FINAL REPORT

# ACES Q4 Aggregated Project Report

**MassCEC**

**Date:** February 1, 2022

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# 1 REPORT OVERVIEW

This report is DNV's fourth quarterly ACES Aggregated Project Report to assess and quantify revenues from the ACES Program Grantees (the Grantees) that have had their data transfers approved by DNV and MassCEC.[1] DNV will prepare quarterly reports for the first year of the reporting cycle and biannual reports during the second and third years, followed by a program summary report.

## 1.1 Scope of Q4 Report

The scope of this fourth report covers all Grantees with approved data streams through April 30, 2021.

The Grantees are proceeding through the ACES program deliverables at their own pace, completing milestones from project kickoff meetings through project readiness assessments, construction, commissioning, and establishing data transfer. As each Grantee commissions their energy storage system (ESS), DNV and MassCEC work closely with the Grantees to establish regular data reporting. Once the reported data is consistent and largely free of errors and omissions, DNV and MassCEC approve the data stream and the Grantee moves to the reporting stage. Grantees will prepare quarterly and biannual reports for the first three years of operations from the data-approval date at the same frequency as these aggregated reports (quarterly during the first year, biannually for the second and third year).

Since Grantees were approved at different times, the start date for reporting differs across Grantees, but each has provided data from their approved start date through April 2021.

There are eight Grantees with approved operational reports spanning April 2019 through April 2021 (there are no additional Grantees since the third aggregated report). To date, DNV has received and approved a total of 39 operational reports from these Grantees. A ninth Grantee has approved data and a first operational report under review by DNV and MassCEC, but revenues have not yet been verified and thus are not included in this report.

DNV and MassCEC have been working closely with the Grantees to ensure that they are submitting their operational reports in a timely fashion. The number of submitted operational reports has been increasing as more Grantees enter their reporting periods. Initial reports also document revenues achieved prior to the data reporting period with the earliest reported revenues starting in January 2019.

## 1.2 Report Structure

This report is structured to summarize revenues and analyses of Grantee performance, broken out into the following sections:

- **Section 2: Market Development Memos.** Each aggregated report will include up to three memos that summarize Grantee activities related to key aspects of ESS project development and/or operations. DNV and MassCEC determine the topics in advance; this report includes memos on ESS technologies and colocation of ESS with other distributed energy resources (DERs).
- **Section 3: Monetizable Revenues and Operational Strategy Tables.** This section first presents a summary discussion of Grantee performance across all monetizable revenues reported in the scope of this report, followed by a discussion of the individual revenue strategies pursued by the Grantees. All the Grantee information presented in the body of the report will remain anonymous.
- **Section 4: Non-Monetizable Benefits.** This section highlights the various non-monetizable benefits reported by Grantees. The majority of the Grantees have been focused on calibrating their operations, and not many have reported

[1] ERS was acquired by DNV in January 2021. The first three quarterly reports in this series were produced under the ERS name. This report and all subsequent reports will reflect the DNV name.

non-monetizable benefits to date. Many Grantees plan to explore these benefits and test the feasibility of other potential benefits during the second and third years of their ESS operations.

# 2 MARKET DEVELOPMENT MEMOS

This section presents the Q4 market development memos. The topics for this Q4 report are 1) energy storage system (ESS) technology and 2) ESS co-location with distributed energy resources (DERs). Each memo contains our analysis of industry trends based on Grantee-submitted documentation and conversations. These memos reflect program achievements through April 2021, and all Grantee data has been anonymized to protect privacy and confidentiality.

## 2.1 ESS Technology Market Development Memo

### 2.1.1 Energy Storage Background

The ACES program aims at piloting innovative, broadly replicable stationary energy storage use cases/business models and promotes leadership and innovation in stationary energy storage deployment. This section provides some background and context for ESS development, while the following section summarizes ACES storage technologies.

Stationary ESS are rapidly growing across the United States; the U.S. market is expected to grow from 1.2 gigawatts in 2020 to 7.5 gigawatts by 2025.[2] The drivers for this projected growth include increased renewable generation and large investments in electrical grid infrastructure for grid reliability. The primary technology options for ESS currently on the market for both large and small applications are batteries, thermal, or mechanical systems, defined below:

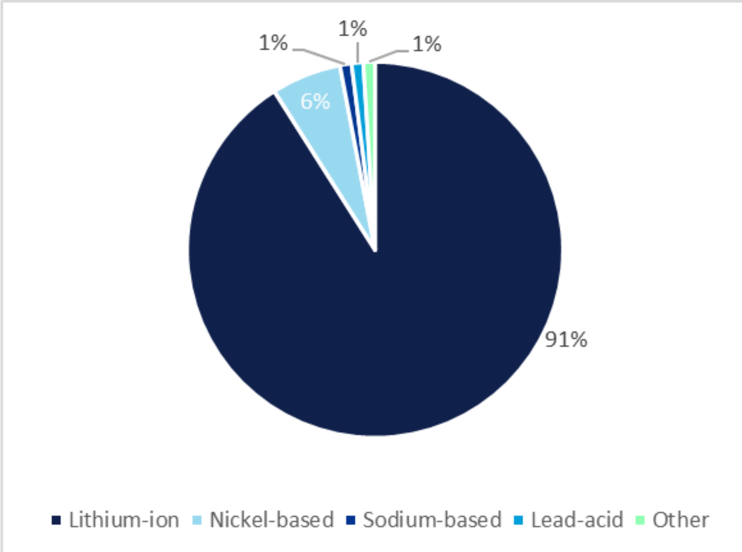
- **Battery storage** technologies leverage a variety of battery chemistries, including lithium-ion, nickel based, sodium-based, lead acid, and flow batteries.
- **Thermal storage** includes water, ice storage, molten salts, and ceramics.
- **Mechanical storage** solutions include hydroelectric pumped storage, flywheels, and compressed-air energy storage.

Pumped hydropower storage is the most developed and widely commercialized energy storage technology for power, representing about 97% of global energy storage capacity. When considering battery storage alone, lithium-ion battery energy storage is a mature energy storage technology that accounts for over 90% of globally deployed battery storage projects, as shown in Figure 2-1.[3] Other technologies are on the market, such as flywheels and compressed air, but only represent a small portion of the battery storage market with ongoing R&D efforts to promote and improve the technology.

[2] US Energy Storage Market Shatters Records in Q3 2020. Energy Storage Association. https://energystorage.org/us-energy-storage-market-shatters-records-in-q3-2020/

[3] US Grid-Scale Energy Storage Technologies Primer. NREL. July 2021. https://www.nrel.gov/docs/fy21osti/76097.pdf

**Figure 2-1. Large-Scale Battery Storage Capacity by Chemistry[4]**




The growth of lithium-ion batteries seen over the last few years in electric vehicle (EV) adoption is expected to continue while simultaneously growing the market for ESS technology. Key advantages to selecting a lithium-ion battery for an ESS include its compact design, numerous available and reputable manufacturers, longevity, efficiency, stability, and the lowest perceived risk compared to other ESS.

### 2.1.2 ACES ESS technologies

Of the original 26 ACES Grantees, 22 Grantees selected lithium-ion batteries for their ESS project. The other four Grantees selected alternative ESS technologies, outlined below in Table 2-2. As of this report, the Grantees active in the ACES program include 17 lithium-ion battery projects and 1 flywheel. It should be noted that one active ACES Grantee includes a project with 200 individual lithium-ion battery projects.

**Table 2-2. ESS Technology Breakdown for ACES Awarded Grants**

| Technology | Technology Type | Number of ACES Awarded Grants |
|---|---|---|
| **Battery** | Lithium-ion Battery | 22 |
| | Vanadium Redox Flow Battery (VRFB) | 1 |
| | Zinc Iron Flow Battery | 1 |
| **Thermal** | Latent Heat Storage | 1 |
| **Mechanical** | Flywheel | 1 |
| **Total** | | **26** |

After reviewing the documentation provided by the Grantees for this report, we have developed the following findings:

- **Lithium-ion batteries are the market leader in battery storage.** Lithium-ion batteries comprise over 90% of the globally deployed battery storage projects.[5] The growing production of consumer electronics, the rise of electric

[4] Battery Storage in the United States: An Update on Market Trends. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf#page=27&zoom=100,92,96

[5] USaid Grid-Scale Energy Storage Technologies Primer. NREL. July 2021. https://www.nrel.gov/docs/fy21osti/76097.pdf

vehicles, and ESS needs are the primary drivers for advancing lithium-ion batteries. Lithium-ion batteries have typical discharge durations of 2-6 hours, making them an ideal choice for facilities pursuing a wide variety of use cases, including targeted demand charge and/or peak reduction. This is consistent with the ACES program as most ACES Grantees (85%) proposed lithium-ion batteries for their ESS. DNV observed several common reasons ACES Grantees chose lithium-ion batteries, including:

- **Commercial availability.** Compared to other technologies, there are several reputable manufacturers that produce lithium-ion batteries for ESS, and these system costs are projected to decline.
- **Market reputation.** Lithium-ion batteries have a strong reputation in the market. They offer operational flexibility, minimal operational risk, and customer confidence in system performance. Many demand response (DR) programs provide a list of qualified, commercially available lithium-ion integrated battery systems that are eligible to participate, which are mainly listed because they come with minimal operational risk and are highly reputable and reliable in the industry. For example, certain programs through Eversource only allow a qualified battery manufacturer to be selected, such as Tesla or SolarEdge. Other DR programs allow more flexibility for ESS technology options but require minimum load reduction targets.
- **Familiarity with the technology.** As a technology that dominates the energy storage market, both ACES Grantees and third-party vendors have chosen lithium-ion batteries because of their confidence and comfort with the technology.

- **Lithium-ion batteries still have associated risks with deployment.** While lithium-ion batteries are the industry leading battery chemistry in the energy storage market, there is still on-going research and development to improve this technology. Challenges include a limited lifetime in comparison to Redox Flow Batteries (RFB) and poor high and low-temperature performance. While battery fires are rare, lithium-ion battery chemistries do have the potential for dangerous incidents and can be a threat to safety, which can increase costs to mitigate these challenges. This has resulted in a requirement for the ACES Grantees to submit all safety plans and correspondences with authorities having jurisdiction (AHJs) and fire departments in the AECS program. This has been discussed in greater detail in the ACES Q2 Aggregated report.[6]
- **Alternative ESS technologies to lithium-ion batteries, such as flywheels, flow batteries and latent heat storage, are available for use, but are generally not mature enough in the market for widespread application.** ACES is a demonstration program designed to encourage and explore the revenue potential of a variety of energy storage technologies and use cases. Four ACES Grantees chose alternative system technologies in their initial program applications, as described below.

  - **Flywheel systems** have both advantages and drawbacks compared to battery storage. Flywheels are typically installed underground create minimal noise and do not cause detrimental system degradation, which can extend the life of the system. They typically operate on a regular (daily) charge/discharge cycle, with a typical discharge duration of 2-6 hours; the ACES flywheel is designed to run two 4-hour discharges each day, mitigating the risk of unnecessary discharges shortening system life and the need to predict specific system peaks. However, flywheel systems contain moving parts that are associated with greater operational risks. For example, the ACES Grantee that installed the flywheel system has experienced several operational issues with the flywheels as the first commercial installation for this flywheel company. As an early demonstration project, this system requires more ongoing maintenance and troubleshooting but can still operate as these issues are resolved.

[6] ACES Q2 Aggregated Project Report. https://files-cdn.masscec.com/uploads/attachments/ACES%20ERS%20Q2%20Aggregated%20Report%20Final.pdf

- Several Grantees pursued other ESS technologies in their applications but are no longer active in the ACES program. These technologies included:
    - **Flow batteries** typically store energy as liquid electrolyte in tanks separated by a membrane, and charge and discharge energy by transferring the liquid through the membrane. They are generally scalable by the size of the electrolyte tanks, and thus offer the potential for longer duration storage than lithium-ion or flywheel technologies. Flow batteries can be configured for a variety of use cases, both for commercial- and utility-scale applications. There were two flow batteries initially pursued in the ACES program: a Zinc Iron Redox Flow Battery (RFB), and a Vanadium Redox Flow Battery (VRFB).
    - **Ice Storage Latent Heat** offers very competitive first-cost per kilowatt-hour, reliability of operation, an expanded lifespan of 20 years, and a compact footprint-to-energy ratio.[7] The ice storage system is typically integrated into a facility's chiller plant, which is used to produce ice at night to meet the facility's thermal cooling loads during the day and thereby reduce peak demand. These systems are scalable and can typically adjust the rate of melting to satisfy a variety of use cases and applications,

- Continued innovation of new and existing energy storage technologies will introduce more ESS options, while lithium-ion batteries will likely continue to dominate market share. Advances in technology have greatly increased the efficiency, reliability, diversity, and stability of new and existing ESS technology. Demonstration programs such as the ACES program continue to pilot innovation and showcase examples of existing and improved energy storage technology. In our 2020 Energy Transition Outlook, DNV projects that in addition to lithium-ion batteries, hydrogen is likely to play a large role in the future of storage technology and grow exponentially in the market, driven largely by a decrease in cost, continued R&D, decarbonization policies in the U.S. and globally, and the expansion of renewables deployment. Battery cost is also expected to decrease in the next several years, mostly due to the increased EV market, promoting the technology further.[8] DNV recommends potential ESS owners take advantage of demonstration programs like the ACES program when available to explore new ESS technology options and their revenue potential.

## 2.2 Co-Located Storage with DERs Market Development Memo

Pairing renewable energy generation and other DERs with energy storage is a trend of increasing importance as the cost of energy storage declines, policies continue to shift towards a greater focus on GHG emissions reductions, and wholesale energy markets evolve under greater penetration of renewable resources. Another driver of co-location is the push for greater electrification of heating and transportation, which will introduce new loads to the grid, alter facilities' typical load profiles, and create new opportunities to dynamically shift load to manage costs using energy storage. Co-location enables facilities and utilities to actively manage their generation and consumption to maximize their monetizable and non-monetizable benefits.

Co-location of ESS with DERs is a common practice for ACES Grantees; 17 out of the 18 active Grantees have co-located or are planning to co-locate their ESS with DER assets. The most common DERs co-located with ESS for the Grantees are solar photovoltaics (PV) and combined heat and power (CHP) or other generation. The ACES Grantees generally fall into two broad use-cases for co-location:

- **Behind-the-meter (BTM) co-location to strategically manage facility loads and usage**. In this use-case, Grantees integrate BTM ESS with DERs to increase their revenues. Common BTM applications for co-location include:

[7] Ice Energy brings the deep freeze to U.S. energy storage. Roselund, Christian. https://pv-magazine-usa.com/2019/02/13/ice-energy-brings-the-deep-freeze-to-u-s-energy-storage/

[8] DNV Energy Transition Outlook 2020. https://eto.dnv.com/2020

- *Peak Load Management*. The classic use case for solar-plus-storage systems, also applicable to other DERs, revolves around the capability of energy storage to store intermittently generated DER power during the day or during periods of higher costs and discharge it during in the evening or when costs are lower to offset grid purchases. This discharged power can be used to reduce peak demand at the facility.
- *SMART Revenue*. Massachusetts's Solar Massachusetts Renewable Target (SMART) program[9] is a long-term solar incentive program sponsored by the MA utilities. It is a declining block program, which means that as more incentives are paid and "blocks" are filled by eligible solar projects, incentive levels decrease. To encourage the development of solar-plus-storage systems in MA, SMART offers a storage adder that increases incentive rates relative to standalone solar, thus improving system economics and generating additional revenue. SMART revenues achieved by Grantees to date are presented in Section 3.7; additional Grantees are planning to include SMART revenue in future reporting.
- ***Microgrids, Islanding, and Resiliency*.** The ability of an ESS to store energy for future discharge offers the potential to use an ESS for resiliency purposes, including by "islanding;" i.e., separating a facility from the rest of the electric grid during an outage or extreme weather event while still meeting energy needs using the ESS. In this use case, the ESS typically forms a portion of a microgrid and is associated with power generation assets such as solar, cogeneration/CHP, or backup generators. Energy storage is usually paired with a dispatchable asset, such as a cogeneration system or generator, particularly when long-duration grid power outages are expected or when operational resiliency is critical, such as at a hospital.
- *Power Conditioning and Optimization*. ESSs can be leveraged to "clean up" the power supply for an end-user (or distribution utility), most often through voltage control and power factor correction. ESSs are able to provide these power conditioning and optimization services due to their advanced power electronics and inverters, which allow for fine control over the characteristics of incoming or outgoing electric power. Two examples of this use case from ACES Grantees include the use of an ESS to improve the operations of a facility's CHP unit at low-load conditions and the use of an ESS at a medical facility to smooth out voltage variations to ensure sensitive medical instruments can be powered reliably during an emergency.
- *EV Charging Opportunity*. Integration of ESS with EV charging stations can provide additional benefits. While this is not specifically a DER use-case, several Grantees are incorporating EV charging into systems that include both ESS and DERs to increase their flexibility in managing their loads.

- **Front-of-the-meter (FTM) co-location to manage system loads and/or enable additional DER growth**. The primary Grantees pursuing this use-case are municipal utilities and facilities located on highly congested grids. FTM co-location increases the grid capacity to enable better asset management and/or provide sufficient buffer to allow additional DER development within the network. Common FTM applications include:

- *Solar Buffering*. Solar buffering refers to the use of an ESS to absorb excess solar generation that would otherwise be exported or curtailed. As described above, not all solar arrays are allowed to export power to the grid; most end-user facilities are not allowed to export onto the local distribution grid, and distribution utilities typically are not allowed to export power back to the bulk transmission system. In light of these rules, solar arrays located at end-user facilities and on distribution networks are sized to minimize the risk of a power export. However, on days where demand is relatively low (such as during the shoulder season) and solar irradiance is high, it is possible for solar generation to exceed demand. Without an ESS, this excess solar power would be curtailed, thus wasting renewable energy generation. However, an ESS can absorb, or buffer, this excess generation, preventing it from being exported and allowing it to be discharged later when demand is higher.

[9] Website for the Solar Massachusetts Renewable Target (SMART) program - https://www.mass.gov/solar-massachusetts-renewable-target-smart

– ***Increasing Hosting Capacity***. Renewable hosting capacity is the aggregate amount of distributed generation that can be supported before grid modifications are required to mitigate risks including reverse power flow, static high voltage, or other problematic electrical conditions on the distribution system. An ESS can be used to increase a utility or grid's hosting capacity and support local growth in distributed generation, which is primarily solar. This use case can be viewed as a special case of the "solar buffering" use case described above, applied to a distributed generation scenario. Several ACES Grantees cite this application for FTM installations.
– ***Peak Load Management***. Similar to the BTM application, for FTM systems, in this application DER generation is stored during periods of high cost or excess generation and discharged when costs or generation is lower. In some cases, primarily for local distribution utilities, this discharged power can be fed back to the grid at higher prices than were in effect during the day, thus generating more value than might have been realized with a standalone DER. Not all co-located systems are capable of exporting to the grid; the ability to do so depends on the project's metering configuration.

The co-location configurations for ACES Grantees are provided in Table 2-3.

**Table 2-3. ACES Grantee Co-Location Configurations**

| ESS Installation Location | Co-location configuration | Number of Grantees |
|---|---|---|
| **Behind-the-meter (BTM)** | ESS and PV | 5 |
| | ESS and cogeneration | 2 |
| | ESS, PV, and cogeneration | 2 |
| | ESS, PV, and EVs | 2 |
| | **Total BTM co-location** | **11** |
| **Front-of-the-meter (FTM)** | ESS and PV | 2 |
| | ESS and cogeneration | 1 |
| | ESS, PV, and cogeneration | 1 |
| | ESS to increase DER hosting capacity | 2 |
| | **Total FTM co-location** | **6** |
| **Total Grantees with co-located ESS** | | **17** |

After reviewing the documentation provided by Grantees as of this report, we have developed the following findings:

- **Co-location of energy storage with DERs is a common practice employed to achieve both monetizable and non-monetizable benefits**. Nearly all of the active ACES Grantees leverage some component of co-location as an opportunity to increase the system revenues generated and to better manage their facility and/or system peak loads.
  – Initial Grantee operational reports suggest that this co-location and the coordinated management of facility assets can maximize benefits. For example, one Grantee facility that has both an ESS and CHP installed was able to reduce their 2020 installed capacity (ICAP) charges despite an unexpected ESS outage by strategically increasing their CHP generation during predicted peak hours while also pursuing additional demand reduction strategies.

- **Municipal light and power (MLP) utilities leverage co-location to better manage their system loads, mitigate peaks, and enable DER growth within their network**. These use-cases are typically called non-wires alternatives (NWAs) as they seek to defer/avoid investments on traditional transmission and distribution infrastructure. MLPs within the ACES program have explicitly integrated front-of-the-meter ESS alongside other DER to more effectively manage their loads and have also installed ESS to enable additional distributed and utility-scale DER development within their territories.
- **Solar PV and CHP are the most common technologies co-located with ESS solutions**. Several Grantees installed solar and storage solutions simultaneously, while others have added ESS as a new resource integrated into existing DERs, and additional Grantees installed ESS with plans to pursue additional future DER installations.
- **Co-location can strengthen facility and utility resiliency planning**. Many MLPs and individual facilities in the ACES program plan to utilize ESS, co-located with DERs, as key assets in future resiliency planning. This includes plans for fully functioning islanded microgrids, as well as capabilities to power critical functions during outages and/or weather events. While full functionality of these solutions will likely require additional investment in controls and infrastructure, this non-monetizable benefit has been a driver for ACES participation.

As discussed in the sections above, co-location offers potential to leverage the unique characteristics of the independent co-located assets to maximize overall value for the project.

# 3 MONETIZABLE REVENUES AND OPERATIONAL STRATEGY TABLES

This section outlines the primary revenue strategies pursued by the Grantees and the aggregate performance of those Grantees for each revenue strategy. Note that this analysis uses the most recent available data for each Grantee, and DNV may update the individual revenue strategy analyses once new data is available in future reports. For some revenue strategies, such as installed capacity (ICAP) and regional network service (RNS) revenue, there is a lag between when the revenue is achieved and when DNV can independently calculate revenues and/or see them reported by Grantees. Table 3-1 shows a summary of the Grantee use cases, ratio of ESS system nameplate power to peak load, and total months of data reported.

**Table 3-1. Summary of Grantee Use Cases and Data Reported**

| Grantee | Use Case | Ratio of ESS System kW to Peak Load (%) | Total Months of Data Reported To-Date |
|---|---|---|---|
| **Grantee 1** | Behind the meter – solar plus storage | 7.6% | 18 |
| **Grantee 2** | Municipal Light Plant (MLP Asset) | N.D. | 18 |
| **Grantee 3** | Municipal Light Plant (MLP Asset) | 10.1% | 19 |
| **Grantee 4** | Municipal Light Plant (MLP Asset) | N.D. | 19 |
| **Grantee 5** | Municipal Light Plant (MLP Asset) | 33.3% | 17 |
| **Grantee 6** | Municipal Light Plant (MLP Asset) | 10.2% | 18 |
| **Grantee 7** | Municipal Light Plant (MLP Asset) | 7.1% | 19 |
| **Grantee 8** | Merchant, solar plus storage | N/A | 12 |

## 3.1 Summary of Revenues and Operational Strategies

Table 3-2 below summarizes by use case the Grantee-achieved revenues reviewed to date. With the exception of ISO-NE ICAP revenues, this report presents data and revenues only from the approved start of the Grantees' data reporting timeline and does not include data prior to the approved data transfer.

**Table 3-2. Summary of Achieved Revenues by Use Case**

| Revenues/Use Case | Number of Grantees | ICAP Tag Reduction | RNS Charge Reduction | Demand Response Programs | Peak Demand Reduction | Arbitrage | SMART |
|---|---|---|---|---|---|---|---|
| **Municipal Light Plant (MLP Asset)** | 6 | $1,801,599 | $1,805,492 | $107,640 | $11,231 | $19,113 | $0 |
| **Behind the meter – solar plus storage** | 1 | $124,688 | $187,157 | $175,760 | $0 | $3,622 | $0 |
| **Merchant, solar plus storage** | 1 | $0 | $0 | $0 | $0 | $0 | $33,594 |
| **Totals** | **8** | **$1,926,287** | **$1,992,649** | **$283,400** | **$11,231** | **$22,735** | **$33,594** |

Note that in Table 3-2, ICAP tag revenues are two-year annual estimates, whereas other revenues are the sum across the months currently reported by Grantees. The 2020 ISO NE system peak hour has been preliminarily established as July 27, hour ending 6 p.m., and initial estimates of revenues achieved by ESS deployments during this hour are included with revenues achieved from the 2019 ISO NE system peak in this table.

Table 3-2 above shows that municipal light and power departments were the quickest to get their systems operational and were the most lucrative systems observed to date. The bulk (over 90%) of the achieved revenues was through ISO-NE peak hour (ICAP tag) and transmission zone (RNS) demand reductions.

Table 3-3 shows a summary of the predicted annual revenues against the total capital costs and estimated simple payback. The simple payback was estimated by extrapolating the average monthly revenues achieved to annual estimates and do not include the impacts of operations and maintenance costs. These impacts may be included in future reports once more data is available.

**Table 3-3. System Overview and Simple Payback Estimate by Use Case**

| Use Case | Total kW Capacity | Total kWh Capacity | Average Estimated Annual Revenues | Capital Cost | Total Capital Cost after Grants | Simple Payback before Grant | Simple Payback after Grant |
|---|---|---|---|---|---|---|---|
| **Municipal Light Plant (MLP Asset)** | 14,528 | 28,804 | $2,194,136 | $13,392,837 | $9,550,274 | 6.1 | 4.4 |
| **Behind the meter – solar plus storage** | 1,320 | 4,000 | $306,703 | $2,500,000 | $1,356,800 | 8.2 | 4.4 |
| **Merchant, solar plus storage** | 500 | 1,170 | $33,594 | $764,390 | $382,196 | 22.8 | 11.4 |
| Totals | **16,348** | **33,974** | **$2,534,433** | **$16,657,227** | **$11,289,270** | **6.6** | **4.5** |

Table 3-4 shows a summary of the submitted predicted revenues against the DNV-verified revenues, as well as some overall performance metrics in terms of available power capacity realized as demand reductions. The normalized revenue per kW of available power capacity is also shown to allow comparison between the revenue streams.

**Table 3-4. Summary of Grantee Achieved Revenues**

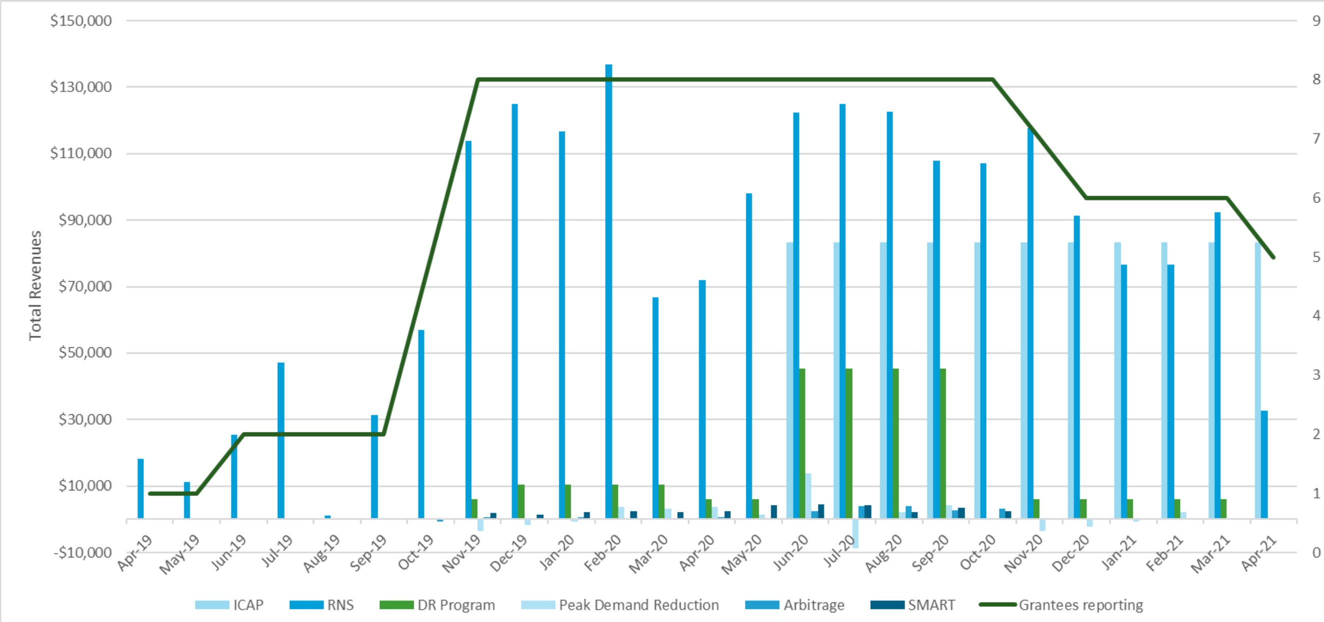
| Revenue Strategy | Reporting Coverage | No. of Grantees Reporting | Predicted Revenues | Realized Revenue | Total ESS Capacity (kW) | Percent Capacity Realized | Avg. $/kW Revenue per Month |
|---|---|---|---|---|---|---|---|
| **ICAP**[1] | 2019 and 2020 system peak | 7 | $1,875,083 | $1,926,287 | 31,696 | 69% | $6.02 |
| **RNS** | Apr 2019 to Apr 2021 | 7 | $1,954,384 | $1,992,649 | 213,944 | 92% | $6.14 |
| **Demand response (DR)**[2] | Jun 2019 to Apr 2021 | 2 | $83,770 | $283,400 | 23,280 | 48% | $8.35 |
| **Peak demand reduction** | Nov 2019 to Apr 2021 | 1 | $190,264.00 | $11,231 | 18,000 | 4% | $1.25 |
| **Energy arbitrage** | Jun 2019 to Apr 2021 | 5 | $75,688 | $22,735 | N/A | N/A | $0.04 |
| **SMART storage adder** | Nov 2019 to Oct 2020 | 1 | $36,751 | $33,593.77 | N/A | N/A | $5.60 |
| **Totals** | **Apr 2019 to Apr 2021** | **8** | **$4,215,939** | **$4,269,896** | | | |

[1] ICAP revenues are annual estimates.
[2] Demand response averages calculated only during months with DR commitments and reported revenues.
[3] Demand response program revenue percent capacity realized is not a direct reflection of realized demand reductions and includes percent losses associated with limitations in enrollment capacity.

As shown in Table 3-4, the eight Grantees included in this report generated revenues (or cost savings) from six different applications of their systems. Throughout this report, revenues are used synonymously with cost savings. The most common revenue strategies are ICAP and RNS demand charge revenues. Demand response revenues are proving to exceed expectations and, for some projects, have replaced other revenue strategies, such as peak demand reduction in terms of deployment priorities. Energy arbitrage benefits were marginal and sometimes even negative for some Grantees as locational marginal price (LMP) differences were not large enough to warrant targeted arbitrage dispatches. Thus, any arbitrage benefits or costs are a byproduct of other demand reduction deployment strategies.

For a deeper understanding of the monthly revenues achieved, DNV has compiled the monthly revenues achieved across Grantees, grouped by the revenue strategy, in Figure 3-1. As the total revenues are dependent on the number of Grantees reporting, this figure includes the number of Grantees reporting data each month for context. Note that the number of Grantees reporting applies to all revenue streams except ICAP revenues for which the data shown in Figure 3-1 represents the current estimates of revenues from eight Grantees.

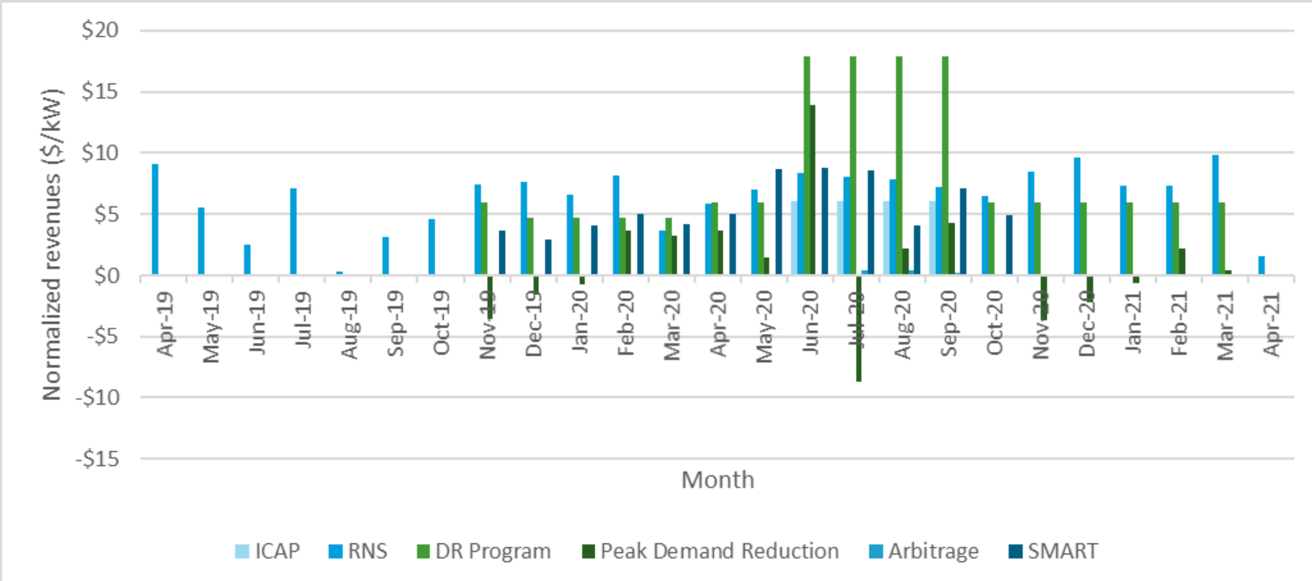
**Figure 3-1. Comparison of Monthly Revenues Achieved**




ICAP revenues from deployment during the 2019 system peak are not realized until June 2020; they are then realized monthly between June 2020 and May 2021. All applicable Grantees who reported their annual ICAP performance associated with deployment during the 2019 system peak have now also submitted operational reports covering the July 2020 system peak.

DNV normalized the revenues on a per kW of power capacity basis to provide better context about the revenues achievable given a system size. Figure 3-2 shows a bar graph of these monthly capacity normalized revenues. Note that the 2020 ISO NE system peak occurred on July 27, from 5 p.m. to 6 p.m., but as explained above for the 2019 system peak, the ICAP revenues will not start accruing until June 2021.

**Figure 3-2. Monthly Revenues Normalized against System Capacity (kW)**




The most striking observation from Figure 3-2 is that the DR program revenues for summer 2020 dwarfed all other revenue strategies in terms of revenues per kW of system capacity. This was driven by one Grantee's participation in Eversource's summer daily dispatch program, which provided a $200 per kW payment based on Grantee performance. The daily dispatch DR revenues are allocated across the four-month program window between June and September, but in 2020, DR events were only called in July and August. Note that this is a summer-only program, and DR programs available in other seasons pay a significantly lower rate. Additionally, the Eversource program called a DR event that aligned with the 2020 ISO-NE system peak, which enabled the Grantee to stack ICAP revenue with DR program revenue for that event's battery dispatch. While further discussion of DR revenues is provided in Section 3.4, at a high level this suggests that DR has the potential to provide significant revenue to ESS projects alongside demand charge management strategies.

RNS and ICAP revenues are similar in terms of benefit per kW, however, RNS revenues are harder to achieve consistently. Conversely, while ICAP revenues are large and easier to predict, they have a long waiting period before they are accrued.

## 3.2 ICAP Revenue

ICAP refers to the installed capacity (kW) charges that suppliers are billed by ISO-NE on a monthly basis. ICAP charges are passed on to municipal light departments and other very large customers who typically receive power at distribution-level voltages. This charge is associated with the costs of generators to meet the peak power demands for the ISO-NE region and is determined by the forward capacity market auctions (FCA) and the suppliers' load during the ISO-NE system peak (their ICAP tag), as well as a monthly adjustment factor. The monthly adjustment factor is associated with the installed capacity requirement (ICR) and accounts for differences in actual peak load versus the total load that needs to be made available based on required reserve margins, as well as other factors such as line losses and reconfiguration auctions. The ICR is generally about 150% of actual load but varies month to month. Essentially, this factor ensures that generators that have made capacity available are paid for the costs of providing this available power. The monthly ICAP charges can be summarized by the following formula:

$$ICAP\ charge\ per\ month = Capacity\ rate\ \times ICAP\ tag\ \times ICR\ ratio$$

ICAP charges are billed monthly from June through May of the year following the system peak. For example, the 2019 ISO-NE system peak occurred on July 30, hour ending 18, and charges for suppliers' portions of that load are billed starting in June 2020. The ICAP peak hour is not known in advance. Suppliers typically need to wait until the end of the year, or at least the end of the summer, to get confirmation on when the peak occurred.

ICAP charge reductions are the most common and important use case for energy storage systems, as they are determined by a single hour and affect capacity charges for a 12-month period. However, these benefits are typically only available to municipal light and power departments, as well as the largest commercial customers who receive power at distribution level voltages.

The forward capacity rate is determined three years in advance through the FCA and is $5.297 per kW per month for the 2020 year (FCA #11 June 2020–May 2021, applied on the 2019 ISO-NE system peak). For the 2021 year (FCA #12 June 2021 – May 2022), the forward capacity rate is $4.63 per kW per month. FCA #13 and #14 results were $3.80 and $2.00 per kW per month, respectively, indicating that short-term future ICAP revenues will be less than the 2020-2021 year. However, Grantees generally reported that ICAP tag rates are expected to increase in the long run. A summary of the ISO NE system peak hour days and hours is provided in Table 3-5.

**Table 3-5. Summary of the ISO NE System Peak Hour Days and Hours[10]**

| Peak Date | Peak Hour | | System Peak Load |
|---|---|---|---|
| | Hour Begin | Hour End | MW |
| **8/09/2001** | 14:00 | 15:00 | -24,723 |
| **8/14/2002** | 14:00 | 15:00 | -25,103 |
| **8/22/2003** | 14:00 | 15:00 | -24,311 |
| **8/30/2004** | 15:00 | 16:00 | -23,719 |
| **7/27/2005** | 14:00 | 15:00 | -26,618 |
| **8/02/2006** | 14:00 | 15:00 | -28,038 |
| **8/03/2007** | 14:00 | 15:00 | -25,773 |
| **6/10/2008** | 14:00 | 15:00 | -25,691 |
| **8/18/2009** | 14:00 | 15:00 | -24,708 |
| **7/06/2010** | 14:00 | 15:00 | -26,701 |
| **7/22/2011** | 14:00 | 15:00 | -27,312 |
| **7/17/2012** | 16:00 | 17:00 | -25,543 |
| **7/19/2013** | 16:00 | 17:00 | -26,911 |
| **7/02/2014** | 14:00 | 15:00 | -24,068 |
| **7/29/2015** | 16:00 | 17:00 | -24,052 |
| **8/12/2016** | 14:00 | 15:00 | -25,111 |
| **6/13/2017** | 16:00 | 17:00 | -23,508 |
| **8/29/2018** | 16:00 | 17:00 | -25,559 |
| **7/30/2019** | 17:00 | 18:00 | -23,929 |
| **7/27/2020** | 17:00 | 18:00 | -24,695 |

[10] ISO NE website: https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/season-peak-hour-data

Note, the ISO NE system peak hour trends towards later in the day, which is a result of increasing amounts of distributed solar PV generation being brought online in the region, which lowers the system load during the early afternoon hours.

### 3.2.1 Grantee ICAP Revenue Summary

Approximately 75% of all the ACES Grantees plan to discharge their ESS to target reductions of ICAP charges. Out of the eight Grantees included in the scope of this report, six reported on ICAP benefits resulting from the load reductions during the 2019 system peak. Of those, only three Grantees had started reporting regular data to DNV by the July 2019 system peak. For the other three Grantees, 2019 ICAP hour performance was provided to DNV in the context of their operational reporting, and we have attempted to include these revenues in this summary with the caveat that we are unable to fully verify these results. Table 3-6 shows a summary of the 2019 ICAP parameters and metrics.

**Table 3-6. 2019 ICAP Revenue Summary**

| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | 2019 |
| **System peak day and hour** | July 30, hour ending 18 |
| **ISO-NE capacity rate** | $5.30 per kW per month[1] |
| **Estimated ICR ratio** | 1.5 |
| **Total estimated revenues** | $999,815 |

[1] https://www.iso-ne.com/about/key-stats/markets#fcaresults

Out of the eight Grantees included in the scope of this report, six reported on ICAP benefits from the 2020 system peak. Table 3-7 shows a summary of the 2020 ICAP parameters and total revenues.

**Table 3-7. 2020 ICAP Revenue Summary**

| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | 2020 |
| **System peak day and hour** | July 27, hour ending 18 |
| **ISO-NE capacity rate** | $4.63 per kW per month[1] |
| **Estimated ICR ratio** | 1.5 |
| **Total estimated revenues** | $926,473 |

[1] https://www.iso-ne.com/about/key-stats/markets#fcaresults

All six Grantees targeting system peak reductions were able to reduce demand for the 2019 ISO-NE system peak hour. Out of the six Grantees reporting benefits for the 2020 system peak, one did not achieve any demand reductions during the peak hour due to an unplanned maintenance issue. DNV was able to verify the deployments for all Grantees for the 2020 system peak. Figure 3-3 shows the annual estimated revenues by Grantee assuming the parameters listed above in Table 3-6 and Table 3-7.

**Figure 3-3. Estimated Annual ICAP Revenues by Grantee**

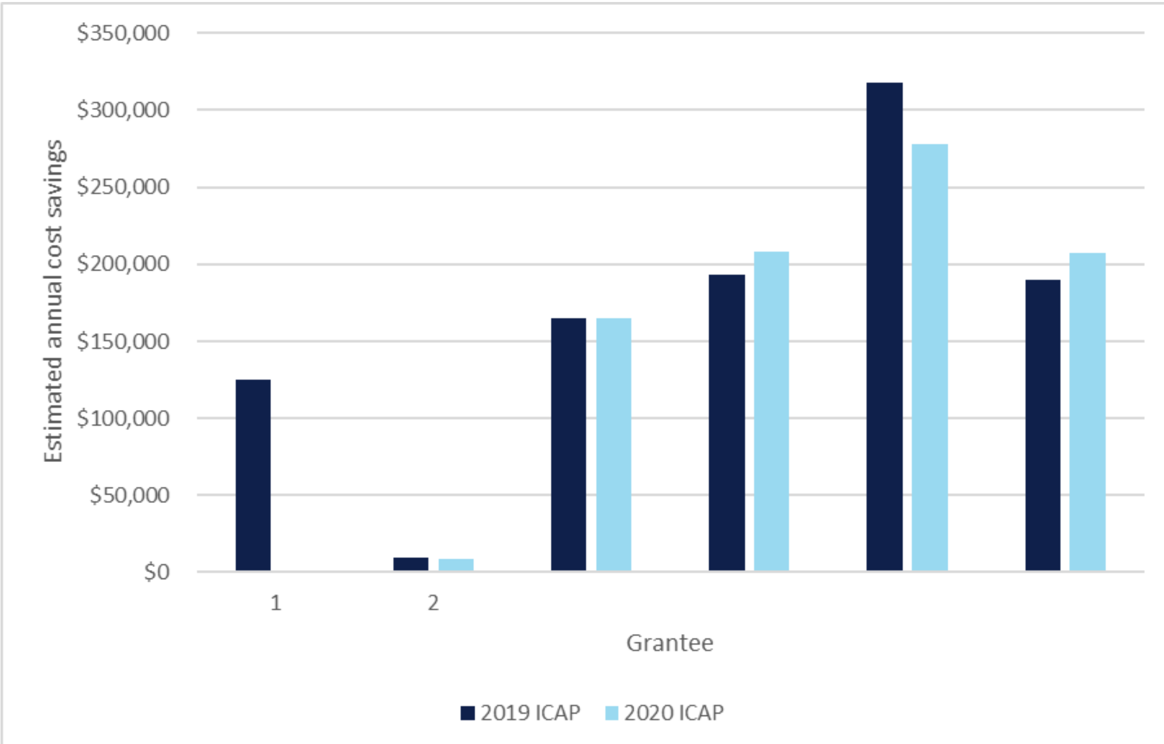
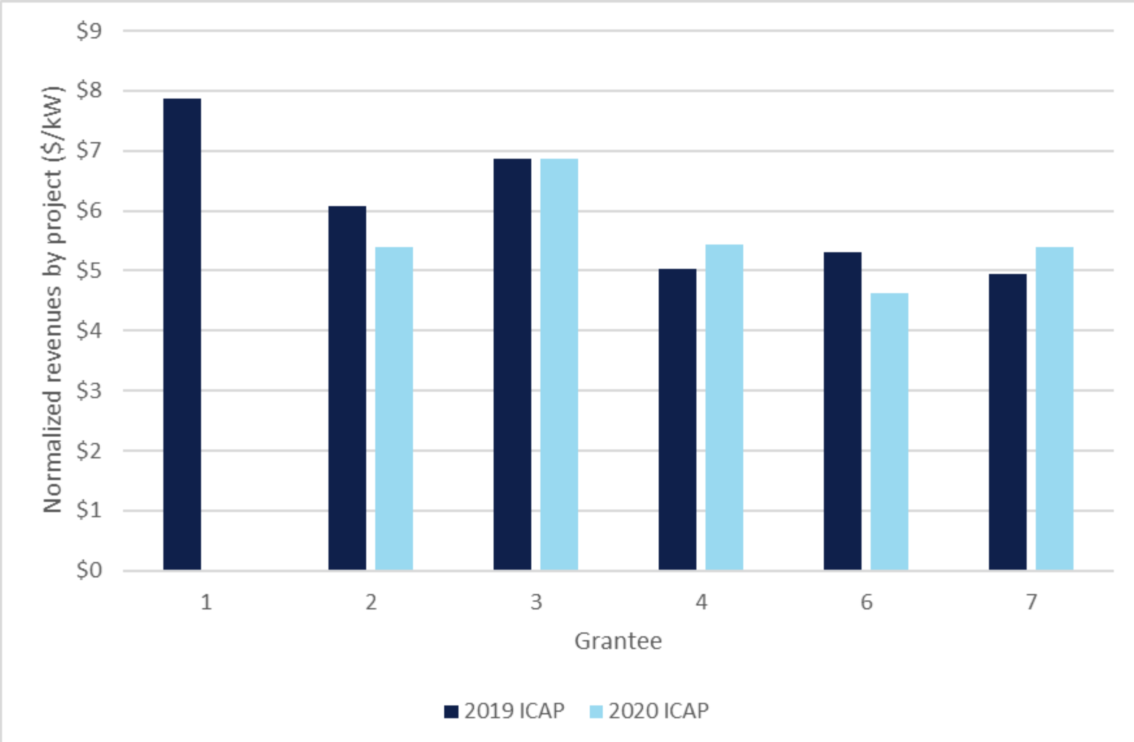



Figure 3-3 shows that Grantee 1 missed the 2020 system peak as mentioned above, and thus had no cost savings.

Because the total revenues are determined by the size of the system, DNV also tabulated the estimated average monthly revenues on a per kW of system capacity basis. These are shown in Figure 3-4, below. Similar to the total revenues by Grantee, these also assume a constant capacity rate and ICR adjustment factor of 1.5 for all months of both the 2020-2021, and 2021-2022 capacity years.

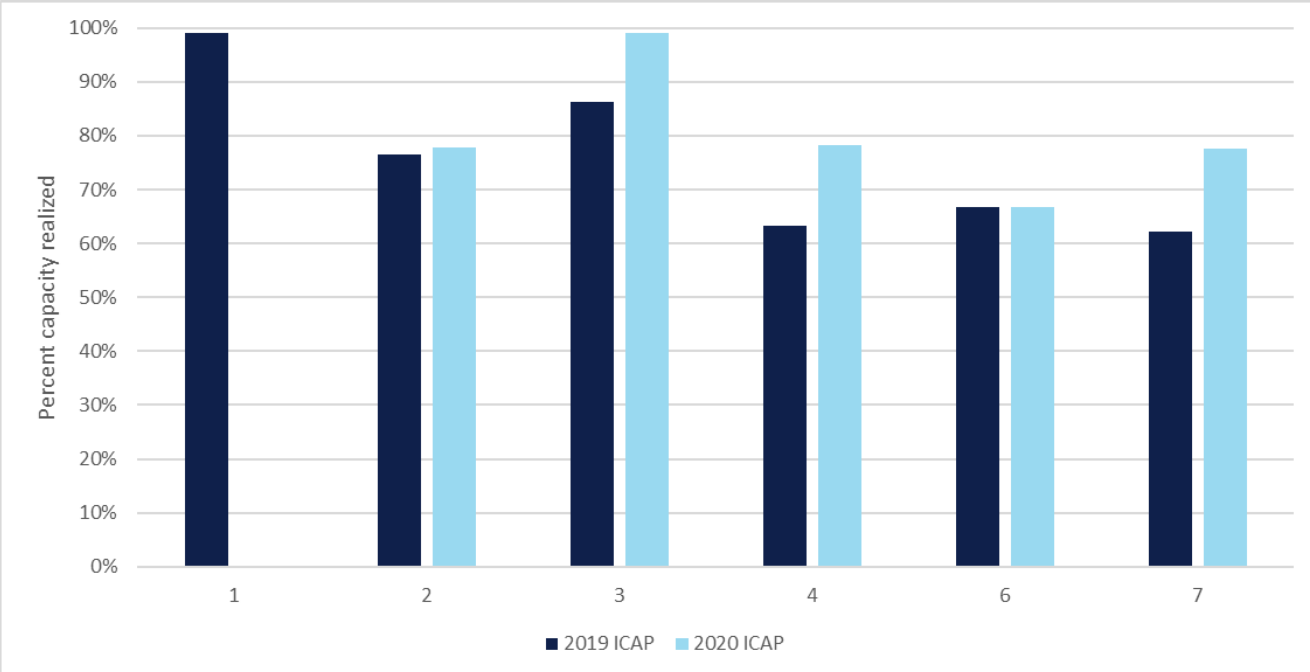
**Figure 3-4. Summary of Capacity-Normalized Average Monthly ICAP Revenues**




It is important to note that the revenues normalized to system capacity reflect the Grantees' abilities to discharge the ESS at the system's full inverter (output) capacity during the peak hour. Depending on the confidence in the ICAP hour prediction, some Grantees choose to deploy their system at less-than-full capacity during the peak hour to enable discharge over a longer duration. This mitigates the risk of missing the ICAP hour but could reduce the achieved revenues, depending on the discharge duration of the ESS. For example, if a system is rated for energy capacity of 10 MWh and has a rated power output of 5 MW, the system operator may choose to deploy for two hours at 5 MW or for three hours at 3.33 MW.

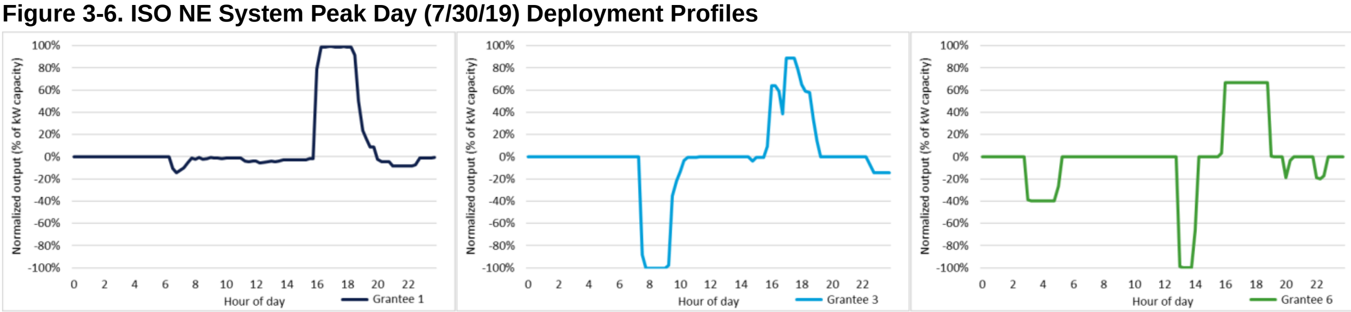
Figure 3-5 illustrates this dynamic by visualizing the percent capacity realized by the Grantees during the 2019 peak hour. The maximum achievable revenue per kW is determined by multiplying the capacity rate ($5.30 for 2019 or $4.63 for 2020) with the ICR ratio (1.5); this results in an upper bound of $7.95 (2019) or $6.95 (2020) per kW per month. Note the relative similarities between the percent capacity realized during the ICAP hour (Figure 3-5) and the normalized revenues achieved (Figure 3-4).

**Figure 3-5. Percent Capacity Realized during 2019 and 2020 ISO-NE Peak Hours**




The deployment profiles for the Grantees during the 2019 ISO-NE system peak day are shown in Figure 3-6. Note that, as mentioned above, only three Grantees provided operational data covering this day.

**Figure 3-6. ISO NE System Peak Day (7/30/19) Deployment Profiles**




The deployment profiles for the Grantees during the 2020 ISO-NE system peak day are shown in Figure 3-7.

**Figure 3-7. ISO NE System Peak Day (7/27/20) Deployment Profiles**

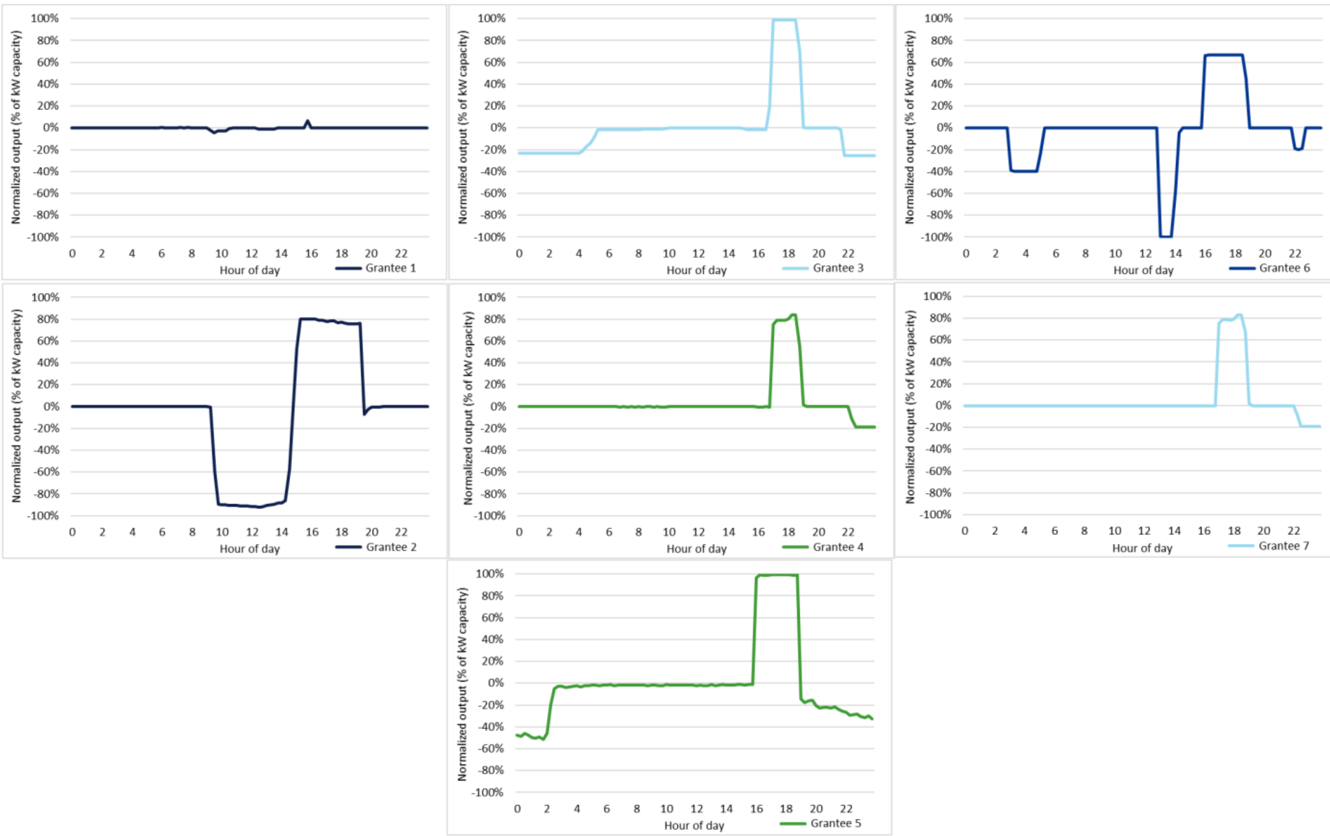



Figure 3-6 and Figure 3-7 depict ESS activity for the Grantees on the ISO-NE System peak days for 2019 and 2020—July 30, 2019, and July 27, 2020, respectively. ESS discharge is indicated by positive values, whereas charging is represented by negative values. DNV notes that the charging profiles of the ESS varied across Grantees, with some systems charging in a single event and others across multiple events throughout the day.

In 2019, all three Grantees deployed for about three hours from approximately 4 p.m. to 7 p.m., anticipating the ISO-NE peak during this window. Ultimately, all three discharges coincided with the ISO-NE peak which occurred during the 5 p.m. to 6 p.m. window.

In 2020, five out of the eight Grantees discharged the ESS during the ISO-NE peak hour. The Grantees typically discharged the ESS over a two- to three-hour window between 3 p.m. and 6 p.m., anticipating the ISO-NE peak during this window.

### 3.2.2 Additional ICAP Insights

DNV's analysis of the 2019 and 2020 ICAP Grantee data and operational reports yielded the following additional insights regarding ICAP revenue and ISO-NE system loads:

- ICAP tag rates are decreasing over the ACES reporting period and will result in less realized revenues for the second and third reporting years. Grantees report that these rates are expected to increase in the long run.
- System peaks are easier to predict than regional peaks in part because ISO-NE provides good access to detailed live loading data and larger systems are also generally more predictable than smaller systems where a relatively small load variation could impact the peak hour.

- The 2019 ICAP hour was the first annual peak to occur from 5 p.m. to 6 p.m. in the 11 years since the creation of the forward capacity market 14 years ago. System peak hours have shifted later in the day as increasing amounts of solar PV capacity have been installed. The 2020 ICAP hour also occurred from 5 p.m. to 6 p.m.
- The 2019 system peak load of 23,919 MW reported by ISO-NE is the second-lowest annual system peak load over the last 10 years, only 2% higher than 2017's 23,508 MW (the lowest regional system peak load over the last decade) and 12% lower than 2012's 27,312 MW (the highest regional system peak load over the last decade).

## 3.3 Regional Network Service (RNS) Revenue Summary

Municipal light departments and other large customers that see ICAP tag charges are also billed a peak demand charge associated with RNS, which reflect the costs associated with transmission and distribution infrastructure requirements to support regional peak loads. Whereas ICAP costs are based on the annual system peak, RNS peak demand costs are based on a monthly regional network peak. These monthly regional peaks and charges vary, albeit marginally, across different ISO-NE regions and therefore for Grantees. Grantees use different models to predict these peaks and sometimes rely on the assumption that regional peaks will align with system peaks, which is not always the case.

Similar to ICAP Tag charges, which operate on a fiscal year starting in June, the RNS charges refresh in June of each year. The RNS charges are determined primarily by Schedule 9 of the ISO-NE Open Access Transmission Tariff (OATT) and were approximately $9.20 per kW for the 2018/2019 fiscal year, $9.33 per kW for 2019/2020, and increased to $10.77 per kW for the 2020/2021 fiscal year. Added to the Schedule 9 charges are a small Schedule 1 charge, which was about $0.13 per kW for 2018/2019 and 2019/2020 and increased to nearly $0.15 for 2020/2021.

RNS charges are arguably the second most important revenue source for ACES Grantees because they are determined during a single regional network peak for the month. They are harder to predict than the ICAP hour, and Grantees typically discharge multiple days during the month based on their RNS projections. For most Grantees included in this report, this entailed four to six deployments per month.

### 3.3.1 Grantee RNS Revenue Summary

At the time of this report, seven Grantees are reporting RNS revenues across 25 months. Table 3-8 shows the summary of total RNS benefits achieved over this reporting period.

**Table 3-8. RNS Revenues Summary**

| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | April 2019 to April 2021 |
| **Typical RNS hour** | 5–6 p.m. or 6–7 p.m. |
| **RNS Schedule 9 and 1 charges – 2018/2019** | $9.335 per kW |
| **RNS Schedule 9 and 1 charges – 2019/2020** | $9.461 per kW |
| **RNS Schedule 9 and 1 charges – 2020/2021** | $10.917 per kW |
| **Total RNS revenues achieved** | **$1,992,649** |

The Grantees included in this report hit 84% of the monthly RNS peaks and realized almost 67% of the total possible capacity that could have been realized for demand reductions during these regional network peaks. The total revenues by month for each Grantee are shown in Figure 3-8.

**Figure 3-8. Monthly RNS Revenues by Grantee**

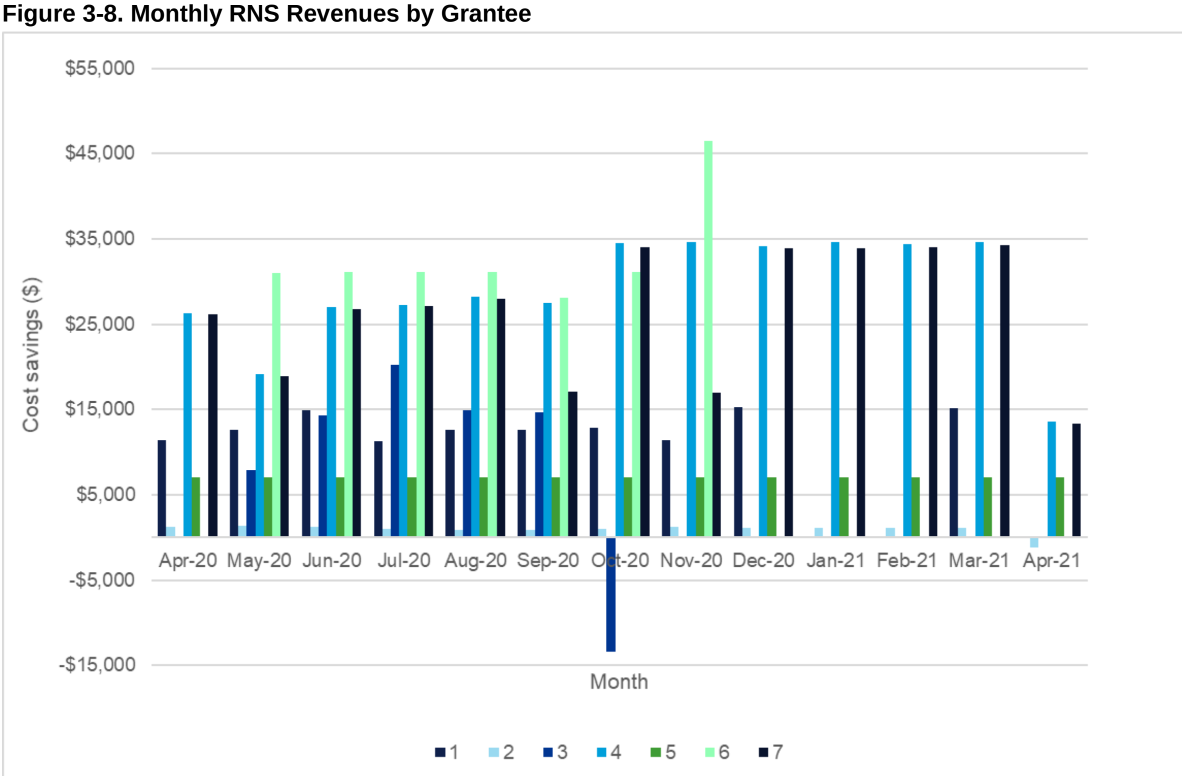



Table 3-9 shows the monthly RNS revenues by Grantee in table form.

**Table 3-9. Monthly RNS Revenues by Grantee**

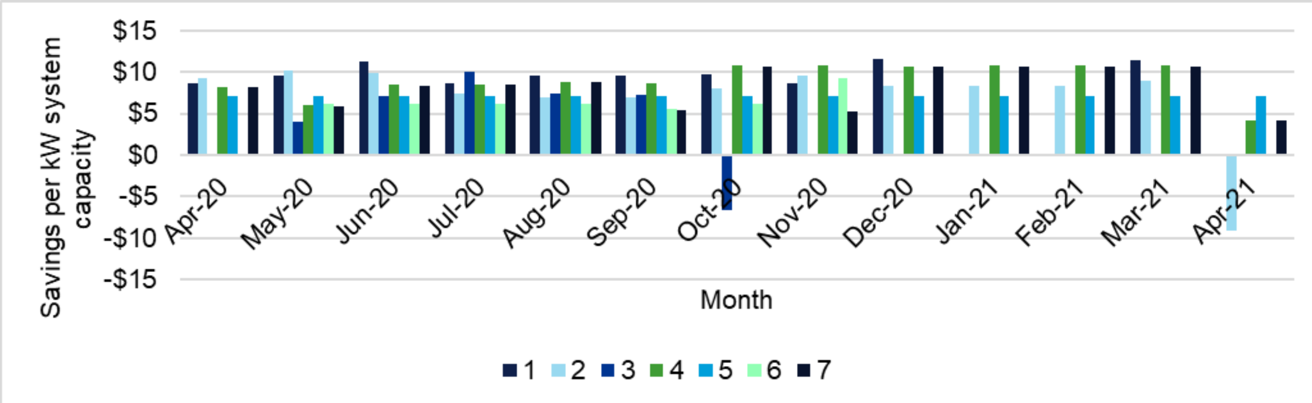
| Month | Grantee 1 | Grantee 2 | Grantee 3 | Grantee 4 | Grantee 5 | Grantee 6 | Grantee 7 | Totals |
|---|---|---|---|---|---|---|---|---|
| **Apr-19** | $0 | $0 | $18,154 | $0 | $0 | $0 | $0 | $18,154 |
| **May-19** | $0 | $0 | $11,182 | $0 | $0 | $0 | $0 | $11,182 |
| **Jun-19** | $0 | $0 | $0 | $0 | $0 | $25,387 | $0 | $25,387 |
| **Jul-19** | $0 | $0 | $16,112 | $0 | $0 | $31,097 | $0 | $47,209 |
| **Aug-19** | $0 | $0 | $1,237 | $0 | $0 | -$100 | $0 | $1,137 |
| **Sep-19** | $0 | $0 | $284 | $0 | $0 | $30,984 | $0 | $31,268 |
| **Oct-19** | $14,530 | $0 | $11,433 | $17 | $0 | $31,013 | -$90 | $56,903 |
| **Nov-19** | $14,371 | $1,051 | $17,139 | $23,941 | $3,442 | $30,061 | $23,714 | $113,719 |
| **Dec-19** | $14,721 | $932 | $17,461 | $29,825 | $1,747 | $30,995 | $29,316 | $124,998 |
| **Jan-20** | $0 | $861 | $17,535 | $23,928 | $7,048 | $43,595 | $23,713 | $116,680 |
| **Feb-20** | $13,478 | $892 | $12,406 | $28,105 | $7,048 | $46,548 | $28,332 | $136,809 |
| **Mar-20** | $0 | -$7 | $0 | $30,006 | $7,049 | -$108 | $29,746 | $66,686 |
| **Apr-20** | $11,399 | $1,180 | $0 | $26,263 | $7,050 | -$109 | $26,132 | $71,914 |
| **May-20** | $12,625 | $1,297 | $7,929 | $19,140 | $7,051 | $31,020 | $18,893 | $97,954 |
| **Jun-20** | $14,865 | $1,263 | $14,327 | $26,981 | $7,052 | $31,085 | $26,744 | $122,317 |
| **Jul-20** | $11,328 | $943 | $20,205 | $27,294 | $7,053 | $31,098 | $27,106 | $125,026 |
| **Aug-20** | $12,582 | $894 | $14,863 | $28,204 | $7,054 | $31,097 | $27,981 | $122,673 |
| **Sep-20** | $12,639 | $894 | $14,666 | $27,496 | $7,055 | $28,049 | $17,121 | $107,920 |
| **Oct-20** | $12,798 | $1,026 | -$13,376 | $34,466 | $7,056 | $31,094 | $34,069 | $107,133 |
| **Nov-20** | $11,413 | $1,230 | N.D. | $34,643 | $7,057 | $46,480 | $16,989 | $117,812 |
| **Dec-20** | $15,212 | $1,059 | N.D. | $34,130 | $7,058 | N.D. | $33,936 | $91,394 |
| **Jan-21** | $13 | $1,070 | N.D. | $34,624 | $7,059 | N.D. | $33,940 | $76,705 |
| **Feb-21** | $0 | $1,068 | N.D. | $34,444 | $7,060 | N.D. | $33,980 | $76,552 |
| **Mar-21** | $15,183 | $1,153 | N.D. | $34,632 | $7,061 | N.D. | $34,308 | $92,336 |
| **Apr-21** | $0 | -$1,167 | N.D. | $13,536 | $7,062 | N.D. | $13,351 | $32,781 |

N/A stands for not applicable, meaning the project reporting period had not started yet.

N.D. stands for no data, meaning the Grantee hasn't reported data for this month yet. Total will update once we receive additional data.

Similar to ICAP revenues, RNS revenues are proportional to the system size, so DNV tabulated the capacity normalized RNS revenues for each reporting Grantee, as well. These are shown by month in Figure 3-9 for the most recent 12 months available. Although the RNS peak demand costs are somewhat higher than ICAP costs on a per kW basis, it is harder to hit these peaks consistently and all Grantees missed at least one regional peak for any 12-month period. In October 2020, one Grantee missed the forecasted peak and was charging the system during the peak hour, resulting in the large negative value.

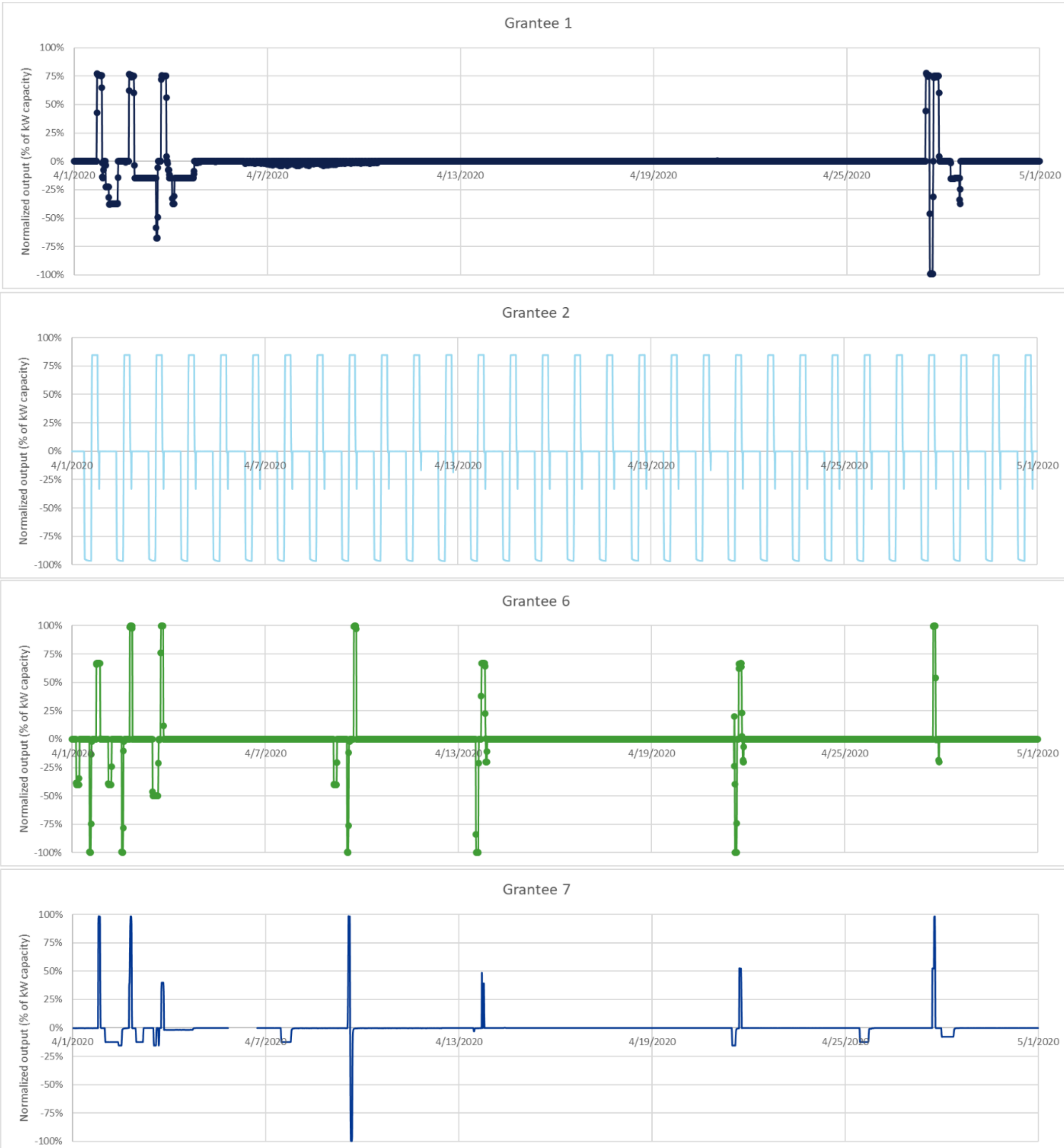
Figure 3-9. Summary of Capacity-Normalized Monthly RNS Revenues by Grantee




As shown in the figures and table above, nearly all Grantees missed the August 2019 and March 2020 RNS peaks but were successful in deploying during most other months. We understand from operational reports that thunderstorms in August 2019 resulted in the regional and system peaks occurring earlier (hour ending 4 p.m.) than predicted. For March 2020, we understand that the peak fell on a Sunday, which was unexpected. We also understand from the operational reports that the regional peaks are more predictable during the winter and summer months than they are in swing season months and are driven by three-day temperature extremes depending on the season.

For context in understanding monthly deployment trends, Figure 3-10, below, shows the deployment in percent capacity during April 2020 for four Grantees. Note that with the exception of Grantee 2 in the figure, all Grantees dispatch the ESS in a largely similar fashion—their independently predicted RNS hour dispatches align on three days during the early part of April and during the end of April.

**Figure 3-10. RNS Deployment Profiles for April 2020**




The Grantees' predictive algorithms drive ESS dispatches during several anticipated peak periods in order to hit the RNS. Note that while the monthly dispatch profiles look similar, Grantees must reduce their loads during the peak hour to achieve the RNS revenue in a given month. Figure 3-11 shows the performance of these same four Grantees on the RNS peak day, which was later determined to be April 27, 2020. Three of the Grantees were able to hit the peak, while the predictions and dispatch for Grantee 6 was off by one hour, resulting in a missed RNS peak.

**Figure 3-11. RNS Deployment Profiles for April 27, 2020**


The Grantees reporting data for this report represent three different transmission networks: the Western Massachusetts Electric Company (WMECO), New England Power Company, and Boston Edison. Table 3-10 shows the date and hour ending of the peak load for each transmission network as reported to us by the Grantees.

**Table 3-10. Regional Transmission Network Peak Day and Hour (Ending)**

| Month | Western Massachusetts Electric Company (WMECO) | New England Power Company (NEP) | Boston Edison (BE) |
|---|---|---|---|
| April 2019 | N.D. | 4/9/19 8:00 PM | 4/9/19 8:00 PM |
| May 2019 | N.D. | 5/20/19 7:00 PM | 5/20/19 6:00 PM |
| June 2019 | N.D. | 6/28/19 6:00 PM | 6/28/19 6:00 PM |
| July 2019 | 7/21/19 6:00 PM | 7/30/19 6:00 PM[1] | 7/30/19 6:00 PM[1] |
| August 2019 | 8/19/19 4:00 PM | 8/19/19 4:00 PM | 8/19/19 4:00 PM |
| September 2019 | 9/11/19 6:00 PM | 9/23/19 6:00 PM | 9/23/19 5:00 PM |
| October 2019 | 10/2/19 3:00 PM | 10/2/19 3:00 PM | 10/2/19 1:00 PM |
| November 2019 | 11/13/19 6:00 PM | 11/13/19 6:00 PM | 11/13/19 6:00 PM |
| December 2019 | 12/19/19 7:00 PM | 12/19/19 6:00 PM | 12/19/19 6:00 PM |
| January 2020 | 1/20/20 6:00 PM | 1/20/20 6:00 PM | 1/21/20 6:00 PM |
| February 2020 | 2/14/20 7:00 PM | 2/14/20 7:00 PM | 2/14/20 7:00 PM |
| March 2020 | 3/23/20 6:00 PM | 3/1/20 7:00 PM | 3/1/20 7:00 PM |
| April 2020 | 4/27/20 6:00 PM | 4/27/20 6:00 PM | 4/27/20 6:00 PM |
| May 2020 | 5/29/20 6:00 PM | 5/29/20 6:00 PM | 5/29/20 6:00 PM |
| June 2020 | 6/22/20 6:00 PM | 6/23/20 6:00 PM | 6/23/20 6:00 PM |
| July 2020 | 7/21/20 6:00 PM | 7/27/20 6:00 PM[2] | 7/28/20 5:00 PM |
| August 2020 | 8/12/20 6:00 PM | 8/11/20 6:00 PM | 8/11/20 6:00 PM |
| September 2020 | 9/8/20 6:00 PM | 9/10/20 6:00 PM | 9/10/20 4:00 PM |
| October 2020 | 10/26/20 6:00 PM | 10/30/20 7:00 PM | 10/30/20 1:00 PM |
| November-20 | 11/18/20 5:00 PM | 11/18/20 6:00 PM | 11/18/20 6:00 PM |
| December-20 | 12/16/20 5:00 PM | 12/17/20 6:00 PM | 12/17/20 6:00 PM |
| January-21 | 1/29/21 6:00 PM | 1/29/21 6:00 PM | 1/29/21 6:00 PM |
| February-21 | 2/1/21 5:00 PM | 2/1/21 6:00 PM | 2/1/21 6:00 PM |
| March-21 | 3/2/21 6:00 PM | 3/2/21 7:00 PM | 3/2/21 7:00 PM |
| April-21 | N.D. | 4/16/21 12:00 PM | 4/16/21 6:00 PM |

[1]ISO NE 2019/2020 system peak day and hour (ending).
[2]ISO NE 2020/2021 system peak day and hour (ending).
N.D. stands for no data.

## 3.3.2 Additional RNS Insights

- RNS revenues are the second-most lucrative for Grantees, but there is substantial risk of missing regional peaks due to regional variability and a lack of available regional load data.
- Regional load curves are flattening as more distributed generation resources are added to the ISO-NE region, and it is becoming increasingly harder to predict these peaks.
- Regional transmission peaks most often occur from 5 p.m. to 6 p.m., but during swing months they often occur earlier in the afternoon.
- Eversource's RNS loads for July through September have returned closer to the three-year average in comparison to the previous three months, which were clearly impacted by COVID-19 shutdowns.

## 3.4 Demand Response Revenue

DR programs compensate participants for reducing their load during prescribed event periods. They are typically offered either by a utility (like Eversource Active Demand Reduction Program) or by a grid operator (like ISO-NE Price Responsive Demand). DR events are typically called during times of high grid-level demand and driven by economic and/or reliability considerations.

Many participants in DR programs achieve load reductions by curtailing systems, processes, and activities such as turning down/off the HVAC system or reducing production volume. However, behind-the-meter energy storage systems are increasingly used for DR participation, as well.

DR programs are pay-for-performance programs where the economic compensation is tied to the achieved performance. Some programs also have penalties for non-performance. While the compensation mechanisms for DR programs vary from one program to another, there are typically two distinct components:

1. **Capacity payment** – Typically these are monthly payments proportional to the pledged capacity (the load that the participant commits to reduce during a DR event) and are paid regardless of whether an event is called or not.
2. **Performance payment** – Payments based on achieved performance during a DR event period.

DR events commonly span three or four hours, and the participants generally receive day-ahead notification of upcoming events. The short duration of the event and advance notice makes ESS well-suited for DR, as facilities can manage ESS charging to maximize DR event performance. Because of these factors, there is less revenue uncertainty in DR participation than with ICAP and RNS dispatches, where the facilities forecast peak periods and dispatch their ESS projects hoping that their projections align with system and/or regional peaks.

Facilities seldom participate in DR programs directly. Rather, they enlist the services of DR aggregators who integrate assets and enroll them for DR program participation. While the revenue-sharing arrangement between the facility and the DR aggregator is typically determined on a case-by-case basis, the aggregator's portion of the revenue can account for up to one-third of the DR revenue. Both of the Grantees reporting DR revenue in this report achieved DR revenues through an aggregator.

### 3.4.1 Grantee DR Revenue Summary

Of the eight Grantees included in this report, two have reported on DR program revenues. Table 3-11 shows the summary of DR program achieved revenues for this period.

**Table 3-11. DR Grantee Revenue Summary**

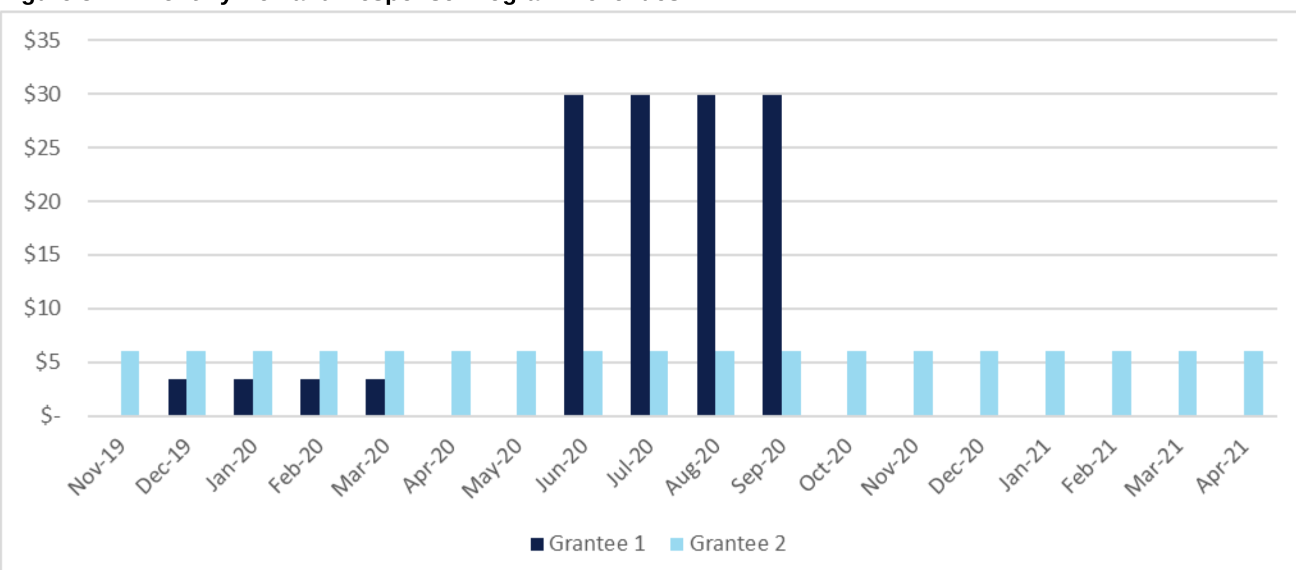
| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | October 2019 to April 2021 |
| **Number of Grantees reporting revenue** | 2 |
| **Total revenue** | $283,400 |

The two Grantees included in this report achieved DR program revenues from two different DR programs: the Eversource Active Demand Reduction program and the ISO-NE Price Responsive Demand program, both outlined below.

- The **Eversource Active Demand Reduction** program includes two components:
  - ***Targeted Storage*** events have a three-hour duration and are activated by the program administrator during periods of peak demand. Incentive rates vary by season and consist of $100 per kW during the summer season (June to September) and $50 per kW during the winter season (December to March).
  - ***Summer Daily Dispatch*** covers weekday non-holidays throughout the summer (June to September) with typically up to 60 events called. The summer daily dispatch incentive is $200 per kW during the season.
- The ISO NE Price Responsive Demand program
  - The Grantee who achieved revenues through the ISO NE Price Responsive Demand program did so through an aggregator and was guaranteed a fixed monthly payment based on fixed commitment for up to four hours of capacity deployment. This could be called during any month with a 30-minute notice.
  - No events were called for the Grantee who participated, but the Grantee still received their fixed monthly payments as arranged for having the resource available.

Figure 3-12 shows a monthly summary of the demand response program revenues achieved by the two reporting grantees over the months of operational report coverage.

**Figure 3-12. Monthly Demand Response Program Revenues**




### 3.4.2 Additional DR Insights

For the Grantee enrolled in the Eversource Active Demand Summer Daily Dispatch program for the summer 2020 period, DR revenues accounted for a significant portion of the revenues achieved to date. The amount of revenues achieved by this participation was greater than both the annual ICAP and RNS revenues, indicating that this program can serve as a core business case for ESS projects. The Active Demand Summer Daily Dispatch revenues stand out as significantly more profitable and reliable than most other revenue sources based on this limited data.

## 3.5 Energy Arbitrage

Energy arbitrage involves time shifting the facility's electric load by charging the ESS at periods of low electricity costs (typically an off-peak period spanning overnight or early morning hours) and discharging it during periods of high electricity costs (typically an on-peak period spanning afternoon and/or evening hours). The ESS discharge offsets the volume of electricity that the facility needs to purchase during the on-peak period and thereby reduces the facility's electric bill.

Monetizable benefits for this revenue stream are calculated by computing the difference between the electricity costs to charge the system and the avoided electricity costs by the system's discharge.

This revenue stream is designed to arbitrage intra-day differences in electricity prices, and thus it is feasible only if there are temporally sensitive components in a facility's retail electric bills. Typically, a component of the volumetric electric prices involves a time-of-use component, which is pegged to the LMP.

Because of the energy lost due to the ESS round-trip efficiency (RTE) and attendant auxiliary and/or parasitic loads such as heating or controls, the gross energy input into an energy storage system will always be greater than its energy output – i.e., there will be an energy loss associated with its operation. Therefore, facilities seeking revenue from energy arbitrage will only dispatch the battery for this revenue strategy if the difference between on-peak and off-peak prices is large enough to offset the RTE losses.

### 3.5.1 Grantee Energy Arbitrage Revenue Summary

Unlike the other revenue streams described in this report, the ESS dispatch for energy arbitrage typically does not yield a large monetizable benefit over any single day. The revenue per cycle of system discharge is smaller by an order of magnitude when compared to revenue streams like ICAP and RNS revenues and accrues in small increments over the year.

Battery ESS projects typically have warranty requirements that place an upper bound on the total number of discharge cycles per year to maintain and extend system life. Because of this, Grantees with battery ESS typically do not dispatch daily. To date, five of the eight Grantees included in the scope of the report have reported energy arbitrage revenues. However, none of the five Grantees actively dispatch the ESS to leverage energy arbitrage alone; the energy arbitrage revenues achieved are incidental, occurring from ESS dispatch for ICAP and RNS savings.

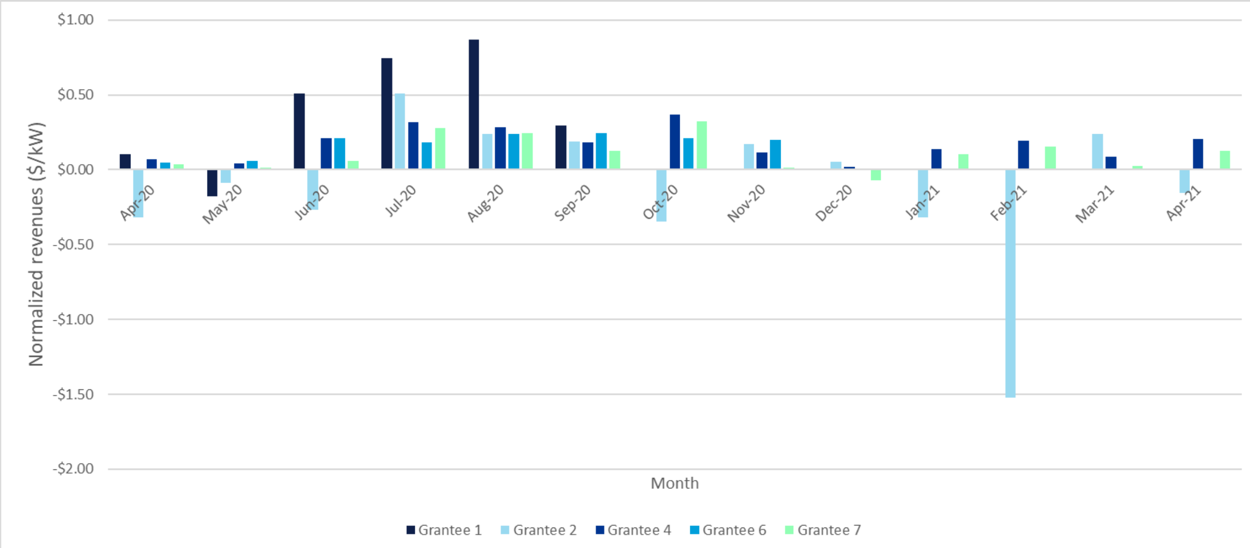
DNV used the granular ESS discharge/charge data, hourly real-time LMP for the specific reliability region accessed from ISO-NE's API, and site-specific adjustment factors to evaluate the energy arbitrage benefits accrued for participating Grantees. Table 3-12 shows the total arbitrage benefits accrued by the five Grantees reporting these benefits for this period.

**Table 3-12. Energy Arbitrage ACES Revenue**

| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | June 2019 – April 2021 |
| **Number of Grantees reporting revenue** | 5 |
| **Total revenue** | $22,735 |

Figure 3-13 shows the verified monthly arbitrage benefits achieved by each Grantee over the reporting period.

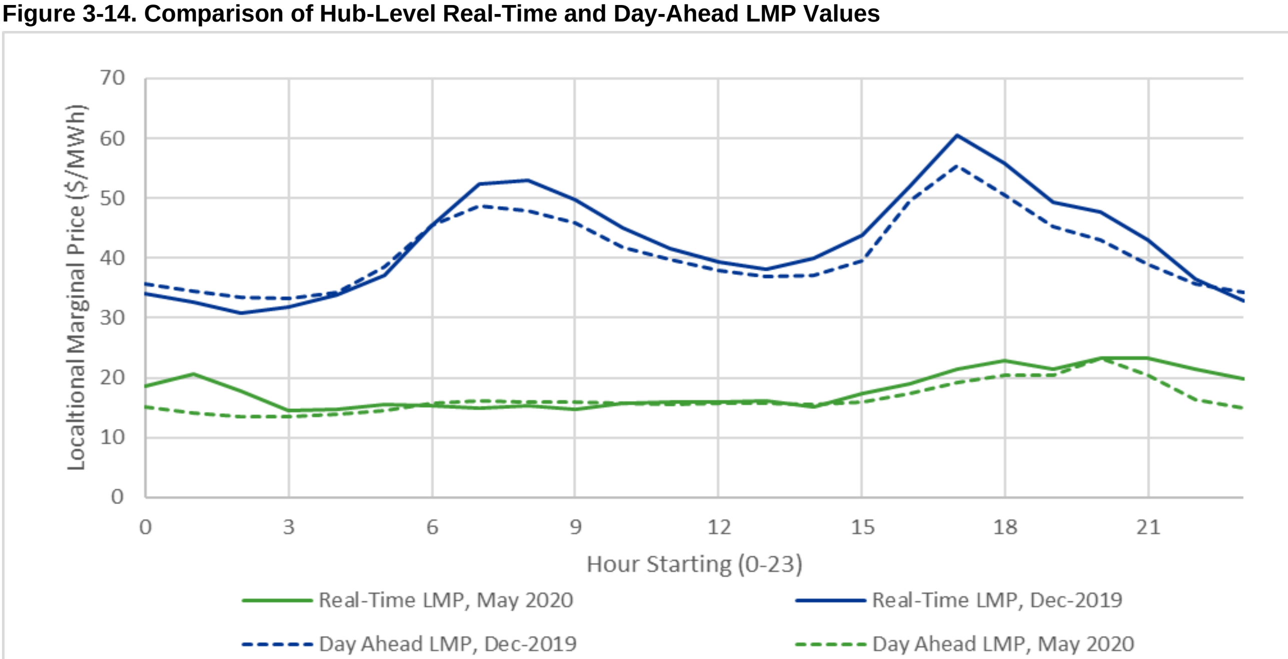
Figure 3-13. Summary of Capacity-Normalized Energy Arbitrage Savings




## 3.5.2 Additional Energy Arbitrage Insights

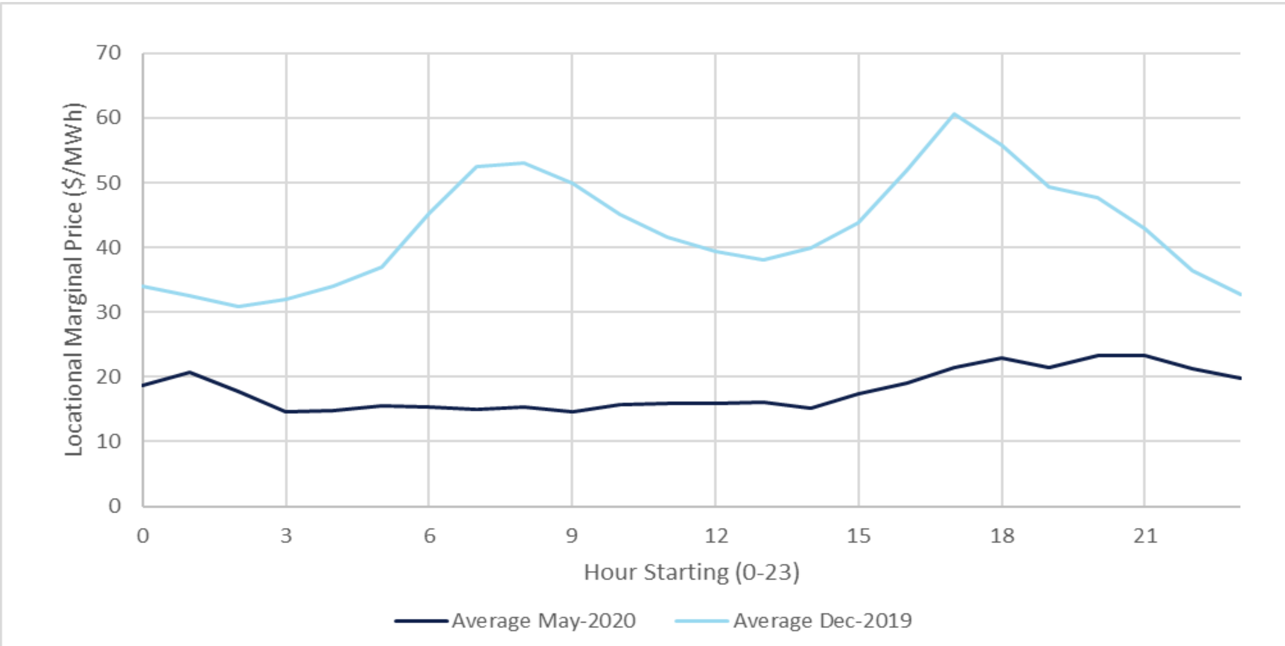
DNV identified differences between the arbitrage revenues reported by Grantees and the revenues calculated from the reported data. This is primarily due to differences in modeling approaches. DNV used real-time LMP values to assess revenues, while some Grantees used day-ahead LMP values or based their estimates on fixed energy costs. Other differences, such as handling of daylight savings time, also played a small role. Figure 3-14 shows the differences between real-time and day-ahead LMP values during two months within the reporting period. While the values are similar in direction and magnitude for either period, there are observable differences between them.

Figure 3-14. Comparison of Hub-Level Real-Time and Day-Ahead LMP Values



There are also differences in the magnitude and intra-day variation of LMP prices throughout the year, which impact the opportunities for energy arbitrage. Figure 3-15 depicts the differences between two months in the reporting period. Note that the LMP in December 2019 is higher and varies greatly throughout the day, making it more conducive for energy arbitrage. Conversely, May 2020 saw relatively flat and lower LMP, suggesting that there is less of an arbitrage opportunity.

**Figure 3-15. Average Hourly Hub-Level Real-Time LMP Value Monthly Variability**




## 3.6 Peak Demand Reduction

Demand charges—charges based on peak demand set by the facility[11]—account for a significant portion of the monthly electricity bills in a typical commercial facility. These charges are typically set by the facility's 15-minute average peak demand for the month and are based on a published rate structure. Behind-the-meter ESS can be strategically dispatched during periods of facility peak demand to reduce the monthly peak demand charges. This revenue stream is called peak demand reduction, or peak shaving. ESS projects commonly leverage sophisticated statistical models of facility load profiles to inform their dispatch. While the magnitude of peak shaving revenue can be comparable to that of ICAP and RNS savings, it is largely driven by a facility's load profile and the retail electric rate structure in place at the facility. It is notable that commercial facility demand profiles can be significantly harder to predict than system or regional profiles due to the complexity of commercial and industrial facility operation. Commercial peak demand management could also require a daily dispatch over the month in comparison to RNS deployments, which are usually only a handful of events each month.

In contrast to a standard monthly demand rate where all hours of all days of the billing period are evaluated for demand charge calculations, time-of-use (TOU) rates commonly focus on a concentrated period of grid constraint to estimate peak demand. These windows typically include only certain daytime hours of the weekdays, and a facility's demand during the weekend or during nighttime hours does not impact the monthly demand charges. Therefore, TOU rates provide the ESS the flexibility to dispatch for other revenue streams outside the TOU windows. In addition, because the TOU windows do not span the entire day, they enable an ESS to achieve higher demand charge reduction given the same energy input. For example, a 1000 kWh ESS dispatching over a four-hour *on-peak* window achieves a 250 kW peak demand reduction

[11] As opposed to charges based on peak demand on the regional transmission network (RNS) or ISO NE system overall (ICAP).

whereas the same ESS dispatching over a 12-hour window achieves only 83.3 kW peak demand reduction. Finally, TOU rates typically have higher demand charges (in $/kW) during the on-peak period. All these factors can make the presence of TOU rates at the facility a key factor in driving peak shaving revenues.

To date, only one of the eight Grantees included in the scope of this report actively dispatches their ESS to seek peak demand reduction.

### 3.6.1 Grantee Peak Demand Management Summary

It was anticipated that peak demand management would be an important source of revenue for commercial facilities participating in the ACES program, but that has not been realized to date. Instead, the one Grantee reporting revenues for this revenue strategy had a negative impact on their charges as result of prioritizing other revenue strategies (RNS and DR program). For comparison to ICAP and RNS revenues, the anticipated normalized per kW revenues for this project was on the order of $11.20 per kW.

Indications from other Grantees approaching reporting on this strategy also show that peak demand management is difficult to achieve effectively. Several Grantees have communicated that DR program revenues are a more reliable and effective way to achieve revenues than peak demand management. We expect that as more Grantees report on peak demand management revenues, our findings on this topic will become more robust.

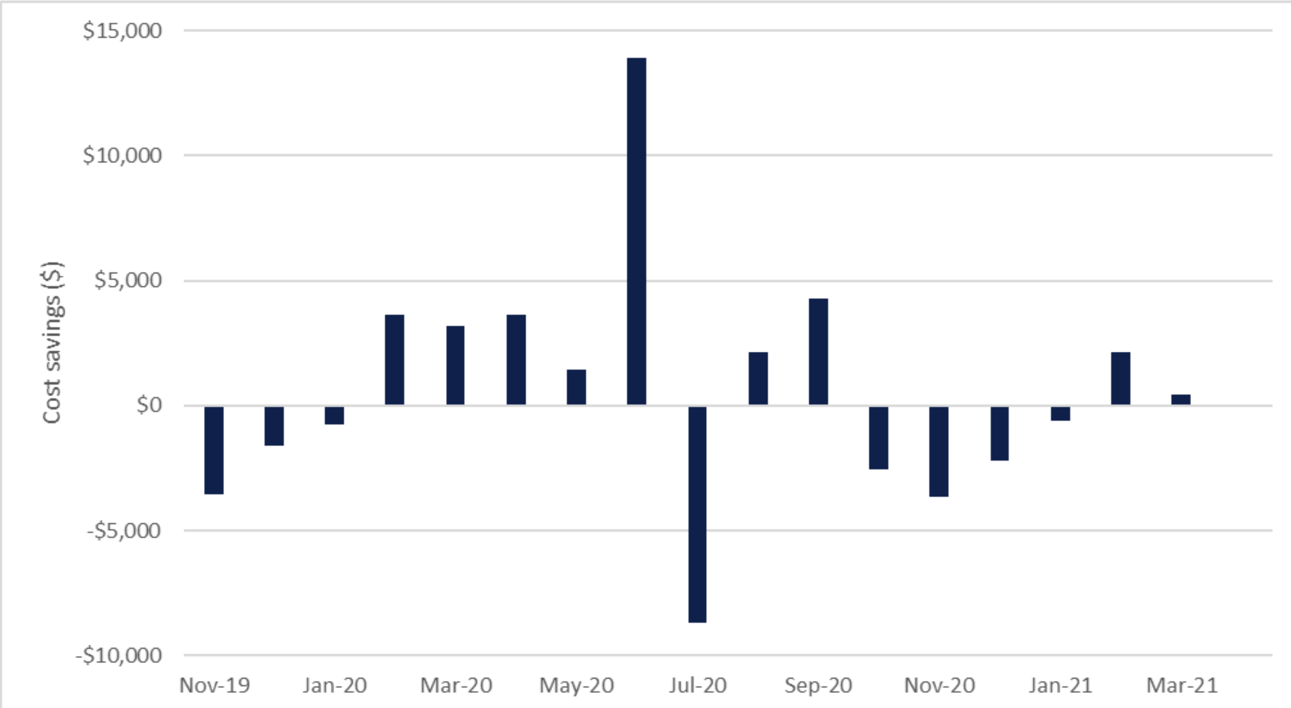
Table 3-13 shows the total peak demand reduction benefits accrued by the one Grantee reporting these benefits for this period.

**Table 3-13. Peak Demand Reduction ACES Revenue**

| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | November 2019 – April 2021 |
| **Number of Grantees reporting revenue** | 1 |
| **Total revenue** | $11,230 |

Figure 3-16 shows the monthly revenues realized by the Grantee who receives these commercial demand charges. As discussed, this revenue stream has been deprioritized in favor of more lucrative revenue streams such as ICAP and demand response.

**Figure 3-16. Monthly Peak Demand Reduction Revenues**




## 3.7 SMART Program Revenue

The Solar Massachusetts Renewable Target (SMART) Program was created by the DOER to promote the long-term sustainable solar incentive program in the Commonwealth. SMART is a declining block program with declining incentives as capacity blocks are filled. The SMART program includes adders for project features, including incorporating energy storage into solar project development.

### 3.7.1 Grantee SMART Revenues

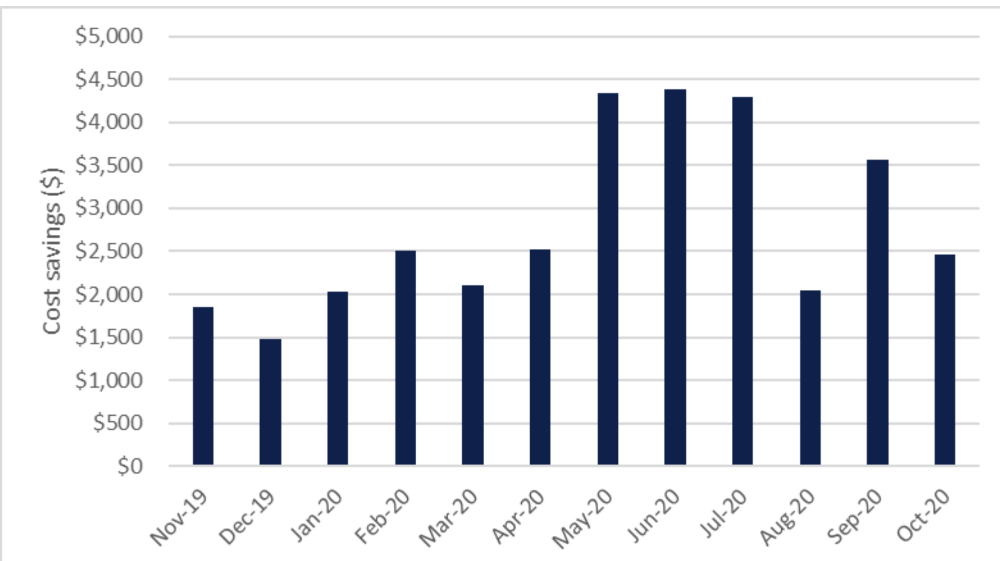
Of the eight Grantees included in this report, only one Grantee currently reports revenues from the SMART program as a result of the energy storage adder. This is a battery project co-located with a ground-mounted solar installation; the battery provides solar PV smoothing for the local grid and also achieves revenues through participation in the SMART program. The SMART program provides a fixed per kWh adder for the addition of energy storage, but the total SMART compensation rate varies with the net metering rate to provide an agreed upon total rate. Table 3-14 shows the summary of achieved SMART storage adder revenues.

**Table 3-14. SMART ACES Revenue**

| Revenue Stream Criteria | Value |
|---|---|
| **Analysis period** | November 2019 to October 2020 |
| **SMART storage adder rate** | $0.05129 per kWh |
| **Number of Grantees reporting revenue** | 1 |
| **Total SMART storage adder revenue** | $33,594 |

As discussed above, the SMART storage adder revenues are dependent on the amount of solar generation and do not depend on ESS deployments, other than meeting the annual SMART requirement of 52 cycles per year. Figure 3-17 shows the monthly SMART revenues achieved by the Grantee who pursued this end use.

**Figure 3-17. Monthly SMART Revenues**




Note that the Grantee's solar PV array was disconnected by the local utility in August 2020 and was not reconnected for at least 10 days, which resulted in significantly less generation and revenues for the month.

# 4 NON-MONETIZABLE BENEFITS

In addition to the monetizable revenue streams discussed in the prior section, Grantees are also required to report non-monetizable revenues from their projects. These revenues vary widely across the Grantees, but generally fall into the following categories:

- **Testing feasibility of potential future revenue streams**. Many Grantees are exploring both actual and simulated ESS dispatches to assess the future revenue potential for programs and strategies not currently part of the existing suite of monetizable revenues. While these vary across Grantees, they can include exploring revenue potential from ISO-NE's Ancillary Service Market, Demand Response programs, SMART, and others.
- **Avoided carbon and other greenhouse gas (GHG) impacts**. Some Grantees will be quantifying avoided carbon costs and other GHG impacts and benefits of the ACES projects. There are different methodologies available to quantify these impacts, and we expect to be able to report on these benefits across projects once more Grantees begin reporting this benefit.
- **Resiliency benefits.** ESS installations provide both local and grid-level resiliency benefits. Local benefits include the ability to deliver power to critical systems and loads during grid outages. Grid resiliency benefits include dispatching ESS to align with network peaks to assist electricity supply. This can have more significant impacts on small or island networks that may be more subject to resource constraints.
- **Educational opportunities**. Several Grantees provide educational opportunities through their projects, typically through ESS sited at universities that offer internships and opportunities to test future revenues or optimization opportunities.
- **System optimization opportunities**. ESS projects can provide various system benefits, including increasing renewable capacity on distribution systems, enabling load optimization across other on-site generators, and deferring transmission and distribution system upgrades by adding capacity to the grid.

## 4.1 Grantee Non-Monetizable Revenue Performance

While Grantees are expected to demonstrate non-monetizable benefits for the project, only one Grantee reported these benefits in their initial operational reports. Many Grantees have committed to testing the feasibility of these benefits during the second and third year of operations as they are currently focused on streamlining system operations to hit ICAP and RNS peaks. We expect to include results and reported non-monetizable benefits once more Grantees report these in their corresponding quarterly and/or biannual operational reports.

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