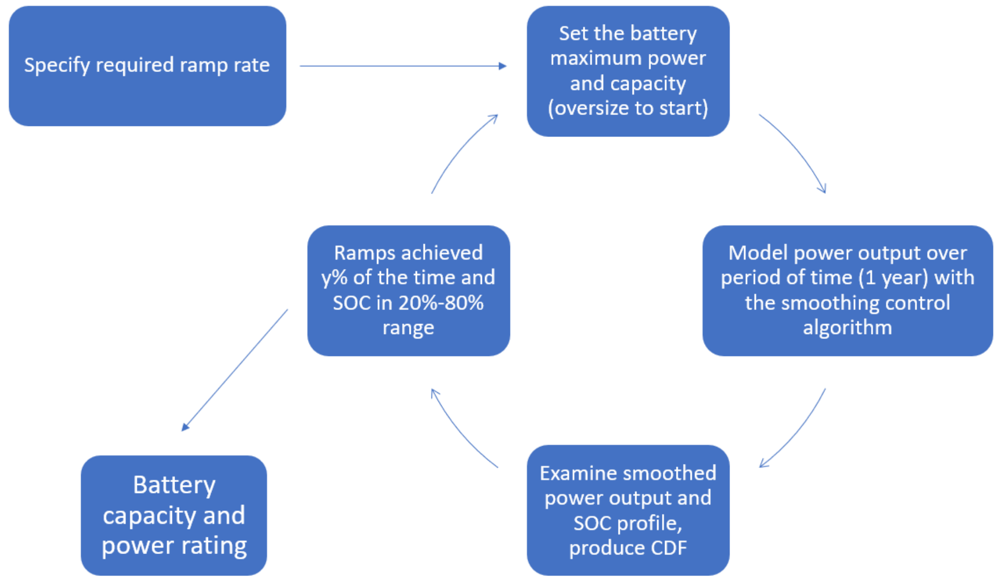

Figure 55. Flowchart of battery-sizing for ramp-mitigation process.

Process for battery sizing

Several ramp smoothing objectives were set and the battery was designed by iteratively running the control algorithm for one year and adjusting the battery size until the ramp mitigation objectives were met. The steps, as illustrated in Figure 55, are:

1. Specify ramp rate limit
2. Set initial battery energy and power capacity- start oversized
3. Run ramp control model for one year worth of data
4. Analyze output power from solar plant to the grid using a cumulative distribution function (CDF) to determine what percent of time ramp limit was successfully achieved.
5. Decrease battery power capacity if ramp objective was met in step 4.
6. Adjust battery energy capacity to keep battery state of charge within limits
7. Re-run model until minimum battery power and energy capacity are found that meet ramp limit and SOC range objectives

A cumulative distribution function was used to determine whether objectives were met. One objective was that the battery stays within the 20%-80% SOC range 99% of the time. This objective was set with an allowance for error because there were few times in a year the battery would go outside the SOC range, and this small tolerance was built in so as not to oversize the battery to accommodate only very occasional excursions. An example of a CDF is given in Figure 56. This shows a CDF of the power from solar plant to the grid before and after battery smoothing action.

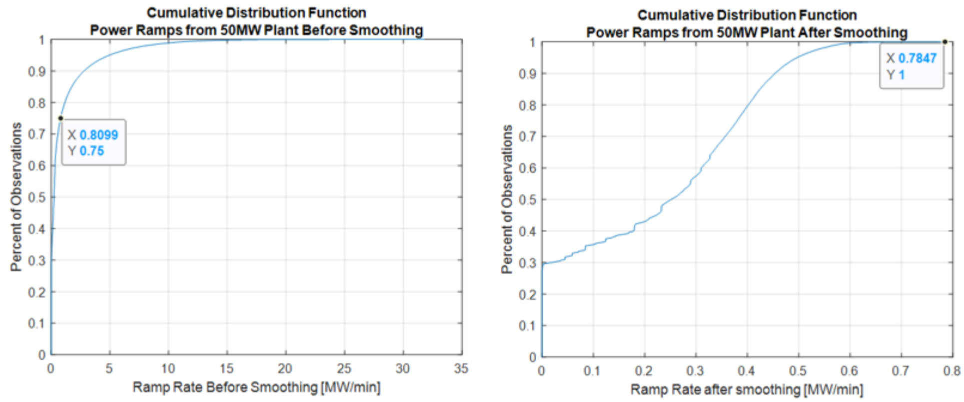

Figure 56. Cumulative distribution function of solar power ramps for 50MW plant. (a) Before smoothing: 75% of ramps below 0.8MW/min target and (b) After smoothing: 100% of ramps below 0.8MW/min target.

Cycling count method

A battery cycle is generally defined as one full charge and discharge of the battery. However, it is more difficult to define what one cycle is when the battery has an irregular charging pattern that never goes exactly from 0% to 100% charged in a straight line. Several methods have been developed to count battery charge cycles with irregular patterns. The two we will discuss are the rainflow method and the energy throughput method. The rain flow cycle counting method is useful for predicting the life-span of a battery, as it measures cycles at different depths of discharge and one can keep track of the average depth of discharge of the cycle along with the cycle count. Anyone designing and planning an energy storage system should be aware of the rainflow cycle counting method, but here, we are interested in the energy throughput method because it is the type of cycling count commonly used in warranties of battery manufacturers.

The energy throughput method counts the total energy in and out of a battery, no matter what SOC or depth of cycle the battery is at. Whenever the energy discharged and charged into the battery adds up to 100%, that is a full cycle. For instance, if a battery starts at 100%, then discharges down to 80%, it has undergone a 20% discharge. If the battery is then charged back up to 100% and back down to 80%, it has undergone another 20% discharge. If the battery does this 5 times, the battery has undergone 1 full discharge cycle, and it has undergone 1 full charge cycle when it charges back up to 100%. So, 1 full cycle is a combination of a discharge and charge cycle. To summarize, discharging from 100% down to 80% and back up again would count as 1 full cycle. This is illustrated in Figure 57. Any other combination of charging and discharging counts as a full cycle as long as it adds up to 100% change in SOC.

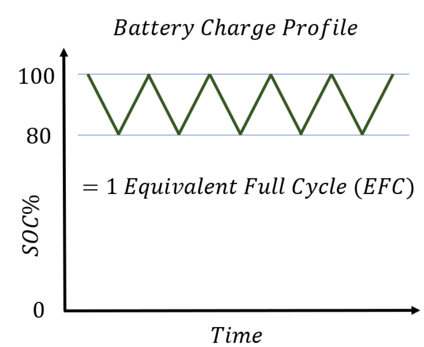

Figure 57. Energy throughput using battery cycle count method

Cost calculation

To fully estimate the cost of a battery, one would have to estimate the life cycle of a battery and then take into account how often one would have to replace the battery with the type of cycling for its intended use. Here, our cost calculation is slightly more simplified and is only calculating the up-front cost of the battery and installation, and then making sure the battery will not void a 10-year warranty by cycling too much. The assumptions used are from the NREL's annual technology baseline published in 2020 [90], and the projected costs for 2021. Some cost estimates of energy storage from various other sources are provided only in terms of energy capacity, and some cost estimates are given in terms only of maximum power output. The NREL ATB report is a good cost estimate source because it uses both energy and power capacity cost estimates. This is important because it is found that some aspects of the installation cost scale with power, such as inverter size, and some scale more with capacity [91][92].

The equation used to calculate the system cost in $/kW of an energy storage system is as follows:

$$Total\ System\ Cost\ \left(\frac{\$}{kW}\right) = Battery\ Energy\ Cost\ \left(\frac{\$}{kWh}\right) * Storage\ Duration(hr)\ + Battery\ Power\ Cost(\frac{\$}{kW})$$

For example, the system cost of a Li-Ion battery with a 10MW power and 40MW-h would be calculated as follows. The duration of the battery is 40MW-h/10MW = 4 hours. Using this equation, the cost per kW is:

$$280\left(\frac{\$}{kWh}\right) * 4hr + 244\left(\frac{\$}{kW}\right) = \$1{,}364(\frac{\$}{kW})$$

Then, using this cost metric, the total CAPEX of the system would be:

$$\$1{,}364\left(\frac{\$}{kW}\right) * 10 * 10^3 kW\ = \$13.6\ million$$

Assumptions

A battery energy storage system was assumed to have a battery round trip efficiency of 85% and a converter efficiency of 95% for a DC-connected case. The battery was designed to stay within 20%-80% state of charge to save battery life. For the first set of results, a ramp rate limit ranging from 1%/min-10%/min of the solar plant was chosen. And for the second set of results, a ramp rate of 4MW/min total for all five solar plants was chosen, breaking down to a limit of 0.8MW/min for each individual solar plant. At first it was also assumed that 100% of solar ramps exceeding limit should be mitigated, but through trial and error it was discovered that battery size could be extremely reduced if the same strict ramp limit was imposed, but with an occasionally allowed failure to meet the ramp restriction because of the battery SOC or maximum power output reaching its limit. Because of this feature, battery sizes were determined for the 0.8MW/min ramp-limit case for capturing 97%, 98%, 99%, 99.9%, and 100% of ramps above the limit.

Battery Sizing and location for 5x50MW solar installation

The control algorithm developed was used to determine battery size in terms of maximum power output in MW and capacity in MWh. Battery size was determined for the following scenarios:

1. A battery located at each 50MW plant (5 total batteries.)
2. One centralized battery to mitigate PV ramps from all 5 50MW plants cumulatively.

This method, based on [87], uses a battery dispatch control algorithm to regulate the amount of power from the PV plant that is sent to the grid. The battery smooths the up and down ramps of the PV power output to an acceptable level. The battery was allowed to charge from the grid in both cases. Figure 58 shows an example result of PV smoothing using this method.

The algorithm was applied to historic load and PV data from Jacksonville, with the PV power scaled up to planned PV installation levels.

The resulting battery size specifications are shown in Table 9. These are the minimum battery sizes to perform this PV smoothing requirement and the capacities are in the minutes range rather than the expected hours range. The battery sizes were calculated for several ramp-rate restrictions in terms of percent of nameplate capacity per minute. For example, looking at sizing a battery for limiting ramps to 5% of nameplate capacity per minute, for the single plant, the required battery power was 31.8MW and for the aggregated solar, the battery power required was 63MW. This enables the ability to make an informed decision about whether one, 63MW battery would be more desirable compared with five ~32MW batteries. Further results were needed because ultimately it is necessary to look at battery size for a ramp-rate restriction in a MW value rather than a percent-nameplate value. These results are presented in the next section.

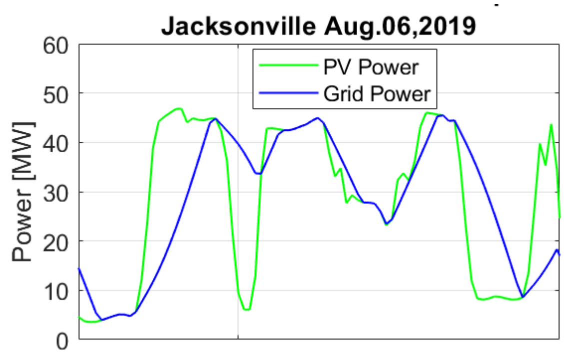

Figure 58. Typical PV smoothing effect of Marcos method using JEA data.

Table 9. Battery sizes for smoothing 50MW individual solar plant versus 250MW of aggregate solar

Battery sized for 50MW solar plant. 5 batteries of this size are required				Battery sized for 250MW aggregate solar. 1 battery of this size is required.			
Percent of Solar Nameplate Capacity	Battery Power [MW]	Battery Capacity [MW-h]	Duration at rated Power (minutes)	Percent of Solar Nameplate Capacity	Battery Power [MW]	Battery Capacity [MW-h]	Duration at rated Power (minutes)
10%/min (5 MW/min)	27.7	4.32	9.4	10%/min (25 MW/min)	48	3	4
5%/min (2.5MW/min)	31.8	8.08	15	5%/min (12.5MW/min)	63	10	9.5
2%/min (1MW/min)	38.2	16	25	2%/min (5MW/min)	83	20	14.5

Battery size requirement for smoothing net load

The previous result was for smoothing PV power directly from one or all of the PV plants. In this section, we will discuss additional battery estimates obtained with the objective of directly smoothing the net load. This would have the effect that the battery would be either absorbing or supplying load so that the load left to be handled by the traditional generators would be smoother. For the following analysis, battery size is obtained for a smoothing target in terms of an absolute MW/min ramp rate restriction.

Battery size was determined based on smoothing the Jacksonville system wide load minus projected aggregate solar for the 5x50 solar installation plus existing utility owned solar. This result is based on one single battery that would smooth all ramps in the system, as opposed to individual batteries to smooth output from each of the 5x50MW solar plants. Nhu Energy sized the battery for 2, 4, 6, and 8MW/minute to observe the general relationship between battery size and ramp rate.

The results are shown Figure 59. The behavior of the ramp-mitigation algorithm relative to battery size suggests that the relationship is non-linear, with the battery capacity increasing but leveling off as ramp-rate restriction becomes tighter. If the battery was designed to smooth net load at a specified rate of 4MW/min, then a 146MW, 1-hour battery would be required.

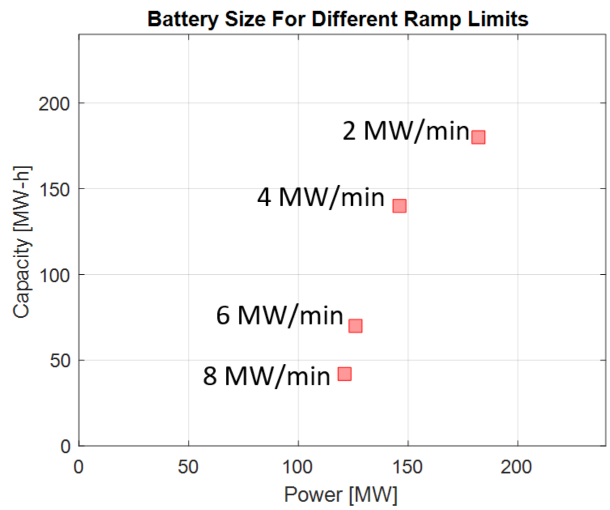

Figure 59. Battery size requirement for different ramp-rate restrictions.

Selecting a ramp-rate restriction

A critical step in utilizing the method described here is in the selection of the ramp-rate restriction. In the first stages of this study, several ramp-rate restrictions were chosen to gain insight into the relationship between battery size and ramp-rate restriction. For utilities considering energy storage for solar PV ramp mitigation, the ramp-rate restriction selection is driven in large part by the need to balance supply and demand *and* stay within NERC requirements related to frequency and ACE. At any given instant in time, the ramp-rate restriction requirement could be considered to vary depending on which generating units are online, how much the load is changing, the operating economics of the generators, the current operating point relative to limits specified in the relevant NERC standards, and, possibly, other factors. For simplicity, with input from municipal utility system operators and engineers, a 4MW/min was selected as the maximum ramp-rate limit for any added solar to the system.

For the case of 5 planned 50MW solar plants, in this analysis, batteries are sized so that each plant is limited to ramp at 1/5 the total limit of power flowing into the system. This results in a 0.8MW/min ramp limit imposed on each solar farm. This is illustrated in Figure 60.

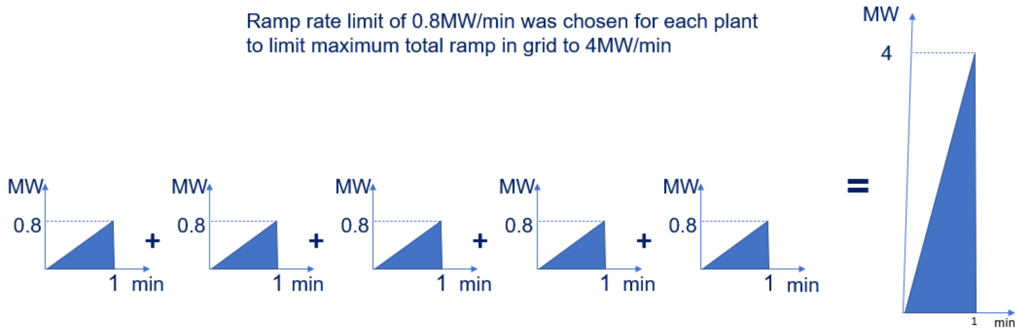

Figure 60. Choice of 0.8MW/min ramp-rate limit for each of 5, 50 MW solar PV plants.

If each one of the solar plants had a 0.8MW/min or greater ramp at the same time, the total added ramp to the system would be 4MW. Limiting each plant to 0.8MW/min is *a conservative estimate* because it is possible that while one plant ramps at 0.8MW/min, one or more of the others are not ramping at as great of a rate due to differences in cloud activity in the different locations, resulting in a total ramp of less that 4MW/min. Therefore, realistically, it would be possible that some of the five plants could be allowed to exceed 0.8MW/min without exceeding the overall system limit of 4MW/min.

Need to oversize battery to account for capacity fade

It is known that the capacity of batteries fades over time and furthermore it is specified in battery warranties that the battery is guaranteed to operate after a number of years, but only at a specified decreased capacity. For this reason, it is necessary to overbuild the capacity of a battery to take into account capacity fade. Otherwise, if the choice is made not to oversize the battery upon installation, it should be understood that additional capacity will need to be added in the future. The second option is not necessarily a bad idea because battery prices are projected to decrease as time goes on, so it may be a smarter economic choice to build what is necessary now and only expand in the future. However, for the sake of precise planning and not leaving anything to chance, battery size requirements included in this report are oversized take into account a 70% capacity fade over 10 years.

Battery size sensitivity to outlier events

Upon examining a year's worth of solar power data for a specific utility, it was observed that the most extreme ramps occurred on relatively few days. If these few most extreme, outlier days are ignored, allowing a small percentage of ramp excursions above the limit, the result is a drastically smaller battery size. Due to the fact that the battery size determined using this method is extremely sensitive to outlier events, we have provided additional battery sizes based on capturing out of bound ramps a smaller percentage of the time. These are reflected in the results in Tables 10 and 11 by showing a different column for percent of ramps kept below the objective for 97%, 98%, 99%, 99.9%, and 100% of solar ramps. For example, only requiring the battery to meet its ramp smoothing objective 99.9% of the time instead of 100% of the time reduced the battery power requirement from 40 MW to 26.1 MW.

ITC impact

We considered the impact of the ITC credit which is still in effect until the end of 2022. One of the requirements of the credit is that the battery be charged from 70% or greater from solar. The easiest way to show that the battery is charging from solar is to have the battery be DC connected directly to the solar plant. If the battery was to be grid connected, JEA could claim that the battery is charging from solar but it is difficult to prove because power is allowed to flow from different sources on the grid, and the IRS may dispute the claim that the battery is being charged from solar power.

In order to compare the difference in design of the battery system with and without the ITC credit, we created one version of the battery model/algorithm where the battery can charge only from solar and is DC connected, and another version where the battery can charge from the grid at night. In the second case, the battery is still assumed to be co-located with the solar and DC connected, but power is still able to flow from the grid to the DC side where the battery is located. The results for the battery which charges only from solar, and thus is guaranteed to obtain the ITC credit, is shown in Table 10. The results from the battery which can charge from the grid are shown in Table 11.

Battery cycling compared with warranty requirements

It is somewhat difficult to obtain battery warranty info regarding cycling for large-scale BESS projects, because the warranty terms are sometimes negotiated as part of procurement for specific projects. Commercial-scale battery warranties were observed in the range of 2000 cycles for a smaller battery to 10,000 cycles for a larger battery for a 10-year warranty. We computed the number of cycles for each battery size determined based on the oversized battery capacity in year one and assuming the battery degrades and loses capacity linearly until year 10 when it is at 70% of its original capacity. The method used for counting cycles is the energy throughput method.

The resulting battery sizes and cycles over 10 years are also shown in Tables 10 and 11, taking into account the revised ramp-rate restriction, oversizing the battery to account for capacity-fade over time, allowing ramp limit excursions a small percentage of the time, and considering the ITC impact.

Table 10. Battery size results, charging from solar only

Percent of Ramps Kept Below 0.8 MW/min	97%	98%	99%	99.9%	100%
Power Capacity [MW]	10.7MW	13.25MW	17.1MW	26.1MW	40MW
Energy Capacity [MWh]	14.8MWh	15.6MW-h	15.7MWh	26.2MWh	52MWh
Oversized Energy Capacity*	21.14MWh	22.3MW-h	22.4MWh	37.4MWh	74.3MWh
Cycles over 10 years	1991	2096	2277	1464	606

*accounting for 70% capacity fade in 10 years

Table 11. Battery size results, charging from solar during the day and grid at night

Percent of Ramps Kept Below 0.8 MW/min	97%	98%	99%	99.9%	100%
Power Capacity [MW]	10.7MW	13.1 MW	17 MW	26 MW	40 MW
Energy Capacity [MWh]	15.2MWh	15.6 MWh	15.6 MWh	26 MW-h	34.0 MWh
Oversized Energy Capacity*	21.71 MWh	22.29 MWh	22.29 MWh	37.14 MWh	48.57MWh
Cycles Over 10 Years	2013	2159	2361	1590	1256

*accounting for 70% capacity fade in 10 years

Several observations can be made based on these results. Battery sizes are extremely sensitive to percent of ramps captured. If the battery was sized to allow a solar ramp that exceeded the limit some percent of the time, a significantly smaller battery size could be achieved. These time percentages are of daylight hours, which are 4,451 hours per year. For instance, 99.9% of ramps captured corresponds to only having 4.5 cumulative hours per year where ramps exceed the limit due to limited battery power output. Consider the grid-charging battery case in table 11. For 100% of ramps captured, the battery power requirement is 40MW, whereas if we require only 99.9% of ramps captured, the battery power requirement is 26MW. This is a 35% reduction in power capacity required with only sacrificing 4.5 hours per year of effectiveness of the battery. This may be a worthwhile tradeoff.

Another result to consider is the expected number of battery cycles over 10 years. The cycles over 10 years found in this study ranged from 606 to 2361, which is within the range presumed to be allowed within most 10-year warranties. While it may not be possible to predict for certain what cycling numbers will be in the battery warranty, these figures should help with negotiating the warranty and knowing how many battery cycles are required for the battery to accomplish its task over 10 years.

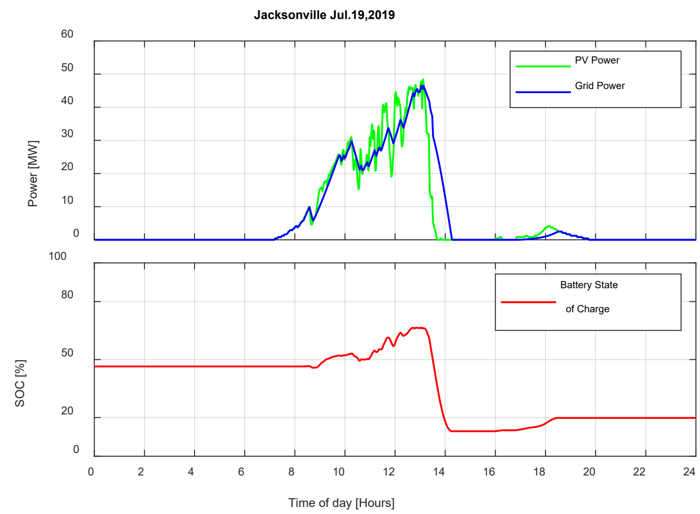

Figure 61. Extreme ramp event from 2019 data

A tradeoff in designing the battery with and without considering the ITC impact can also be deduced by comparing Tables 10 and 11. No significant increase in battery power or energy capacity was required for charging the battery only from solar versus allowing the battery to charge from the grid. This is because the biggest solar ramps happen in the middle of the day, and no matter how you charge the battery, it is always possible to charge the battery up to its setpoint by the middle of the day. So, charging the battery at night doesn't help decrease the battery size required, except in the case of the strictest ramp requirement of capturing 100% of ramps. One day of data in particular was driving the battery size up in in the case of the strictest ramp restrictions, and this illustrates a possible but rare event. The day in question is shown in Figure 61, showing an extreme plummet in solar power in the afternoon when a storm appeared. In this case, the modeled battery drained so low from smoothing the huge solar plummet, that the battery could not get back up to its needed state of charge the next day without charging at night. Some further analysis and judgement based on the overall economic and operational

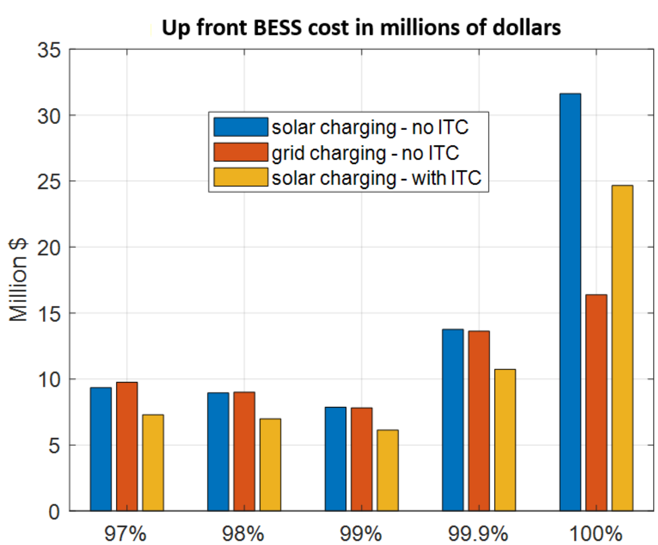

Figure 62. Battery cost comparisons

considerations is required to determine whether the battery should be sized for this type of extreme event, or whether other, already available ramp mitigation methods will be sufficient.

Figure 62 shows battery cost comparisons for the different design scenarios: Solar charging but without taking the ITC credit, solar charging with taking the ITC credit, and grid charging and no ITC credit. Before considering the ITC, similar costs result whether the battery is allowed to charge only from solar, or if it can charge from the grid as well. This is because, as stated earlier, charging the battery at night does not help much to cut down the battery size when the battery's task is ramp-smoothing. This is true except for the case of the robust design where the battery captures 100% of ramps, in which case charging from solar alone is much more costly. As long as the battery size is capturing less than 100% of ramps, it is the most cost effective to aim for the ITC.

Curtailment

When solar PV production exceeds expectations in higher PV penetration scenarios, it can cause excess generation supply in the system. This can arise, for example, due to load or solar PV forecast errors (larger than expected) and, as discussed previously, is more likely to occur in light system load "shoulder" months in the spring and fall. One strategy for addressing this is for the utility to have the capability to curtail solar PV plant power output. This requires technical capability within the solar PV plant inverters and SCADA system to accept a curtailment signal and some sort of communications path between utility operators and the solar PV plant. For IOU's, who normally own and operate utility-scale solar PV plants, implementing this is under their control. For municipal electric utilities, solar PV plants are usually owned and operated by third parties, under contract with the utility through a Power Purchase Agreement (PPA). In those cases, in addition to the practical matter of having the technical capability to curtail solar production, there must be some provision in the commercial terms of the agreement [93].

Utilities are planning for and, in some cases, already have this capability in place. For example, the City of Tallahassee has curtailment provisions in it's latest PPA for the 42 MW_{AC} solar plant located at Tallahassee International Airport. And, Duke Energy Florida (DEF) is incorporating the ability to place its solar facilities on Automatic Generation Control (AGC) "to prepare DEF for future scenarios where there is an excess of generation on the system and a need to utilize the solar resources to balance generation with demand. DEF is utilizing its operational experience and historic data from these solar resources to optimize the daily economic system dispatch, to quantify additional system flexibility needs to counteract the variability of solar generation and investigate potential fuel diversity contributions." [39]

A Municipal Utility Case Study

In this study, the aim was to determine how much over-production could potentially occur with 62 MW_{AC} of solar in the system. In order to do this, we considered what would happen if no measures were taken to prevent PV over-production. In reality, over-production would not simply be allowed to happen. However, making this assumption facilitates the creation of a baseline scenario for assessing over-production and comparing different methods of managing it.

Data from 2018 January-June was used to create a baseline scenario for estimating the potential for PV over-production. During this time period, 20 MW_{AC} of solar were already online. Data were only used for half of the year because the solar plant had frequent inverter outages and would represent inconsistent maximum outputs. The data sets used were solar PV power output from the 20 MW_{AC} plant that was online in 2018, the system load, net interchange, and the power profiles of individual units of the COT generating fleet. The solar data were scaled up to represent 62 MW_{AC} of solar power. The operating schedule of the generators was derived from the historic output of each generating unit and determining whether it was operational at any given moment or not. The historic on/off status of each generator was used to calculate the AGC down-margin for the time period.

During the 2018 year used for the baseline scenario, there was a 20 MW_{AC} solar farm operating in the system. Although, ideally, a baseline scenario would have been created from the system before any solar was added, we did not have this data available at the time of research. Therefore, this study represents an over-production scenario based on what would happen if 42 MW_{AC} of solar was added to the existing 20 MW_{AC} of solar without changing unit-scheduling practices.

Over-Production Calculation

To determine potential over-production, the following definitions were used:

$$Generation\ Needed = Load + Scheduled\ net\ Interchange$$

$$Net\ Generation\ Needed = Generation\ Needed - Solar$$

$$Minimum\ AGC\ Output = Sum\ of\ Minimum\ AGC\ Output\ of\ Online\ Generators$$

Table 12 shows how PV over-production was calculated based on these definitions. Two example scenarios are shown: one with no interchange and one with an interchange consisting of a 25 MW sale. In both scenarios, solar production is 50 MW. The generation needed was determined by the sum of the system load and the scheduled net interchange, using the convention that an energy sale is positive. The minimum AGC generation was determined by summing the minimum AGC outputs of all the online generators. In this example, two generators are operating, HP2 and PP8. Their combined minimum AGC output is 255. If the net generation needed is below the combined AGC minimum, over-production occurs.

In the first row of the example where the net interchange is zero, the generation needed is equal to the load, 250 MW. Subtracting 50 MW of solar results in a net generation need of 200 MW. Since the minimum AGC margin is 255 MW, this results in over-production of 55 MW.

In the first row of the second example with a net interchange of 25 MW, the generation needed is the load, 250 MW, plus the net interchange, 25 MW, for a total generation needed of 275 MW. Subtracting 50 MW of solar gives a net generation needed of 225 MW. With a minimum AGC generation of 255 MW, this results in an over-production of 30 MW. This technique was applied in MATLAB for every one-minute sample using six months of data.

Table 12. Example over-production calculations

AGC Minima		
HP2	PP8	Total
120	135	255

Net Interchange is Zero							Net Interchange is a 25 MW Sale					
Load	Net Intchg Sale	Total Gen Needed	Solar	Net Gen Needed	Over-Production		Load	Net Intchg Sale	Total Gen Needed	Solar	Net Gen Needed	Over-Production
250	0	250	50	200	55		250	25	275	50	225	30
275	0	275	50	225	30		275	25	300	50	250	5
300	0	300	50	250	5		300	25	325	50	275	0

* All units are MW.

Results

It was seen that over the 6 months of data that were studied, there was a maximum of 78 MW of potential power over-production and 149 MW of energy over-production. A potential for a total of 1,232 MWh of energy over-production was present in the half-year of time. To obtain an estimate of potential PV over-production in one year, this number is multiplied by two. Ideally, a year of data should be studied because the late summer and fall months might not have the same potential for curtailment as the Jan-June time span. However, with this assumption, we expect a potential 2,464MWh of over-production in one year.

Figure 63 shows potential power over-production of 62 MW of combined solar capacity over the range of data studied, January-June 2018. The two greatest over-production days are in April and the beginning of May, owing to the low load. However, it can be seen that over-production is a potential problem at any time, not just during shoulder months.

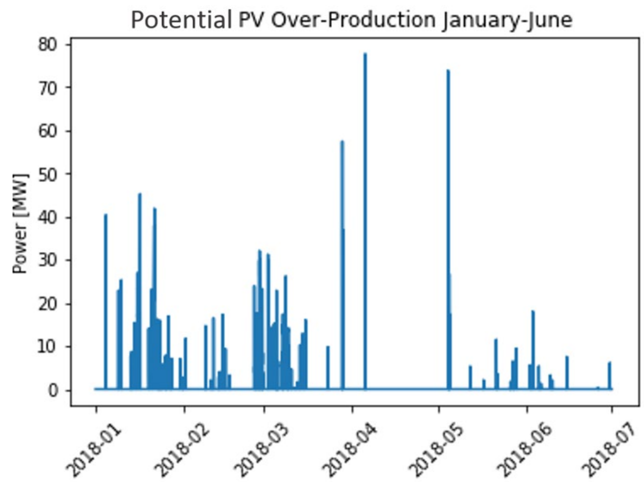

Figure 63. Potential PV over-production of 62 MW of combined solar capacity over the range of data studied, January-June 2018.

Curtailment - one of several "flexibility" strategies

A 2018 study by E3, First Solar, and Tampa Electric Company (TECO) examined four operating modes for utilizing solar as a flexible resource: "Must-Take," "Curtailable," "Downward Dispatch," and "Full Flexibility" [94][95]. The study found that, for TECO, a relatively small IOU compared with FPL and DEF, "Must-Take" solar "becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the Curtailable mode of solar operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment. Flexible solar reduces uncertainty, enabling leaner operations and providing significant economic value. At penetration levels exceeding 20% on the TECO system, solar curtailment can be reduced by more than half by moving from the Curtailable to the Full Flexibility solar operating mode. This results in significant additional value due to reduced fuel costs, operations and maintenance costs, and air emissions." For "Full Flexibility", a solar PV plant is configured to have "footroom" for downward dispatch and "headroom" for upward dispatch. The latter requires intentionally operating a plant in a curtailed or under-scheduled state to allow room to provide regulation up or spinning reserve capability.

Absorbing the Sun: Balancing and Reserves

Numerous studies of renewable energy integration and the value of renewable energy forecasting suggest that Florida power system operators may modify their operations to absorb increasing amounts of solar generation. In addition to cycling generators and periodically curtailing solar to satisfy, e.g., minimum generation and ramp-rate limits [96], Florida balancing authorities (BAs) may integrate solar forecasting [97] and specify additional operating reserves to cover increasing net-load[28] variability and uncertainty on 4-second (regulating reserve) to 1-hour (ramping) timescales [98][99].

These activities can be undertaken by power system operators of any size; however, the actions required of large system operators or neighboring systems operated cooperatively are smaller than those required of a small system when measured on a normalized basis (e.g., percent of load for a given solar penetration) due to the damping effects of aggregating many geographically dispersed solar plants [100][101][102]. Although this fact is generally known, the impacts on reserve requirements have not been well-quantified for small utilities. For example, Bloom, et al, [103] quantify reserve savings of BA aggregation, but their smallest level of aggregation corresponds to our most aggregated case.

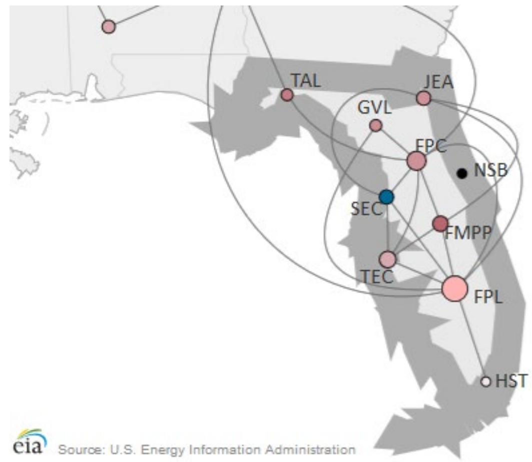

Figure 64. Geographic location and interconnections between FRCC BA's.

The Florida municipal utilities make a good case study in this regard, as they are operated as four different BAs of varying size. They can also be analyzed alongside other Florida Reliability Coordinating Council (FRCC)[29] balancing authorities that add to the diversity of system size and ownership type (Figure 64).

In order to develop insight into possible strategies for municipal utilities, it is necessary to understand and quantify in some way the impact of system size and operating practice on the amounts of balancing reserves that need to be held to cover the variability and uncertainty of net load over a wide range of PV penetrations.

Large System Operational Practices and Implications for Balancing Reserves

Power systems are operated by means of an interwoven series of processes, each characterized by its decision methodology and time frame. Focusing on the day-to-day operations that ensure electricity supply and demand balance at all times, these processes can generally be categorized into the three stages of unit commitment (UC), security-constrained economic dispatch (SCED), and real-time operations. The first stage is typically run once a day, ahead of the following day's operations, and is therefore often referred to as day-ahead UC. In the UC process, the system operator determines the least-cost combination of generating units to be on during each time interval in the next 24-hour period based on the day-ahead load forecast and respecting the limitations of the transmission system and each unit's

[28] Net load refers to load minus variable generation (e.g., from solar or wind plants). It is the amount of generation to be supplied from more dispatchable generators.

[29] Starting July 1, 2019, FRCC has been winding down its regional entity functions, but will continue its traditional member functions and coordinating roles, which include its work as a Reliability Coordinator and Planning Authority. SERC is the new Compliance Enforcement Authority for all NERC registered entities that are currently within the FRCC Region [104]. In 2019, early release of U.S. Energy Information Administration (EIA) Form 861 reported some utilities as SERC and others as FRCC. For consistency, we use 2018 data instead.

physical operating constraints, including minimum off and on times [105]. This process fixes the binary on/off unit commitment decision for slower-starting generators (e.g., nuclear, coal, and natural gas combined cycle plants) and provides an initial dispatch plan that is refined in subsequent stages. The second stage, SCED, happens throughout the operating day, on regular, potentially interlocking schedules, or in response to new information. During SCED, operators determine the level at which each committed resource should operate to ensure reliability at minimum cost, subject to the physical, contractual, and institutional constraints in the system. In addition to the units committed in the first stage, operators can also quick-start generators (e.g., natural gas combustion turbines) on reserve to respond to unexpected changes in supply and demand or contingencies [106]. Real-time operations must keep the demand, generation, and interchange in balance to maintain a system frequency within defined limits [107]. During real-time operations, generators follow the dispatch plans set by the SCED phase; for a subset of generators, those plans include the supply of operating reserves, which are the control mechanisms by which real-time balancing and reliability are achieved.

Operating the power system is difficult because there is variability and uncertainty in both supply and demand, and the two must be in balance every second. Operating reserves are needed to achieve this feat for both normal operation and during severe yet rare events [108]. Among the operating reserves, regulation is held to provide continuous, fast, and frequent (second-to-second and minute-to-minute) correction of supply and demand and provide frequency support [109]. The service is dispatched by system operators sending out a 4-second-interval automatic generation control (AGC) signal to generating units and responsive loads that have the ability to rapidly adjust their dispatch set point and automatically follow such signals. This regulation process is a key part of operators' balancing strategies during normal operation [110]. Flexibility reserve, also known as ramping reserve, is used to respond to less frequent failures and events that occur over longer time frames (typically 10–20 minutes) and that may lead to a shortage of ramping capability, such as wind forecast errors [111]. Regulating reserve is required in all U.S. power markets, whereas ramping reserve is an emerging product that is currently only available in the California Independent System Operator (CAISO) and Midcontinent Independent System Operator (MISO). In this report, we use balancing reserves to refer to these two types of real-time adjustments that operate at different timescales.

NERC requires BAs to hold sufficient amounts of operating reserves to respond to imbalances between demand and supply, recover after an event (e.g., sudden loss of supply or transmission), and respond to frequency deviations, but leaves the specific calculation of the reserve needs to the balancing area's discretion [112]. Failure to meet a frequency-related control performance standard or exceeding the balancing authority area control error limit for more than 30 consecutive minutes triggers a violation [107] and results in a base penalty that ranges from $1,000–$25,000/day and $2,000–$335,000/day depending on such factors as violation risk factor, severity level, and the BA's compliance history [113]. The addition of solar PV increases the variability and uncertainty between day-ahead scheduling and real-time operations [114][115]. As a result, additional regulation and flexibility reserves may be deployed to stay within NERC's reliability bounds by managing the added variability and uncertainty [116][117][118][119].

Newer flexibility (or ramping) reserve products have been designed to address deviations from the forecasted net-load ramp. As such, they are generally slower (i.e., lower ramp rate) and longer in duration than regulating reserves. For example, CAISO procures flexible ramping reserve (both up and down in the 15-minute and 5-minute markets) at a maximum of the 2.5th percentile (down reserves) and the 97.5th percentile (up reserves) of the net-load error [120]. It is continuously procured and dispatched in the real time dispatch. This ensures that sufficient ramp capability is committed in the real-time unit commitment to cover uncertainty materializing in real-time dispatch, but does not cover uncertainty between the 15-minute market runs [121]. A variety of technologies provide this service, including natural gas, hydro, demand response, and coal. The price of flexible ramping reserve is very low in the upward direction and almost always at $0 per megawatt-hour (MWh) in the downward direction [121]. In contrast, regulation reserves are dispatched after the final SCED run (sometimes referred to as the real-time market), through following the AGC signal, not through economic bids, because the system relies on regulation reserves to resolve second-to-second imbalances that drive frequency deviation and area control error [122]. CAISO's regulation reserve averaged around 430 MW and 350 MW (representing 1.0% and 0.8% of peak load) for up and down regulation in 2019, respectively, and typically has the highest price among all ancillary services [121]. It is served primarily by natural gas and hydro, with an increasing share served by battery storage.

Capacity expansion models (CEMs), which are used in planning processes to help determine what new generating units may be needed and what older generating units should be retired, often include reduced-form representations of reserve requirements to ensure that they are planning a realistic, reliable system. The CEMs the authors are familiar with were designed for larger systems with significant quantities of wind and solar generation, and therefore have reserve requirements that attempt to summarize the reserve needs implied by different quantities of wind and solar capacity [123][124]. For example, the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) capacity expansion model [125] requires regulation reserve to be 1% of load plus 0.5% of wind generation and 0.3% of solar PV capacity, and flexibility reserves equal to 10% of wind generation plus 4% of solar PV capacity, with the additional reserves for PV only held during daylight hours. These requirements were derived from [98] and are generally understood to apply only to large-enough BAs operating with day-ahead unit commitment followed by intraday and sub-hourly (SH) SCED, with all operations informed by load, wind, and solar forecasts at the relevant timescales.

Florida Municipal Utilities' Operational Practices

In Florida, 33 municipal electric utilities serve approximately three million residents—14% of the state's population [126]. Their operational practices in forecasting, dispatch, and reserves vary. To understand their practices, we sent a questionnaire out to six utilities: GVL, TAL, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Florida Municipal Power Agency (FMPA), and OUC.

The questionnaire focused on four issues: (1) operational relationships, including trading and reserve sharing partners; (2) dispatch and reserve practices, including unit commitment frequency, dispatch frequency, software, reserve amount, risks, and concerns; (3) load forecasting, including historical data used, forecast method, forecast scope, accuracy, and corrective actions; and (4) solar forecasting, including method and scope.

One of our main observations based on the questionnaire answers is that the municipal BAs have significantly different forecast and dispatch procedures (Table 13). GVL, for example, relies mainly on day-ahead forecasting, unit commitment, and dispatch. Because they dispatch only a handful of generating units, the headroom of the one or two units assigned to follow the AGC signal is relatively large proportional to load such that GVL can ride through most day-ahead forecast errors using the day-ahead dispatch plan—additional forecast adjustments mid-day would be unlikely to significantly change dispatch instructions. TAL and JEA are the only BAs in this group that systematically update load forecasts and system dispatch on an hourly basis. FMPP is the only BA to incorporate solar forecasts based on expected weather. At this point, none of the Florida municipal utilities are conducting sub-hourly, real-time dispatch with accompanying sub-hourly load and solar forecasts.

Table 13. Summary of FRCC Municipal BA Operating Practice

Balancing Authority	Day-Ahead Forecasting		Intraday Updates		Operating Reserves
	Load	**Solar**	**Load**	**Solar**	
Gainesville (GVL)	Hourly 10-day horizon	N/A	N/A	N/A	N/A[b]
Tallahassee (TAL)	Hourly 16-day horizon	Hourly fixed profile	Hourly updates	N/A	±16 MW
JEA	Hourly 14-day horizon	N/A	Hourly 5-min updates	N/A	±50 MW
FMPP (incl. FMPA, OUC, Lakeland)	Hourly 7-day horizon	Hourly 7-day horizon	Infrequent updates as needed	Infrequent updates as needed	+50 MW[a,b] (more if no quick starts)

[a] FMPP requires 50 MW of up reserve during unit commitment, primarily to have sufficient spinning capacity to meet Florida Reserve Sharing Group obligations. As such, this does not represent “regulation reserves” per se.

[b] Although Gainesville and FMPP do not have precise regulation reserve requirements, during real-time operations they have significant capacity following AGC and continuously monitor both area control error and their ability to meet Florida Reserve Sharing Group obligations.

The findings from this questionnaire clarified that in addition to BA size, it is important to consider operational practice as a key driver that impacts the amount of reserves a BA needs to hold to manage net-load variability and uncertainty. We identified three categories of operational practice, distinguished by the highest frequency of forecasts and dispatch: day-ahead (only), hour-ahead, and sub-hourly. This process also clarified that the reserves literature for systems with significant wind and solar generation, which almost exclusively addresses these questions for large BAs with sub-hourly operations, provides little actionable information for smaller BAs with less frequent dispatch.

Methods

The amount of reserves a balancing authority needs to hold fundamentally depends on the expected sizes of the gaps between generator dispatch points and actual demand. For balancing (e.g., regulation and flexibility) reserves, the key differences of interest are between forecasted and actual demand, because under normal operating conditions the system dispatch will be set to follow the load forecast—reserves then need to be available to make up the difference between the forecasted dispatch point and the actual real-time demand. Because PV generation is zero marginal cost, its variable output is generally dispatched first and, in many ways, shows up in the system as a negative load. Therefore, we can also think about balancing reserves in relation to the gap between forecasted and actual net load, where for the purposes of this study net load is defined as load minus PV generation.[30] In either case, balancing reserve requirements are driven by forecast errors.

Although we are ultimately interested in net-load forecast errors, because load and solar data are fundamentally different, in this study we estimate load and solar forecast errors separately, estimate the

[30] More generally, net load is defined as load minus all variable generation, which could include resources like wind and run-of-river hyrdo, in addition to PV.

amounts of reserves needed to cover those types of forecast errors separately, and then combine them (nonlinearly) to arrive at an overall reserves requirement.

We focus on estimating reserve requirements for different FRCC BAs assuming different levels of PV penetration and different operating practices. We estimate forecast errors for load and solar generation using different forecasting horizons (e.g., day-ahead, hour-ahead, or 5-minute-ahead) selected based on assumed operational practice. The forecast methods we use are conservative, persistence-type forecasts that have low data requirements but are tailored to make use of all the load and solar data that were available. Then, the estimated load or solar forecast errors were binned and we computed percentile levels per bin to establish a per-bin level of reserves in megawatts or percent of load. The reserve requirements were then applied to a time-synchronized data set of historical load and simulated solar generation that covers 2007–2012 at 5-minute resolution (described in the next subsection). Our results consist of statistical summaries of the reserve requirements themselves, which we use to analyze the impact of PV generation and operational practices on the reserve requirements of FRCC BAs of different electrical size and geographic extent.

Time-Synchronized Load and Solar Data Sets

The primary inputs of our analysis are historical load shapes paired with solar generation profiles created to contain an amount of available energy approximately equal to a certain percentage of annual load. The simulated solar generation profiles are for the same weather years as the historic load shapes to capture realistic correlations between load and solar generation. Our starting point for analysis is an estimate of PV capacity and annual load levels for the 2024-time frame.

The load profiles used in our analysis are historical data from 2007–2012 that were scaled to contain an equal amount of load in each year. The original data are 2006–2015 net energy for load for the eight BAs listed in **Error! Reference source not found.**. The energy contained in each profile was scaled to capture the growth expected between 2015 and 2024 by the 2019 Florida electric utilities' Ten-Year Site Plans [127]. We chose 2024 as the target model year to better align with our starting point of all planned PV capacity (current plants plus known PV development plans).

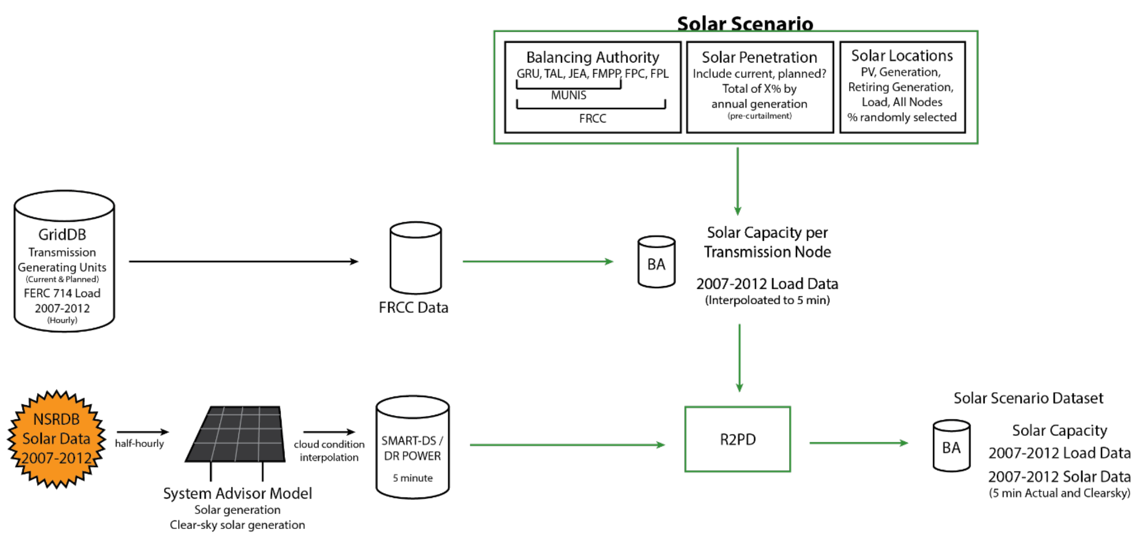

Figure 65. Workflow used to construct time-synchronized load and solar data sets for FRCC balancing authorities.

The goal of the study was to analyze reserve requirements over a wide range of solar penetrations, where solar penetration is defined as the percent of annual load that, on net and absent any solar curtailment, could be supplied by solar generation. To develop realistic solar generation profiles for each BA, we started with the locations of existing and planned PV plants and then added simulated PV plants to obtain aggregate generation profiles with realistic geographic scaling. The entire process is shown in Figure 65.

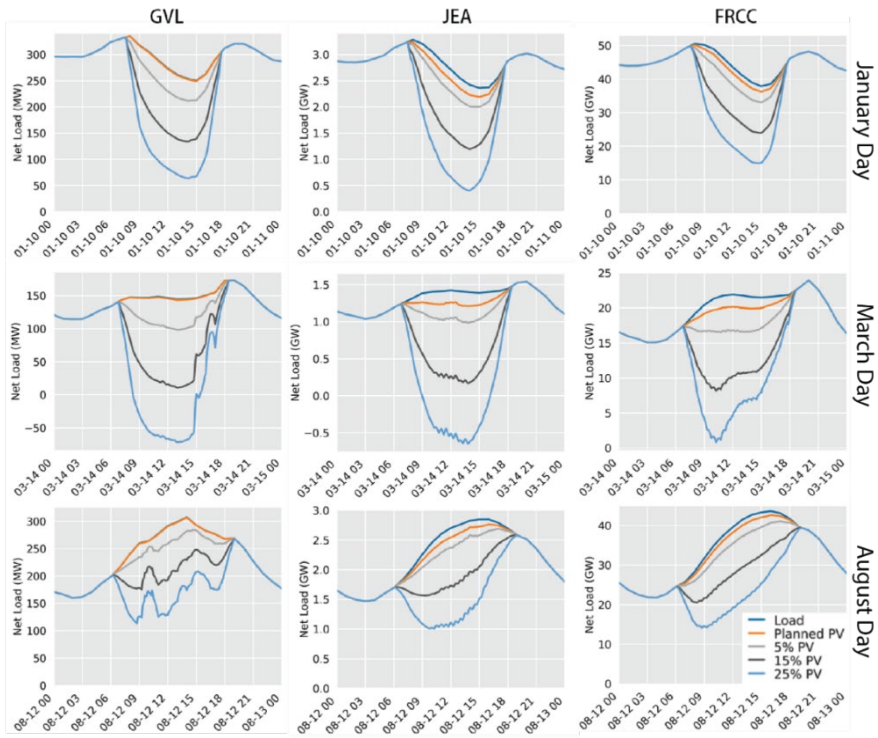

Figure 66. Example net-load shapes for different balancing authorities, seasons, and PV penetrations.

The resulting data sets show expected net-load patterns that reflect balancing authority size, geographic distribution, seasonality, weather, and amount of solar generation. For example, Figure 66 shows how net-load patterns change with increasing amounts of PV for three selected historical days (one in January, one in March, and one in August) and balancing authorities of different sizes. For all three balancing authorities, we see similar seasonal load patterns: two daily peaks in winter that reflect significant amounts of electric heating, low and fairly flat daytime load with an evening residential peak in spring, and a classic summer-peaking pattern in August. Regarding solar generation, for similar penetration levels we see more variability in the net-load profiles of the smallest balancing authority (GVL) and much larger net-load dips on this particular March day in both GVL and JEA as compared to all of FRCC considered together. However, that does not mean that FRCC's profiles are unimpacted by weather; the March FRCC profile is influenced by widespread afternoon cloudiness, at least at higher PV penetrations.

One difference affecting municipal utilities acting as balancing authorities that can be quantified is relative solar variability. Figure 67 depicts envelopes that contain 95% of the clear-sky fraction ramps ($R_{CF,\Delta t}$), defined for each ramp timescale Δt from 5 minutes to 8 hours as:

$$R_{CF,\Delta t}(t) = CF(t) - CF(t - \Delta t) = \frac{G_{actual}(t)}{G_{clearsky}(t)} - \frac{G_{actual}(t-\Delta t)}{G_{clearsky}(t-\Delta t)}$$

where *CF* indicates clear-sky fraction, G_{actual} is actual solar generation, and $G_{clearsky}$ is the corresponding solar generation under clear-sky conditions. The clear-sky fraction, $CF = G_{actual}/G_{clearsky}$, is an important quantity that describes how actual solar generation deviates from what would be expected under perfect conditions. Because it is normalized, it is also comparable across systems of any size. By plotting bounds that contain 95% of clear-sky ramps, the envelopes in Figure 67 describe solar variability beyond what is already expected based on Earth's movements relative to the sun—the wider the envelope, the more variable the solar generation contained in the overall data set.

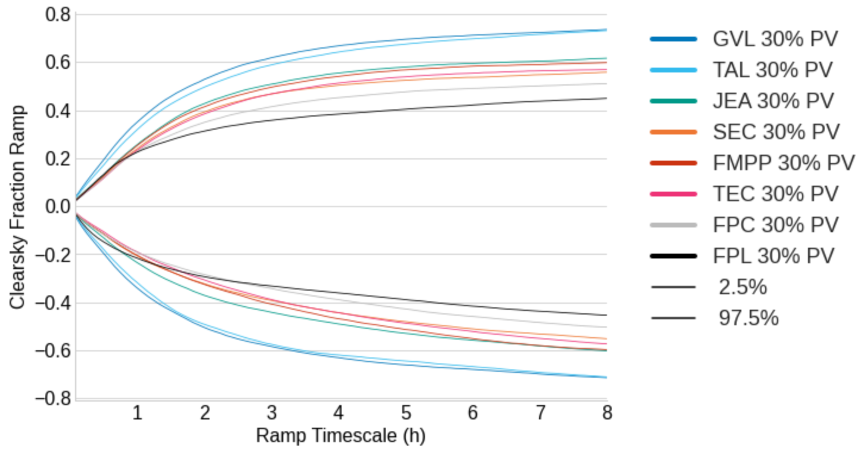

Figure 67. Clear-sky fraction ramp envelopes for eight BAs with PV penetrations on an annual generation basis (around 30% PV for each respective BA).

Figure 67 shows clear-sky fraction ramps for eight BAs, all at around 30% PV penetration. Because the sizes of the BAs are so different, the corresponding capacities vary greatly—from GVL's 341 MW to FPL's 23,400 MW—and we end up with clear groupings solely based on BA electrical (rather than geographic) size. Smaller quantities of PV show higher relative variability, such that GVL and TAL profiles are most variable, and FPL profiles are the least variable, according to the clear-sky fraction ramp metric.

Assumed Operational Practices

Based on our understanding of Florida municipal utility and large balancing authority operations, we estimate balancing reserve requirements for three types of operational practice:

- Day-ahead (DA) forecasts and dispatch
- Hour-ahead (HA) forecasts and dispatch
- Sub-hourly (SH) forecasts and dispatch.

A utility that follows DA operational practice is assumed to create or obtain day-ahead load and solar forecasts, run a unit-commitment and SCED process to create an operational plan for the next day, and then typically use that plan as-is for the following day. By necessity, such operations require commitment of a significant amount of capacity to follow an AGC signal and thereby keep area control error within NERC limits, because AGC will need to make up for day-ahead forecast errors. Our example for this type of operation is Gainesville, which serves most of its load by dispatching just four main plants—a biomass steam turbine, a natural gas combined cycle plant, a natural gas combustion turbine plant, and a steam plant with one natural gas and one coal unit. Assigning the headroom that remains on one or two of these units to follow AGC gives the system plenty of balancing capacity as a percent of load.

HA operational practice starts with a day-ahead forecast and unit commitment and dispatch process, but during the following day, although the initial plan is set, the remainder of the day's plan is adjusted every hour as updated load and solar forecasts come in. In this case, balancing reserves only need to handle the difference between hour-ahead forecasts and actual net load, rather than the full day-ahead mismatch, and that amount of reserve requirement may be accounted for in both the day-ahead UC and the SCED processes, if reserves provision is co-optimized along with dispatch. Tallahassee and JEA are current exemplars of this type of operational practice, although currently only with respect to load forecasts. (Weather-based solar forecasts have not yet been incorporated into their operational practices.)

Large balancing authorities with SH operational practice typically go through day-ahead and hour-ahead steps (although the latter may be on a longer timescale, as many as 4 hours), but then also run a forecast and dispatch process at the 15- to 5-minute timescale. Regulation reserves therefore need to balance out second-to-second supply and demand differences whose sizes are dictated by 5- to 15-minute net-load forecast errors and variability. Flexibility reserves are procured at the 15–60-minute timescale and dispatched every 5 minutes to address any ramping challenges that emerge from variable generation forecasting errors. For simplicity of comparison with the other operational practice categories, we combine these two reserve types in our results. However, as discussed, regulation reserve is generally the more demanding and expensive service.

Load Forecast Errors

Historical load data used in our 2007–2012 data set do not contain any information on load forecast errors. We, instead, use EIA Form 930 hourly data, including day-ahead forecast and actual load self-reported by BA's, along with historical day-ahead forecast error data, accessed via the ABB data service Energy Velocity Suite (2020), to directly quantify the uncertainty FRCC balancing authorities start with considering their day-ahead load forecast errors.

Figure 68 summarizes the historical day-ahead load forecast errors as reported in the EIA 930 data set. Different balancing authorities show significantly different levels of accuracy and distributional patterns. The data from SEC appear to contain many outliers that may signify frequent reporting errors. None of the BAs demonstrate classic normal distributions.

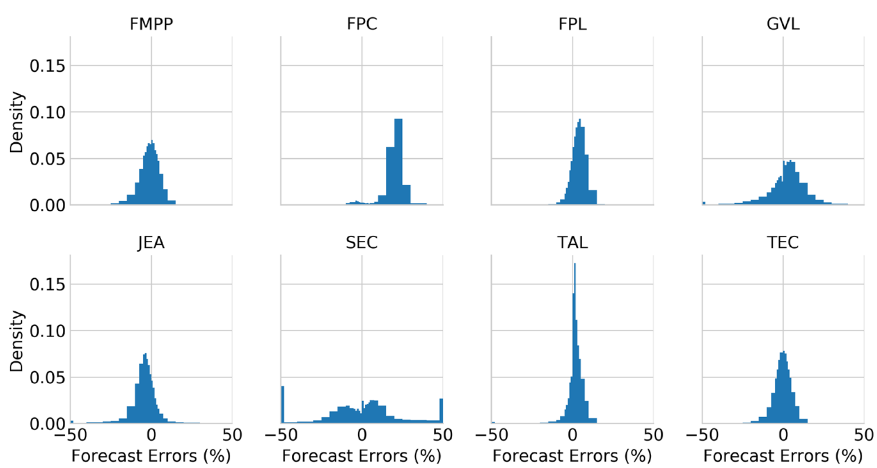

Figure 68. Historical day-ahead load forecast errors for FRCC balancing authorities as reported in EIA Form 930 for 2015–2019 (Reported values are (Actual – Forecast) × 100/Actual. Positive values reflect underestimates of actual load and a need for up reserves; negative values reflect overestimates of actual load and a need for down reserves. Forecast errors outside the limits shown are placed in the first (FE < −50%) or last (FE > 50%) bins.)

Some of the balancing authorities' forecasts appear to be significantly biased—FPC's data are particularly notable in this regard as actual demand is usually significantly higher than forecast demand. The long negative tails may reflect hurricanes and other events that drive significant outages.

The data in Figure 68 are used directly for the DA operational assumptions. For HA operations, we require estimates of hour-ahead load forecast errors. We construct such forecast errors by making the conservative assumption, which requires no additional data, that an hour-ahead forecast is constructed by assuming that the next hour's day-ahead forecast error will be the same as this hour's. This is a form of persistence forecast because we are assuming that a current observation (namely, the day-ahead load forecast error) will persist into the future. As with other forms of persistence forecast, this can be considered a conservative "forecast to beat".

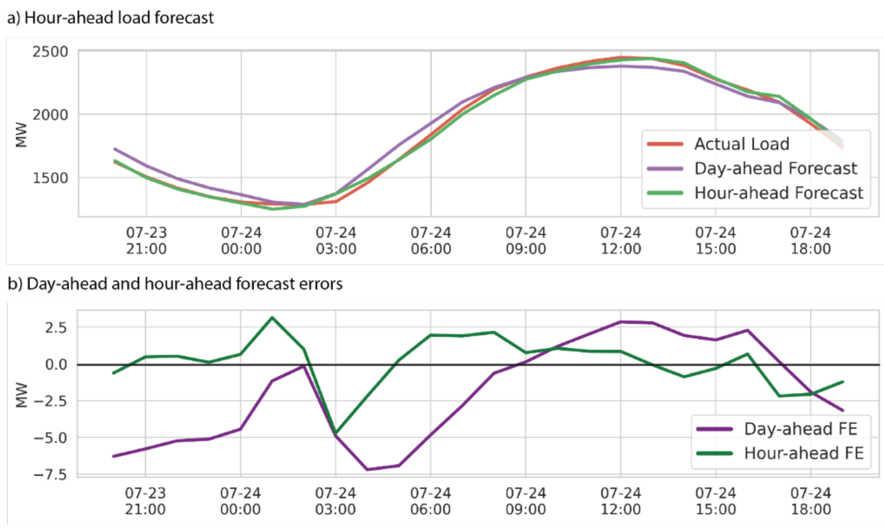

Figure 69. Hour-ahead load forecast made by persisting day-ahead forecast errors, illustrated for an example day (Top plot (a) shows actual, day-ahead forecast, and hour-ahead forecast load. Bottom plot (b) shows the resulting hour-ahead forecast errors alongside the historical day-ahead forecast errors.)

Figure 69 illustrates this hour-ahead load forecast method by plotting study data for an example day. The top plot (a) shows how the hour-ahead forecast profile is generally closer than the day-ahead forecast to the actual load profile. In the bottom plot (b), we can see how this is accomplished. When the day-ahead forecast errors are relatively constant for a period of time (e.g., during the evening of July 23), the persistence forecast assumption is good and the hour-ahead forecast errors are much smaller than the day-ahead forecast errors. The hour-ahead forecast errors are larger when the day-ahead forecast errors are changing from one hour to the next, but overall, the process tends to reduce the magnitude of errors in both directions.

Because we do not have measured sub-hourly load data, we do not create a data set of sub-hourly (e.g., 5-, 10-, or 15-minute) load forecast errors from which to estimate regulation reserve requirements for SH operations. Instead, we borrow the assumption from [115] that 1% of load should be held for regulation reserve in this case.

Solar Forecast Errors

To construct solar forecast errors we use the simulated "actual" and clear-sky generation in our solar data sets along with the notion of a "clear-sky persistence" forecast as described in [98]. Although highly conservative in the day-ahead case, we use this method to construct both day-ahead and hour-ahead forecasts. Fundamentally, the forecasts are constructed by assuming that the current time period's clear-sky fraction profile, computed by dividing actual solar generation by the clear-sky generation, will persist. Similar to the hour-ahead load forecast method, this assumption is conservative in the sense that it requires little data and is straightforward to compute.

Figure 70 shows how we construct day-ahead solar forecasts by assuming that tomorrow's clear-sky fraction pattern will be the same as today's. In the particular example shown, the day-ahead forecast errors for July 25 are quite large in the morning and early afternoon, but the day-ahead forecast profile for the late afternoon matches the actual profile quite well.

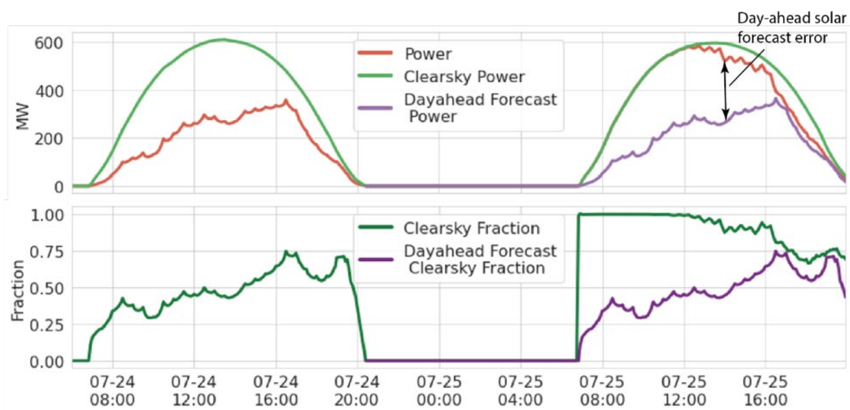

Figure 70. Example day-ahead solar forecast constructed using clear-sky persistence (The top plot shows clear-sky, actual, and forecasted generation. The bottom plot shows the corresponding actual and forecasted clear-sky fraction profiles.)

Building a day-ahead solar generation forecast based on day-ahead weather forecast information would be expected to perform much better than this method almost all the time [128]. Thus, our results for DA operations that use these forecasts should be considered quite conservative from the standpoint of requiring more reserves to cover larger forecast errors than would likely be needed if weather-based day-ahead solar forecasts are used instead[31].

Hour- and 5-minute-ahead solar forecasts are constructed by assuming that the clear-sky fraction in the current hour or 5-minute interval will persist to the next hour or 5-minute interval. The former are used for HA and SH operations; the latter only for SH operations. The forecast error distributions that result for all three forecast horizons, expressed as a fraction of nameplate PV capacity, are shown for three different example PV capacities in Figure 71. As expected, normalized solar forecast errors are smaller when the forecast horizon is shorter, the PV capacity is larger, or both. In our examples, the forecast horizon appears to make a larger difference than amount of PV, and the amount of PV is most influential at the hour-ahead scale.

[31] The full Absorbing the Sun report [129] includes sensitivity analysis of DA reserve requirements for GVL if the day-ahead solar forecast errors are 50% or 75% smaller than our conservative estimates.

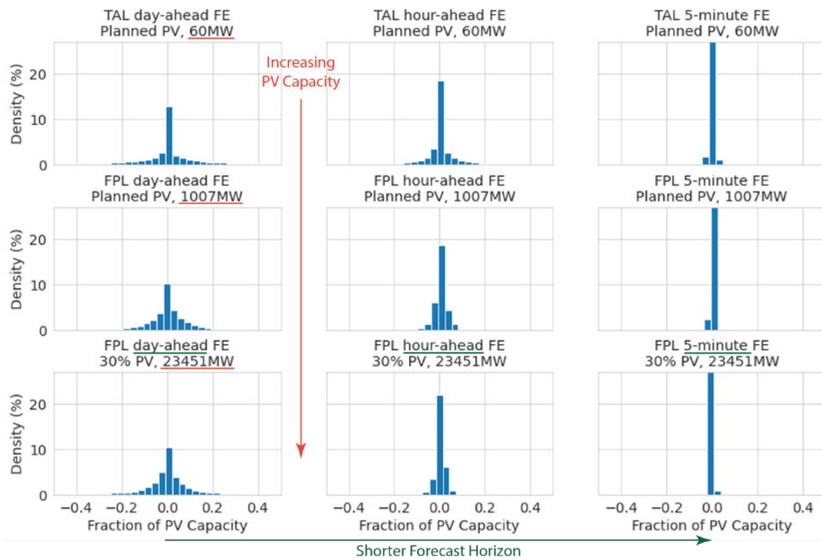

Figure 71. Solar forecast error distributions as a fraction of PV capacity (Examples for 60 MW, 1.0 GW, and 23.4 GW of PV capacity over day-ahead, hour-ahead, and 5-minute forecast horizons are shown.)

Calculating Reserve Requirements

Estimates of how much reserve capacity is needed to operate smoothly in the face of load and solar forecast errors are calculated for each solar scenario and operational practice type by:

1. Considering the type of balancing reserves needed
2. Constructing corresponding forecast error databases and normalizing the resulting megawatts if necessary
3. Binning the forecast errors based on measurable characteristics
4. Computing percentile statistics per bin over both the positive and negative forecast errors separately
5. Binning the actual load and solar data
6. Applying the reserve levels computed in Step 4 to the binned data from Step 5.

This process produces up and down reserve estimates for load and solar separately. Following [96], we combine the load and solar requirements into a total reserve requirement using the heuristic that the two components are similar to standard deviations taken from independent distributions. Thus, we have total reserve requirements (σ_{total}) computed from load (σ_{load}) and solar (σ_{solar}) reserve requirements as:

$$\sigma_{\text{total}} = \sqrt{\sigma_{\text{load}}^2 + \sigma_{\text{solar}}^2}.$$

This means that although solar reserve requirements may be significant, they are not directly additive with load reserve requirements, which mutes their impact. As an example, if $\sigma_{\text{load}} = \sigma_{\text{solar}} = 10$ MW, the total reserve requirement is 14.1 MW, not 20 MW.

Specific individual processes were developed and utilized for 1.) Day-Ahead (DA) reserves, 2.) Hour-Ahead (HA) reserves, and 3.) Sub-Hourly (SH) reserves. For illustration, the DA reserves calculation process is shown in Figure 72. For detailed descriptions of all three processes and the resulting reserves calculations for each BA, see the full NREL report [129].

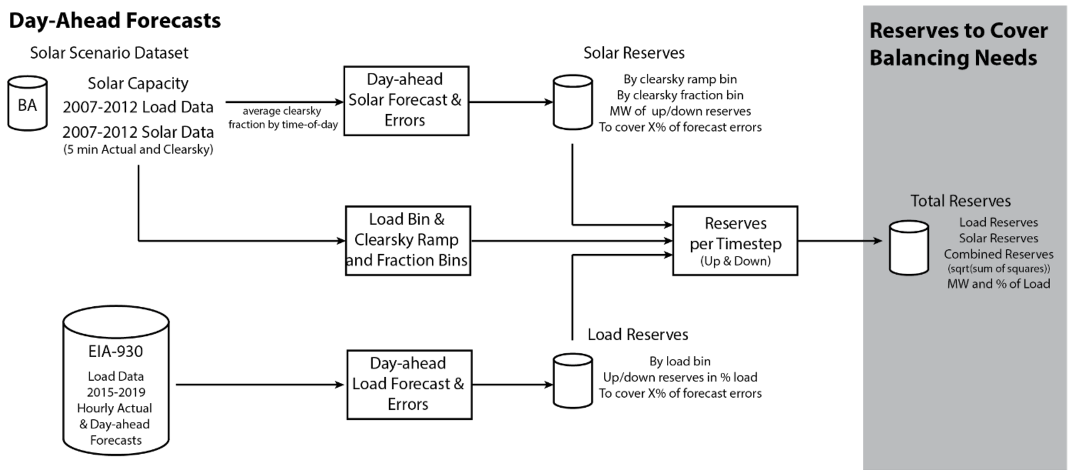

Figure 72. Study process for estimating reserve requirements under assumed day-ahead operational practices.

Results

We study the reserve implications of a wide range of PV penetrations for different FRCC BAs and combinations thereof through the scenarios composed by selecting one value from each column in Table 14. All combinations shown were run for this study; however, the results focus on the municipal BAs using select PV penetrations, with all balancing reserves calculated assuming 95% coverage of forecast errors and with PV placed at a random selection of 50% of each BA's nodes. These key default focal points and parameter selections are shown in bold in the table.

Table 14. Scenario Framework for Studying the Impact of PV on Reserve Needs Depending on BA Size and Operational Practice

BAs	PV (Approx. Available Generation as % of Annual Load)	Operational Practice	Percent of Forecast Errors Covered	PV Expansion Nodes
GVL	Current[a]	Day-ahead	80%	Current & planned PV nodes only
TAL	**Planned**[b]	Hour-ahead	**95%**	
JEA	5%	Sub-hourly	99%	**Randomly selected 50% of all nodes**
FMPP	10%			
MUNIS (GVL, TAL, JEA, and FMPP)	**15%**			
	20%			
TEC	25%			
FPC	**30%**			
FPL	35%			
FRCC (GVL, TAL, JEA, FMPP, TEC, FPC, FPL)	40%			
	45%			
	50%			

[a] PV capacity operating as of fall 2018
[b] Current PV capacity plus deployments expected through 2024 as expected in 2018

In the remainder of this section, we examine where the BAs are now in terms of estimated reserve requirements given near-future, planned PV penetrations and current operational practice. We then explore two options for reducing reserve requirements as solar penetrations increase through the particular lens of GVL. In addition, see the full NREL Absorbing the Sun report [129] for sensitivity analysis to forecast accuracy and percent of forecast errors covered.

Current Reserve Requirements Depend on Balancing Authority Size and Operational Practices

Based on the operational survey of FRCC municipal utilities, we analyze GVL with DA operational practice and TAL, JEA, and FMPP with HA practice. We assume that TEC, FPC, and FPL operations are most similar to our SH assumptions. Figure 73 summarizes the reserve requirements estimated for each BA under these assumed current practices under PV penetrations estimated for 2024.

The median reserve requirements for these BAs vary greatly: from as low as 1.5% of load for FPC and FPL to as high as 25% and 10% of load for GVL and JEA, respectively (Figure 73, top panel). In general, reserve requirements as a portion of load decrease with increasing system size and operational frequency, even though larger BAs tend to require more absolute megawatts of reserves (Figure 73, bottom panel). Here and in what follows, operational frequency encompasses the frequency of load and solar forecasts as well as the frequency of dispatch.

Comparing regions that are similar in size—GVL with TAL and FMPP with TEC—we find that higher operational frequency leads to lower reserve requirements. Hourly operation in TAL results in much lower reserve requirements (with an interquartile range of 5%–6% of load) than does day-ahead operations in GVL (with an interquartile range of 19%–31% of load); sub-hourly operation in TEC results in lower median reserve requirements (3% of load) as compared to hourly operations in FMPP (5% of load). Overall, our findings are in line with others who have found that larger BAs have less load variability [110], access to more resources for balancing the system, and smoother VRE time series outputs [130][98].

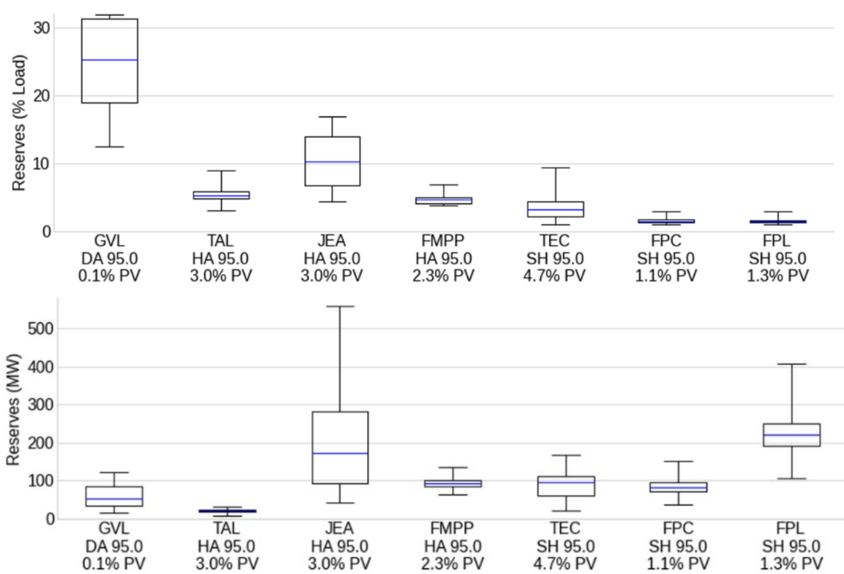

Figure 73. Up reserves needed to provide regulation and flexibility services with current operational practices and at planned PV penetration levels (top panel: as a percentage of load in each timestep; bottom panel: in absolute megawatts) {Blue lines show the medians; whiskers extend to the full range of the data. The labels on the x-axis indicate the region, modeled operational practice, forecast error coverage (95.0 means covering 95% of the balancing authority's load and solar forecast errors), and estimated PV penetration levels in 2024.}

Reserve Requirements at Different PV Penetrations

All BAs face more variability and uncertainty as they integrate more PV into their systems [98][131]. We illustrate this for our context using three selected BAs in Figure 74: as GVL (with DA operations), TAL (with HA operations), and FPL (with SH operations) add more PV—from less than 3% of BA load to about 15% and to about 30%—the reserve requirements increase both as a percentage of load (top panel) and in absolute megawatts (bottom panel). As the penetrations increase, the reserve requirements also increase from median values of 53 MW to 138 MW for GVL, 20 MW to 62 MW for TAL, and 220 MW to 1,126 MW for FPL.

Comparing across regions, we again find that more frequent forecasts and dispatch have a significant impact on reducing the required reserves. For example, GVL and TAL annual load is similar, around 1.73 TWh and 2.93 TWh, respectively; however, similar PV penetrations yield very different levels of estimated reserve need. At PV penetrations around 30%, GVL's reserve requirement with day-ahead operations reaches 61% of load (median value), whereas TAL's reserve requirement with hourly operation is only around 16% (median value).

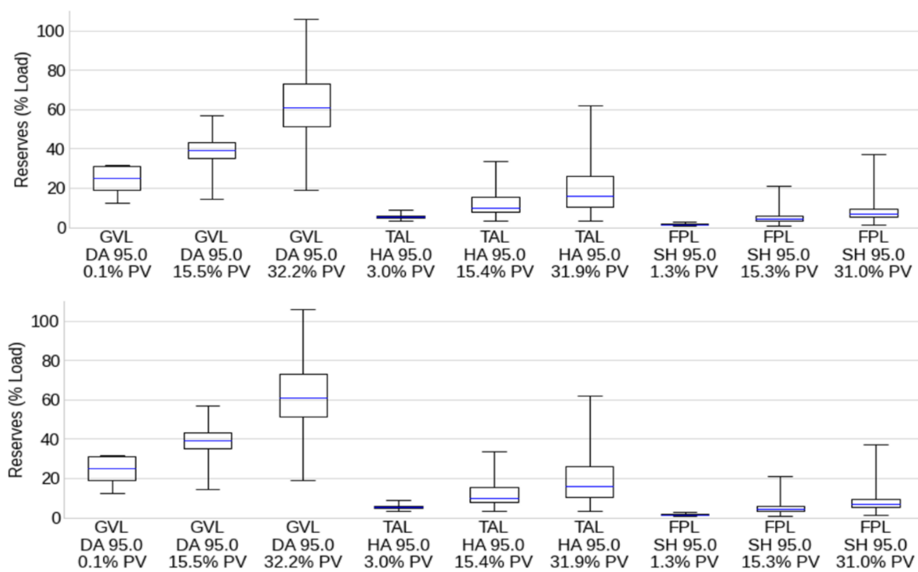

Figure 74. Up reserves (top: as a percentage of load in each timestep; bottom: in megawatts) needed to provide regulation and flexibility services at current and future PV penetration levels {Blue lines show the medians; whiskers extend to the full range of the data. The labels on the x-axis indicate the region, modeled operational practice, forecast error coverage (95.0 means covering 95% of the balancing authority's load and solar forecast errors), and PV penetration levels.}

Both GVL and TAL's reserve requirements are significantly larger than FPL's as a percentage of load, presumably because of their relative size as compared to FPL. Two potential measures to limit the impact of higher solar PV penetrations on small BA reserve requirements are increasing operational frequency and coordinating operations with other BAs.

Mitigation Option 1: Increase Operational Frequency

Figure 75 shows the impact of increasing operational frequency for the particular example of GVL moving from day-ahead to hourly operations for forecasting, quick-start unit commitment, and dispatch. At around 30% solar PV penetration, moving from day-ahead operation to hourly operation reduces the median reserve requirement from about 60% to about 20% as a percentage of load.

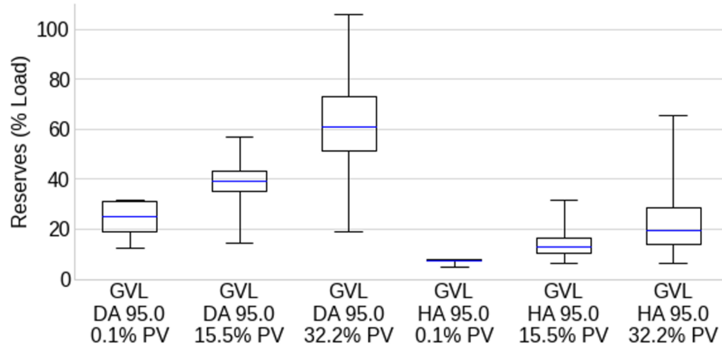

Figure 75. Up reserves needed (as a percentage of load in each timestep) to provide regulation and flexibility services in GVL at current and future PV penetration levels with day-ahead or hourly operation {Blue lines show the medians; whiskers extend to the full range of the data. The labels on the x-axis indicate the region, modeled operational practice, forecast error coverage (95.0 means covering 95% of the balancing authority's load and solar forecast errors), and PV penetration levels.}

This corresponds to a difference of medians in absolute terms of 87 MW. Although more frequent forecasts alone do not necessarily lead to reduced reserve requirements [132], more frequent forecasts and dispatch can provide multiple benefits, including reduced reserve requirements, reduced generator cycling, and the attendant economic savings [98][133][134].

Mitigation Option 2: Coordinate Operations with Other Balancing Authorities

The second way to reduce reserve requirements is through balancing area coordination, such as forming an operating reserve sharing group. In a reserve sharing group, two or more balancing authorities collectively maintain, allocate, and supply the operational reserves for each balancing authority to maintain system reliability [135][136]. Forming an operational reserve sharing group by sharing regulation and flexibility services among GVL, TAL, JEA, and FMPP (i.e., MUNIS), for example, can reduce the reserve requirements for an individual balancing area (Figure 76). In this case, the reserve requirement for GVL at around 30% PV penetration is reduced from around 20% of load to around 10% of load (median values) if GVL is part of MUNIS. This finding is consistent with previous studies on the potential benefits of balancing area coordination in the western United States [137][138].

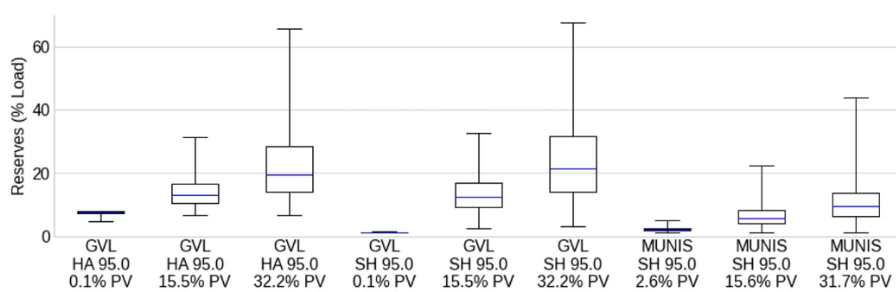

Figure 76. Up reserves needed (as a percentage of load in each timestep) to provide regulation and flexibility services under different PV penetration levels in GVL and MUNIS {Blue lines show the medians; whiskers extend to the full range of the data. The labels on the x-axis indicate the region, modeled operational practice, forecast error coverage (95.0 means covering 95% of the balancing authority's load and solar forecast errors), and PV penetration levels.}

A more subtle point is also evident in Figure 76. Namely, as modeled in this study, sub-hourly operations alone would not necessarily reduce overall reserve requirements for GVL. This is because the hour-ahead solar uncertainty is the same and covered by both the HA and SH operational practice categories. The only difference in total reserve requirement therefore comes down to SH regulation reserve requirements (1%

of load combined geometrically with 5-minute solar forecast errors) compared to geometrically combining hour-ahead load reserve requirements with the aforementioned hour-ahead solar reserve requirements in the HA case. However, although total SH balancing reserve requirements are similar to or even larger than HA balancing reserve requirements, they are composed of two distinct types of reserve: regulation and flexibility, the latter of which tends to be less costly to procure and operate

Conclusions

Previous studies have demonstrated how reserve needs increase with increasing solar penetration. However, that body of work is underdeveloped on the question of reserve needs for small BAs with increasing amounts of solar generation. By working with Florida BAs of different sizes through the FAASSTeR project, the authors came to appreciate this lack of actionable, quantitative information as well as the importance of operational practice, given the likelihood of smaller BAs operating with less frequent forecasting and dispatch. In this study, we explore how both of these aspects of smaller BAs—less PV capacity across a smaller footprint and different operational practices—impact reserve requirements over a range of PV penetrations, and how large reserve requirements at high PV penetration can be mitigated.

Regarding the Florida municipal utilities and how their operational practices may need to change as they deploy more solar PV, we conclude the following:

- FRCC balancing authorities' reserve needs currently depend on system size and operational practices. All else equal, smaller balancing authorities and less frequent forecasts lead to greater reserve requirements (measured as a fraction of load).
- Increasing solar deployment increases reserve requirements for all balancing authorities. For the same PV penetration, the reserve requirements (measured as a fraction of load) are less for larger balancing authorities with more frequent forecasts and dispatch.
- Moving from day-ahead to hour-ahead load and solar forecasting and system dispatch could enable FRCC's smallest municipal balancing authority, GVL, to incorporate about 30% solar generation with median reserves around 20% instead of 30% to 60% of load. (Median day-ahead reserves of 60% reflect the conservative, low-data solar forecasting methodology used in this study, while the 30% lower bound reflects 75% improvement on that benchmark, as may be achievable with weather forecast-based solar forecasts.)
- If all Florida municipal utilities collectively procured operational reserves, this could again halve GVL's reserve requirements at 30% solar generation, reducing the median requirements to about 10% of load. For comparison, the median reserve needs of an "FRCC" reserve sharing group at 30% PV would be about 6% of load (all else equal).
- Reserve needs vary greatly depending on how much forecast uncertainty is covered. For example, if all Florida municipal utilities collectively procured operational reserves and had a PV penetration of about 30%, the median reserve requirements could be anywhere from 5.5% to 14% of load assuming the "right" level of uncertainty to cover falls between 80% and 99%. This range overlaps with the analogous range for all of FRCC analyzed together, which is 3.5% to 9.0% of load.

Although we did not analyze reserve requirements from a rigorous, BA-specific NERC reliability perspective and used conservative, low-data "persistence" forecasts when historical data on forecast errors were not available, this analysis demonstrates clear, quantified trends that can help guide utility decisions regarding operational changes in support of PV integration. Solar forecasting, operational forecast and dispatch frequency, and operational footprint are first-order drivers of reserve need with increasing PV capacity. It appears that BAs of all sizes have options for integrating more solar with affordable reserve costs relative to current practice.

Resource Adequacy Contribution of Solar, Storage, and Solar+Storage

One of the value streams associated with significant levels of solar and energy storge in the electric power system is the contribution these resources have to resource adequacy. This can be expressed in terms of *capacity credit (CC)*[32], the percentage of a generating technology's nameplate capacity that contributes to meeting utility peak load requirements. How capacity credit is assessed has important planning, operational, and economic ramifications. As part of the FAASSTeR project, research at Lawrence Berkeley National Laboratory [35] has produced an efficient methodology for calculating the capacity credit for solar, storage, or solar plus storage. And, an assessment of capacity credit by the City of Tallahassee (COT) electric utility specifically for recent utility-scale solar PV additions to their system provides further insight and guidance on possible strategies.

The CC of energy resources is particularly important in long-term utility planning. It can be one of the key assumptions affecting resource selection in the capacity- expansion models frequently used in integrated resource planning [140]–[143]. The National Renewable Energy Laboratory's (NREL's) Resource Planning Model (RPM), for example, develops a CC estimate for different resources to find least-cost portfolios of resources that meet projected grid needs [142][33]. This model was used to provide a preliminary quantitative evaluation of scenarios associated with accelerating the deployment of solar and storage in Florida [145].

The limitations on solar's CC—due to variable cloud cover and the timing of sunlight versus the timing of peak power-system demand—are well understood [140], [146]– [152]. Also understood is the decline in solar's CC with increasing solar penetration on the grid, as the net peak (system demand minus generation supplied by variable resources such as solar) shifts into hours without strong sunlight [140], [156]. Many detailed evaluations of solar's CC focus on regions that have their highest peaks on summer afternoons (e.g., much of the western United States), but solar's CC is smaller in regions with winter night peaks. Relatively few studies focus on regions with a dual-peaking pattern, where summer cooling loads are nearly equivalent to winter heating loads.

Understanding is much more limited with regard to the factors affecting the reliability contribution of energy storage, and estimates of storage's CC are sparse in the literature. Sioshansi et al. [157] use probabilistic methods to quantify the CC of different storage durations for various U.S. utilities. They show that the CC of long- duration storage (8–10 hours) approaches 100%, while short-duration storage (1–2 hours) achieves only about half that value. They highlight the importance of accounting for the probability of subsequent outages, through dynamic programming techniques, when estimating the CC. They demonstrate that previous estimates of storage's CC with probabilistic techniques from Tuohy et al. [158] do not account for subsequent outages and therefore represent maximum estimates. These studies assume storage is dispatched to maximize its arbitrage value, and then they evaluate the CC associated with that dispatch. They do not indicate the degree to which the CC could be increased if storage's dispatch were optimized to maximize CC. Zhou et al. [159] develop a more general framework for evaluating the CC of storage and demand-side resources, noting the interplay between energy capacity

[32] Noting, that "capacity value" is used in some literature and in practice to have the same meaning as "capacity credit" as has been defined here. However, in this report, "capacity value" is defined as the economic value in monetary terms.

[33] In RPM, conventional resources are assumed to contribute their full nameplate capacity toward meeting planning reserve margins [144].

and power capacity in determining the CC. Nolan et al. [160] similarly focus on demand-side resources and highlight the dependence of the CC on the characteristics of customer loads and timing of system-wide peaks.

Solar and storage can also interact to affect the CC of both technologies, though these interactions have only been studied in a limited number of regions. Denholm et al. [161] identify a declining CC of storage with increasing storage deployment, because the remaining load peaks become wider as storage clips off more peaks. However, they show that high solar penetrations in California can narrow net load peaks and delay the decline in storage's CC. Interactions between solar and storage using probabilistic reliability techniques have also been investigated in Singapore [162] and Ontario, Canada [163]. Aside from peak impacts, solar and storage also impact net load ramps [164]. Recent studies demonstrate the economic value associated with flexible solar plant operation and the tradeoffs relative to storage [165], though we limit our focus to the CC and do not investigate the implications of these operational issues.

To fill in research gaps in this area, we expanded on previous literature and prior work in four ways. First, we focused on Florida, a state in the Southeast with a growing share of U.S. solar deployment where dual-peaking loads are common. Second, we developed a method for finding the storage dispatch that maximizes the CC as defined in NREL's RPM. Third, we evaluated the impact of different solar + storage configurations on CC, particularly with respect to coupled storage and PV. Finally, we validated the method for approximating the CC of resources with a detailed probabilistic method.

Methods for Assessing Capacity Credit

Given the temporal variation of solar on diurnal, seasonal and longer time scales, relative to the timing of peak load and availability of other generation, quantifying CC is non-trivial and, even at best, inexact. Broadly speaking, there are two methodologies for quantifying CC: 1.) Probabilistic methods, and, 2.) Time-period-based methods.

Probabilistic Methods

Probabilistic methods are widely accepted as an accurate way to calculate the CC of solar (and wind), with several approximation methods developed to reduce the large data and computational needs [153]–[155]. Effective Load Carrying Capability (ELCC) is a measure of the additional load that the system can supply with a particular power supply resource with no net change in reliability and can be used to determine CC for a resource. ELCC can be established using one or more of several alternative probabilistic reliability measures (LOLE, LOLH, EUE) and can distinguish between power supply resources with different levels of reliability, size, and on/off-peak capabilities.

Table 15. Probabilistic measures and associated characteristics that can be identified by each measure.

Measure	***Frequency***	***Duration***	***Magnitude***	***Hours Considered***
Loss of Load Probability (LOLP)	Yes	Yes	No	Daily Peaks, or All Hours
Loss of Load Expectation (LOLE)	Yes	No	No	Daily Peaks, or Subset Of or All Daily
Loss of Load Hours (LOLH)	No	Yes	No	All Hours
Expected Unserved Energy (EUE)	No	Yes	Yes	All Hours

For variable generators such as solar, the method can distinguish between solar production patterns that consistently, sometimes, or never deliver during high-risk periods. Table 15 summarizes common probabilistic measures in terms of three characteristics used to describe the reliability risks - frequency, duration, and magnitude of loss of load [166][167][168]. ELCC and associated risk-based methods place greater weight on high-risk hours, and less weight on low-risk hours.

Time-period Based Methods

Time-period-based methods attempt to capture risk indirectly, by assuming a high correlation between hourly demand and probabilistic resource adequacy metrics[34]. The approximation method used here is convenient for easily and transparently evaluating the CC of solar and storage under many different possible weather years, combinations of hypothetical sites and utilities, and system configurations. This approach, which is validated against more detailed methods, can be useful highlighting general directional relationships and identifying where more detailed analysis is warranted.

Our approach enables broad exploration of the many factors that affect solar and storage CCs, rather than detailed quantification under specific configurations or circumstances. We approximate CCs using the load duration curve (LDC) method employed in NREL's RPM [142]. We then validate this approach by comparing the LDC approximation with CC calculations from the probabilistic effective load carrying capability (ELCC) method.

Load Duration Curve Method

The LDC method approximates the CC of a variable energy or energy-limited resource, such as storage, based on the reduction in the average highest peak net load hours relative to the average highest peak load hours. The calculation method can be visualized as the difference between an LDC, which sorts the load from the highest to the lowest over a specified period such as a year, and a net LDC during the peak hours (Figure 77). The net LDC is created by first reducing the hourly load by the corresponding generation from the resource in the same hour and then sorting the resulting net load from highest to lowest. Because the load and net load duration curves are sorted independently, the gap between the load and net load duration curves represents the decrease in the highest net load hours, irrespective of when they occur. This method can therefore capture any effects where deployment of a resource leads to a shift in the time of day that the net load peak hours occur. In the case of storage, the net LDC is created by both reducing the load by the energy generation from discharging storage and increasing the load by the energy required for charging storage.

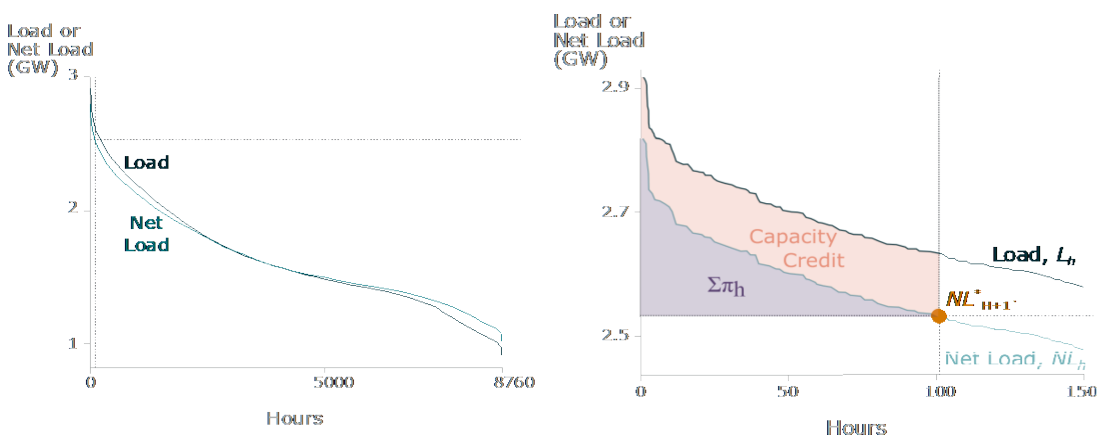

Figure 77. Illustration of load and net load duration curves with storage for all hours of a year (left) and focusing on just the peak hours of a year (right).

[34] Although this relationship generally holds, it can be compromised by scheduled maintenance of other units.

Because of the influence of weather on CC, we calculate the CC over two timeframes. For the majority of the results, we use 11 different historical years and calculate the CC separately for each year. This way we are able to see how sensitive the results are to the choice of one particular year. In each of these cases, we use the top 100 hours of the year (the top 1.1% of hours) as peak hours. We also, however, calculate the CC using all hourly data across 11 years at once. The CC using all hourly data across 11 years at once is arguably the most accurate way to estimate the overall contribution of a resource toward reliability. Long multi-year datasets are not always available, however, leading to individual years often being used in practice. This 11-year CC uses the top 1,100 hours (also the top 1.1% of hours) as peak hours.

Storage Dispatch Model

Though the LDC method can approximate the CC of storage, it does not directly specify the dispatch schedule for storage. To estimate an upper bound to the CC, we develop a linear model whose solution maximizes the CC of storage, where the CC is defined based on the LDC method. The approach leverages insights from the literature on optimizing the conditional value at risk (CVaR) [169], [170] and the fact that maximizing the CC of a resource, based on the LDC method, is equivalent to minimizing the area under the net LDC in the peak net load hours. Because the resulting optimization model is linear, it can be solved extremely quickly, even when considering 11 years of hourly data.

An energy storage system is characterized by its nameplate capacity (MW), its energy capacity (MWh), and its roundtrip efficiency. We assume the storage system charges and discharges at rates up to its nameplate capacity. The storage duration (in hours) is therefore the ratio of the energy capacity to the nameplate capacity. The analysis uses hourly time steps—no shorter time constraints or ramping limits have been considered. In our storage dispatch model, we assume that storage can be dispatched with perfect foresight. Though this is not feasible, it provides an upper bound to the achievable CC as defined by the LDC method. We find a lower bound by implementing a feasible, though naïve, dispatch strategy: dispatch the storage today based on the optimal dispatch schedule for yesterday's load[35].

Because the model searches for an optimal storage dispatch profile, the hourly system load net of storage generation (the net load) is also a decision variable obtained from the model. The level of the net load just outside of the peak net load hours, NL*H+1, is especially significant, as it defines the area of the net LDC that when minimized leads to the storage dispatch with the maximum CC.

Validation Against Probabilistic Benchmark

We compare the CC calculated with the LDC method versus the CC calculated as the ELCC using the probabilistic approach outlined by Keane et al. [171][36]. The probabilistic benchmark accounts for the probability that random forced outages at power plants will lead to insufficient generation to meet demand, as quantified by the loss of load probability (LOLP). Overall reliability is then measured by the loss of load expectation (LOLE), which accumulates the LOLP over all hours. The ELCC represents the amount that the demand can be increased after a resource is added to the generation mix while

[35] Clearly this naïve dispatch strategy could be improved using state-of-the-art forecasting. In our analysis, however, it simply provides a lower bound that can be calculated without making assumptions about forecasting capabilities.

[36] The level of reliability based on the generation and demand can change from year to year. Similar to the approach used by Madaeni et al [128], we scale the load levels so that LOLPs of the base system in each year sum to 2.4 in order to have a consistent starting point for determining the reliability contribution of solar and storage.

maintaining the same level of overall reliability. To validate the LDC method for storage, we calculate storage's ELCC using the storage dispatch profile that results from the linear storage dispatch model.

Case Study Data and Assumptions

An advantage of the LDC method is that it requires relatively little data, only the load and the resource generation profile. Our case study quantifies the CC of solar and storage using load data from three municipal utilities: JEA, City of Tallahassee, and the Florida Municipal Power Pool (FMPP)[37]. Hourly load data for the three utilities were obtained from ABB Velocity Suite (based on Federal Energy Regulatory Commission Form 714) for 2006–2016. Solar generation data for the same period were generated using the default assumptions in NREL's PVWatts model, with historical weather data sourced from the National Solar Radiation Database for particular hypothetical PV sites located near each utility.

For the probabilistic benchmark, we also require the nameplate capacity and forced outage rate for generators associated with each utility, which we obtained from ABB Velocity Suite augmented with 10-year site plans filed with the Florida Public Service Commission. For the City of Tallahassee, a small utility with two relatively large generators and a limited number of small generators, we also include 200 MW of firm capacity based on transmission capacity between the City of Tallahassee and resources in Georgia. This transmission capacity is not tied to any one generator, but provides the City of Tallahassee with access to a wide variety of resources at times when its own units experience forced outages.

Throughout the analysis, we assume storage has a roundtrip efficiency of 85%.

Results

We use the LDC method to find the CC of solar, storage, and different configurations of solar + storage. We then validate the results from the LDC method against a probabilistic benchmark and find a lower bound to the CC of storage associated with forecast errors. The following are our key results.

Capacity Credit of Solar Varies by Utility and Weather Year

Using the LDC method, we find that solar's CC varies from one utility to another, and it varies by weather year (Figure 78a). The CC of solar is highest (about 30%–50% of nameplate capacity) when using the hourly load shapes from FMPP along with the solar generation patterns from hypothetical sites near FMPP. The CC is somewhat lower (about 20%–40%) when using the load shapes and solar generation data for JEA and the City of Tallahassee. The primary reason for the higher solar CC in FMPP is that almost all of the peak 100 load hours occur on summer afternoons, whereas JEA and the City of Tallahassee also have peak load hours during winter mornings or nights when solar generation is minimal or zero.

Though there is a large range in solar CC across years, only a few particular years drive that range. The CCs calculated using the full 11 years of data, represented by the colored dots in Figure 78a, are close to the medians of the CCs calculated from each year individually. In addition, the CC varies very little with the choice of hypothetical sites within the relatively small footprint of the utilities[38]. As such, for the

[37] FMPP member utilities include the Orlando Utilities Commission, Lakeland Electric, and the Florida Municipal Power Agency. FMPP operates the combined resources of the utilities as if they were one utility.

[38] We also find that geographic diversity within the region around the utilities does not significantly impact the solar CC. We conducted a simple experiment where the CCs of hypothetical sites were estimated individually then compared to the CC of a similar amount of aggregate PV distributed across multiple sites. The aggregate CC was not noticeably greater than the average of the individual site CCs. Geographic diversity can, however, help mitigate sub-hourly variability even for sites within a utility service territory [172], [173].

remainder of this analysis, we present results from only one PV site within each utility. We also focus the rest of our analysis on a single weather year, 2012, because this is the weather year used in the current version of RPM for all demand, wind, and solar shapes. The 2012 weather year yields CC estimates that are close to the medians across all 11 years (Figure 73b).

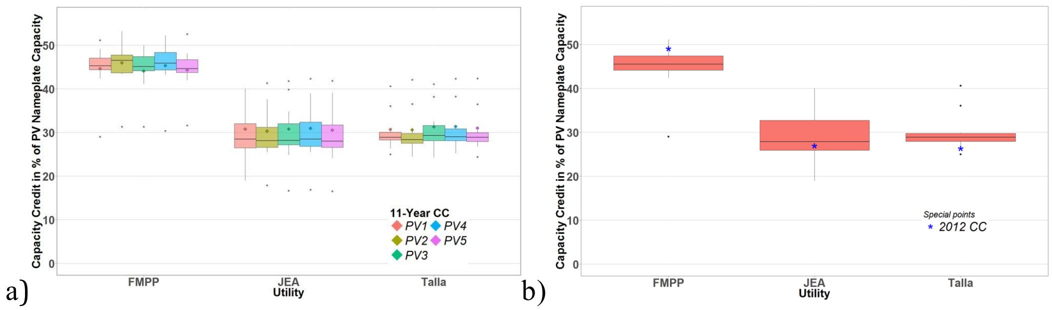

Figure 78. Variability in solar CC across each of the 11 weather years and 5 PV sites compared to the solar CC from the full 11 years of data (a) and comparison of the CC from the 2012 weather year to all other years for the one representative PV site (b).

The CCs of solar calculated with the LDC method are within the range of solar CCs, at low penetrations, reported in other studies or assumed in utility planning studies, though at the lower end [140], [150]. The LDC method yields a solar CC that is somewhat lower than the 54% CC assigned to solar by a major investor-owned utility, Florida Power & Light (FPL), in its cost-effectiveness evaluation. FPL estimates the CC based on the expected solar generation during the typical peak demand periods of 4-5pm in August. FPL also estimates CC for the winter period, based on generation between 7-8am in January, finding little contribution to reliability in this period because the winter peak occurs when solar generation is low. Because the peak is higher in summer than in winter, FPL finds that solar can defer the need to build new capacity commensurate with solar's summer CC [174][39].

Capacity Credit of Solar Declines with Increasing Solar Deployment

Consistent with findings in the literature, solar's CC based on the LDC method declines with increasing solar deployment (Figure 79), primarily because more solar shifts the peak net load hours away from summer daytime hours and into early evening hours in the summer or early morning hours in the winter. Adding solar does little to reduce the peak net load in these hours, thereby lowering solar's CC. This trend is consistent across the three utilities. By the time solar deployment has increased to generate enough energy to meet 15% of annual sales, the average CCs are less than half of the CCs at very low deployment levels. The reduction in solar CC

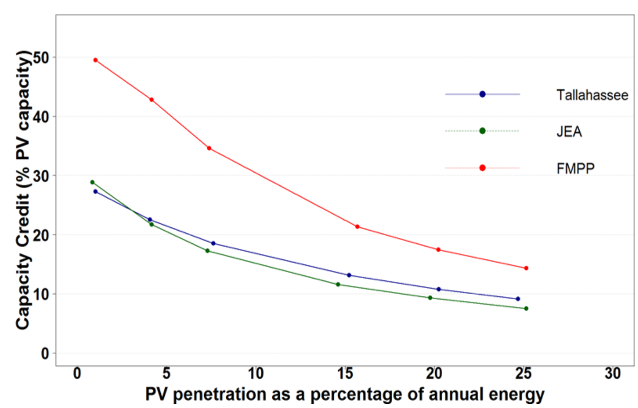

Figure 79. Declining average CC of solar with increasing solar deployment.

[39] Though, here, we present the CC calculated using all hours of the year, Florida utilities partition the year by season or by summer/winter in order to calculate CC and generally are assigning CC only for summer.

with higher deployment is helping to drive interest in solutions that ensure resources are adequate to meet demand, including adding storage.

Capacity Credit of Storage Depends on the Storage Duration and Declines with Increasing Storage Deployment

In contrast to solar, which has weather-dependent generation, storage is viewed as more reliable owing to its dispatchable nature. We find, however, that the fraction of storage's nameplate power rating that contributes to resource adequacy (i.e., storage's CC) is highly dependent on the duration of storage, which is based on the ratio of the energy capacity to the power rating. With too few hours of energy, storage cannot continuously reduce the peak net load hours on days with high, broad peaks. On these days, storage is more likely to be depleted when reducing peak load, leaving it unavailable for discharge during other peak hours. The impact of storage duration on storage's ability to reduce winter and summer peak load hours is illustrated in Figure 80. In this illustration, 1 hour of storage is insufficient to reduce winter or summer peaks, 4 hours is more effective in reducing the narrow winter peak and less effective for the broader summer peak, and 6 hours is effective in both winter and summer. This is just an illustration—the duration of summer and winter peaks varies from year-to-year and between utilities.

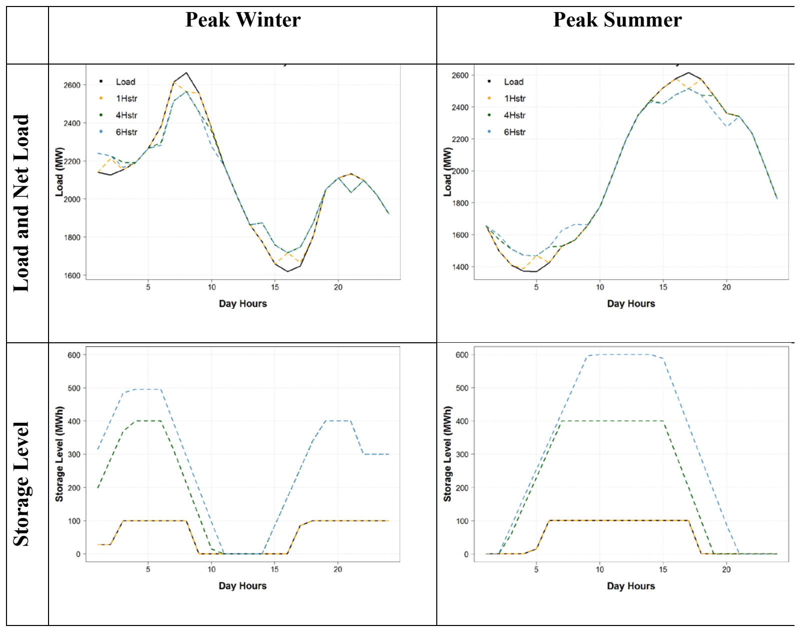

Figure 80. Load and net load (load less storage generation) for a peak winter and summer day with varying storage reservoir sizes

Also apparent in Figure 75 is that, for storage to continue reducing peak loads, broader and broader peaks must be clipped as more and more storage is deployed. Conversely, for the same hours of storage, the average storage CC is reduced as more and more storage is deployed. Figure 81 illustrates both the relationship between storage CC and hours of storage as well as the declining storage CC with increasing storage deployment, as calculated with the LDC method. Here the nameplate capacity is 0.3% of the peak load (low storage

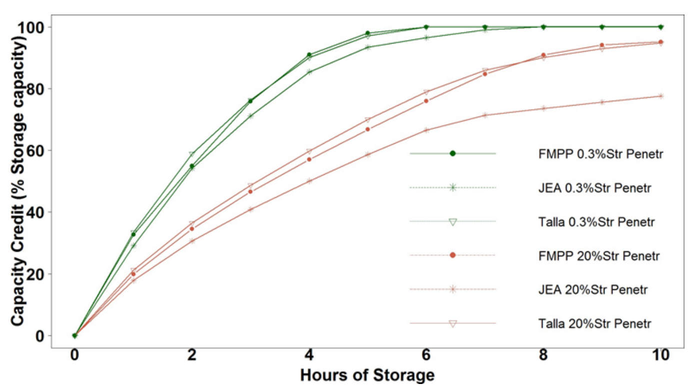

Figure 81. Dependence of storage CC on storage duration, declining CC with increasing storage deployment.

penetration requiring about 2–10 MW of storage depending on the utility) or 20% of the peak load (high storage penetration requiring about 120–600 MW of storage).

Across the three utilities, storage's CC, even though it is fully controllable by the system operator, depends strongly on the storage duration. Achieving a 90% CC requires at least 4–5 hours of storage at low storage penetration, when storage capacity is small relative to the system peak. As storage deployment increases to 20% of the peak demand, 9 hours— and sometimes more than 10 hours—of storage are needed to achieve a 90% CC. These findings, based on the LDC method for calculating CC, are in line with previous estimates based on more detailed probabilistic methods (e.g., [157]).

Capacity Credit of Storage Can Vary with Weather Year

Because storage's CC depends on load shape, it can vary from year to year. Based on the findings, storage with a given duration is more likely to have a higher CC in years with narrower peaks, while achieving a high CC in years with broader peaks requires longer-duration storage. As Figure 82 shows, for FMPP, the variation in storage CC with weather year is largest for medium-duration storage (3–5 hours). For short- duration storage (1 hour), the CC is small across all weather years. For long-duration storage (10 hours), the CC is close to 100% in almost all weather years. Overall, the variation in storage CC with weather years (Figure 82) is somewhat smaller than the variation in solar CC for FMPP (Figure 79). Qualitatively similar patterns were observed for the variation in storage CC using the other utility load shapes.

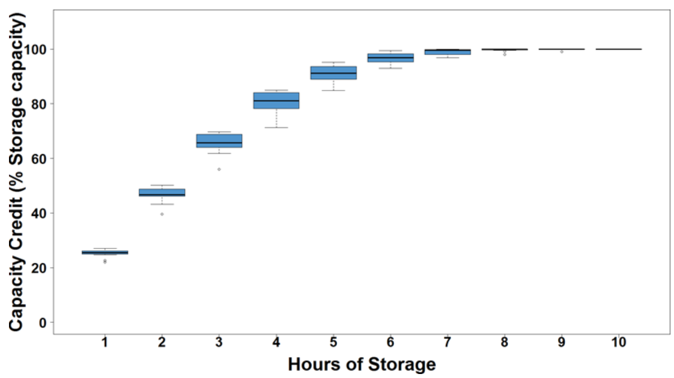

Figure 82. Variation in storage CC by weather year and storage duration, for 100 MW of storage in FMPP.

Capacity Credit of Storage Depends on System-Level Solar Deployment

Seeing the dependence of storage CC on the width of peaks, we expect the storage CC to change as net load peaks narrow with increasing solar deployment. To test this, we compare the decline in storage CC with increasing deployment of 4-hour storage under a case with no system-wide solar and a case with as much as 15% of the annual energy being met by solar (Figure 78).

The CC of 4-hour storage is greater with system-wide deployment of solar than without solar, though the storage CC still declines with increasing storage deployment. The increase in 4-hour storage CC with system-wide solar deployment is greatest for FMPP, the utility with a load shape that peaks only in the summer and therefore likely sees the

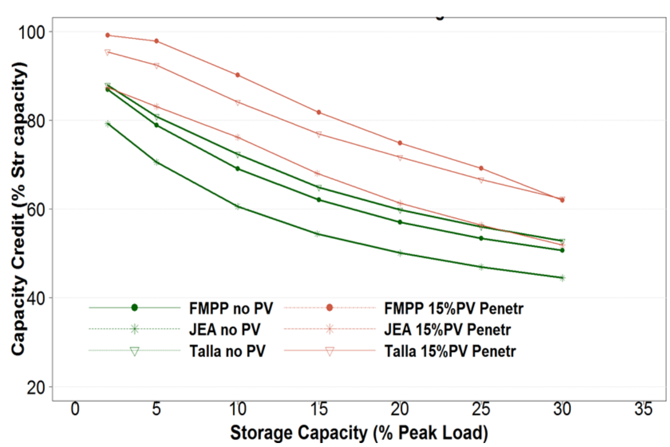

Figure 83. Impact of system-wide solar deployment on storage CC, 4-hour duration storage.

greatest change in peak net load shape with solar. The effect is smaller for the two utilities (JEA and the City of Tallahassee) that tend to have some peak load hours in winter mornings or late winter nights.

For storage with a duration shorter or longer than 4 hours, the storage CC follows a similar declining trend with increased deployment of storage, though with some differences. For shorter duration storage, the storage CC begins at a lower level, hence the decline with increasing storage deployment appears flatter. For longer duration storage, the storage CC begins at a level closer to 100% CC and maintains that level before beginning to decline as storage deployment increase.

Here we present only the incremental CC of storage with and without large shares on solar on the system. Storage deployment can also increase solar's CC at high solar penetrations, though we do not show that here. The interaction between the CCs of storage and solar demonstrates a synergy that may be important to capture in capacity-expansion models. In the next section, we analyze the CC of solar + storage facilities, though only at low penetration. We leave further investigation of synergies at very high penetrations of solar and storage to future studies.

Solar + Storage Configuration Affects Capacity Credit

Increasingly, storage is considered as a resource that can be combined with solar to create a dispatchable resource similar to concentrating solar power with thermal storage [175]. Though there are many factors to consider when sizing storage and solar and deciding on the configuration, we focus solely on the implications for the CC of solar + storage.

The factors that can be adjusted when designing a solar + storage system include the number of hours of storage, the storage power capacity relative to the PV module capacity, the ratio of the inverter capacity to the PV module capacity, whether the solar and storage are independent (alternating current [AC] coupled) or share an inverter (direct current [DC] coupled), and whether the storage can charge from the grid or solar (loosely coupled) or whether it can only charge from solar (tightly coupled)[40]. One reason to model a restriction under which storage can only charge with solar power relates to tax credit policy. Currently, storage can qualify for the U.S. federal Investment Tax Credit (ITC) that is available for solar plants if the storage charges from solar at least 75% of the time. We consider the implications on solar + storage CC by comparing results for the extreme case in which storage is only charged from solar or it can be charged from either the grid or solar (Table 16).

Table 16. Definition of Analyzed Solar + Storage Configurations

Configuration	***Description***	***Share Equipment?***	***Source of Electricity for Storage***
Independent	*PV and storage do not share equipment, and storage is charged from the grid.*	*No*	*Grid*
Loosely Coupled	*PV and storage both connect on the DC side of shared inverters, but storage can charge from storage or the grid.*	*Shared inverter*	*Grid or PV*
Tightly Coupled	*PV and storage connect on the DC side of shared inverters, and storage can only charge from PV.*	*Shared inverter*	*Only PV*

[40] We follow the naming convention for this configuration as described by Denholm et al. [35]

In all coupled cases, we assume that the ratio of the inverter capacity to the PV module capacity is kept constant, rather than changing the inverter size as storage is added. In the independent case, the CC of a solar + storage system is equivalent to the sum of the CC of solar alone and the CC of storage alone. When coupling solar and storage together with a shared inverter, the CC can be less than the sum of the individual CCs if the shared inverter limits the joint production of solar and storage or, in the case of the tightly coupled system, the solar is insufficient to fully recharge the storage before the next system peak.

Using JEA load and solar data for 2012 along with the assumption that storage and PV both have a nameplate capacity of 100 MW, we find examples in which a coupled solar + storage system can have a CC less than the CC of an independent system or even less than the CC of storage alone (Figure 84a). In this particular case, the CC of solar + storage is not impacted by configuration for short-duration storage (1 hour). Increasing the duration, however, produces a gap between the CCs of independent and coupled systems. The CC of the loosely coupled solar + storage system is limited by the capacity of the shared inverter. Requiring storage to only charge from solar (tightly coupled) further restricts the CC; at 6 hours of storage and above, the CC of the tightly coupled solar + storage system is less than the CC of storage alone (which can charge from the grid during off-peak hours). Similar behavior is observed with the FMPP load and solar data, but with less difference between the CC of the tightly and loosely coupled configurations and the CC of solar + storage is never less than the CC of storage alone (Figure 84b). The reason the solar + storage CC is less impacted by restricting charging to solar in FMPP than in JEA may be that FMPP peak hours all occur in the summer, when solar production is greater and more consistent, while some of the JEA peak hours occur in the winter, when solar production is lower. In addition, the duration of peaks is wider for JEA than for FMPP; wider peaks require more energy, which is limited by solar generation in the tightly coupled case.

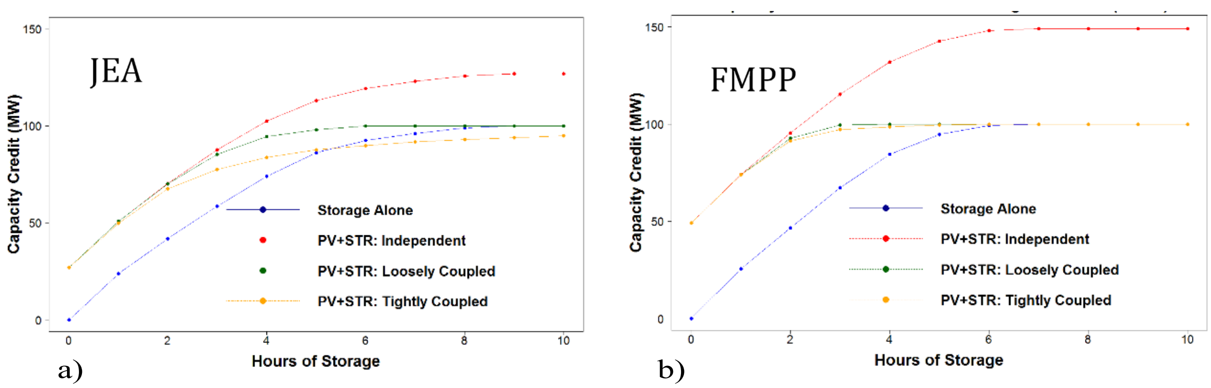

Figure 84. Variation in solar + storage CC with different configurations with 100 MW storage and 100 MW of solar using (a) JEA and (b) FMPP load and solar profiles from 2012.

We find that if the storage size is reduced to only 20% of the solar nameplate capacity, the CC of solar + storage is nearly equivalent across the independent, loosely coupled and tightly coupled configurations. With storage sized well below the inverter capacity, and the CC of solar less than 50% of its nameplate capacity, there are few opportunities for storage and solar to compete for limited inverter capacity. Likewise, in the tightly coupled case, a much smaller amount of solar is required to charge the smaller storage system, making storage easier to charge only with solar energy.

Even if storage and solar are equally sized, it may be possible to achieve the same (or similar) CC with a coupled system as with an independent system if the inverter capacity is increased in the coupled system.

This increases the cost of the coupled system, but it may be worth the cost if reliability is a high priority for the utility. The requirement to only charge storage from solar in the tightly coupled case may continue to be a limiting factor.

Capacity Credit Calculated with LDC Method is Consistent with Probabilistic Benchmark Except for Very Small Utilities

As mentioned in the Introduction, the LDC method is convenient for easily and transparently evaluating the CC of solar and storage under many different possible weather years, combinations of hypothetical sites and utilities, and system configurations. To be useful in decision making, however, it should also yield reliability estimates similar to those derived from a more detailed evaluation with probabilistic reliability methods. Here we validate the approximation by comparing the CC estimated with the LDC method to the ELCC calculated with a probabilistic method (Figure 85). We develop storage dispatch profiles such that they maximize storage CC under the LDC method, and then we apply those profiles in the ELCC calculation. In both methods, we use the same solar, load, and storage dispatch data. The only additional information used in the probabilistic method is the capacity and forced outage rate of the conventional generation operated by the utilities.

For the two larger utilities with peak demand over 3 GW (JEA and FMPP), the CC with LDC method is directionally consistent and quantitatively similar to the ELCC calculated with the probabilistic methods for solar and storage. For these two utilities, the main difference is that the LDC method tends to overestimate the CC of solar and storage, particularly for longer durations. Even for the small utility with a peak demand of less than 1 GW (City of Tallahassee), the solar CC with the LDC method is somewhat similar to, though slightly higher than, the ELCC.

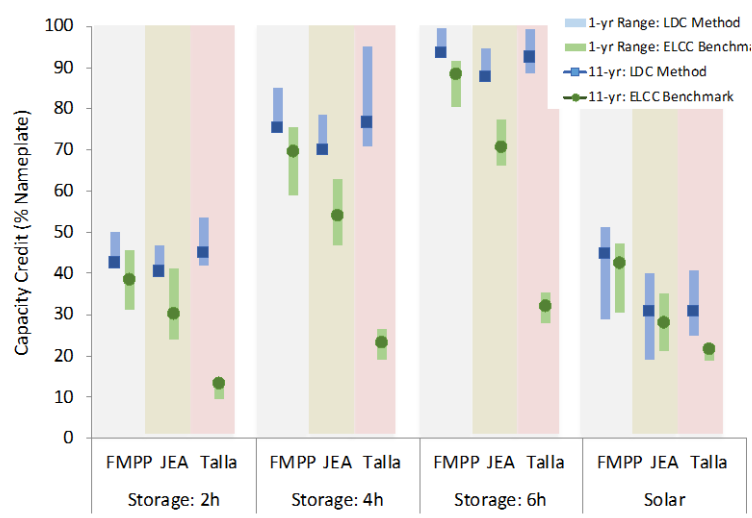

Figure 85. Comparison of the CC estimated with the LDC method to the ELCC calculated with a probabilistic method.

On the other hand, for the small utility (City of Tallahassee), the CC of storage estimated with the LDC method is much greater than the ELCC. This starkly different result stems from the small number of conventional generating stations operated by Tallahassee, with some relatively large compared to the load, which leads to a widely distributed risk of outages (or a widely distributed LOLP). Whereas the risk is concentrated in less than about 0.5% of the hours for JEA and FMPP, Tallahassee's risk is distributed over about 17% of the year[41]. As a result, short-duration storage makes a much smaller contribution to

[41] We measure the concentration of the risk of outages as the percentage of hours in which the LOLP is greater than 5% of the maximum LOLP. A smaller percentage of hours in which the LOLP is greater than 5% of the maximum indicates that the risk of outage is more concentrated in peak hours.

increasing the overall system reliability for the City of Tallahassee compared to the contribution of storage in JEA and FMPP.

Though the deviation between the CC estimated with the LDC method and the ELCC for the City of Tallahassee is important to understand, we consider this to be a rare failure of the approximation rather than a common occurrence. Few utilities are as small as the City of Tallahassee, and even among small utilities it is rare to find individual generators that constitute such a large fraction of the total capacity. More generally, since we largely treat each utility as an island, we do not model several factors that could be important in determining the true risk profile for utilities including the potential to access generation over other transmission lines and to leverage shared reserves for short-term events. Probabilistic methods that can account for transmission capacity to neighboring utilities exist [177], [178], though we do not consider those approaches in this simple validation.

Forecasting Matters for Storage Capacity Credit, Particularly with Small Storage Reservoirs

Throughout the preceding analysis, we estimate an upper bound to storage's CC with the LDC method assuming that demand could be perfectly forecast. In reality, storage dispatch will depend on many factors, including how well peak periods are forecasted. A lower bound to the storage CC can be established by assuming that the schedule based on the previous day's observations is implemented in the current operating day. This naïve "day-ahead persistence" dispatch approach is practicable, though it should be easy to improve by considering information like weather forecasts in the dispatch development.

We find that the impact of forecasts on storage CC is more important for shorter- duration storage than for longer duration-storage. We illustrate this in Figure 86 by showing the fraction of the perfect foresight CC achieved with storage dispatched with day-ahead persistence. With 1-hour storage, for example, the optimal storage schedule with perfect foresight often results in storage being fully discharged in the peak hour. If, however, the peak hour in the previous day shifts by as little as an hour during the operating day, the contribution of storage to meeting peak hours could be greatly diminished. With 4 hours of storage, however, the dispatch often discharges the storage over the highest 4 hours of a day. Even if the peak shifts by 1 hour from one day to the next, the storage dispatch profile is much more likely to reduce demand in that hour. Forecasting is particularly important for a small utility (the City of Tallahassee) with variable peak hours.

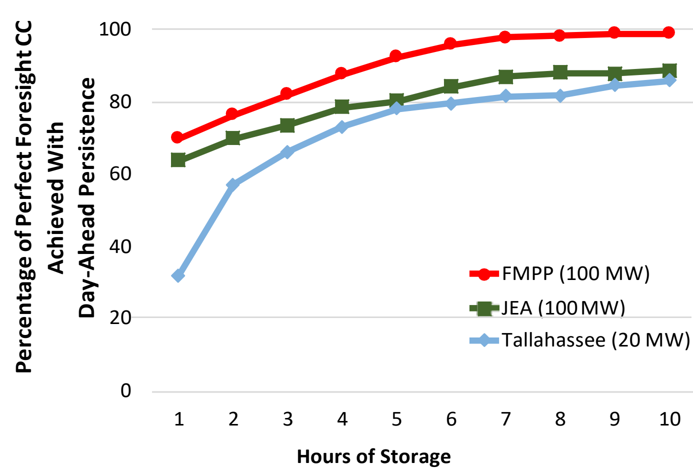

Figure 86. Importance of forecasting to the CC of storage.

Conclusions

Many factors impact the CC of solar and storage, including weather, utility demand profiles, solar and storage deployment levels, and the configuration of solar and storage systems. Exploratory analysis of the relative importance of different factors can be useful before evaluating specific cases via more detailed and resource- intensive modeling. ***We have developed and demonstrated a fast and relatively simple***

algorithm for identifying the dispatch that maximizes the CC of storage and solar, suitable for such exploratory analysis.

Applying this approach to a case study in Florida, we find that ***storage's CC—even though it is fully controllable by the system operator—strongly depends on the storage duration.*** Achieving a 90% CC requires at least 4–5 hours of storage when storage capacity is small relative to the system peak. As with solar, the CC of storage can vary with weather year, though it is somewhat less sensitive to year-to-year variations, and the variability tends to be largest with moderate storage durations (e.g., 3–5 hours). As storage deployment increases to 20% of the peak demand, 9 hours—and sometimes more than 10 hours—of storage are needed to achieve a 90% CC. Or from another perspective, the CC of storage with the same duration will decline with increasing storage deployment.

Increased solar deployment at the system level can increase the CC of 4 hours of storage. Directly pairing solar and storage can also impact the CC. Storage with a power rating similar to the solar inverter rating loses CC when coupled with solar if its duration is more than 1–2 hours, because storage competes with solar for use of the inverter. Restricting storage to only charge with solar can reduce the CC of a solar + storage system, sometimes to the point that it becomes smaller than the CC of storage alone. On the other hand, there is no reduction in CC when the storage is small relative to the solar inverter.

Utility Solar Capacity Credit - Recent Practice in Florida

Most Florida utilities with significant solar have now adopted a strategy of assigning CC to their utility-scale solar generation, only for summer firm net capability. For each nominal 75 MW solar PV plant, FPL is using between 28 MW and 45 MW for net summer firm capacity, and DEF is using around 43 MW. FPL is adjusting the capacity down somewhat for new plants over time to reflect the effect solar has on shifting the peak later in the day. In a 2020 survey, the City of Tallahassee found a range of CC values being assigned by Florida utilities, as shown in Table 17. More recently, in its 2021 TYSP, the City of Tallahassee assigned a net summer firm capacity of 12 MW (20%) for 60 MW of installed utility-scale solar. This was based in part on analysis by probabilistic methods starting with calculation of ELCC.

Table 17. Solar PV Capacity Credit assignments by Florida utilities, 2020 survey (only counted in summer firm capacity) (table by P. Clark, City of Tallahassee [166]).

Utility	***CC [% of Rated Capacity]***
DEF	57%
FMPA	40%
FPL	16%-55%
GRU	55%
JEA	0%
LAK	50%
OUC	50%
SEC	33%-60%
TAL	0%
TEC	30%-55%

Solar PV Contribution to Peak – Additional Factors and Insights

Solar contribution to meeting peak load is significantly less in winter in Florida, where there is a peak more towards the evening and in a significant portion of the state there is a dual peak, morning and evening (Figure 29b). For example, Figure 87 shows a winter day in Tallahassee with the peak demand around 8 a.m. and a smaller evening peak shortly before 7 p.m. To help somewhat with solar's contribution to peak, the solar output can be flattened to extend earlier and later in the day by employing single-axis tracking and/or higher inverter load ratios (ILR's). Both are fairly common.

Another potential strategy to produce solar output more coincident with demand peak is re-orienting some portion a fixed-axis plant away from the optimal (Northern hemisphere) southerly orientation; For example, orient some arrays in a more westerly direction to optimize output to coincide better with summer peak hours (late afternoon, early evening). This happens to be the case with the City of Tallahassee 42 MW_{AC} solar plant located at the airport, though the reason was to meet FAA requirements to eliminate possible reflections interfering with pilot navigation. Nonetheless, the result was some of the panels near the airstrip were situated with a more westerly orientation, shifting the peak output of the entire plant later in the day. This is shown in Figure 88, which compares the output in percent of rated capacity of the 42 MW_{AC} plant with some panel arrays oriented more west and the 20 MW_{AC} plant with all panel arrays in the same southern orientation [166]. This would affect the CC analysis.

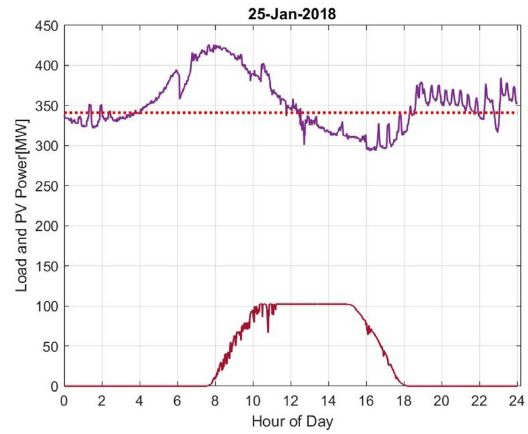

Figure 87. A dual-peak winter-day in Tallahassee, with the larger peak demand occurring in the morning. The upper solid trace is system load and the lower solid trace is solar PV production scaled up to 100 MW_{AC}.

Also, with respect to determining CC, solar PV plants characteristics are distinctly different from traditional fossil and nuclear power plants. Forced outage rate (FOR) is one of the metrics used to determine the probability a plant will be available to help supply peak demand. There is not only the fact that a solar PV plant's output varies with irradiance, but, also the nature of plant outages due to equipment reliability. The total output of utility-scale PV plants is the sum of the output of multiple inverters that convert DC output from various sections of the plant. Inverters are a critical component and subject to failure, but, loss of inverter does not normally take an entire utility-scale solar plant down.

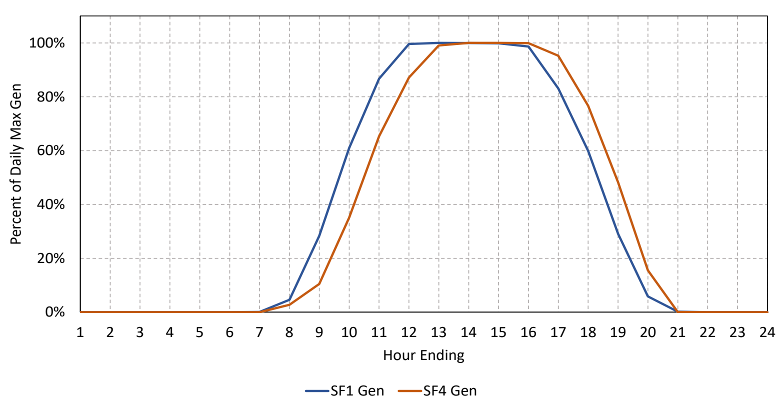

Figure 88. Comparison of the output (in percent of rated capacity) of the City of Tallahassee (COT) 42 MW_{AC} solar PV plant (SF4) having some panel arrays oriented more west with a COT 20 MW_{AC} solar PV plant (SF1) at the same general location (Tallahassee International Airport) with all panels in the same southern orientation (figure by P. Clark, City of Tall. [166]).

So, the "partial performance" characteristic of solar PV plants arising from inverter-related failures, is important to consider when utilizing probabilistic assessment methods (Table 15) to assess plant reliability and availability to serve load [166][180]. Figure 89 shows how different numbers of inverter failures on different days in different months affect solar plant output and coincidence between solar and demand peaks.

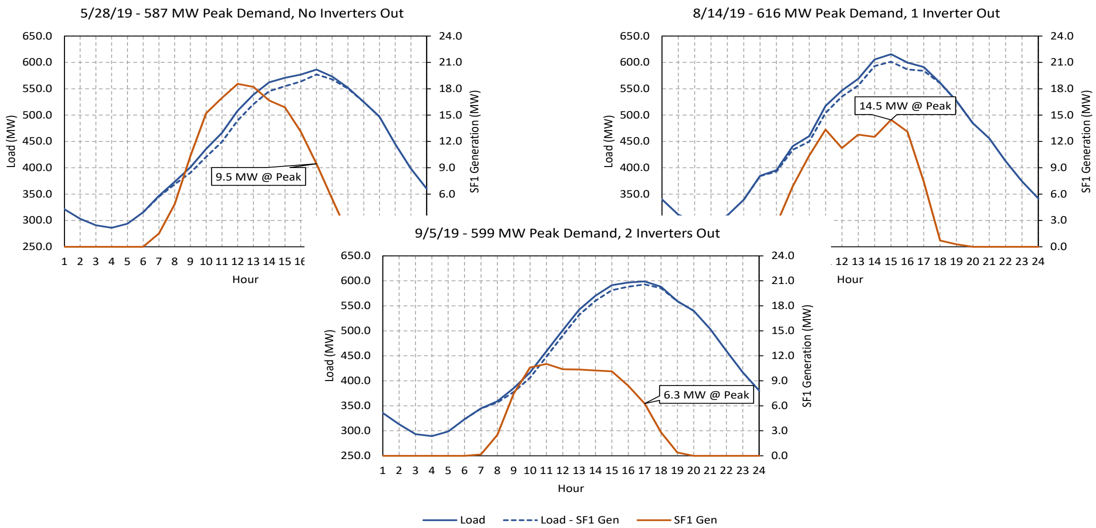

Figure 89. Effect of inverter outages on output of a 20 MW_{AC} solar PV plant relative to system load (figure by P. Clark, City of Tall. [166]).

Solar + Storage for Resilience

Strategies for distributed solar+ should include the significant contribution it can make to increasing resilience According to the Department of Homeland Security's National Infrastructure Protection Plan, resilience is defined as "the ability to resist, absorb, recover from, or successfully adapt to adversity or a change in conditions" [181]. In a 2013 Presidential Policy Directive (PPD), resilience was defined as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions", adding that resilience "includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents" [182]. SEPA's Microgrid Playbook distinguishes resiliency from reliability as follows – "In comparison to reliability, resiliency has more to do with a system's response or behavior when subjected to largely unavoidable events not intrinsic to the system itself" [183].

Figure 90. Through the SunSmart Schools and Emergency Shelters Program, over 106 schools in Florida have solar PV + battery energy storage systems (photo by Amy Kidd) [185].

Distributed solar+, in particular solar+storage, can enable more resilient electric power and, in doing so, improves the resiliency of the facilities, infrastructures, and communities that rely on electric power. Distributed energy of any kind improves ability to continue providing power to local loads when electric infrastructure is damaged due to extreme events such as hurricanes or fires, or even more common localized events such as a tree limb falling on a power line or a vehicle striking a power pole. Fossil, nuclear, and hydroelectric power plants are also dependent on water, which is impacted by climate, weather, cyclical and extreme events. In addition to reducing dependency on power lines, poles, and towers, and central generating stations, solar also reduces dependency on fuel supplies, which are, in turn, dependent on pipeline infrastructures and transportation networks. And, when coupled with energy storage, solar can power local loads for extended periods of time, sometimes indefinitely.

NREL's REOpt tool [184] and the latest version of NREL's System Advisor Model (SAM) [185] provide the capability to analyze solar+storage solutions for resilience applications and assess the performance and benefits. Figure 91 is an example of such an analysis performed for a 75 kW solar PV system and a 150 kWh, 50 kW battery energy storage (ES) system for a Tallahassee commercial building being planned with approximately 400 kW peak load and 10 kW of critical load. The graph shows the probability that the PV+ES system will be able to continue to supply a 10 kW critical load for a given number of hours of power outage. The graph shows that the system can continue to support operation of 10 kW of critical load for 9 hours with a 0.96 probability. But the probability of continuous operation decreases below 0.50 with an outage time of 19 hours and finally there is a 0.32 probability of supporting the critical loads for 24 hours.

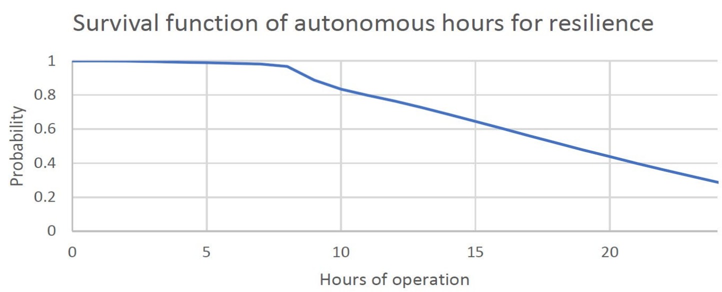

Figure 91. Example of resilience analysis using SAM (Nhu Energy).

The resilience to continue to power local loads during major power outages that normally follow a hurricane can be a major benefit, even lifesaving. For example, following Hurricane Irma, in 2017, the 10kW solar PV + battery energy storage system at Apollo Elementary School, in Brevard County, Florida, was able to provide electric power to run lights and outlets for phones, nebulizers and a coffee maker for local residents in need [186]. Over 100 Florida schools have solar + battery energy storage systems installed as part of the SunSmart Schools and Emergency Shelter Program, supported by the Dept. of Energy, the State of Florida, and Florida utilities [187] (Figure 90).

A Solar+Storage Resiliency Use Case – Wastewater Lift Stations

Wastewater lift stations are among the many possible use cases improving resilience using solar+storage to improve resilience. The benefits and a possible approach for this were examined by JEA and Nhu Energy as part of the FAASSTeR project.

Wastewater systems are an often-overlooked critical infrastructure that can have major impacts on other systems when they fail or are compromised, including deleterious environmental and human health impacts. Extreme storm and flood events overload wastewater lift stations, severely impacting the environment. This often comes in the form of discharges to sensitive bodies of water, and it also exacerbates water removal from flooding just when it is most needed. This has occurred repeatedly in Florida following major hurricanes. Of further concern, parts of South Florida also have elevated flood risk due to sea level rise.

Major hurricanes making landfall in the U.S. have repeatedly impacted these systems these systems. For example, in Sept. 2017, when Hurricane Irma cut electric power to nearly 2/3 of Florida's electric customers, it also resulted in over 9 million gallons of wastewater spilled across the state, including 1.3 million gallons of sewage in Jacksonville, Florida due to power failures. In 2016, in Jacksonville, Florida, following hurricane Matthew, treatment plants and lift stations were damaged, and 5 million gallons of wastewater entered the Ortega River. In 2018, following hurricane Michael, the strongest storm on record to make landfall in NW Florida, the City of Panama City lost 124 out of 127 water lift stations due to wind, water, or damage related to the hurricane. A wastewater treatment system failure due to the storm in a neighboring rural community resulted in 80,000 gallons of partially-treated wastewater being released into the sensitive waterways connected to the Apalachicola River.

Wastewater systems in medium to large cities and counties consist of treatment plants and large networks of pumping stations and various types of conduits for moving, processing and handling liquid waste and stormwater streams. Backup power systems for wastewater and stormwater lift stations are usually fossil-fueled engine-driven generators, sometimes portable, sometimes stationary. They are interdependent on transportation and fuel energy infrastructures. Wastewater systems are an often-overlooked critical infrastructure that can have major impacts on other systems when they fail or are compromised, including deleterious environmental and human health impacts. Wastewater lift station failures can severely impact the environment and public health, in the form of discharges to sensitive bodies of water. Failures also exacerbate water removal from flooding just when it is most needed. This has occurred repeatedly in Florida following major hurricanes.

Impacts to lift stations following hurricanes are often due to power loss. The most common solution is to provide backup power in the form of a fossil-fueled engine (diesel, natural gas, or gasoline), most commonly driving an electric generator, or, alternatively a bypass pump[42]. This requires a fuel source, including an on-site storage tank in the case of diesel, and the associated environmental permitting both for the fuel systems and for the air emissions. And these engines used in backup applications are not permitted for continuous operation due to the additional cost that would be required to meet emissions requirements. So, it becomes a significant capital investment that only runs occasionally. And, because it is a mechanical system that only runs occasionally, it requires regular testing and maintenance, and often does not startup properly when it is most needed.

It is recognized that one challenge with the solar+storage alternative is that the solar panels can require a significant amount of space to provide the energy required to run a typical lift station continuously, even when integrated with energy storage. Land for ground mount solar may be available for some lift station locations, and, when not, there are a number of options that can still make it feasible and advantageous, including floating solar, parking canopy solar, or solar on rooftops of on-site or nearby or adjacent facilities. In some cases, the space requirement may preclude a solar+storage solution.

JEA investigated solar + storage as a solution to power lift stations in the event of a grid outage and completed initial definition and analysis of a feasible solution. Four locations across the service territory were identified as suitable sites for solar and storage equipment. Suitability for a solar + storage solution for wastewater lift station backup is a function of available land area for solar, wastewater pump size, and "blue sky" (normal) and "gray sky" (storm) expected wastewater flows (which influence pump run times).

[42] The City of Panama City, Florida is using federal funds to install diesel-driven bypass pumps.

Several assumptions were made regarding solar PV and storage system sizing, equipment efficiencies, unit costs, and equipment operating schedules to determine the most optimal installment. Under these assumptions, a solar + storage solution was priced for the following scenarios: blue sky, gray sky, maximized land use, and battery only. Of the four locations studied, one was deemed most suitable for an a demonstration project, as the PV and storage were not limited by the land area. The site, labeled Shamrock, is proposed to host an 87 kW solar PV system coupled with a 600 kWh (nominal) battery energy storage system (BESS). With a total land mass of 3.43 acres, the site has ample area for the solar, battery, and balance of systems (BOS) equipment.

Solar+Storge as an Alternative to Diesel Back-up Generators

Over-reliance on diesel generators for backing up critical infrastructure power worsens air quality, impacting public health and quality of life. Reducing reliance on these sources supports clean energy goals being set by many cities, including 10 Florida cities, over 160 across the U.S., and 7 states that have made commitments to 100% clean energy [5], and would be directionally consistent with other initiatives such as the Florida Department of Environment Protection’s $166 million program to reduce diesel emissions, most of it focused on changing from diesel to electric engines in a wide range of applications [188].

Air pollution is the fifth leading risk factor for mortality worldwide. Typical diesel generator exhaust contains more than 40 toxic air contaminants, including a variety of carcinogenic compounds. Diesel engines in backup applications have to be started regularly to help keep them ready to run and to verify that they will run. During Hurricane Sandy, 16 percent of emergency medical services organizations reported diesel generators not performing as expected [189] and 14 percent of hospitals experiencing power outages also experienced generator fuel shortages [190].

Backup diesel engines are typically started weekly for testing and to keep parts moving and lubrication circulating. Under these light-loaded conditions, they emit even more pollutants, and may be subject to “wet-stacking”, the emission of unburned fuel, which is not only highly polluting but harmful to engine performance and life. Also, concerning use of an electric-motor versus a diesel-engine for driving a pump, there is a misleading claim by at least one major supplier that a diesel engine is more efficient. An electric motor running at close to normal rated load is much more efficient than a diesel engine.

With no dependency on a fuel source, solar+storage can form part of an improved strategy for maximizing resiliency and power reliability at a time when extreme events like hurricanes are becoming more intense [191]. Eliminating dependence on fuel availability and transportation infrastructure has significant benefits, particularly following extreme events such as hurricanes, when both fuel availability and transportation networks are routinely impaired. According to the National Renewable Energy Laboratory, long outages “often coincide with abnormal conditions such as extreme weather events, which can close roads and impede normal transportation”. The same storm or flood that prevents cars from driving on the roads prevents fuel trucks from resupplying dwindling diesel tanks. A diesel engine is a less-than-ideal solution for prolonged, multi-day outages.

Energy is moving towards a new era of “electrification” and away from fuels in many applications. Energy from the electric utility grid is increasingly clean and efficient as the entire electric system is moving towards cleaner sources. When the grid goes down, clean and emissions free electric power can now be economically produced locally from solar, an abundant energy source with no fuel cost. This provides “blue-sky” benefits year-round that diesel backup generators cannot in most cases due to environmental permit restrictions. Energy storage technology such as lithium-ion batteries can make the solar energy available for continuous operation day and night, and, the cost of energy storage has been declining exponentially as happened with solar.

FUTURE RESEARCH, DEVELOPMENT, AND DEMONSTRATION NEEDS

With this project, there is now considerable new analysis completed, using relevant data and informed by experience, issues, and needs identified by Florida municipal utilities, on wide area high penetration solar PV in general and specific electric utility operational considerations. However, there remain a number of areas where additional research is needed or beneficial to continuing to increase the value proposition for solar+ and maximize its beneficial use in meeting clean energy goals as well as improving grid and community and critical infrastructure resilience. Some of these are described here.

Siting Solar+: Assessing Land Availability and Suitability

The tools, data, and methods exist to arrive at much better answers as to current and future projected potential sites for solar. This includes siting of utility-scale ground-mount solar, other ground-mount solar, rooftop solar potential (residential and commercial-industrial), and floating solar. Doing this well and arriving at better answers would provide a much-needed clearer view for choosing from among feasible options and pathways for a low to zero-carbon energy system. Extensive land-use, demographic, utility, and infrastructure data already exist in formats compatible with geographic mapping tools such as ArcGIS. On the FAASSTeR project, NREL demonstrated an approach to setting up criteria to assess available land suitable for solar. A valid approach that allows judicious selection of land types for exclusion in GIS layers and subsequent analysis was established and is a useful foundation on which to conduct a more comprehensive and accurate study for the whole state or specific geographies. Figure 92, for illustration only, shows very preliminary results for areas surrounding FAASSTeR municipal utility partner locations.

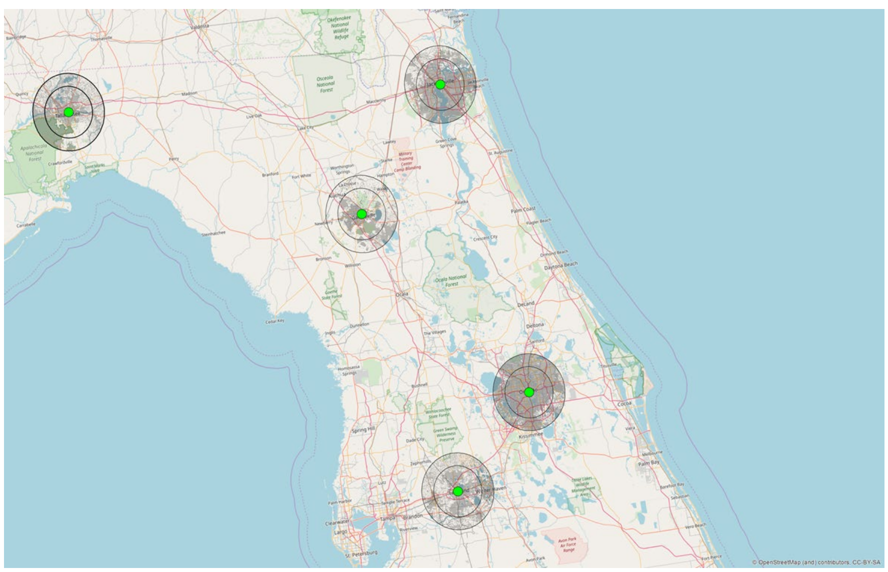

Figure 92. Example from preliminary analysis of land availability for five major Florida cities served by municipal electric utilities (FAASSTeR core team utilities).

Further, there are sophisticated tools, data, and methods for assessing rooftop solar that exist at the national labs, including LBNL and NREL. Also, the Stanford DeepSolar project [192][193] developed a unique AI based approach with data and tools for assessing rooftop solar deployment and correlating it with income, demographic, and other attributes. The foundation exists to develop more clear, accurate and comprehensive answers to current and future solar+ siting potential and options.

Solar-Agriculture Dual-use

Agriculture is Florida's second largest industry and accounts for a very large portion of land-use. NREL research has shown the potential value of solar co-location with agricultural uses, but, there has been very little research on this in Florida. Of the numerous research sites for the NREL InSPIRE project, none are in Florida. Given the land issues identified here regarding solar PV expansion and the size of the agriculture industry in Florida in both economic and land-use terms, it should be a priority to conduct research in Florida on various potential agriculture dual-use applications for solar PV.

Distributed Solar+

Considerably more research is needed on the economic and operational issues, strategies, and pathways for co-adoption or co-deployment of highly distributed solar+, including customer-sited BTM and FTM resources and utility or third-party sited resources that are considerably smaller than utility-scale systems and located close to load and other synergistic resources (e.g. solar+ EV charging and V2G).

Forecasting

Continued improvements are still needed in both solar and load forecasting to enable the level of grid flexibility and control required with very high penetration levels of variable resources, increasing temporally and spatially (e.g. EV) varying loads, and significantly increased numbers and complexity in the network of entities that form or interact dynamically with the electric power system. Forecasting accuracy and resolution improvements are still needed on multiple timescales, from minutes and hours ahead, to days and months ahead. The techniques that will be most effective vary considerably depending on the time-scale.

Grid Planning and Operations

A new generation of tools and technologies for both grid planning and operation are needed that address challenges of the power system of the future. This includes economic dispatch and real-time generation control and system balancing are needed that account for the future environment of extensive reliance on highly variable resources, extensive use of energy storage with its unique properties, highly variable loads and increased electrification, orders of magnitude growth in resources that make up the power system and entities involved in operating or aggregating them, more stochastic and probabilistic overall system behavior, and increased extreme events and external threats.

Modeling and Predicting ACE

On the FAASSTeR project, as part of technical assistance provided to utilities, a need was identified to better model and predict impacts of high penetrations of variable generation on system frequency and area control error (ACE). Doing this with sufficient accuracy to aid planning and operation is not trivial because of the large number of factors that must be included and the dependence on specific operating policies and practices which vary among utilities and, sometimes, even between operating shifts within a given utility. An accurate model of ACE could serve as both a planning and operational tool to provide insights into reserve scheduling, generation dispatch, managing high-penetration solar PV, forecasting, and more. A methodology and some preliminary success in producing such a model has been developed as part of this effort. Additional development is needed to increase the accuracy and to validate it against utility operating data under a range of realistic conditions.

Resource Adequacy and Capacity Credit of Solar and Storage

Several directions for future work emerge from the analysis reported here. First, the optimal configuration of solar and storage depends on much more than maximizing the resource adequacy contribution [176]. Storage might reduce solar's levelized cost of energy, especially when the PV panels are oversized relative to the inverter, by charging coupled storage using energy that would otherwise be clipped. Storage can also provide additional value streams beyond the capacity value, including energy value and ancillary services. It can also smooth the solar production profile due to passing clouds. Future analysis could investigate how the different uses of storage alter the optimal solar + storage configuration and whether any of these other factors affect the CC. Second, we see evidence of synergy, with high solar penetrations increasing storage's CC and high storage penetrations increasing solar's CC. This synergy may be important to capture in capacity-expansion models. Finally, our CC approximations appear to mimic results from more detailed probabilistic methods, except for a very small utility with relatively large generators and widely distributed high-risk hours. Additional analysis could more broadly investigate the circumstances that cause the approximations to deviate from the probabilistic results.

Electric Utility Regulatory and Business Models

For grid transformation and high solar+ futures, it is acknowledged by most that the regulatory and business models have to evolve. This has perhaps is the most challenging and lagging aspect of grid transformation and high solar+ adoption. Progress in these areas varies considerably by region of the country, in the case of the U.S. This is an area where federal funding of teams that include utilities, regulatory and policy groups, new market entrants, and consumer groups could accelerate progress. Regional or state level efforts will make the most sense and be most effective, again, because of the significant variation in regulatory frameworks and utility business structures across states and regions.

A useful framework for organizing the process has been proposed by A. Satchwell, et al, at LBNL [194]. Figure 93, from that framework is a quad chart to help map out a shift from commodities more toward services and from assets more toward value.

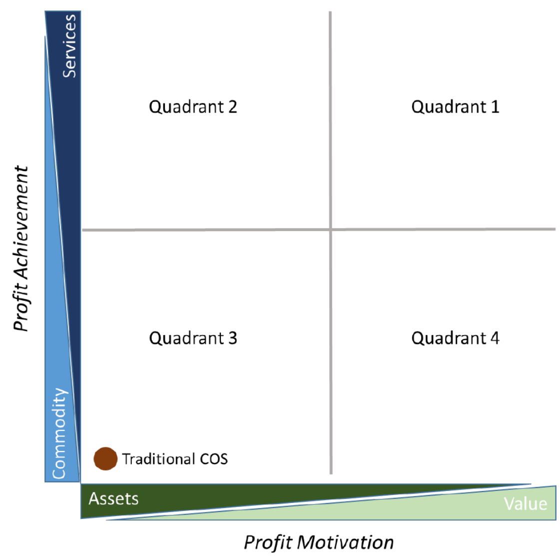

Figure 93. Quad chart to assist in organizing the process of examining current and future electric utility regulatory and business models [194].

Education and Training

Workforce education and training for the future high solar+ power system needs to impart knowledge and competence in a number of new important areas include digitalization, uncertainty and variability, forecasting, advanced controls including AI and machine learning, human-machine interaction, and technical and transactional characteristics of technologies to become pervasive in the grid such as power electronics and energy storage.

State and Regional Energy Strategies

Multi-stakeholder engagement at the state level is vital to achieving transformation of energy systems to cleaner and more distributed generation including solar and energy storage. Engagement and cooperation is required across diverse key stakeholder entities including the utility industry, suppliers, industry and consumer groups and associations, executive and legislative state and local governing bodies, state regulatory commissions, and the research and academic community. The necessary level of engagement and cooperation required for successful change-efforts does not tend to exist already, nor arise on its own. It is more often the result of a conscious and deliberate effort. Organization of FAASSTeR, initially in response to the DOE State Energy Strategies program opportunity, and, now with steps in place and an Articles of Collaboration to form it into an ongoing collaboration organized as an unincorporated consortium, is an example of a possible model for such state-level collaboration. This has the potential to improve the effectiveness, impact, and value of federal funding investments.

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APPENDIX A – Florida Cities with 100% Clean Energy Commitments

City	*Year Made*	*Commitments*
St. Petersburg	11/21/2016	allocated $250K of BP Oil Spill settlement funds to an "Integrated Sustainability Action Plan" (ISAP), which will chart a roadmap to 100% clean, renewable energy in Saint Petersburg. In addition, the plan also incorporates components of a climate action plan, a resiliency plan and strategies for Saint Petersburg to achieve a 5 STAR Community rating. The 100% clean energy roadmap builds on Mayor's Executive Order establishing a net-zero energy goal for the City earlier in 2016
Sarasota	6/19/2017	adopted a goal of powering all of Sarasota with 100 percent clean, renewable energy by 2045, all municipal operations in the city with 100 percent renewable energy by 2030, and at least 50 percent by 2024
Orlando	8/8/2017	a goal to move Orlando to 100 percent clean and renewable energy by 2050
Largo	8/8/2018	commitment to switch to 100 percent clean energy comes as an addition to and approval of the Largo Environmental Action Plan (LEAP), which "sets the direction for collaborative and sustainable operations" across the City of Largo. The plan includes 35 indicators to guide sustainability efforts across the City of Largo focusing on three main areas: infrastructure, workforce, and natural resources.
Gainesville	10/18/2018	a resolution committing the city to be powered by 100 percent renewable electricity and net zero greenhouse gas emissions community-wide by 2045
Dunedin	12/6/2018	goal of powering municipal operations entirely with renewable sources of energy by 2035, and community-wide by 2050
Tallahassee	2/20/2019	a resolution establishing a goal of powering municipal operations entirely with renewable sources (like wind and solar) by 2035, and community-wide by 2050
South Miami	5/7/2019	committing the city to transition to 100 percent clean, renewable energy community-wide by 2040
Safety Harbor	6/18/2019	plan for the complete elimination of all fossil fuels in the electricity sector by 2035 for municipal operations and 2050 community-wide.
Satellite Beach	8/7/2019	committing the city to transition to 100 percent clean, renewable energy for the entire community by 2050 and for municipal operations by 2032
Cocoa	10/27/2020	committing the city to transition to 100 percent clean, renewable energy for the entire community by 2050 and for municipal operations by 2035

Source: Sierra Club Ready for 100, https://www.sierraclub.org/ready-for-100/map [5]

APPENDIX B - Organizations represented at FAASSTeR stakeholder workshops

8minutenergy
Acelerex
AES Energy Storage
Amber Kinetics
Applied Economics Clinic
Ascend Analytics
ASSET Engineering
Astrape
Battery Storage
Beaches Energy Services
Blue Planet Energy
BOW Renewables
Burns & McDonnell
City of Leesburg - Electric Department
City of Tallahassee
City of Wauchula
Clean Energy Group
CMUA
Company
Duke Energy
Ecology and Environment, Inc.
EDF Renewables
EPRI
ESA Renewables
First Solar
FL Office of Energy
FL PSC
Florida Department of Environmental Protection
Florida Municipal Electric Association (FMEA)
Florida Municipal Power Agency (FMPA)
Florida Power & Light Company (FPL)
Florida Renewable Partners, LLC
Fractal Energy Storage Consultants
FRCC
Fred Wilson & Associates, Inc.
FSEC
Gainesville Regional Utilties
Gardner Law Firm
GL Power Solutions, Inc.
GRESCO
Gulf Power Company
Humless
Inman Solar
Invenergy
JEA
JinKO Solar
Kissimmee Utility Authority (KUA)
Lakeland Electric
Lawrence Berkeley National Laboratory (LBNL)
LG Chem
Lockheed Martin Energy
Mas Energy
MG Consultant
MIT
National Renewable Energy Laboratory (NREL)
NC Clean Energy Technology Center
Nexant
NextEra Energy
nFront Consulting LLC
Nhu Energy, Inc.
NWESA
Ocala Electric Utility
Orlando Utilities Commission (OUC)
Pacific Northwest National Laboratory
PCE Investment Bankers
Pinegate Renewables
Polytech Services
Power Association of Northern California
POWER Engineers, Inc.
Primus
Public Utility Research Center
Quanta Technologies
Reedy Creek Energy Services
RMS
Saft Batteries
Sandia National Labs
Sensatek
Shell Ventures
Siemens Energy, Inc.
SLAC
Smart Electric Power Alliance (SEPA)
Solar Impact
Solar Turbines
SOLPAD
Sonnen
Southern Alliance for Clean Energy (SACE)
Southern Company Services
Southern Research Institute
Stanley Consultants, Inc.
StormGEO
Strata Solar
SunEnergy1
Sustainable Tallahassee & LWVT
Talquin Electric Cooperative
Tampa Electric Company
Tenaska
Trojan Battery Sales
U.S. Green Building Council
UET
United Renewable Energy
University of Central Florida
University of Florida
UTILICOM

APPENDIX C – Municipal Electric Utility Solar+ Strategies

Strategy (& issues addressing)	*Category* *A = Existing / de-facto* *B = New*	*Priority / Viability (A, B, C)*	*Comments / Plan, Related TA (if any)*
Utility-scale community solar (provides solar to broad base – environmental justice, access to LMI customers; economic advantage depends on multiple factors) Includes solar subscription / voluntary green pricing, etc.	A	A	COT, OUC have implemented; (FAASSTeR TA with COT) GRU, Lakeland have considered. FMPA (contemplated / may emerge at Ocala, KUA) JEA has Solarmax (large commercial), Solarsmart (small resid./comm.)
Floating solar (land availability)	B	A	A lot of activity and interest. Uniquely a good fit with FL solar growth plans. Intersection with state govt / DOT – land use. OUC has implemented in two phases.
BTM storage + net billing + TOU energy and/or demand (helps utility with timing of solar export; helps customer with resiliency)	A	A	JEA, OUC (not coupled with any rate incentives now; later, may have an opt-in program for utility access to use a portion) For both JEA, OUC, has to be coupled with PV Utility strategy is to incentivize beneficial use.
Incorporate storage in solar PPA RFP's	B	A	GRU is trying this for ~50MW solar PPA (FAASSTeR mini-TA provided some consultation/assistance)
PPA 2.0 – incorporating additional value streams and services into PPA structure, e.g. curtailment, voltage/VAR, … Above, combined Avoiding integration charges by making plant controllable / curtailable	B	A	Could use some models / examples to extent they might exist. NREL identified available and under-development resources related to advanced solar power purchase agreements. A report by Sterling, et al [1] was prepared for the Hawaiian Electric Companies to describe potential contract structures that recognize the need to sometimes curtail utility-scale renewables. Eric O'Shaughnessy identified it as the best available resource at the moment, and we passed it along to the broader FAASSTeR project team. Eric also informed us that NREL is preparing a more comprehensive and up-to-date report on the topic that should be complete by the end of FY2019. We plan to invite a speaker on that topic to the June FAASSTeR workshop; hoping that their findings will largely be in place by that time.
Solar Curtailment (to enable higher penetration levels of PV)	B	A	Part of FAASSTeR TA with COT. See also above and the E3 report on curtailment as well as A. Brink work on FAASSTeR

Strategy (& issues addressing)	*Category* *A = Existing / de-facto* *B = New*	*Priority / Viability (A, B, C)*	*Comments / Plan, Related TA (if any)*
T&D deferral / NWA projects (e.g. DEF projects shared at FAASSTeR Stakeholder Workshop)	B	B	Dependent on economics, case-by-case basis. Need to assemble relevant data / case studies.
Critical infrastructure resiliency projects, e.g. wastewater lift stations	B	A	JEA has developed a specific use case for solar+storage lift-station backup power.
Demand response (solar+DR)	B	A	Survey of core team utility members conducted by COT revealed DR programs to be basic and sparse overall currently.
Supporting transportation electrification	B	A	FAASSTeR TA provided NREL data to FMPA. Also interest from GRU
Reduce solar+ interconnection timelines – identify and eliminate bottlenecks (TSP does study in a queue in order; FRCC transmission study queue is long and backlogged; FRCC entity does it one at a time in sequence)	A	A	e.g. FMPA 74.5 MW project with Duke TSP
Forecasting improvement (solar and load); Increasing dispatch frequency	B	A	Mostly day-ahead currently. Expect to need increasingly better intra-day forecasting.
Pooling reserves for balancing (like FMPP). Muni groups. A coordinated pool, BA cooperation (easiest to do) or a consolidation (less likely)	B	B	Some examples exist

Appendix D – FPL Community Solar (SolarTogether) Settlement Agreement

<u>The Settlement Agreement</u> [82]

The Settlement Agreement includes the principle features of the Program, the capacity allocation to low income customers, and FPL's recovery of the Program costs.

Program Features

The Program size (Phase 1) is 1,490 MW, consisting of 20 individual solar power plants sized at 74.5 MW each. The 1,490 MW capacity is allocated 75 percent (1,117.5 MW) to commercial, industrial, and governmental customers and 25 percent (372.5 MW) to residential and small business. Customers may elect a subscription level equivalent to the capacity that would generate up to 100 percent of their previous 12 months' total kilowatt-hour usage, subject to capacity availability.

Participation in the Program is voluntary. Participants may terminate or reduce their subscription level at any time without penalty. Increases in subscription level will be limited to once per year based on available Program capacity.

Participants will pay a monthly subscription charge and will receive a subscription credit for each kilowatt of capacity subscribed. The subscription charge reflects the revenue requirement associated with constructing the power plants built for the Program, net of avoided generation. The subscription credit reflects the estimated economic value of the Program's solar power plants on FPL's system, which consists of reduced fuel, purchased power, and carbon emission costs. Paragraph 5 of the Settlement Agreement states that Tariff STR sets out the pricing for the subscription charge and the rate for the subscription credit for standard and low income customers.

Participants may elect to have FPL retire on their behalf all renewable energy certificates (RECs) associated with their subscription. FPL will not utilize RECs generated by the Program.

The 1,490 MW of solar generation that comprises Phase 1 is projected to save customers $249 million. FPL will allocate 55 percent of the projected benefits to participants and 45 percent to the general body of customers. Of the 45 percent benefit allocated to the general body of customers, approximately $56 million is a fixed base benefit. Unsubscribed capacity, including the associated energy and resulting savings, will flow to the general body of customers.

Low Income Customers (Paragraph 4)

Phase 1 of the Program will reserve capacity for low income customers. FPL will allocate 10 percent of the residential capacity, or 37.5 MW, to low income customers. For purposes of this Program, low income customers are those whose income falls at or below 200 percent of the federal poverty level. At the time of enrollment, FPL will advise low income participants that they also have the option to participate in a free home energy efficiency survey. For low income participants, the subscription charge will not exceed the subscription credit in any month. Provisions for the low income participants will begin with Project 3 (expected billing start month February 2021).

In the event FPL intends to propose a Phase 2, it will engage in outreach to groups that advocate solar access for low income populations, including SACE and Vote Solar, and will seek input regarding the low income component for Phase 2. This provision does not constitute an obligation to make any changes to the Program.

Cost Recovery

FPL is authorized to recover the $1.79 billion Program cost. FPL will record the revenue received from the participants for their subscription charge as revenues received from the sales of electricity. The revenue will be included as base rate revenues in FPL's monthly earnings surveillance report. The subscription credit will be recovered through FPL's fuel cost recovery clause, partially offsetting system savings resulting from the addition of the Program's solar power plants.

Appendix E. Energy storage technology Selection: PV Ramp Mitigation

Table A-1. Comparison of different types of energy storage technology

2018	Sodium-sulfur Battery	Lithium-Ion Battery	Lead Acid Battery	Redox Flow Battery	Pumped Storage Hydropower	Compressed Air Energy Storage (CAES)	Flywheel	Ultra-Capacitor
Total project cost($/kWh)	907	469	549	858	165	105	11,520	74,480
Response time	1 sec	1 sec	1 sec	1 sec	minutes	3-10 minutes	0.25s	0.016s
Life(years)	13.5	10	2.6	15	>25	25	>20	16

Table A-1 shows a comparison of different energy storage technology, from [90]. Pumped hydro and CAES have attractive pricing. However, the construction of those two options relies on having a site with naturally occurring geographically convenient features, making them both unfeasible. CAES requires very large volumes of suitable underground storage space for the compressed air. Florida's water table and geology are not well-suited to CAES. Pumped hydro normally requires geography with significant elevation change that is not found in Florida. Neither of these options provide fast enough response times for solar PV ramp-mitigation. Flywheel technology has a fast enough response time and could be used for ramp-mitigation, but has a relatively higher cost than other options.

Presently, this leaves battery technology as the best option in terms of cost and performance (response time). Among the battery technologies, Li-Ion was chosen for the ramp mitigation strategy analysis contained in this report because of its good balance of life span and cost-effectiveness.