FINAL REPORT

ACES Sixth Aggregated Project Report

MassCEC

Date: December 16, 2022

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1 REPORT OVERVIEW

This report is DNV's sixth 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 prepared quarterly reports for the first year of the reporting cycle and prepares biannual reports during the remaining years, followed by a program summary report.

1.1 Scope of sixth aggregated report

The scope of this sixth report covers all Grantees with approved data streams through April 30, 2022.

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 2022.

There are ten Grantees with approved operational reports spanning April 2019 through April 2022. To date, DNV has received and approved a total of 57 operational reports from these Grantees. An eleventh 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 they submit 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 before 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 memo.** Each aggregated report includes 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 a memo on operations and maintenance (O&M) challenges encountered during project development and operations.
- **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. Most Grantees have been focused on calibrating their operations, and not many have reported non-

[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.

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 MEMO – O&M AND SUPPLY CHAIN CHALLENGES

This section presents the market development memo for the sixth aggregated report. This memo highlights supply chain and operations and maintenance (O&M) challenges encountered by the Grantees throughout the development and/or operation of their energy storage systems (ESS). The memo reflects program achievements through April 2022, and all Grantee data has been anonymized to protect privacy and confidentiality.

2.1 Supply chain and O&M challenge themes

Throughout the course of project development and operations, many Grantees encountered supply chain delays and/or O&M challenges that impacted the timing and/or performance of their ESS. This memo identifies the primary categories of challenges encountered and provides several case studies that demonstrate how these challenges can impact ESS operations and revenue performance.

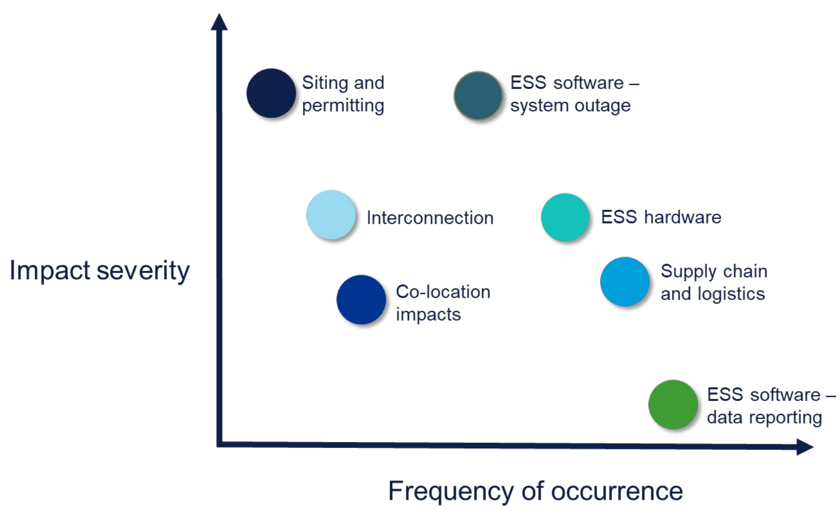
- **Siting and permitting challenges** have affected Grantees prior to ESS commissioning. Typically, these challenges reflect ongoing interactions with local planning and permitting departments, which have required several Grantees to change their siting plans to obtain approvals and necessary permits. Often this was due to the authorities having jurisdiction (AHJs) not having significant familiarity or experience with ESS and system components, and thus a lack of standardized site design criteria and/or approval processes. The primary impacts of these challenges have been delays in the development process as designs are redone and resubmitted for approval. For one Grantee, design changes were made and initially approved, but additional delays were encountered once the ESS was installed and proceeding through final commissioning, requiring a hold until AHJ approval is granted. The siting and permitting challenges were previously discussed in greater detail in DNV's (then ERS) first aggregate report.
- **Interconnection impacts** primarily have affected project planning and development timelines, but they also have impacted ongoing operations in some cases. For several Grantees, local utilities required specific interconnection studies, and long queues for these studies delayed project timelines and created uncertainty regarding when projects would be able to proceed. Additionally, existing interconnection constraints in some grid networks have impacted ongoing operations by the utility taking a system or network offline for extended periods. The interconnection impacts were previously discussed in greater detail in DNV's (then ERS) second aggregate report.
  - ***Co-location management challenges***. This is a subset of interconnection challenges, but is considered a separate category as several Grantees are co-located with photovoltaics (PV), combined heat and power (CHP), or other generation. Performance requirements and/or settings of the co-located equipment have impacted ESS operations, with the most common impact reducing or prohibiting the ESS from discharging during planned dispatches.
- **Supply chain/logistics challenges** have been experienced during both the pre- and post-commissioning activities, likely exacerbated by the COVID-19 pandemic. These challenges have primarily materialized as delays in receiving new and/or replacement parts, but also include personnel shortages delaying response times for technicians to conduct required service and/or repairs. These supply chain challenges were not anticipated by the Grantees during their original project planning, as the planning occurred prior to the widespread disruption of global supply chains resulting from continued impacts of the COVID-19 pandemic. These impacts continue to be felt and have resulted in extended ESS downtimes – in part or in full – depending on the underlying hardware or software challenge.
- **ESS hardware issues** occur when components within an ESS malfunction, break, or otherwise require operations at a reduced capacity. In some cases, this causes the system to be taken fully offline. Grantees have experienced a variety of hardware challenges, including cooling fan failures, broken electric control enclosures, and manufacturing defects in battery cells that reduce available discharge capacity until defective modules can be replaced. Most of the Grantee projected full capacity operations in their initial estimates of the revenue potential, suggesting that these hardware

issues were not anticipated. The severity of the impact of hardware issues varies greatly based on the components that require fixing, and the availability of equipment and/or personnel to conduct any repairs, which in several cases have been subject to the supply chain challenges discussed previously.

- **ESS software challenges** occur when some of the software components fail to communicate with battery control and/or reporting mechanisms. The impacts of software challenges most commonly fall into one of two outcomes:
  - ***Data reporting outage*** – the software challenge affects the connection between the ESS and the data reporting mechanism(s) such that some or all ongoing system performance data is interrupted, but the system maintains operational connectivity and remains online. Typically, supplementary datasets are available to backfill any missing operational performance data and, in some cases, replacement data acquisition systems (DAS) have been required to correct recurring data reporting challenges.
  - ***System outage*** – the software challenge prevents the ESS from effectively communicating with control mechanisms and renders the system partially or fully offline. Examples include system settings and faults that affect ESS controls, and communication interruptions or errors in data algorithms and settings affecting ESS charge/discharge operations and prioritizations of competing revenue streams.

While the actual impacts of these challenges on each Grantee project can vary greatly and are often interrelated, Figure 2-1 below presents our assessment of the typical frequency of occurrence and the severity of impact for the challenges discussed in this memo. This highlights that siting and system outage issues often have the largest impacts, as they prevent the ESS from coming online or operating, while other challenges such as hardware and supply impacts more commonly affect only a portion of the ESS.

Figure 2-1. Typical impact and frequency of ACES Grantee O&M challenges



2.2 Case studies

The following case studies highlight some of the challenges experienced by Grantees throughout their ESS operations, as well as any impacts on revenue and performance.

- **Case Study A**. This case study is for a municipal Grantee with an ESS designed to help manage municipal load. While their ESS has largely remained operational, they have experienced software and hardware challenges throughout the reporting period that affected their ESS operations. The charge and discharge cycles are controlled through the manufacturer's scheduling software off-site. While this has limited the site's operational flexibility in controlling cycling in real-time, this facility and network have fairly regular, predictable peaks, and operate on a set daily schedule of charging and discharging with limited impact on revenue performance.

This ESS consists of multiple modular units and has regularly had to take some units offline for repair/replacement due to performance issues and communications failures of individual units. The ESS can operate at a reduced capacity when individual units are offline, but this reduces the total peak reduction potential of the system. Defective units require site visits from the manufacturer, who is located outside of Massachusetts, and there have been repair delays due to travel challenges for maintenance technicians – exacerbated by the COVID-19 pandemic – and supply chain challenges for replacement equipment. Additionally, the whole ESS needs to be taken offline during repairs, which has caused the project to miss some RNS peaks.

The Grantee also experienced a recurring software data reporting challenge, where their data acquisition system (DAS) regularly lost connection to report their data to the ACES program. While this did not have an impact on revenues and most data was able to be backfilled, it eventually required a new DAS that could transmit the required data consistently.

- **Case Study B**. This Grantee has a behind-the-meter ESS coupled with a combined heat and power (CHP) plant. ESS operations have experienced interconnection and co-location challenges. There was an initial interconnection challenge due to an inadvertent registration error that resulted in the ESS being registered in the wrong load zone; the ESS was thus unable to earn revenues from capacity payments until this was resolved.

  The Grantee also had co-location challenges due to difficulties with the on-site CHP plant. Challenges with the equipment performance resulted in lower than anticipated cogeneration loads, which reduced the revenue generated from ESS demand reduction operations significantly below Grantee forecasts. Additionally, switchgear repairs for the CHP system caused several prolonged shutdowns of ESS operations, further inhibiting revenues.

  This facility also faces an ongoing interconnection challenge, as the local utility has a non-export relay installed at the point of interconnection requiring that the facility maintain a net import of at least 220 kW. Tripping this relay results in the CHP plant going offline. This has affected ESS operations, as the Grantee had to program the battery to curtail any discharging that would push the facility load below a level that would inadvertently trip this relay. The impact of this programming is to reduce the capacity available in the ESS to pursue its revenue streams, which include demand response, ICAP, and frequency regulation.

- **Case Study C**. This Grantee has an ESS coupled with a solar photovoltaic (PV) installation. The ESS operates in a relatively constrained network and provides the smoothing of power onto the grid, necessary to enable PV operations. The ESS generates revenues through the SMART program storage adder. Challenges include hardware challenges, ongoing interconnection challenges, and data reporting outages. The Grantee has experienced regular hardware challenges, primarily due to defective inverters and optimizers that require field visits to repair and/or replace. The Grantee is regularly working to replace defective parts, but has seen delays in receiving replacement parts from the manufacturer. This has had ongoing impacts on both data reporting for the system and on revenues, as the system cannot operate at full capacity.

  Ongoing interconnection challenges have been the result of recurring power outages in the network. During an outage, the solar PV system is automatically disconnected, and the ESS goes into idle mode, only operating to deliver power to its own air conditioning requirements. When power is restored, the project has reclosers that need to be manually reconnected in order to resume operations. The local utility has had delays restoring power at times and has not communicated to the Grantee that operations are able to resume; this has resulted in reduced revenue while the ESS and PV systems remain offline longer than necessary.

2.3 Conclusions

Analysis of the challenges encountered to-date in the ACES program leads to the following conclusions:

- **Challenges are often interrelated and can have significant impact on project revenues**. We presented the individual types of challenges and their typical impacts, but thus far many of the Grantees have experienced multiple challenges – often interrelated – throughout their reporting periods. As evidenced by the case studies, hardware issues can be affected by supply chain impacts delaying resolution, and interconnection impacts can further hamper projects' ability to realize anticipated revenues.
- **Initial pro forma and project modelling for the ACES program commonly failed to adequately anticipate O&M challenges.** Much of the initial estimations done at the onset of the ACES program assumed full project operations and did not consider many of the O&M and supply chain challenges experienced. Future project development should consider these impacts in planning and estimating revenues from ESS.
- **The COVID-19 pandemic likely exacerbated supply chain challenges, affecting response times for software and hardware issues**. Continued disruptions to global supply chains have been cited by several Grantees as a contributing factor affecting the timelines to replace ESS components and/or service ESS software challenges.

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%	24
Grantee 2	Municipal Light Plant (MLP Asset)	N.D.	24
Grantee 3	Municipal Light Plant (MLP Asset)	10.1%	25
Grantee 4	Municipal Light Plant (MLP Asset)	N.D.	25
Grantee 5	Municipal Light Plant (MLP Asset)	33.3%	23
Grantee 6	Municipal Light Plant (MLP Asset)	10.2%	26
Grantee 7	Municipal Light Plant (MLP Asset)	7.1%	25
Grantee 8	Merchant, solar plus storage	N/A	18
Grantee 9	Behind the meter – solar plus storage	N.D.	3
Grantee 10	Merchant, solar plus storage	N.D.	3

3.1 Summary of revenues and operational strategies

Table 3-2 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	Clean Peak Standard
Municipal Light Plant (MLP Asset)	6	$1,801,599	$3,119,961	$179,400	$45,070	$37,279	$0	$0
Behind the meter – solar plus storage	2	$124,688	$414,452	$366,561	-$2,406	$23,250	$11,881	$269,536
Merchant, solar plus storage	2	$0	$0	$119,318	$11,417	$0	$84,969	$0
Totals	**10**	**$1,926,287**	**$3,534,413**	**$665,279**	**$54,081**	**$60,529**	**$96,850**	**$269,536**

Note that in Table 3-2, ICAP tag revenues are three-year annual estimates, whereas other revenues are the sum across the months currently reported by Grantees. The 2021 ISO NE system peak hour has been confirmed as June 29, hour ending 6 p.m., but initial estimates of revenues achieved by ESS deployments during this hour are not included in this table.

Table 3-2 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 were 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	$2,325,213	$13,392,837	$9,550,274	5.8	4.1
Behind the meter – solar plus storage	1,840	6,088	$457,723	$4,259,182	$2,265,982	9.3	5.0
Merchant, solar plus storage	2,600	5,370	$565,927	$3,437,758	$1,805,564	6.2	3.2
Totals	**18,968**	**40,262**	**$3,339,863**	**$21,089,777**	**$13,621,820**	**6.3**	**4.1**

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

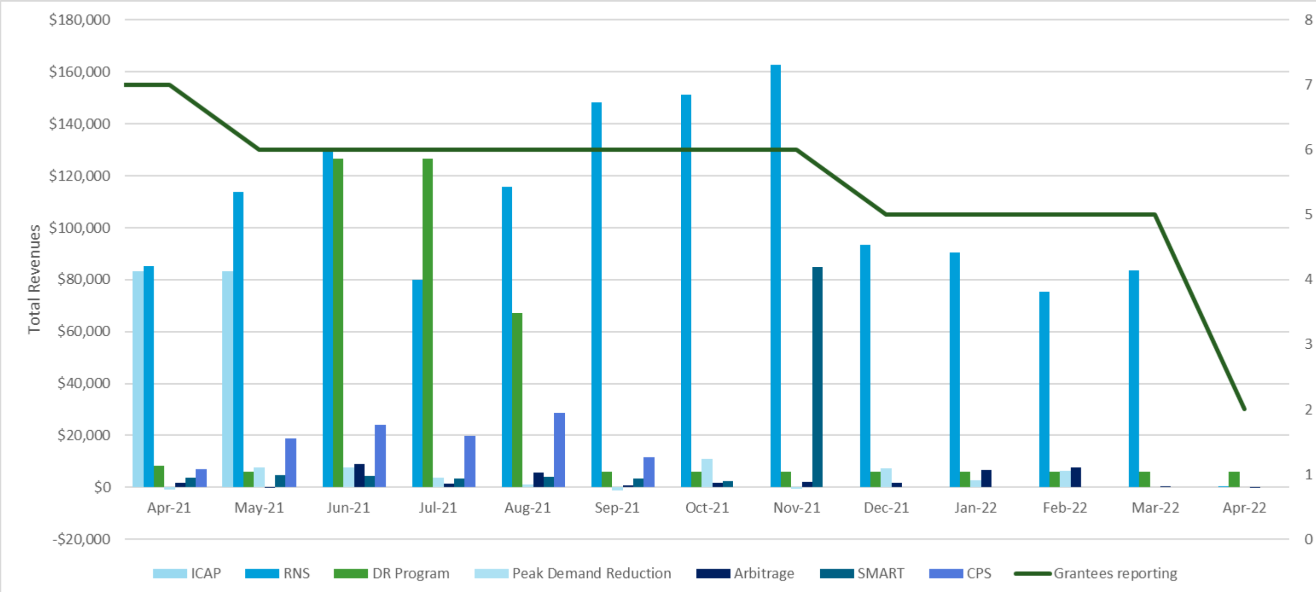
Revenue Strategy	Reporting Coverage	No. of Grantees Reporting	Predicted Revenues	Realized Revenue	Total ESS Capacity (kW)	Percent Capacity Realized	Avg. $/kW Revenue per Month
ICAP[1]	2019, and 2020 system peak	7	$1,875,083	$1,926,287	31,696	69%	$5.02
RNS	Apr 2019 to Apr 2022	7	$3,043,041	$3,534,413	464,440	70%	$6.99
Demand response (DR)[2]	Jun 2019 to Apr 2022	4	$251,660	$665,279	45,000	84%	$9.03
Peak demand reduction	Nov 2019 to Apr 2022	3	$399,246	$45,070	30,000	7%	$1.71
Energy arbitrage	Jun 2019 to Apr 2022	5	$109,045	$60,529	N/A	N/A	$0.13
SMART storage adder	Nov 2019 to Apr 2022	2	$145,782	$96,850	N/A	N/A	$5.73
Clean Peak Energy Standard	Jan 2020 to Oct 2021	1	N/A	$269,536	1,320	N/A	$9.72
TOTALS	APR 2019 TO APR 2022	10	$5,823,858	$6,597,965			

[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 ten Grantees included in this report generated revenues (or cost savings) from seven 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 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.

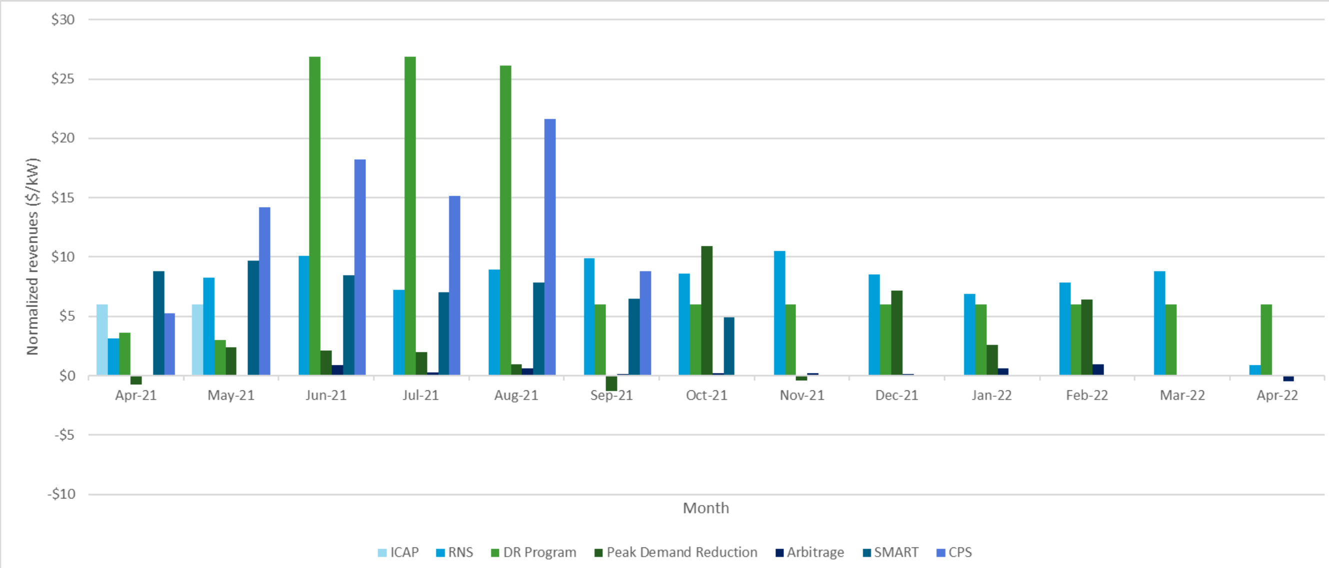
Figure 3-1. Comparison of monthly revenues achieved



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 submitted operational reports covering the July 2020 system peak. However, revenue from deployment during the 2021 system peak are not yet realized.

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., and the 2021 ISO NE system peak occurred on June 29, from 5 p.m. to 6 p.m., but as explained above for the 2021 system peak, the ICAP revenues will not start accruing until June 2022 and are not included.

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 2021 dwarfed all other revenue strategies in terms of revenues per kW of system capacity. This is consistent with summer 2020 and 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. 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, 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 each month. 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 was $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 was $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[2]

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
6/29/2021	17:00	18:00	-25,159

[2] ISO NE website: https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/ann-sys-peak-day-hr-load

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 ten 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. Out of the ten Grantees included in the scope of this report, seven reported on ICAP benefits from the 2020 system peak. Table 3-6 shows a summary of the 2019 and 2020 ICAP parameters and metrics. As revenue from the 2021 system peak is earned beginning in June 2022, the scope of this report does not include benefits from the 2021 peak hour.

Table 3-6. ICAP revenue summary

Revenue Stream Criteria	2019	2020
Grantees reporting	6	7
System peak day and hour	July 30, hour ending 18	July 27, hour ending 18
ISO-NE capacity rate	$5.30 per kW per month[1]	$4.63 per kW per month[1]
Estimated ICR ratio	1.5	1.5
Total estimated revenues	$999,814	$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 seven 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 in Table 3-6.

Figure 3-3. Estimated annual ICAP revenues by Grantee

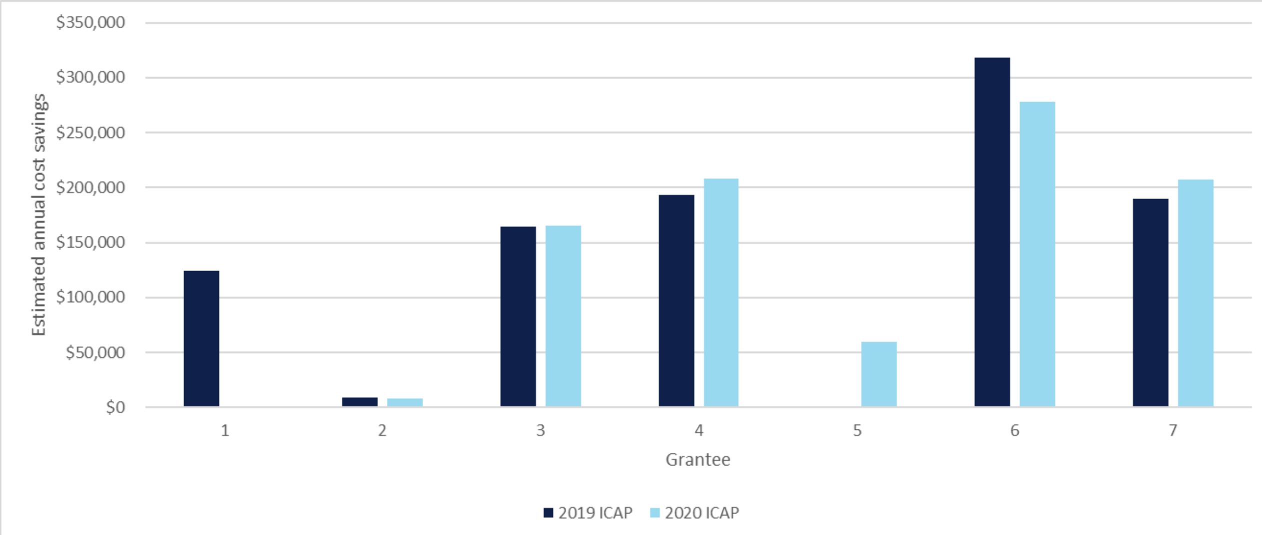
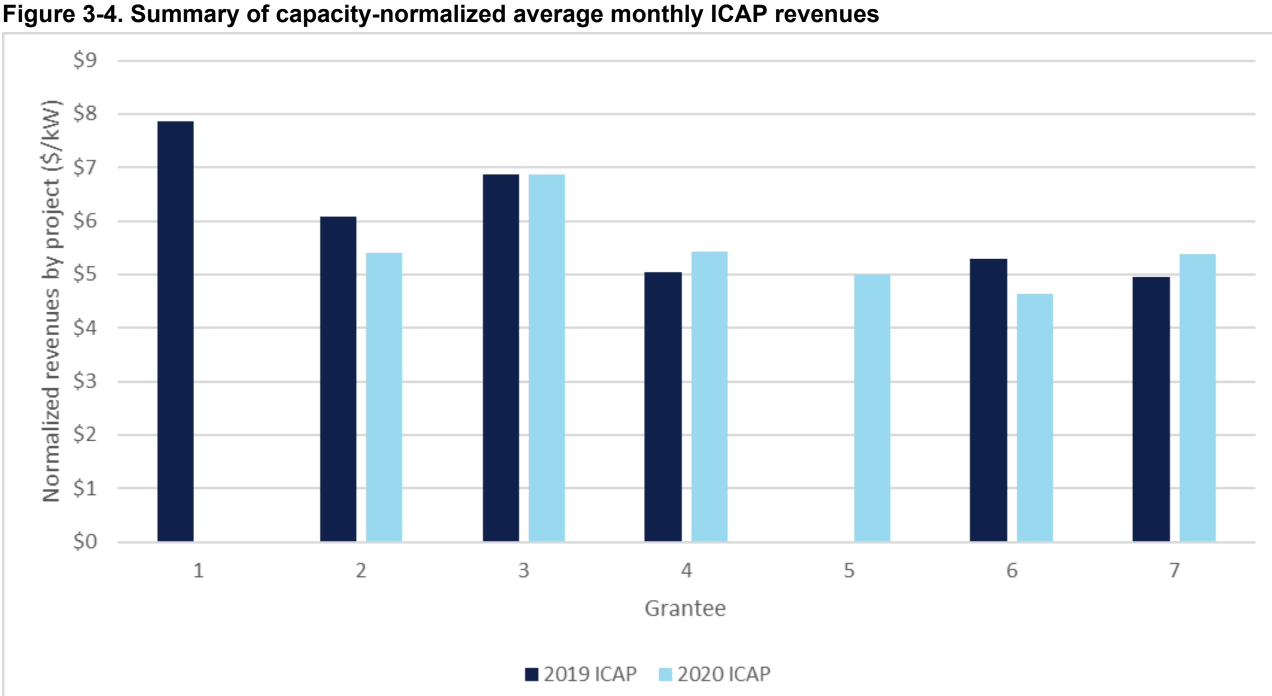


Figure 3-3 shows that Grantee 1 missed the 2020 system peak as mentioned above, and thus had no cost savings. Grantee 5 was not reporting at the time of the 2019 ICAP peak hour.

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. 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.

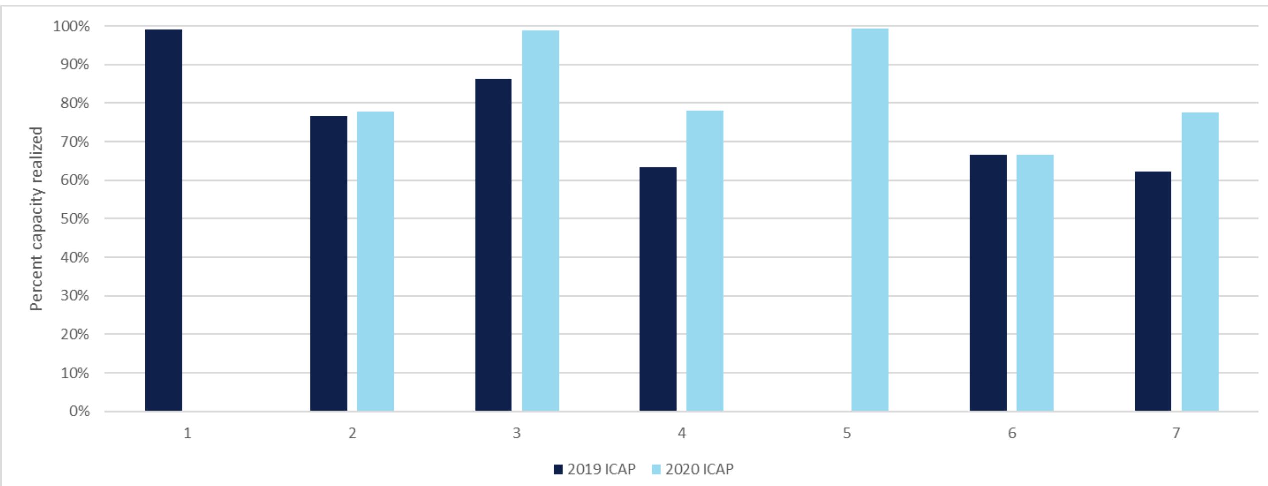
Figure 3-4. Summary of capacity-normalized average monthly ICAP revenues



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.

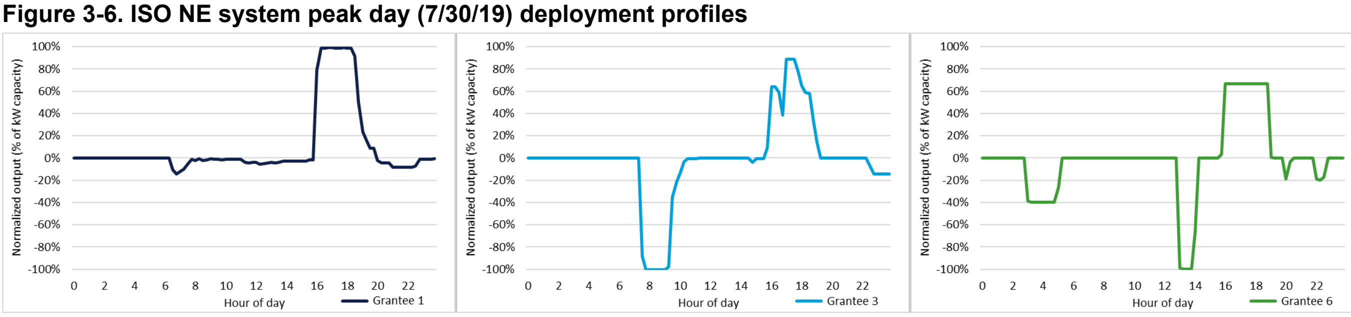
Figure 3-5 illustrates this dynamic by visualizing the percent capacity realized by the Grantees during the 2019 and 2020 peak hours. The maximum achievable revenue per kW is determined by multiplying the capacity rate ($5.30 for 2019 or $4.63 for 2020) with the ICR ratio (1.5); this results in an upper 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

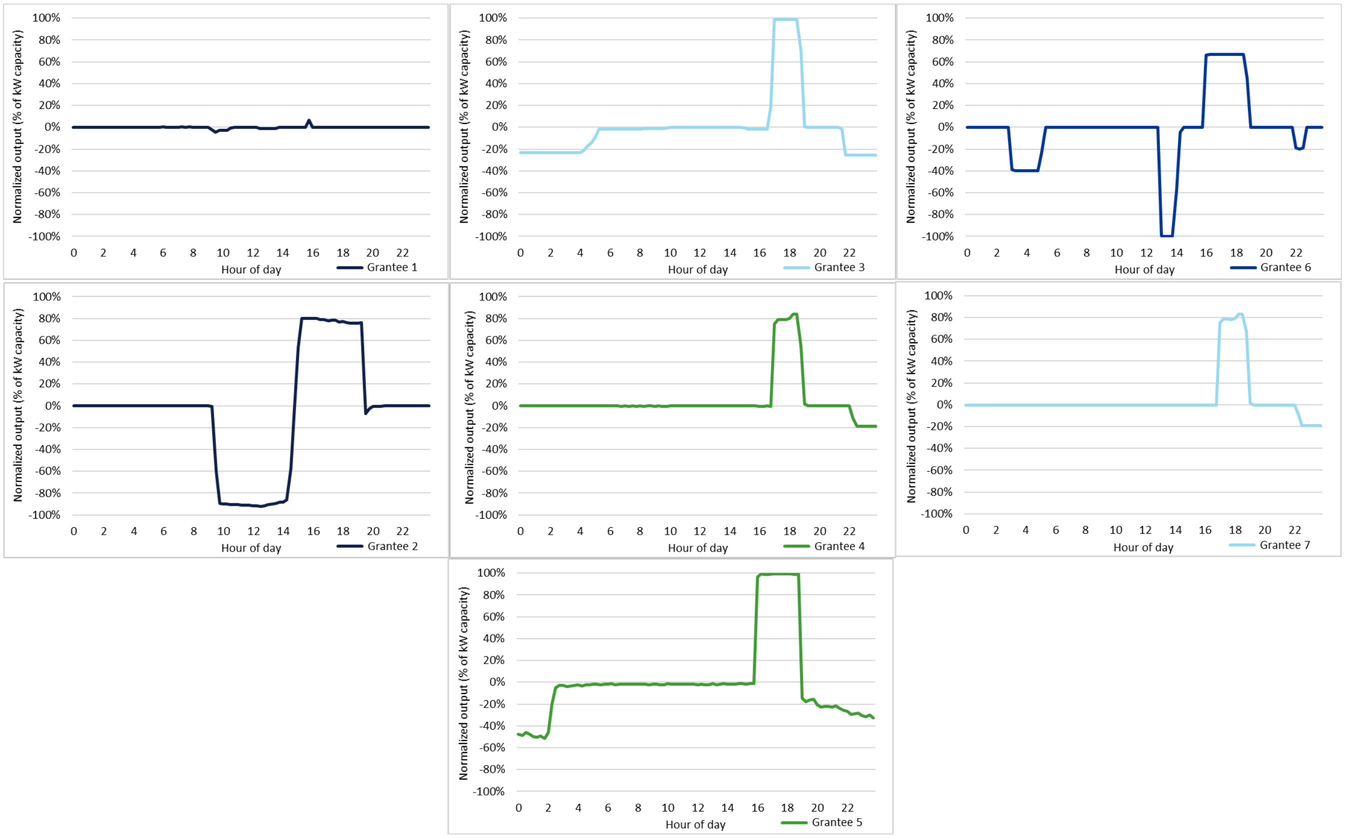


Figure 3-6 and Figure 3-7 depict ESS activity for the Grantees on the ISO-NE System peak days for 2019 and 2020 – July 30, 2019, and July 27, 2020, respectively. ESS discharge is indicated by positive values, whereas charging is represented by negative values. DNV notes that the charging profiles of 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, six out of the ten 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.

In 2021, six out of the ten Grantees discharged during the ISO-NE peak hour on June 29 from 5 p.m. to 6.p.m. (with one additional Grantee yet to provide data for this date). Grantees will realize revenue from the 2021 peak hour beginning in June 2022.

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 and 2021 ICAP hours 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). However, 2020 and 2021 system peak loads increased from the 2019 low.

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, $10.77 per kW for the 2020/2021 fiscal year, and increased to $11.75 for the 2021/2022 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, nearly $0.15 for 2020/2021, and increased to nearly $0.16 for 2021/2022.

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 ten deployments per month.

3.3.1 Grantee RNS revenue summary

At the time of this report, seven Grantees are reporting RNS revenues across 37 months. Table 3-7 shows the summary of total RNS benefits achieved over this reporting period.

Table 3-7. RNS revenues summary

Revenue Stream Criteria	Value
Analysis period	April 2019 to April 2022
Typical RNS hour	5–6 p.m. or 6–7 p.m.
RNS Schedule 9 and 1 charges – 2018/2019	$9.20 per kW
RNS Schedule 9 and 1 charges – 2019/2020	$9.33 per kW
RNS Schedule 9 and 1 charges – 2020/2021	$10.77 per kW
RNS Schedule 9 and 1 charges – 2021/2022	$11.75 per kW
TOTAL RNS REVENUES ACHIEVED	$3,534,413

The Grantees included in this report hit 86% of the monthly RNS peaks and realized 70% 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 for the prior 12 months are shown in Figure 3-8.

Figure 3-8. Monthly RNS revenues by Grantee (May 2021 – April 2022)

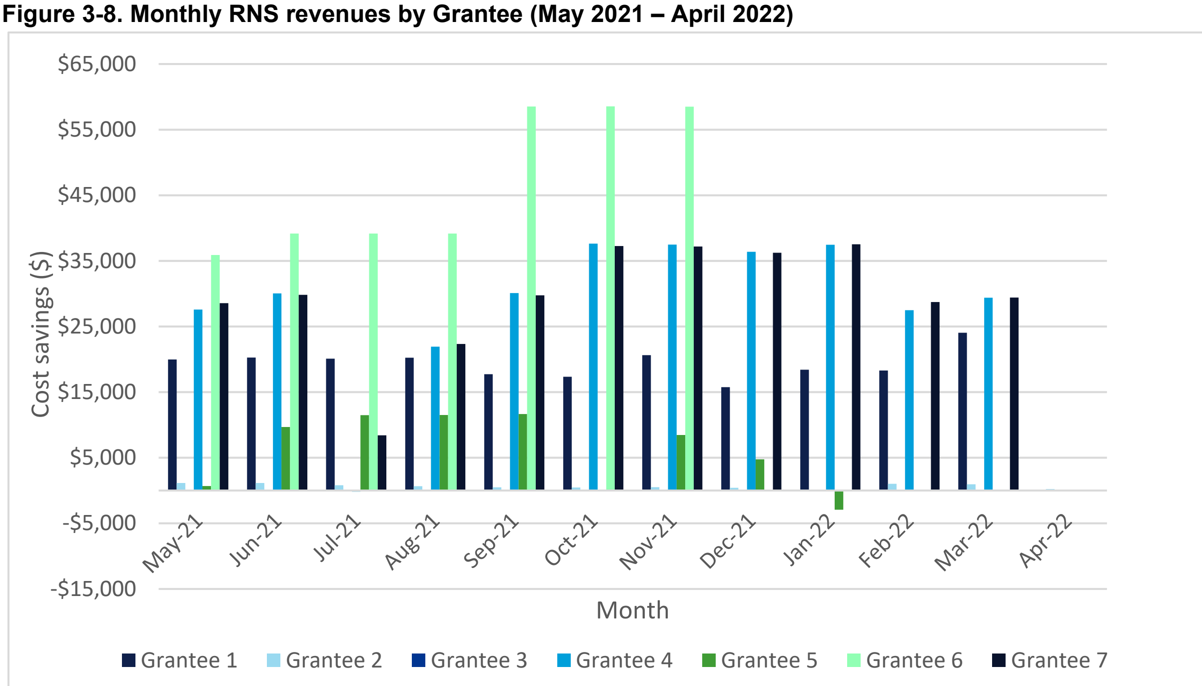


Table 3-8 shows the monthly RNS revenues by Grantee in table form.

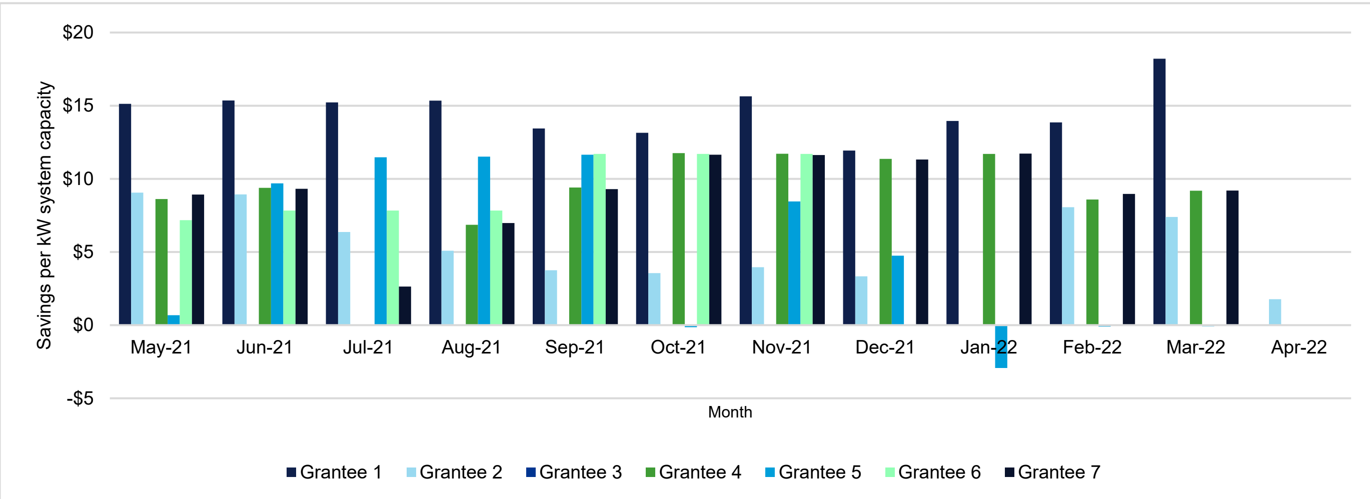
Table 3-8. Monthly RNS revenues by Grantee

Month	Grantee 1	Grantee 2	Grantee 3	Grantee 4	Grantee 5	Grantee 6	Grantee 7	Totals
Apr-19	N/A	N/A	$18,154	N/A	N/A	N/A	N/A	$18,154
May-19	N/A	N/A	$11,182	N/A	N/A	N/A	N/A	$11,182
Jun-19	N/A	N/A	$0	N/A	N/A	$25,387	N/A	$25,387
Jul-19	N/A	N/A	$16,112	N/A	N/A	$31,097	N/A	$47,209
Aug-19	N/A	N/A	$1,237	N/A	N/A	-$100	N/A	$1,137
Sep-19	N/A	N/A	$284	N/A	N/A	$30,984	N/A	$31,268
Oct-19	$14,530	N/A	$11,433	$17	N/A	$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	$20,225	$34,643	$7,057	$46,480	$16,989	$138,038
Dec-20	$15,212	$1,059	$20,853	$34,130	$7,058	$0	$33,936	$112,247
Jan-21	$13	$1,070	$20,926	$34,624	$7,059	$53,620	$33,940	$151,251
Feb-21	$0	$1,068	$21,314	$34,444	$7,060	$53,760	$33,980	$151,626
Mar-21	$15,183	$1,153	$0	$34,632	$7,061	$53,386	$34,308	$145,723
Apr-21	$14,489	-$1,167	$9,528	$13,536	$0	$35,526	$13,351	$85,262
May-21	$19,973	$1,159	N.D.	$27,593	$684	$35,897	$28,556	$113,862
Jun-21	$20,267	$1,144	N.D.	$30,047	$9,692	$39,163	$29,822	$130,135
Jul-21	$20,099	$815	N.D.	-$160	$11,479	$39,163	$8,426	$79,823
Aug-21	$20,253	$651	N.D.	$21,932	$11,515	$39,163	$22,345	$115,859
Sep-21	$17,737	$480	N.D.	$30,095	$11,653	$58,519	$29,751	$148,235
Oct-21	$17,349	$455	N.D.	$37,628	-$141	$58,540	$37,260	$151,091
Nov-21	$20,638	$507	N.D.	$37,491	$8,454	$58,513	$37,196	$162,799
Dec-21	$15,744	$427	N.D.	$36,376	$4,753	N.D.	$36,238	$93,538
Jan-22	$18,420	$0	N.D.	$37,459	-$2,933	N.D.	$37,536	$90,483
Feb-22	$18,290	$1,032	N.D.	$27,485	-$95	N.D.	$28,719	$75,432
Mar-22	$24,036	$946	N.D.	$29,391	-$78	N.D.	$29,419	$83,715
Apr-22	N.D.	$227	N.D.	N.D.	$0	N.D.	N.D.	$227

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 revenues 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 several Grantees missed at least one regional peak during the last 12-month period. Additionally, at times Grantees miss the forecasted peak and were charging their systems during the peak hour, resulting in negative values for this revenue stream.

Figure 3-9. Summary of capacity-normalized monthly RNS revenues by Grantee (May 2021 – April 2022)



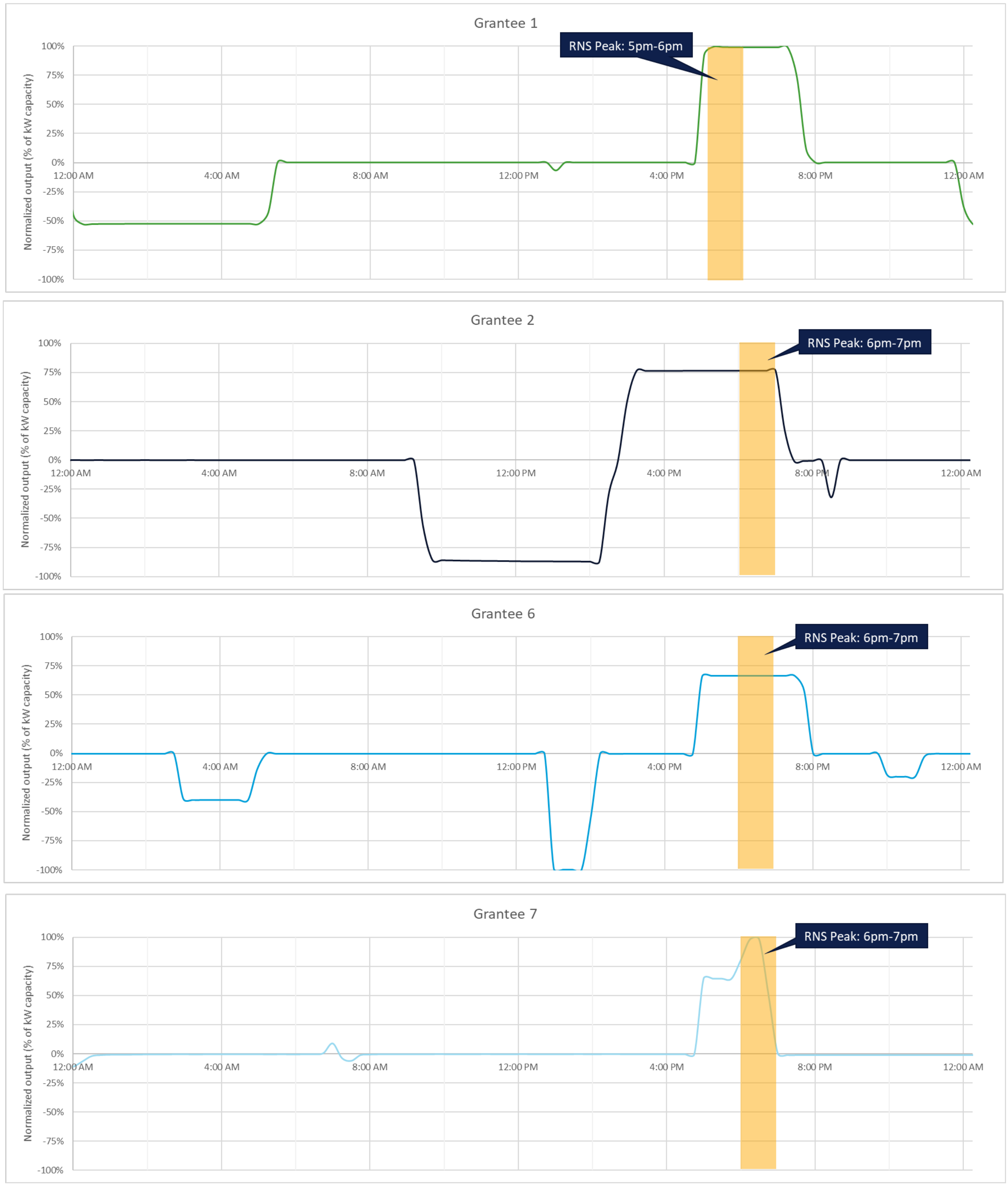
As shown in the figures and table above, Grantee 5 missed RNS peaks in January, February, and March 2022. The Grantee noted that an error in programming caused the system's algorithm to prioritize peak reduction over RNS revenue during this period. The error has since been resolved and the Grantee has instituted regular peak dispatch monitoring to avoid future occurrences of this issue. One other Grantee missed the January 2022 peak as the system was offline for planned maintenance.

For context in understanding monthly deployment trends, Figure 3-10 shows the deployment in percent capacity during May 2021 for four Grantees. ESS operational strategies and targeted revenue streams impact overall dispatch behavior. Grantees 6 and 7 have clearly identifiable RNS targeting, while Grantee 2 dispatches in the same fashion almost every day, and Grantee 1 dispatches more frequently during the month to pursue other revenue streams. Still, the independently predicted RNS hour dispatches across these four Grantees seem to align in the later part of May.

Figure 3-10. RNS deployment profiles for May 2021

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 May 26, 2021. All four of the Grantees hit the peak.

Figure 3-11. RNS deployment profiles for May 26, 2021



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 3-8 shows the date and hour ending of the peak load for each transmission network as reported to us by the Grantees.

Table 3-8. 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.	4/9/2019 8:00 PM	4/9/2019 8:00 PM
May 2019	N.D.	5/20/2019 7:00 PM	5/20/2019 6:00 PM
June 2019	N.D.	6/28/2019 6:00 PM	6/28/2019 6:00 PM
July 2019	7/21/2019 6:00 PM	7/30/2019 6:00 PM[1]	7/30/2019 6:00 PM[1]
August 2019	8/19/2019 4:00 PM	8/19/2019 4:00 PM	8/19/2019 4:00 PM
September 2019	9/11/2019 6:00 PM	9/23/2019 6:00 PM	9/23/2019 5:00 PM
October 2019	10/2/2019 3:00 PM	10/2/2019 3:00 PM	10/2/2019 1:00 PM
November 2019	11/13/2019 6:00 PM	11/13/2019 6:00 PM	11/13/2019 6:00 PM
December 2019	12/19/2019 7:00 PM	12/19/2019 6:00 PM	12/19/2019 6:00 PM
January 2020	1/20/2020 6:00 PM	1/20/2020 6:00 PM	1/21/2020 6:00 PM
February 2020	2/14/2020 7:00 PM	2/14/2020 7:00 PM	2/14/2020 7:00 PM
March 2020	3/23/2020 6:00 PM	3/1/2020 7:00 PM	3/1/2020 7:00 PM
April 2020	4/27/2020 6:00 PM	4/27/2020 6:00 PM	4/27/2020 6:00 PM
May 2020	5/29/2020 6:00 PM	5/29/2020 6:00 PM	5/29/2020 6:00 PM
June 2020	6/22/2020 6:00 PM	6/23/2020 6:00 PM	6/23/2020 6:00 PM
July 2020	7/21/2020 6:00 PM[2]	7/27/2020 6:00 PM[2]	7/28/2020 5:00 PM
August 2020	8/12/2020 6:00 PM	8/11/2020 6:00 PM	8/11/2020 6:00 PM
September 2020	9/8/2020 6:00 PM	9/10/2020 6:00 PM	9/10/2020 4:00 PM
October 2020	10/26/2020 6:00 PM	10/30/2020 7:00 PM	10/30/2020 1:00 PM
November 2020	11/18/2020 5:00 PM	11/18/2020 6:00 PM	11/18/2020 6:00 PM
December 2020	12/16/2020 5:00 PM	12/17/2020 6:00 PM	12/17/2020 6:00 PM
January 2021	1/29/2021 6:00 PM	1/29/2021 6:00 PM	1/29/2021 6:00 PM
February 2021	2/1/2021 5:00 PM	2/1/2021 6:00 PM	2/1/2021 6:00 PM
March 2021	3/2/2021 6:00 PM	3/2/2021 7:00 PM	3/2/2021 7:00 PM
April 2021	4/2/2021 8:00 PM	4/16/2021 12:00 PM	4/16/2021 6:00 PM
May 2021	5/26/2021 6:00 PM	5/26/2021 7:00 PM	5/26/2021 7:00 PM
June 2021	6/29/2021 6:00 PM	6/29/2021 6:00 PM	6/30/2021 6:00 PM
July 2021	7/16/2021 5:00 PM	7/16/2021 6:00 PM	7/16/2021 6:00 PM
August 2021	8/12/2021 6:00 PM	8/12/2021 6:00 PM	8/26/2021 6:00 PM
September 2021	9/15/2021 6:00 PM	9/15/2021 6:00 PM	9/15/2021 6:00 PM
October 2021	10/14/2021 6:00 PM	10/14/2021 7:00 PM	10/13/2021 7:00 PM
November 2021	11/30/2021 5:00 PM	11/23/2021 6:00 PM	11/29/2021 6:00 PM
December 2021	12/20/2021 5:00 PM	12/8/2021 6:00 PM	12/20/2021 6:00 PM
January 2022	1/11/2022 5:00 PM	1/11/2022 6:00 PM	1/11/2022 6:00 PM
February 2022	2/14/2022 6:00 PM	2/14/2022 7:00 PM	2/14/2022 7:00 PM
March 2022	3/9/2022 6:00 PM	3/9/2022 7:00 PM	3/1/2022 6:00 PM
April 2022	N.D.	4/7/2022 8:00 PM	4/6/2022 12:00 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 risk of missing regional peaks due to regional variability and a lack of available regional load data. RNS peak forecasting is performed by all Grantees either in-hour or through third parties targeting RNS revenue.
- 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.

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 or Forward Capacity Market). 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, four have reported on DR program revenues. Table 3-9 shows the summary of DR program achieved revenues for this period.

Table 3-9. DR Grantee revenue summary

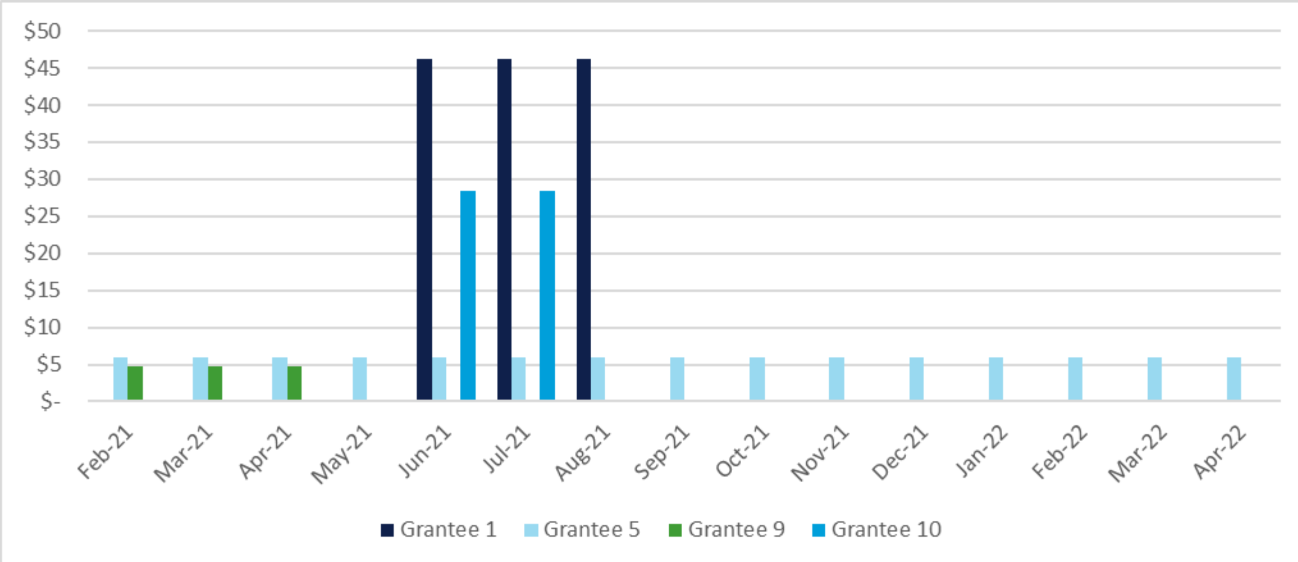
Revenue Stream Criteria	Value
Analysis period	October 2019 to April 2022
Number of Grantees reporting revenue	4
Total revenue	$671,259

The four 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 Demand Response programs**:
  - One Grantee achieved revenues through the ***ISO NE Price Responsive Demand program***. This Grantee achieved revenues 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.
  - One Grantee achieves revenue through the ***ISO NE Forward Capacity Market***. The Grantee performed during one audit during this reporting period; no demand response events were called. Revenue for each season is calculated by multiplying the average delivered kW across all events by the FCA clearing price and the number of months of active participation. As demand response events are called, the Grantee's average per-event performance will be updated, impacting the recurring monthly capacity payments earned by the Grantee.

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

Figure 3-12. Monthly capacity-normalized 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 2021 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, RNS, and CPES savings.

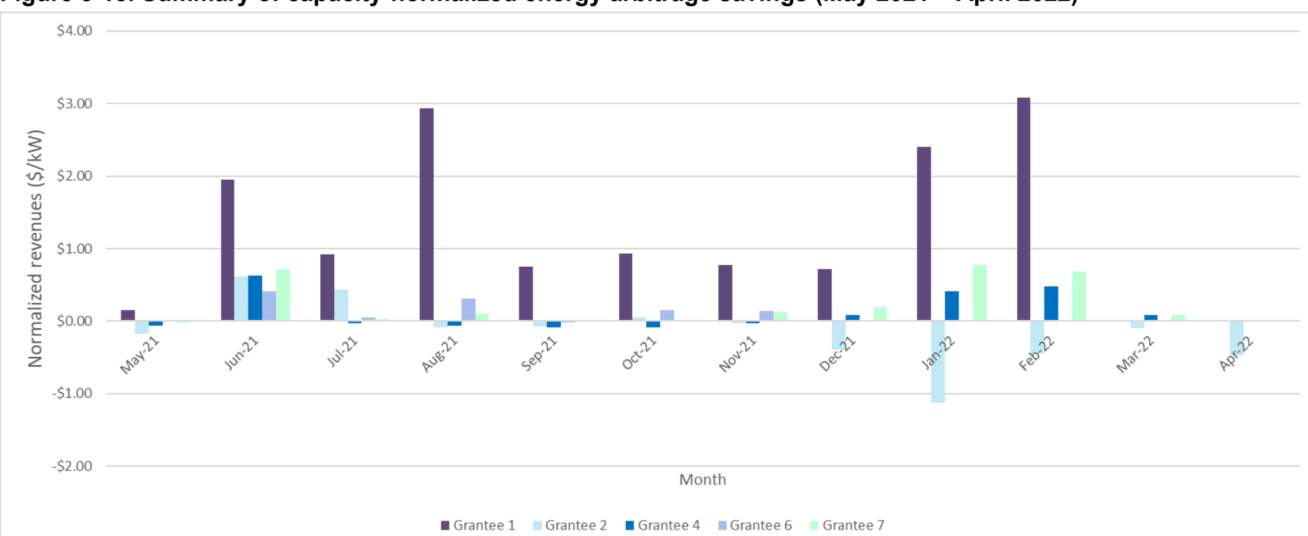
DNV used the granular ESS discharge/charge data, hourly real-time LMP for the specific reliability region accessed from ISO-NE's API, and site-specific adjustment factors to evaluate the energy arbitrage benefits accrued for participating Grantees. Table 3-10 shows the total arbitrage benefits accrued by the five Grantees reporting these benefits for this period.

Table 3-10. Energy arbitrage ACES revenue

Revenue Stream Criteria	Value
Analysis period	June 2019–April 2022
Number of Grantees reporting revenue	5
Total revenue	$60,529

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

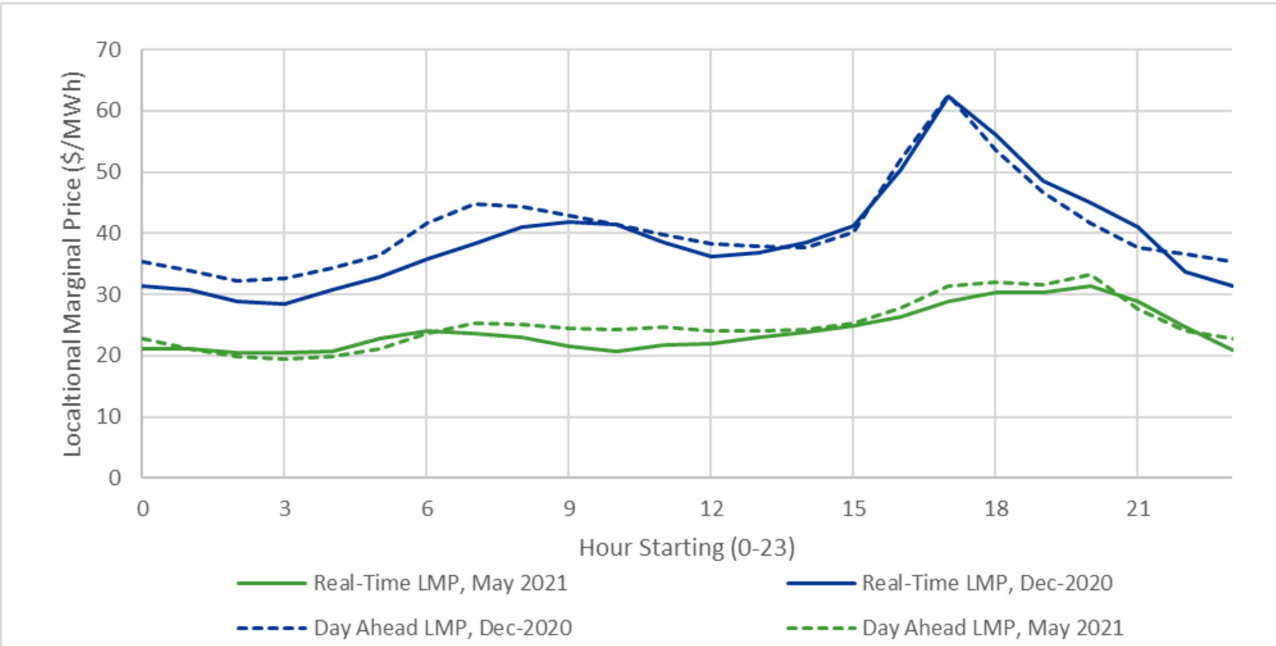
Figure 3-13. Summary of capacity-normalized energy arbitrage savings (May 2021 – April 2022)



3.5.2 Additional energy arbitrage insights

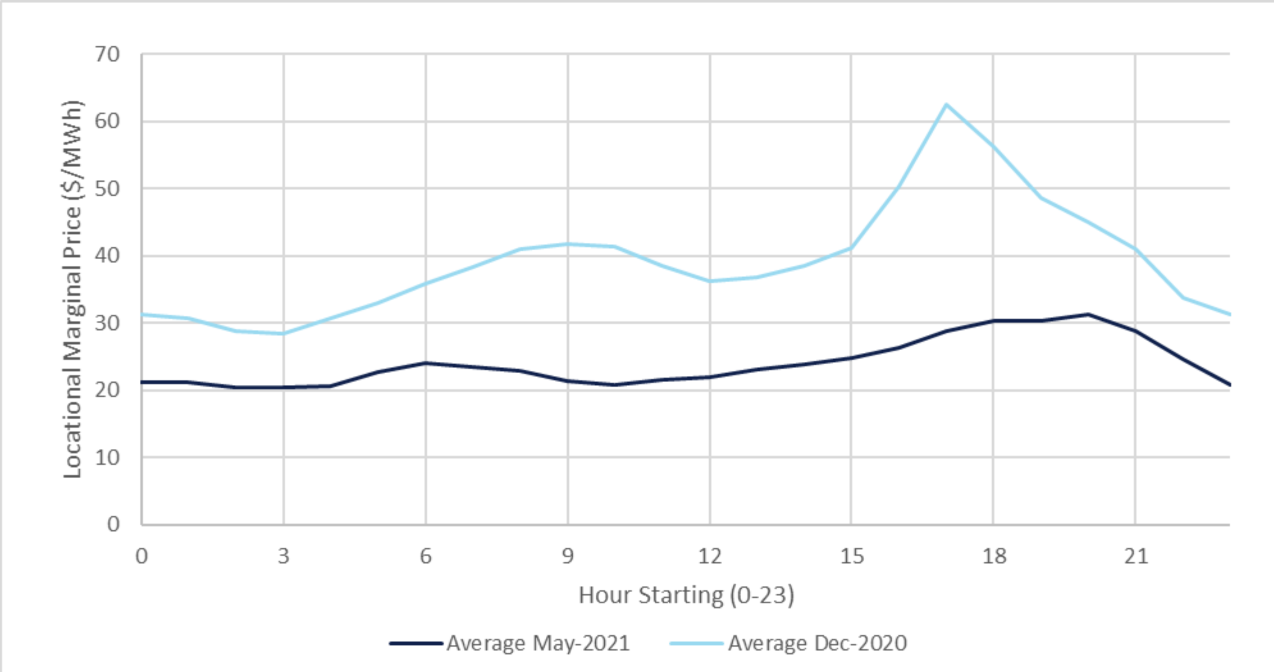
DNV identified differences between the arbitrage revenues reported by Grantees and the revenues calculated from the reported data. This is primarily due to differences in modeling approaches. DNV used real-time LMP values to assess revenues, while some Grantees used day-ahead LMP values or based their 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 2020 is higher and varies greatly throughout the day, making it more conducive for energy arbitrage. Conversely, May 2021 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[3] – 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 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.

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

To date, three of the ten 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 Grantees pursuing peak demand management have prioritized their other revenue strategies (primarily ICAP, RNS, and DR) and earn notably higher revenue per kW for those revenue streams. For comparison, the latest reporting period for the three Grantees targeting peak demand management showed an average normalized revenue of $5.53/kW for peak demand versus $35.67 for demand response.

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.

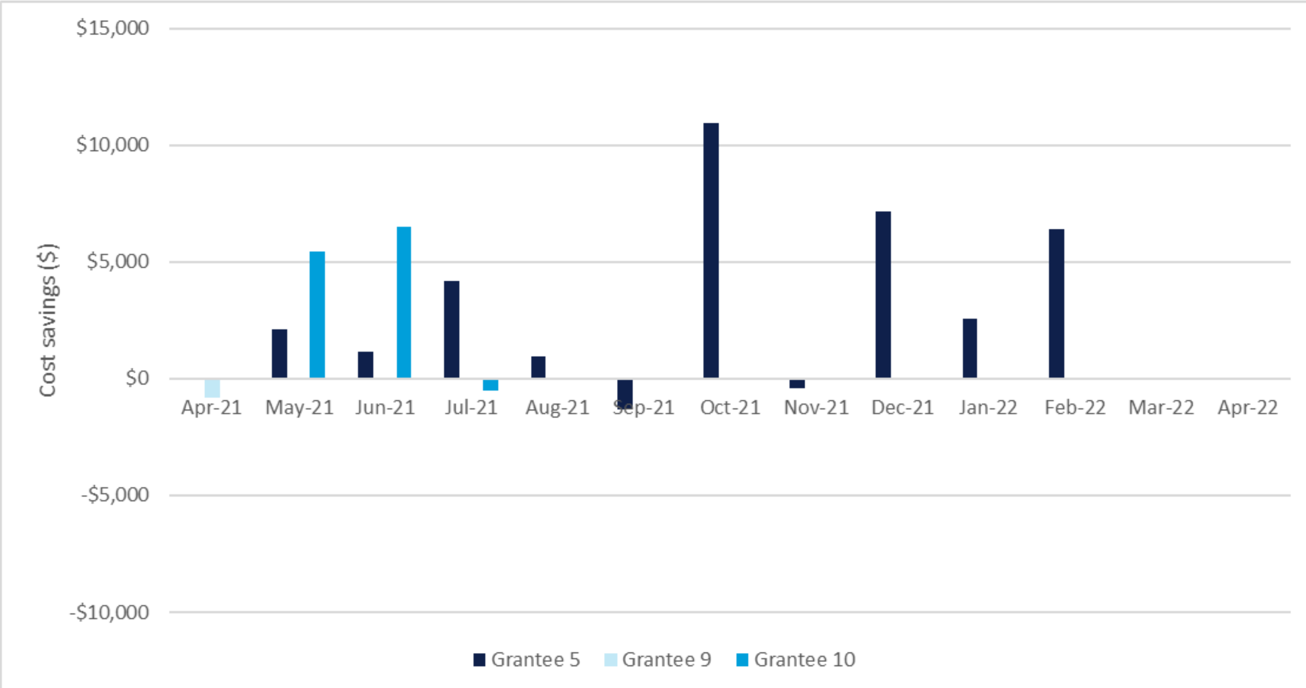
Table 3-11 shows the total peak demand reduction benefits accrued by the three Grantees reporting these benefits for this period.

Table 3-11. Peak demand reduction ACES revenue

Revenue Stream Criteria	Value
Analysis period	November 2019–April 2022
Number of Grantees reporting revenue	3
Total revenue	$65,030

Figure 3-16 shows the monthly revenues realized by the three Grantees who receive 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

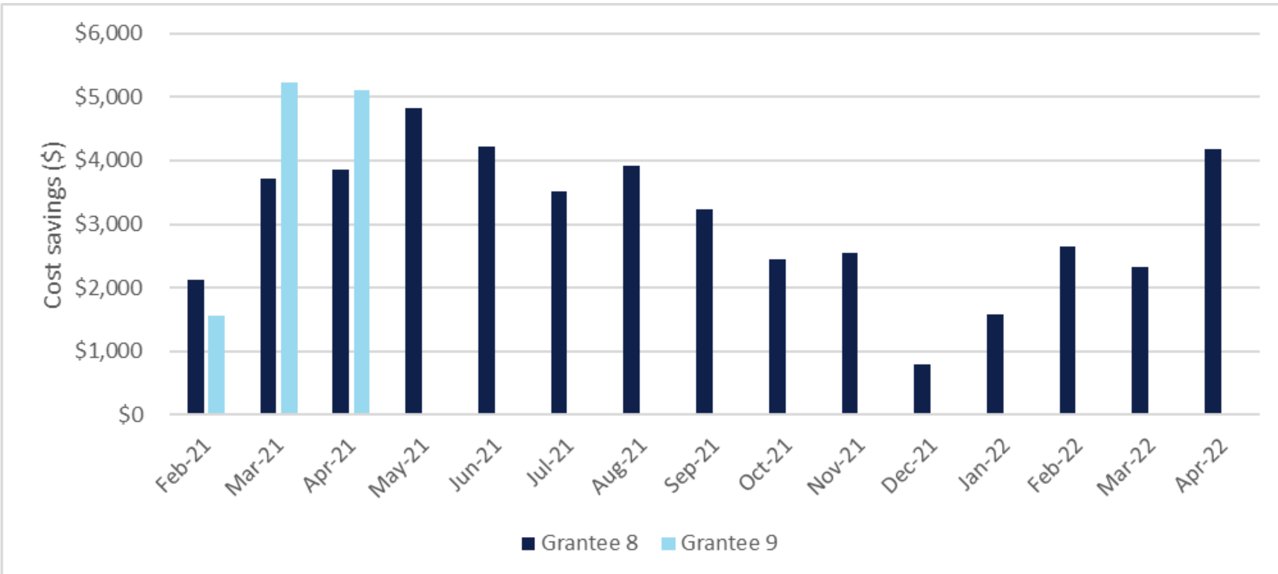
Of the ten Grantees included in this report, two Grantees currently report revenues from the SMART program as a result of the energy storage adder. Both are battery projects co-located with solar installations (one ground-mounted and the other rooftop). One battery provides solar PV smoothing for the local grid, and both batteries achieve 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 3-12 shows the summary of achieved SMART storage adder revenues.

Table 3-12. SMART ACES Revenue

Revenue Stream Criteria	Value
Analysis period	November 2019–April 2022
SMART storage adder rate	$2.38 per kWh
Number of Grantees reporting revenue	2
Total SMART storage adder revenue	$96,850

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 Grantees who pursued this end use.

Figure 3-17. Monthly SMART revenues



Note the seasonal periodicity of SMART revenue; decreased solar production typically results in lower revenues in winter months, as seen here for winter 2021 and consistent with earlier reporting years.

3.8 Clean Peak Energy Standard

The Clean Peak Energy Standard (CPES) was created by the Massachusetts Department of Energy Resources (DOER) to procure more clean energy during peak periods of demand. Started in August 2020, the CPES program provides incentives to clean energy technologies (renewables, energy storage systems charged with renewables, and other demand response systems) that can supply electricity or reduce demand during daily peak periods.

The DOER specifies a four-hour peak window for each season. Program participants can earn Clean Peak Energy Certificates (CPECs) by generating clean electricity of discharging their clean energy storage system during the peak window on any given business day. Seasonal multipliers are included for summer and winter demand periods (awarding four times more CPECs in these seasons), and a resilience multiplier is included for any participant whose system can provide electricity during an outage (awarding 1.5 times more CPECs to resilient systems). Program participants then generate revenue by selling CPECs to retail electricity suppliers who must meet a minimum CPEC purchase requirement. At program inception in 2020, the CPEC purchase requirement was set at 1.5% of the electricity provider's kWh sales, and the requirement will increase with each program year.[4]

3.8.1 Grantee Clean Peak Standard revenues

Of the eight Grantees included in this report, only one Grantee currently reports revenue from the CPES program. This Grantee enrolled as a Clean Peak Resource and began reporting CPEC revenue in January 2021 while also reporting revenue from retroactively minted CPECs backdating to January 1, 2020. As of the most recent reporting period, CPES

[4] For more information on the Clean Peak Energy Standard, see the Commonwealth of Massachusetts's webpage: https://www.mass.gov/clean-peak-energy-standard.

ranked the fourth highest of the Grantee's five active revenue streams in terms of total value generated (behind ICAP, RNS, and Demand Reduction streams).

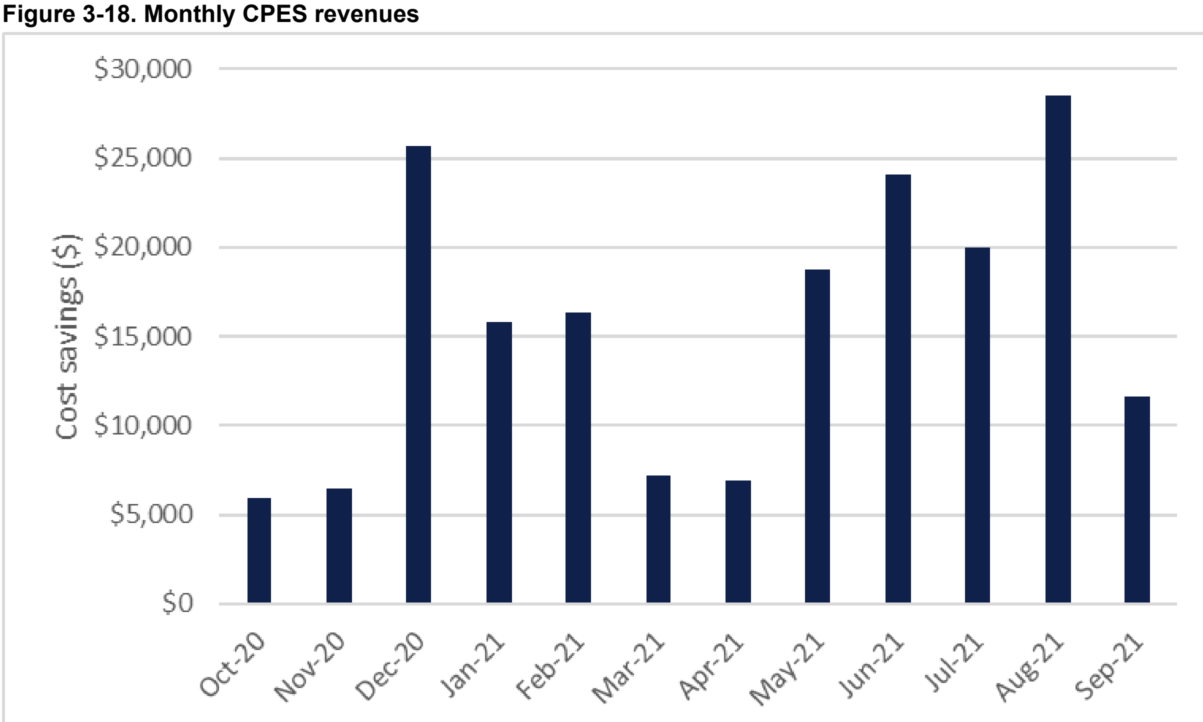
CPEC monthly revenue ranged from $252 to $28,524 with an average revenue of $12,835 across 21 months. Table 3-13 shows the summary of Clean Peak Standard earnings achieved to date. While the Grantee has completed reporting for October 2021 to April 2022, CPEC revenues for that period are still estimates. Those estimated values are not included here, but will be included in future reporting when the Grantee's CPECs are sold and actual revenue is reported.

Table 3-13. Clean Peak Energy Standard ACES revenue

Revenue Stream Criteria	Value
Analysis period	January 2020–September 2021
Number of Grantees reporting revenue	1
Total revenue	$269,536

In September 2020, the Grantee adjusted BESS operation to optimize CPEC earnings, discharging during specified program peak periods and charging overnight. Regardless of adjusting battery operations for the CPES program, ICAP, RNS, and demand response revenue continued to be equal to or greater than the revenue generated for those programs pre-CPEC optimization. Figure 3-18 shows the monthly CPES revenues achieved by the Grantee who pursued this end use.

Figure 3-18. Monthly CPES revenues



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. 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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