FINAL REPORT

ACES Seventh Aggregated Project Report

MassCEC

Date: July 12, 2023

Table of contents

1 REPORT OVERVIEW 1
1.1 Scope of seventh aggregated report 1
1.2 Report structure 1

2 MARKET DEVELOPMENT MEMO – GRANTEE LESSONS LEARNED 3
2.1 Grantee lessons learned 3

3 MONETIZABLE REVENUES AND OPERATIONAL STRATEGY TABLES 6
3.1 Summary of revenues and operational strategies 6
3.2 ICAP revenue 10
3.3 Regional network service (RNS) revenue summary 17
3.4 Demand response revenue 24
3.5 Energy arbitrage 26
3.6 Peak demand reduction 29
3.7 SMART Program revenue 31
3.8 Clean Peak Energy Standard 32

4 NON-MONETIZABLE BENEFITS 35
4.1 Grantee non-monetizable revenue performance 35

List of figures

Figure 3-1. Comparison of monthly revenues achieved 9
Figure 3-2. Monthly revenues normalized against system capacity (kW) 9
Figure 3-3. Estimated annual ICAP revenues by Grantee 12
Figure 3-4. Summary of capacity-normalized average monthly ICAP revenues 13
Figure 3-5. Percent capacity realized during 2019, 2020, and 2021 ISO-NE peak hours 14
Figure 3-6. ISO NE system peak day (7/30/19) deployment profiles 14
Figure 3-7. ISO NE system peak day (7/27/20) deployment profiles 15
Figure 3-8. ISO NE system peak day (6/29/21) deployment profiles 16
Figure 3-9. Monthly RNS revenues by Grantee (November 2021 – October 2022) 18
Figure 3-10. Summary of capacity-normalized monthly RNS revenues by Grantee (November 2021 – April 2022) 20
Figure 3-11. RNS deployment profiles for May 2021 21
Figure 3-12. RNS deployment profiles for May 26, 2021 22
Figure 3-13. Monthly capacity-normalized demand response program revenues 26
Figure 3-14. Summary of capacity-normalized energy arbitrage savings (November 2021 – October 2022) 27
Figure 3-15. Comparison of hub-level real-time and day-ahead LMP values 28
Figure 3-16. Average hourly hub-level real-time LMP value monthly variability 29
Figure 3-17. Monthly peak demand reduction revenues 31
Figure 3-18. Monthly SMART revenues 32
Figure 3-19. Monthly CPES revenues 34

List of tables

Table 3-1. Summary of Grantee use cases and data reported 6
Table 3-2. Summary of achieved revenues by use case 7
Table 3-3. System overview and simple payback estimate by use case 7
Table 3-4. Summary of Grantee achieved revenues 8
Table 3-5. Summary of the ISO NE system peak hour days and hours 11
Table 3-6. ICAP revenue summary 12
Table 3-7. RNS revenues summary 17
Table 3-8. Regional transmission network peak day and hour (ending) 23
Table 3-9. DR Grantee revenue summary 25
Table 3-10. Energy arbitrage ACES revenue 27
Table 3-11. Peak demand reduction ACES revenue 30
Table 3-12. SMART ACES Revenue 32
Table 3-13. Clean Peak Energy Standard ACES revenue 33

1 REPORT OVERVIEW

This report is DNV's seventh 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 seventh aggregated report

The scope of this seventh report covers all Grantees with approved data streams through October 31, 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 its 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 years). After the three-year reporting period, Grantees no longer report operational data. Thus, while cumulative assessments of revenues include all Grantee data to date, monthly revenue reporting includes only the actively reporting Grantees within each given time frame.

Since Grantees were approved at different times, the start date for reporting differs across Grantees, but each has provided data from its approved start date through October 2022.

There are 11 Grantees with approved operational reports spanning April 2019 through October 2022. To date, DNV has received and approved a total of 79 operational reports from these Grantees. A twelfth 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 a memo that summarizes 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 that aggregates lessons learned from the first several Grantees that have completed their required reporting period and submitted their final report.
- **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.

[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.

- **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-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 – GRANTEE LESSONS LEARNED

This section presents the market development memo for the seventh aggregated report. This memo highlights lessons learned from the Grantees that have completed their reporting period and submitted their final reports and Grantees that are still reporting. Five Grantees are still reporting and six have completed their reporting period. For the sites that have completed reporting, one use case is behind-the-meter solar plus storage and the other sites were Municipal Light Plants. ICAP and RNS were the most profitable revenue streams for each of the six Grantees. The memo reflects program achievements through October 2022; all Grantee data has been anonymized to protect privacy and confidentiality.

2.1 Grantee lessons learned

This memo summarizes the primary lessons learned by Grantees as they reach the conclusion of their participation in the ACES program. Their consolidated insights about project development, operations, and future insights are summarized below to inform future ESS development within and beyond the Commonwealth.

- **Planning and project development** are critical activities where issues that arise can lead to significant delays in bringing ESS online. Multiple Grantees emphasized that the time required for planning and permitting should not be underestimated. Below are several key lessons learned by Grantees during the planning process.
  - **Stakeholder engagement is critical.** Engaging with entities like conservation commissions, planning boards, fire departments, building inspectors, and any other authorities having jurisdiction (commonly called AHJs) helped raise awareness of energy storage in general and specific project details. Where successful, this engagement helped reduce the impact of future hurdles; however, in some cases, lack of insight by various AHJs resulted in significant delays for project approvals and permits.
  - **Allowing sufficient time for interconnection processes is essential.** To reduce the risk of interconnection delays or challenges, project developers need to collaborate with utilities and other grid stakeholders to ensure that behind-the-meter battery storage projects are appropriately studied to reflect the actual impacts and benefits the systems will have on the grid. Several Grantees said that interconnection study delays have large impacts on their project timing, and allocating additional time in the planning process for these engagements would have helped the early stages of project development proceed more smoothly.
  - **Grantees should consider non-ESS facility activities and their impacts on project timing.** Many Grantees had other non-ESS related activities planned that limited available resources for ESS development. Additionally, several Grantees encountered unanticipated impacts, such as siting restrictions and additional metering needs, that affected their ESS development schedule. For example, one Grantee noted that their facility needed to run new fiber optic cables to connect distant parts of its facility and that activity delayed the start of its reporting period significantly. Another Grantee cited additional facility metering and sub-metering needs driving delays, and a third highlighted limited resources available to support the ESS due to state regulatory reviews.
  - **Support additional education and training for local AHJs.** For most Grantees, ESS permitting occurs with their utility and local (municipal) building and permit authorities. Many of the initial ESS installations were for Grantees who were Municipal Light Plants (MLPs); these Grantees generally had an easier time getting interconnection and other approvals since they were conducted essentially in-house. Many local permitting and fire department officials do not have much experience with energy storage technology. Uniform federal/state standards on topics like wetlands buffer distance, training for emergencies, equipment tax treatment, and local zoning for ESSs could be helpful for local officials to improve their knowledge and enable them to more effectively permit these installations.
- **Monetizable revenues lessons learned.** Throughout their ACES engagement, Grantees have pursued a variety of different revenue (or cost savings) strategies. Lessons learned include:

- **Making the correct dispatch predictions is critical for achieving demand reduction revenues.** For a variety of reasons, many grantees found it challenging to hit monthly and annual peaks for demand reduction. Management of the monthly and annuals peaks is the revenue driver for the majority of Grantees, and failing to reduce load during the peak can have large implications on revenues. One Grantee mentioned that it used a regional utility's peak rather than the ISO-NE system forecast, which led to the battery discharging at a lower power level over a longer duration and reducing the magnitude of its savings. Some Grantees felt that they were unable to accurately guess when the peak hour would be. One Grantee found that daily weather monitoring and review of ISO-NE's load forecast were very helpful in hitting those peak hours.
- **Balancing dispatch across revenue streams is essential.** Several Grantees said that they maintain a prioritized list of revenue strategies that influences how and when they dispatch their ESS. Sometimes these strategies overlap; in some cases this can lead to stacked revenue, but in other cases, Grantees must choose one revenue opportunity in lieu of another. For example, if the monthly RNS peak hour overlaps with the annual ICAP, Grantees dispatching during that hour can realize benefits for both revenue streams. If that hour also aligns with a summer demand response event, additional stacking benefits could accrue. However, if the peak hour is separate from the demand response event, Grantees typically don't have the discharge duration to meet both and must choose which opportunity to pursue. Grantees identified that monitoring these streams--especially their trend—is important to evolve their decision-making criteria. For example, several Grantees identified that monthly RNS revenue opportunities were increasing while annual ICAP revenues were decreasing. While harder to hit consistently, more focus on the RNS revenues could help them achieve greater overall project returns.
- **Energy arbitrage resulted in lower-than-expected savings.** A combination of a small price differential between real-time hourly prices during charging and discharging hours and lower than expected round-trip efficiency often resulted in low savings. Because of this, several Grantees chose not to initiate charge or discharge events to specifically target energy arbitrage. Rather, learning from their operations, arbitrage revenues were seen as additional benefits (or penalties) resulting from pursuing higher priority revenue opportunities.
- **Frequency regulation did not offer sufficient revenue for Grantees to pursue it.** Many Grantees targeted frequency regulation as a monetizable revenue stream in their initial ACES program applications and pro formas, but after further consideration through project development, only one Grantee ultimately elected to pursue this revenue. Grantees cited data reporting challenges, potential negative impacts on battery life due to frequent cycling, and lack of revenue opportunity compared to other revenue streams as rationales for not pursuing this revenue.
- **ESS Incentive program requirements can result in suboptimal charge/discharge operations**. Program participation and dispatch requirements can interfere with ideal ESS operations. For example, one Grantee found the SMART Storage Adder's 52 cycle discharge per year requirement was difficult to achieve among other system needs. After trying multiple discharge strategies, the Grantee decided to discharge an entire cycle each day during the evening to lessen the strain on distribution feeder cables. This decision was made to satisfy the program but did not generate any additional revenue for the Grantee. In another year, this Grantee also ran into data submission issues that disqualified them from receiving program benefits for the year.

• **Data outages and supply chain impacts lessons learned**. Nearly all ACES projects encountered challenges throughout their 3-year reporting period that required operations to be taken offline for maintenance and/or repairs. In some cases, these outages were exacerbated by supply chain challenges affecting their ability to acquire equipment and/or personnel expertise necessary to resume operations. These challenges led to some ESS ceasing all operations for a period and/or operating at a reduced capacity until repairs could be made. Additional lessons learned include the following:

- **Data connections challenges and other system integration issues can influence charge/discharge operations.** Several Grantees reported some challenges in data connectivity that affected how they operate their systems. In a couple of examples, firewalls and other issues led to system operators manually setting their charge/discharge schedules rather than leveraging an external operator to manage the ESS, resulting in missed deployment cues. One Grantee noted that this issue led to its facility having a strong preference for discharging the battery the same way every day rather than optimizing for the current conditions. Going forward, Grantees could avoid some of these issues by better coordinating and confirming that connectivity between their facility and any external operators is functional.
- **Having staff readily available to resolve any issues is critical to achieving revenues.** Many of the revenue strategies pursued in the ACES program require predicting peaks and fully discharging ESS to maximize cost savings. To maximize this benefit, the system needs to be online and ready to be charged/discharged. Grantees reported that it's critical to have personnel able to troubleshoot any outages or other system impacts in a timely manner to reduce the risk of losing any revenue from missing peak windows, demand response events, or other dispatches for their respective revenue streams.
- **Outages coupled with a supply shortage made it difficult for some Grantees to get their projects back online in a timely manner.** While some delay is unavoidable, some actions can be taken to reduce the scale of the impact of the outage. One Grantee mentioned how forming partnerships with manufacturers was critical to addressing some of their equipment issues. The Grantee developed this relationship later in the project's life and wished it had been established sooner in order to diagnose their system issues much more quickly. Another Grantee noted that working with trade organizations to advocate for building domestic supply chains could reduce future supply chain delays. Some Grantees also noted that building redundancies into their system could also protect their operations from the impact of outages.

- **ACES program experience led to additional ESS development.** The lessons learned from the ACES program are leading several Grantees to pursue additional ESS projects at their facilities.
  - **Additional ESS development offers an opportunity for additional revenues and education.** One Grantee noted how ESSs are being embraced by its municipality to control costs and keep rates stable for their utility. This Grantee is currently in the planning stages of building another battery system at a school to serve as a demonstration and active classroom.
  - **More energy storage can help Grantees achieve their GHG reduction goals.** A Grantee noted that additional ESS development will be an essential part in achieving their net-zero target. They also mentioned that it is important to consider regional and state policies in GHG reduction goals because offshoring and importing energy will not reduce GHGs on a more global scale.
  - **Consider alternative ESS implementation strategies to reduce risk and scale ESS operations.** Some Grantees pursuing additional project development noted that they are looking to implement larger-scale ESS to achieve economic returns on their projects, primarily to achieve longer duration discharges and achieve additional revenues. In some cases, Grantees identified pursuing alternative ownership structures from their ACES project, seeking private equity partners or other developers to reduce their risk and some of the ESS ownership challenges.
  - **Standardizing planning, development, and operations processes can streamline future development.** As mentioned above, planning and project development often take longer than expected. A Grantee noted that standardizing processes could accelerate adoption.

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 summarizes the Grantee use cases, the ratio of ESS system nameplate power to peak load, and the 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%	36
Grantee 2	Municipal Light Plant (MLP Asset)	N.D.	36
Grantee 3	Municipal Light Plant (MLP Asset)	10.1%	24
Grantee 4	Municipal Light Plant (MLP Asset)	N.D.	36
Grantee 5	Municipal Light Plant (MLP Asset)	33.3%	36
Grantee 6	Municipal Light Plant (MLP Asset)	10.2%	36
Grantee 7	Municipal Light Plant (MLP Asset)	7.1%	36
Grantee 8	Merchant, solar plus storage	N/A	30
Grantee 9	Behind the meter – solar plus storage	6.9%.	18
Grantee 10	Merchant, solar plus storage	N.D.	18
Grantee 11	Municipal Light Plant (MLP Asset)	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)	7	$2,534,649	$3,755,529	$198,380	$19,102	$53,996	$0	$0
Behind the meter – solar plus storage	2	$231,758	$496,669	$646,705	($5,172)	$41,651	$76,715	$451,630
Merchant, solar plus storage	2	$0	$0	$443,691	$21,461	$0	$84,969	$0
Totals	**11**	**$2,766,407**	**$4,252,198**	**$1,288,775**	**$35,391**	**$95,646**	**$161,684**	**$451,630**

The 2022 ISO NE system peak hour has been confirmed as August 8, hour ending 4 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 summarizes 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.

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)	17,528	34,804	$2,552,034	$17,197,837	$12,105,274	7	5
Behind the meter – solar plus storage	1,840	6,088	$686,527	$4,259,182	$2,265,982	6	3
Merchant, solar plus storage	2,600	5,370	$344,089	$3,437,758	$1,805,564	10	5
Totals	**21,968**	**46,262**	**$3,582,650**	**$24,894,777**	**$16,176,820**	**7**	**5**

Table 3-4 summarizes 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

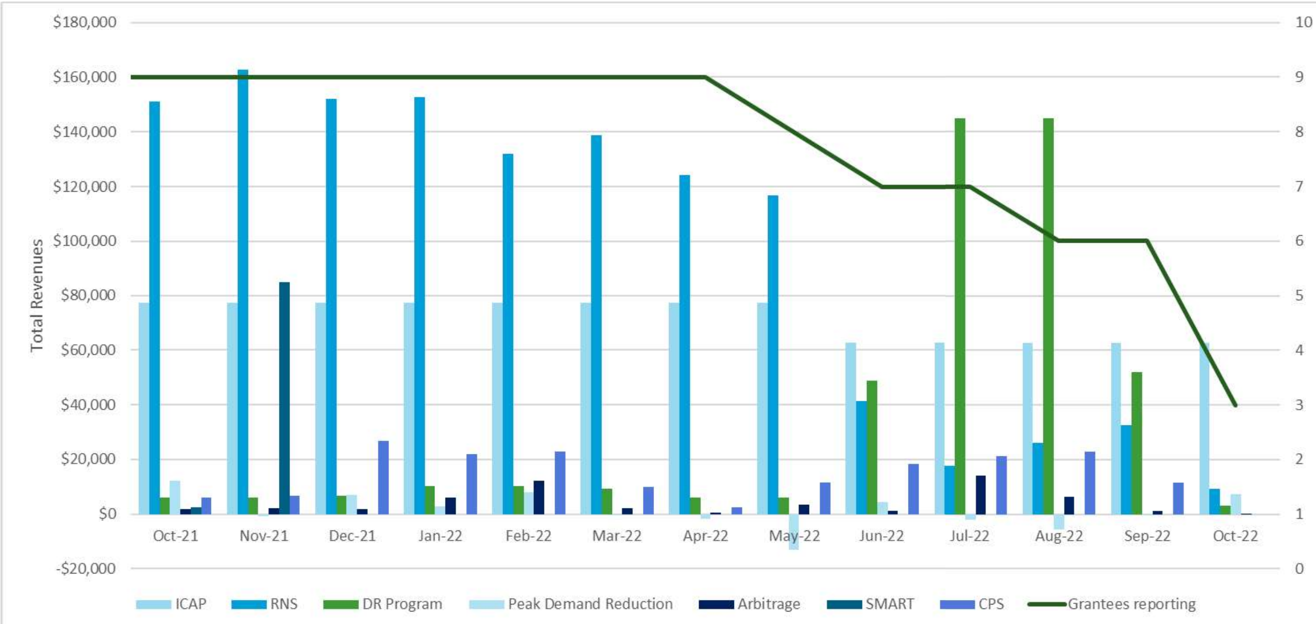
Revenue Strategy	Reporting Coverage	No. of Grantees Reporting	Predicted Revenues	Realized Revenue	Total ESS Capacity (kW)	Percent Capacity Realized	Avg. $/kW Revenue per Month
ICAP	2019, 2020, and 2021 system peak	7	$2,294,932	$2,766,407	21,468	150%	$4.88
RNS	Apr 2019 to Oct 2022	7	$3,498,308	$4,252,198	558,296	69%	$6.98
Demand response (DR)[1,2]	Jun 2019 to Oct 2022	4	$622,371	$1,288,775	84,340	66%	$8.24
Peak demand reduction	Nov 2019 to Oct 2022	3	$413,091	$35,391	36,000	3%	$0.96
Energy arbitrage	Jun 2019 to Oct 2022	5	$268,412	$95,646	N/A	N/A	$0.23
SMART storage adder	Nov 2019 to Jul 2022	2	$484,132	$161,684	N/A	N/A	$6.57
Clean Peak Energy Standard	Jan 2020 to Sep 2022	1	N/A	$451,630	1,320	N/A	$10.37
TOTALS	**APR 2019 TO OCT 2022**	**11**	**$7,581,246**	**$9,051,732**			

[1] Demand response averages calculated only during months with DR commitments and reported revenues.
[2] 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 eleven 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.

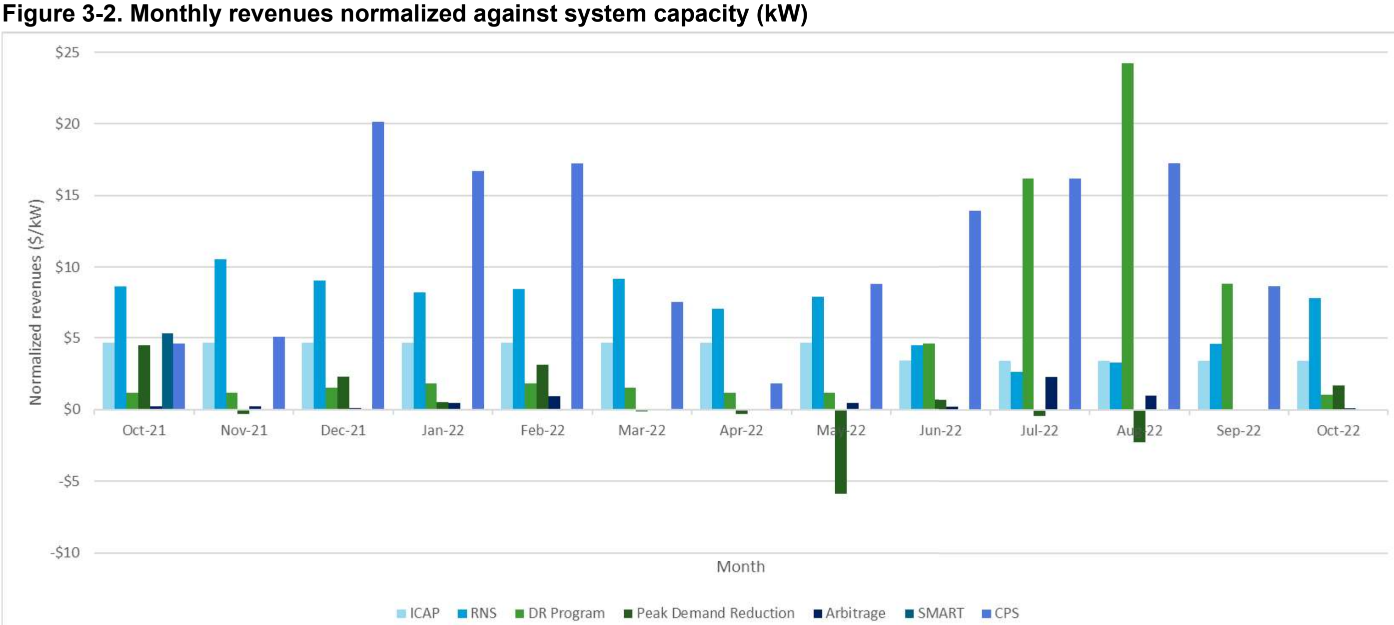
For a deeper understanding of the monthly revenues achieved, DNV has compiled the monthly revenues achieved across Grantees, grouped by revenue strategy, in Figure 3-1. As the total revenues are dependent on the number of Grantees reporting, this figure includes the number of Grantees reporting data 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 seven Grantees. ICAP revenues from deployment during each calendar year's system peak are realized for 12 months starting in June of the following year.

Figure 3-1. Comparison of monthly revenues achieved



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 4 p.m. to 5 p.m. The 2022 ISO NE peak occurred on August 8, 2022, from 3 p.m. to 4.pm., but as explained above, the 2022 ICAP revenues will not start accruing until June 2023 and are not included in this report.

Figure 3-2. Monthly revenues normalized against system capacity (kW)



Consistent with prior years, Figure 3-2 highlights that the DR and RNS program revenues for summer 2022 were much higher than all other revenue strategies in terms of revenues per kW of system capacity. The DR performance was driven by Grantees' 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. 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 one of the most common and important use cases 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	16:00	17:00	-25,159
8/8/2022	15:00	16:00	-24,396

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 eleven 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 eleven Grantees included in the scope of this report, seven reported on ICAP benefits from the 2020 system peak and eight reported benefits from the 2021 peak. Table 3-6 shows a summary of the 2019, 2020, and 2021 ICAP parameters and metrics.

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

Table 3-6. ICAP revenue summary

Revenue Stream Criteria	2019	2020	2021
Grantees reporting	6	7	8
System peak day and hour	July 30, hour ending 18	July 27, hour ending 18	June 29, hour ending 17
ISO-NE capacity rate	\$5.30 per kW per month[1]	\$4.63 per kW per month[1]	\$3.80 per kW per month[1]
Estimated ICR ratio	1.5	1.5	1.5
Total estimated revenues	\$1,050,142	\$926,473	\$789,793

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

All 6 Grantees targeting system peak reductions were able to reduce demand for the 2019 ISO-NE system peak hour. Out of the7 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. For the 2021 system peak, 7 out of 8 Grantees dispatched their ESS, but the remaining Grantee had a long-term system outage and was thus did not achieve any demand reductions during the peak hour. 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

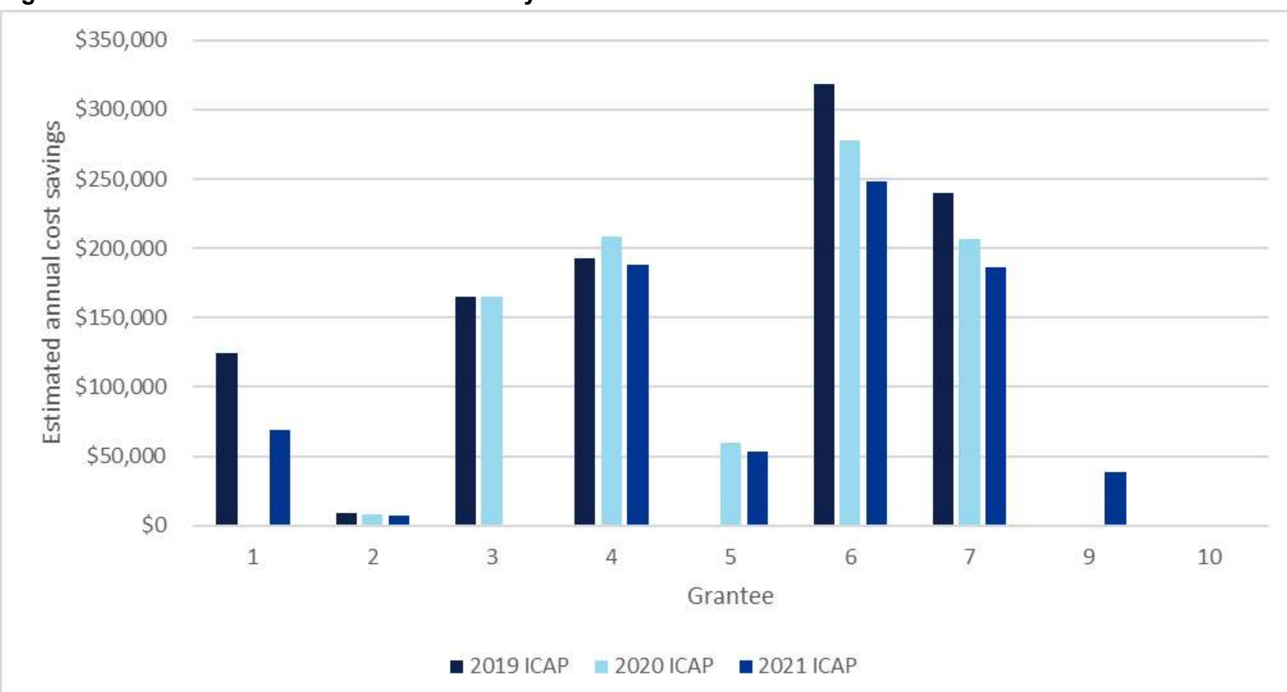
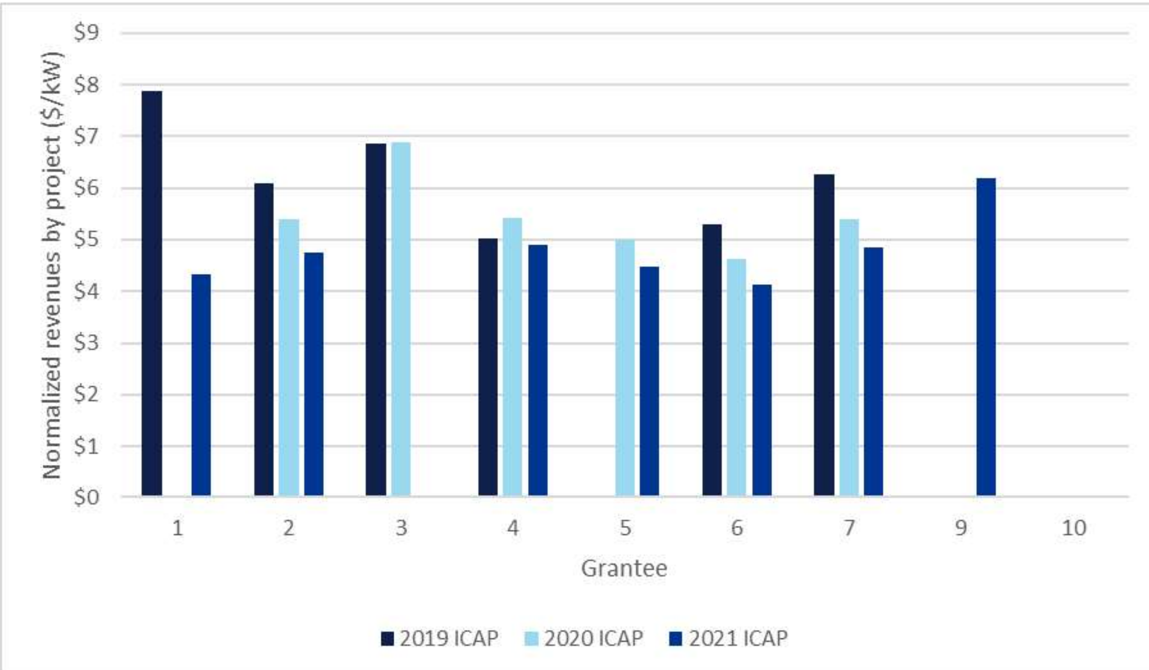


Figure 3-3 shows that Grantee 1 missed the 2020 system peak and Grantee 10 missed the 2021 system peak as mentioned above, and thus had no cost savings. Grantee 5 was not reporting at the time of the 2019 ICAP peak hour. Grantee 3 has completed reporting for the period during the 2021 system peak, but the data has not been verified. The estimated cost savings will be included for this Grantee in future reporting once the data has been verified.

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 an 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, 2020, 2021 peak hours. The maximum achievable revenue per kW is determined by multiplying the capacity rate ($5.30 for 2019, $4.63 for 2020, or $3.80 for 2021) with the ICR ratio (1.5); this results in an upper bound of $7.95 (2019), $6.95 (2020), or $5.70 (2021) 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, 2020, and 2021 ISO-NE peak hours

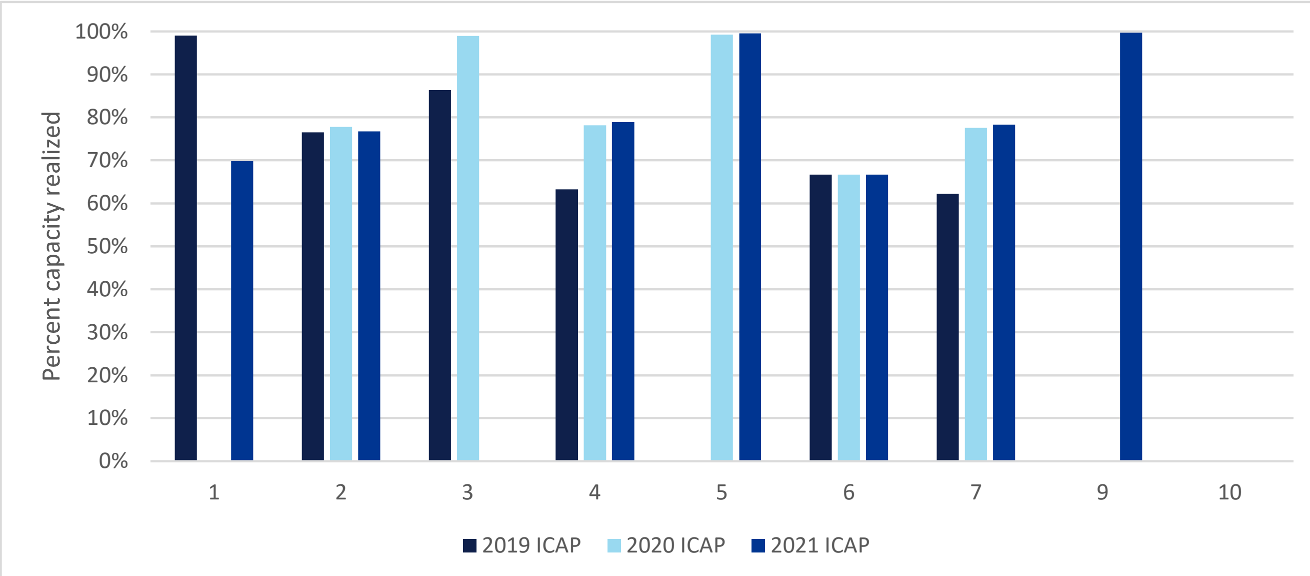


Figure 3-6, Figure 3-7, and Figure 3-8 depict ESS deployment activity for the Grantees on the ISO-NE System peak days for 2019, 2020, and 2021– July 30, 2019, July 27, 2020, and June 29, 2021, respectively. ESS discharge is indicated by positive values, whereas charging is represented by negative values. 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.

Figure 3-6. ISO NE system peak day (7/30/19) deployment profiles

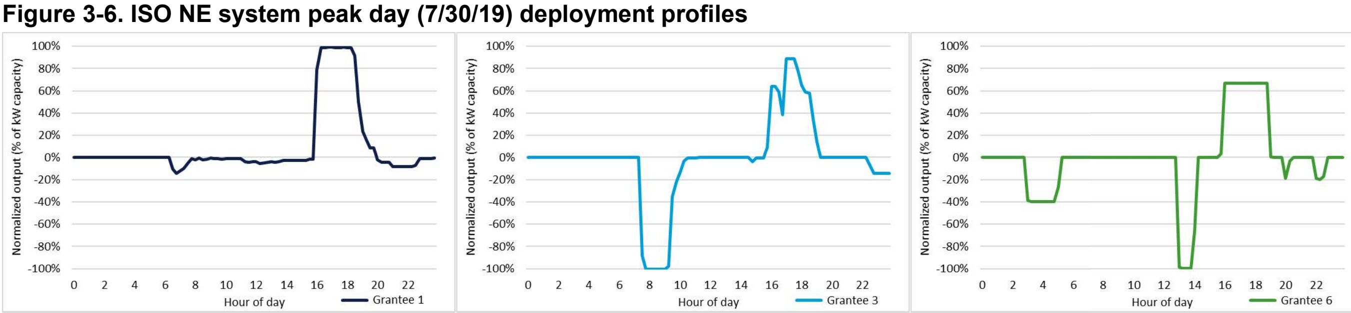


Figure 3-7. ISO NE system peak day (7/27/20) deployment profiles

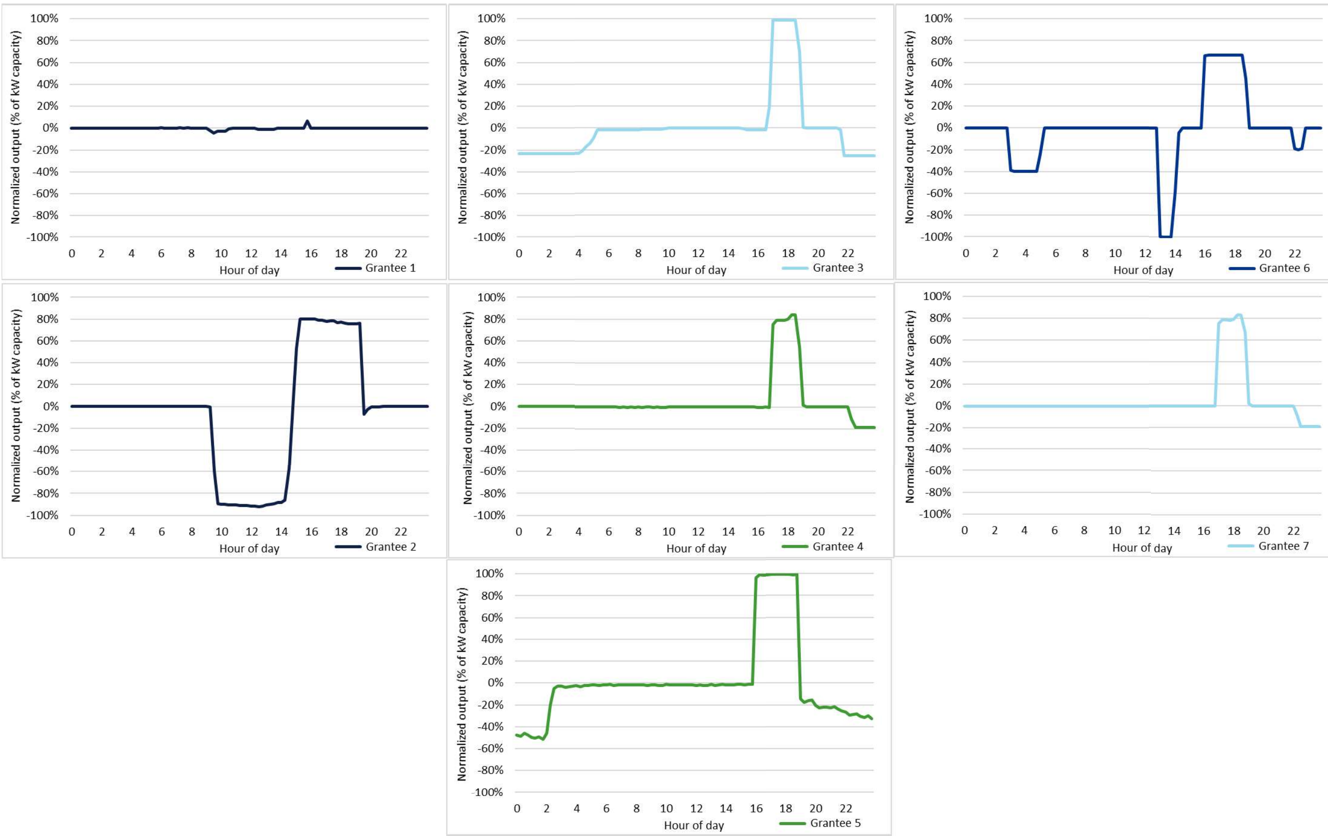
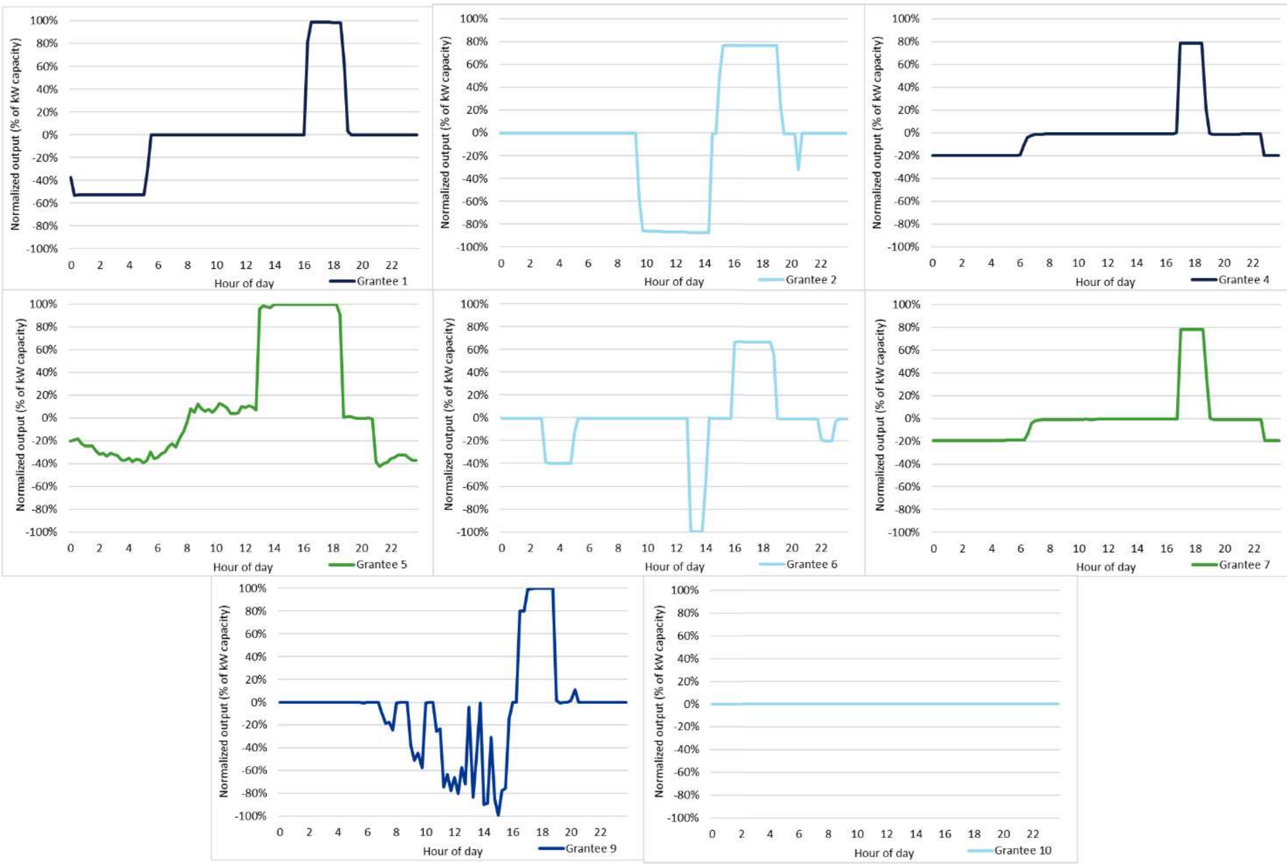


Figure 3-8. ISO NE system peak day (6/29/21) deployment profiles



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, 6 out of the 7 Grantees discharged the ESS during the ISO-NE peak hour. The Grantees typically discharged the ESS over a 2- to 3-hour window between 3 p.m. and 6 p.m., anticipating the ISO-NE peak during this window.

In 2021, 7 out of the 8 Grantees discharged during the ISO-NE peak hour on June 29 from 4 p.m. to 5.p.m. (with one additional Grantee yet to provide data for this date). Grantees 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

To date, 8 Grantees have reported RNS revenues across a total of 42 months. Due to reporting timelines coming to an end for some of the Grantees, and other reporting delays, in October 2022 there are only 2 Grantees reporting RNS revenue for this report. 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 October 2022
Typical RNS hour	5-6 p.m. or 6-7 p.m.
Total RNS revenues achieved	$4,252,198

The Grantees included in this report hit 85% of the monthly RNS peaks and realized 69% 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 3-9.

Figure 3-9. Monthly RNS revenues by Grantee (November 2021 – October 2022)

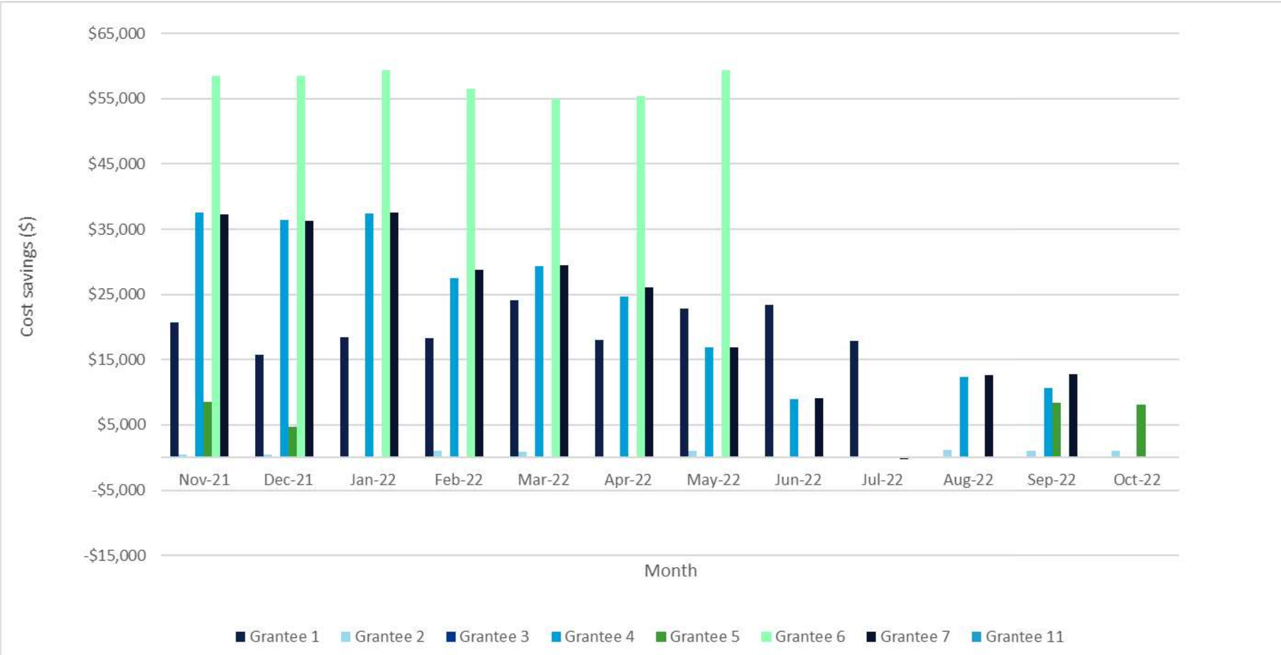


Table 3-8 shows the monthly RNS revenues by Grantee in table form.

Table 3-8. Monthly RNS revenues by Grantee

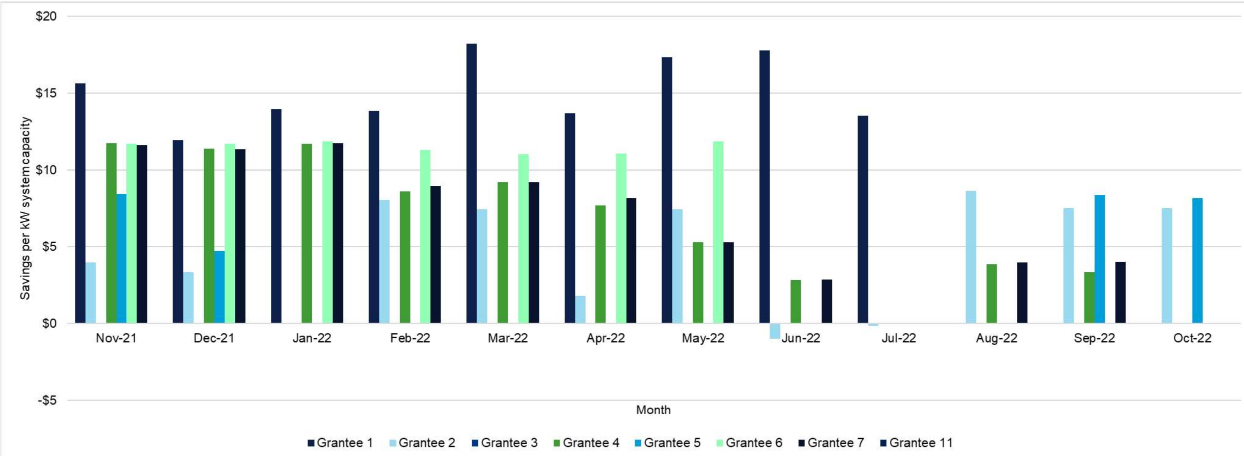
Month	Grantee 1	Grantee 2	Grantee 3	Grantee 4	Grantee 5	Grantee 6	Grantee 7	Grantee 11	Totals
Apr-19	N/A	N/A	$18,154	N/A	N/A	N/A	N/A	N/A	$18,154
May-19	N/A	N/A	$11,182	N/A	N/A	N/A	N/A	N/A	$11,182
Jun-19	N/A	N/A	$0	N/A	N/A	$25,387	N/A	N/A	$25,387
Jul-19	N/A	N/A	$16,112	N/A	N/A	$31,097	N/A	N/A	$47,209
Aug-19	N/A	N/A	$1,237	N/A	N/A	-$100	N/A	N/A	$1,137
Sep-19	N/A	N/A	$284	N/A	N/A	$30,984	N/A	N/A	$31,268
Oct-19	$14,530	N/A	$11,433	$17	N/A	$31,013	-$90	N/A	$56,903
Nov-19	$14,371	$1,051	$17,139	$23,941	$3,442	$30,061	$23,714	N/A	$113,719
Dec-19	$14,721	$932	$17,461	$29,825	$1,747	$30,995	$29,316	N/A	$124,998
Jan-20	$0	$861	$17,535	$23,928	$7,048	$43,595	$23,713	N/A	$116,680
Feb-20	$13,478	$892	$12,406	$28,105	$7,048	$46,548	$28,332	N/A	$136,809
Mar-20	$0	-$7	$0	$30,006	$7,049	-$108	$29,746	N/A	$66,686
Apr-20	$11,399	$1,180	$0	$26,263	$7,050	-$109	$26,132	$24,314	$71,914
May-20	$12,625	$1,297	$7,929	$19,140	$7,051	$31,020	$18,893	$29,007	$97,954
Jun-20	$14,865	$1,263	$14,327	$26,981	$7,052	$31,085	$26,744	$33,389	$122,317
Jul-20	$11,328	$943	$20,205	$27,294	$7,053	$31,098	$27,106	N.D.	$125,026

Month	Grantee 1	Grantee 2	Grantee 3	Grantee 4	Grantee 5	Grantee 6	Grantee 7	Grantee 11	Totals
Aug-20	$12,582	$894	$14,863	$28,204	$7,054	$31,097	$27,981	N.D.	$122,673
Sep-20	$12,639	$894	$14,666	$27,496	$7,055	$28,049	$17,121	N.D.	$107,920
Oct-20	$12,798	$1,026	-$13,376	$34,466	$7,056	$31,094	$34,069	N.D.	$107,133
Nov-20	$11,413	$1,230	$20,225	$34,643	$7,057	$46,480	$16,989	N.D.	$138,038
Dec-20	$15,212	$1,059	$20,853	$34,130	$7,058	$0	$33,936	N.D.	$112,247
Jan-21	$13	$1,070	$20,926	$34,624	$7,059	$53,620	$33,940	N.D.	$151,251
Feb-21	$0	$1,068	$21,314	$34,444	$7,060	$53,760	$33,980	N.D.	$151,626
Mar-21	$15,183	$1,153	$0	$34,632	$7,061	$53,386	$34,308	N.D.	$145,723
Apr-21	$14,489	-$1,167	$9,528	$13,536	$0	$35,526	$13,351	N.D.	$85,262
May-21	$19,973	$1,159	N.D.	$27,593	$684	$35,897	$28,556	N.D.	$113,862
Jun-21	$20,267	$1,144	N.D.	$30,047	$9,692	$39,163	$29,822	N.D.	$130,135
Jul-21	$20,099	$815	N.D.	-$160	$11,479	$39,163	$8,426	N.D.	$79,823
Aug-21	$20,253	$651	N.D.	$21,932	$11,515	$39,163	$22,345	N.D.	$115,859
Sep-21	$17,737	$480	N.D.	$30,095	$11,653	$58,519	$29,751	N.D.	$148,235
Oct-21	$17,349	$455	N.D.	$37,628	-$141	$58,540	$37,260	N.D.	$151,091
Nov-21	$20,638	$507	N.D.	$37,491	$8,454	$58,513	$37,196	N.D.	$162,799
Dec-21	$15,744	$427	N.D.	$36,376	$4,693	$58,533	$36,238	N.D.	$152,011
Jan-22	$18,420	$0	N.D.	$37,459	$0	$59,286	$37,536	N.D.	$152,701
Feb-22	$18,290	$1,032	N.D.	$27,485	$0	$56,556	$28,719	N.D.	$132,082
Mar-22	$24,036	$946	N.D.	$29,391	$0	$55,010	$29,419	N.D.	$138,803
Apr-22	$18,068	$227	N.D.	$24,633	$0	$55,342	$26,103	N.D.	$124,373
May-22	$22,861	$949	N.D.	$16,895	$10	$59,281	$16,860	N.D.	$116,855
Jun-22	$23,435	-$128	N.D.	$8,964	$0	N.D.	$9,127	N.D.	$41,397
Jul-22	$17,853	-$20	N.D.	$19	$0	N.D.	-$186	N.D.	$17,667
Aug-22	N.D.	$1,104	N.D.	$12,348	$0	N.D.	$12,612	N.D.	$26,064
Sep-22	N.D.	$957	N.D.	$10,606	$8,368	N.D.	$12,746	N.D.	$32,678
Oct-22	N.D.	$956	N.D.	N.D.	$8,162	N.D.	N.D.	N.D.	$9,119

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 3-10 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 3-10. Summary of capacity-normalized monthly RNS revenues by Grantee (November 2021 – April 2022)



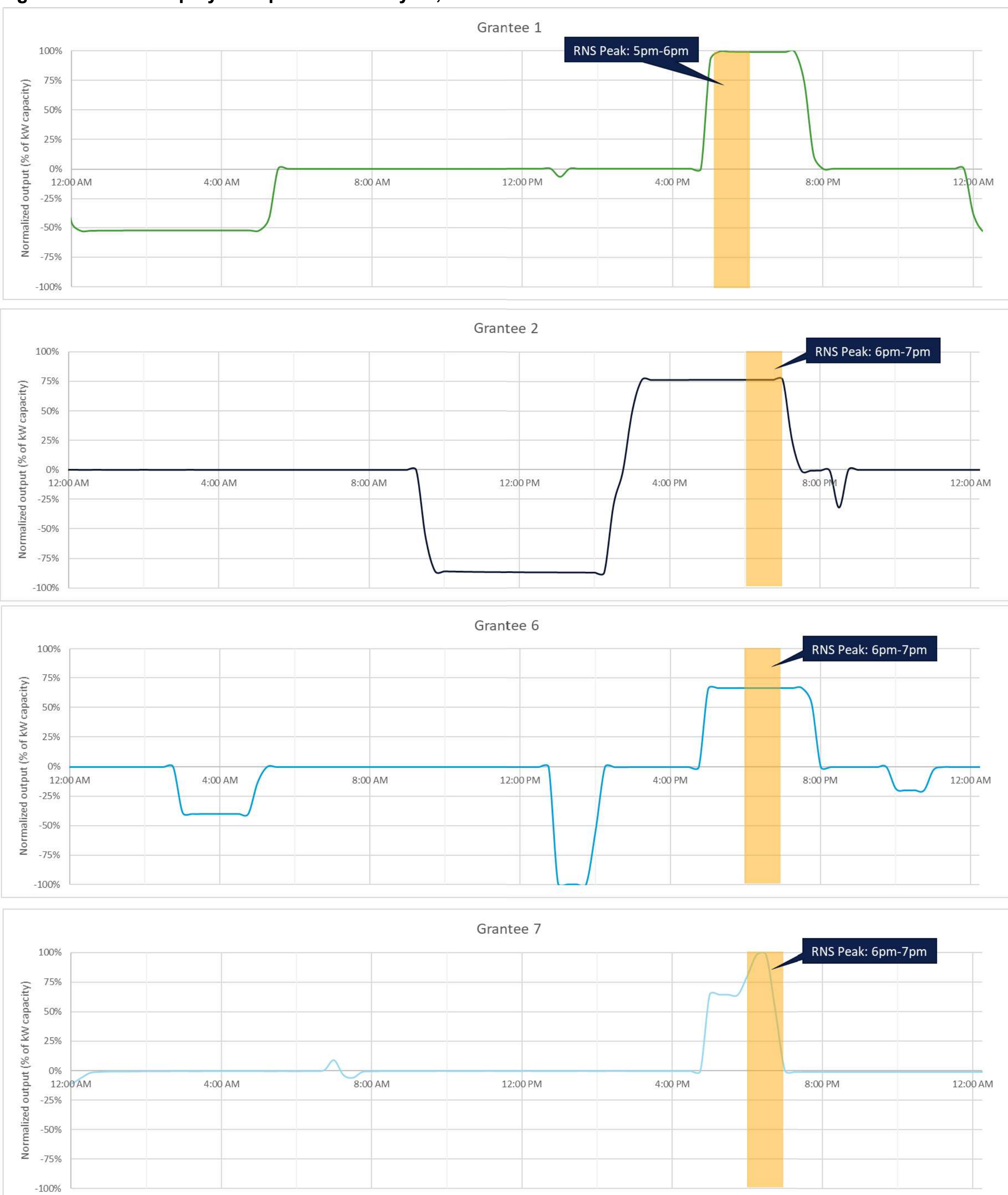
As shown in the figures and table above, Grantee 5 missed RNS peaks from January through August 2022. The Grantee noted that an error in programming caused the system's algorithm to prioritize peak reduction over RNS revenue during this period; additionally, communications failures were the cause of some of these missed peaks. These errors have since been resolved and the Grantee has instituted regular peak dispatch monitoring to avoid future occurrences of this issue. Only one of the 5 Grantees targeting RNS hit the peak in July 2022. In addition to the communication issue mentioned previously, several Grantees dispatched the day before the RNS peak to hit an ISO-NE system peak and did not predict the actual RNS peak the subsequent day.

For context in understanding monthly deployment trends, Figure 3-11 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 3-11. 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 3-12 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 3-12. 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 PM1	7/30/2019 6:00 PM1
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 PM2	7/27/2020 6:00 PM2	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-22	4/7/2022 7:00 PM	4/7/2022 8:00 PM	4/6/2022 12:00 PM
May-22	5/22/2022 5:00 PM	5/22/2022 7:00 PM	5/22/2022 5:00 PM
June-22	6/26/2022 5:00 PM	6/26/2022 6:00 PM	6/26/2022 5:00 PM
July-22	7/20/2022 5:00 PM	7/21/2022 4:00 PM	7/21/2022 3:00 PM
August-22	8/9/2022 2:00 PM	8/8/2022 5:00 PM	8/8/2022 3:00 PM
September-22	9/4/2022 5:00 PM	9/12/2022 8:00 PM	9/12/2022 3:00 PM
October-22	N.D.	10/13/2022 7:00 PM	10/26/2022 5:00 PM

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. All 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

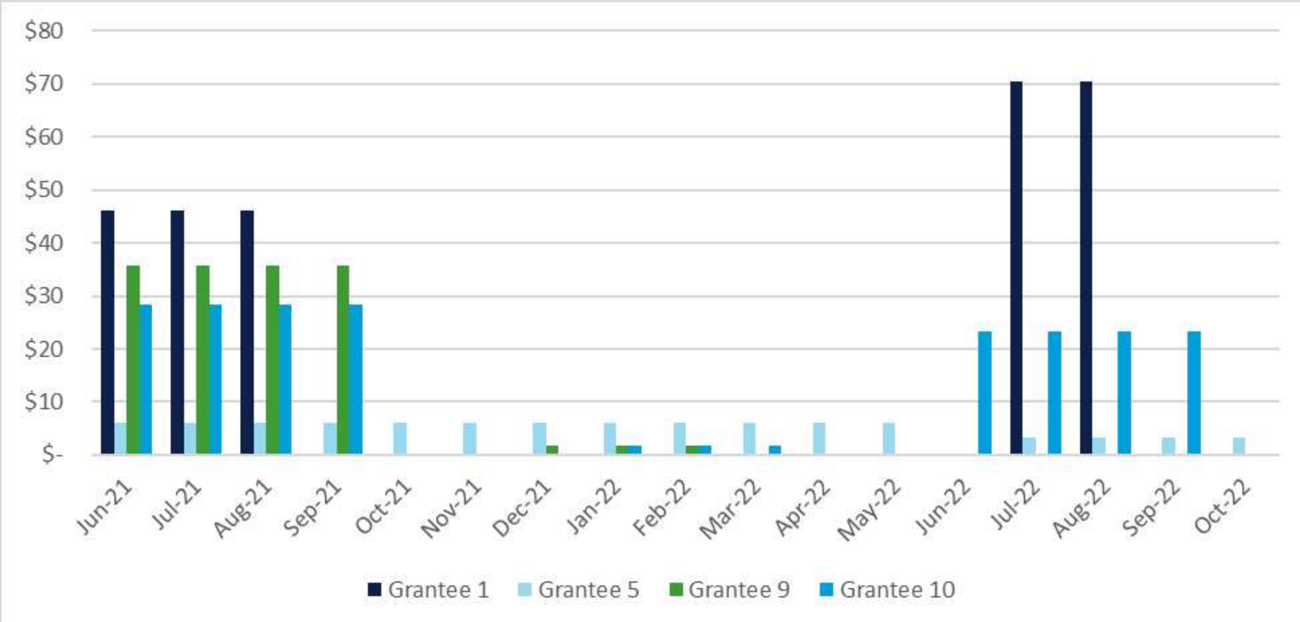
Revenue Stream Criteria	Value
Analysis period	October 2019 to October 2022
Number of Grantees reporting revenue	4
Total revenue	$1,288,775

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 3-13 shows a monthly summary of the demand response program revenues achieved by the four reporting Grantees over the months of operational report coverage.

Figure 3-13. 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.

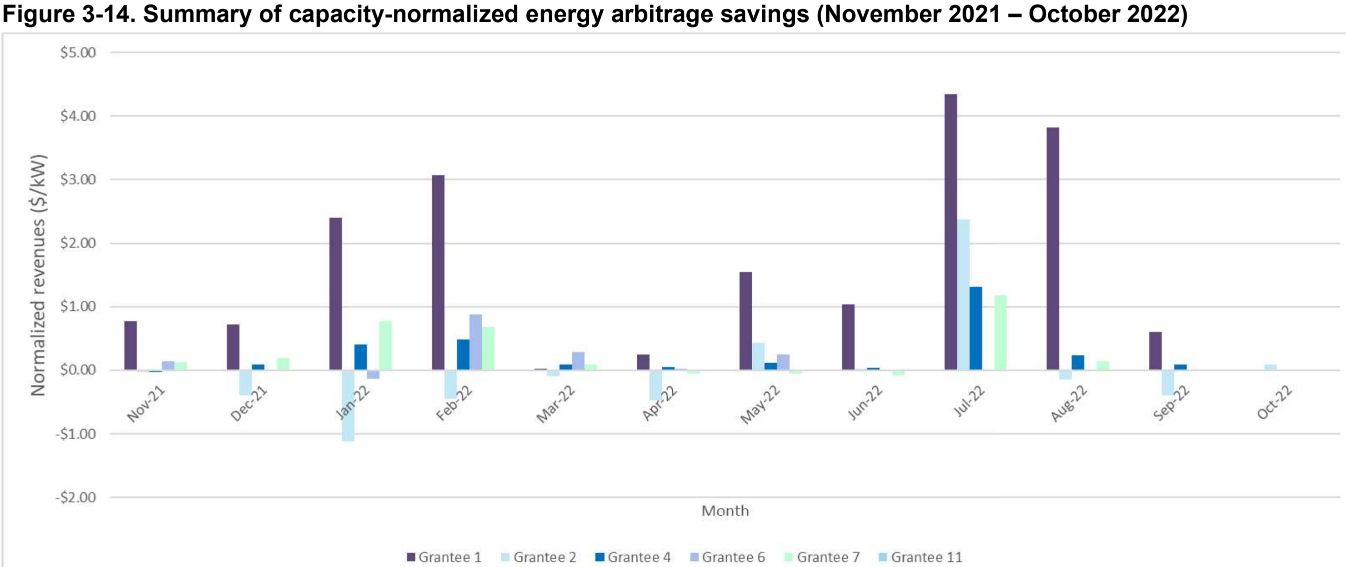
DNV used the granular ESS discharge/charge data, hourly real-time LMP for the specific reliability region accessed from ISO-NE's API, and site-specific adjustment factors to evaluate the energy arbitrage benefits accrued for participating Grantees. Table 3-10 shows the total arbitrage benefits accrued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

Table 3-10. Energy arbitrage ACES revenue

Revenue Stream Criteria	Value
Analysis period	June 2019–October 2022
Number of Grantees reporting revenue	6
Total revenue	$95,646

Figure 3-14 shows the verified monthly arbitrage benefits achieved by each Grantee over the reporting period.

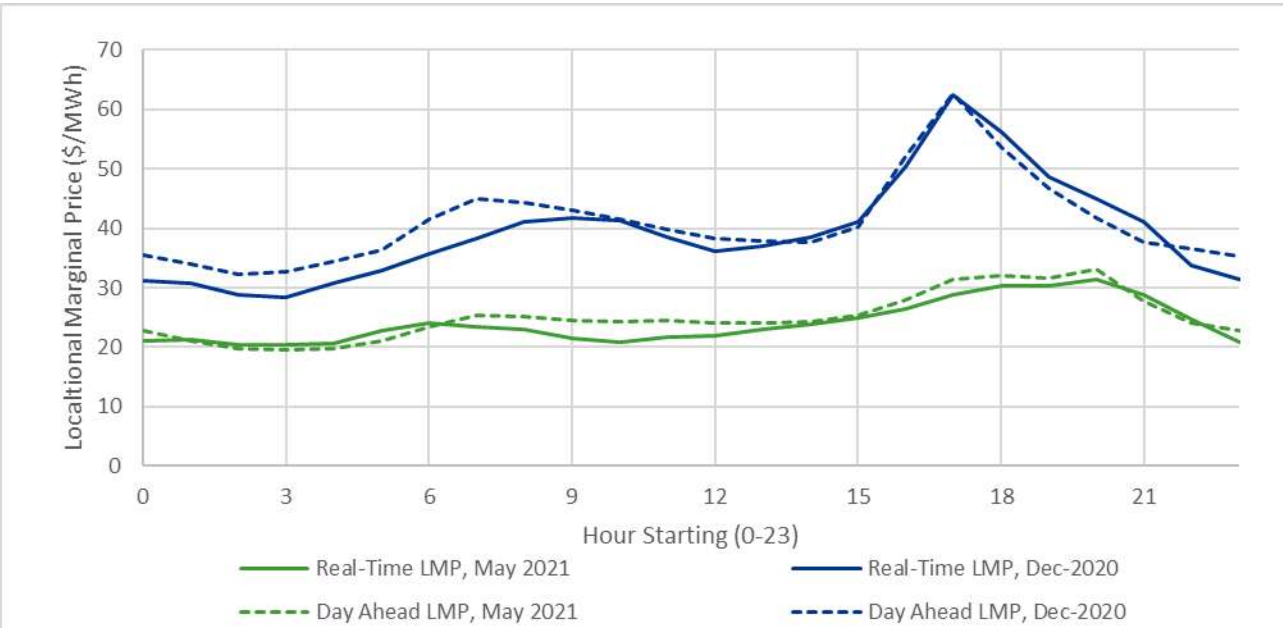
Figure 3-14. Summary of capacity-normalized energy arbitrage savings (November 2021 – October 2022)



3.5.2 Additional energy arbitrage insights

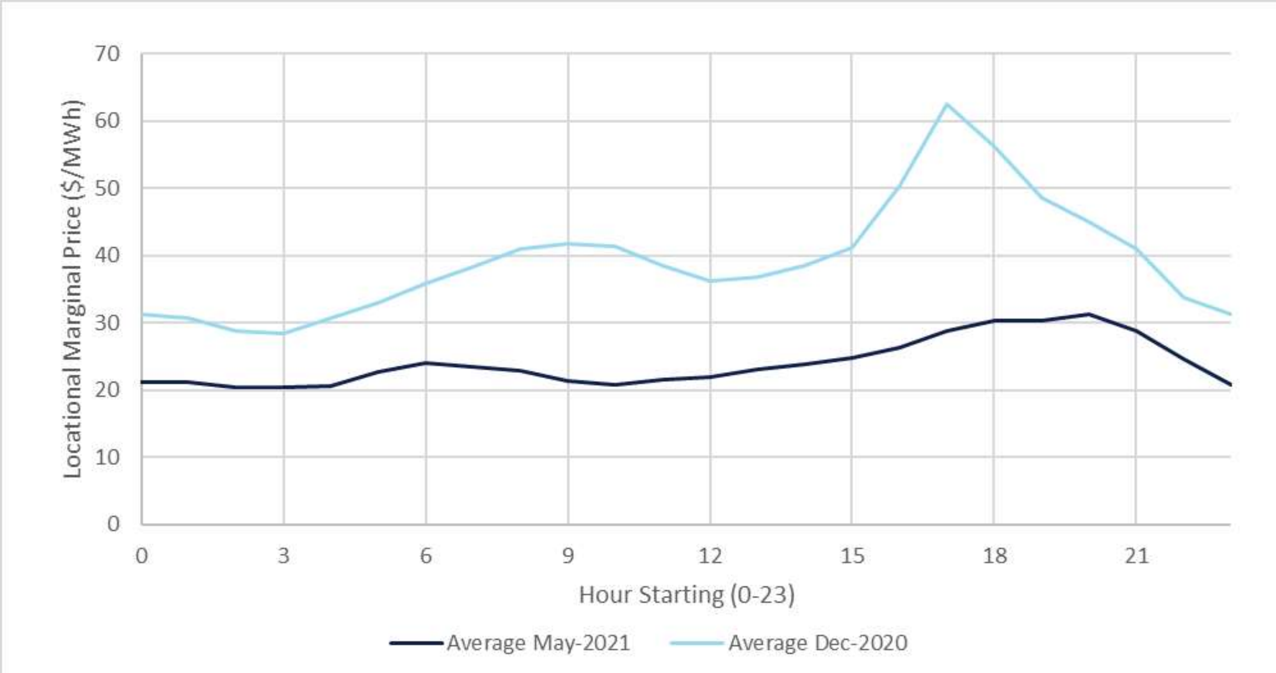
DNV identified differences between the arbitrage revenues reported by Grantees and the revenues calculated from the reported data. This is primarily due to differences in modeling approaches. DNV used real-time LMP values to assess revenues, while some Grantees used day-ahead LMP values or based their estimates on fixed energy costs. Other differences, such as handling of daylight savings time, also played a small role. Figure 3-15 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 3-15. 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 3-16 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 3-16. 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, 3 of the 11 Grantees included in the scope of this report actively dispatch 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, to-date, the three Grantees targeting peak demand management showed an average normalized revenue of $6.46/kW for peak demand versus $250.14 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.

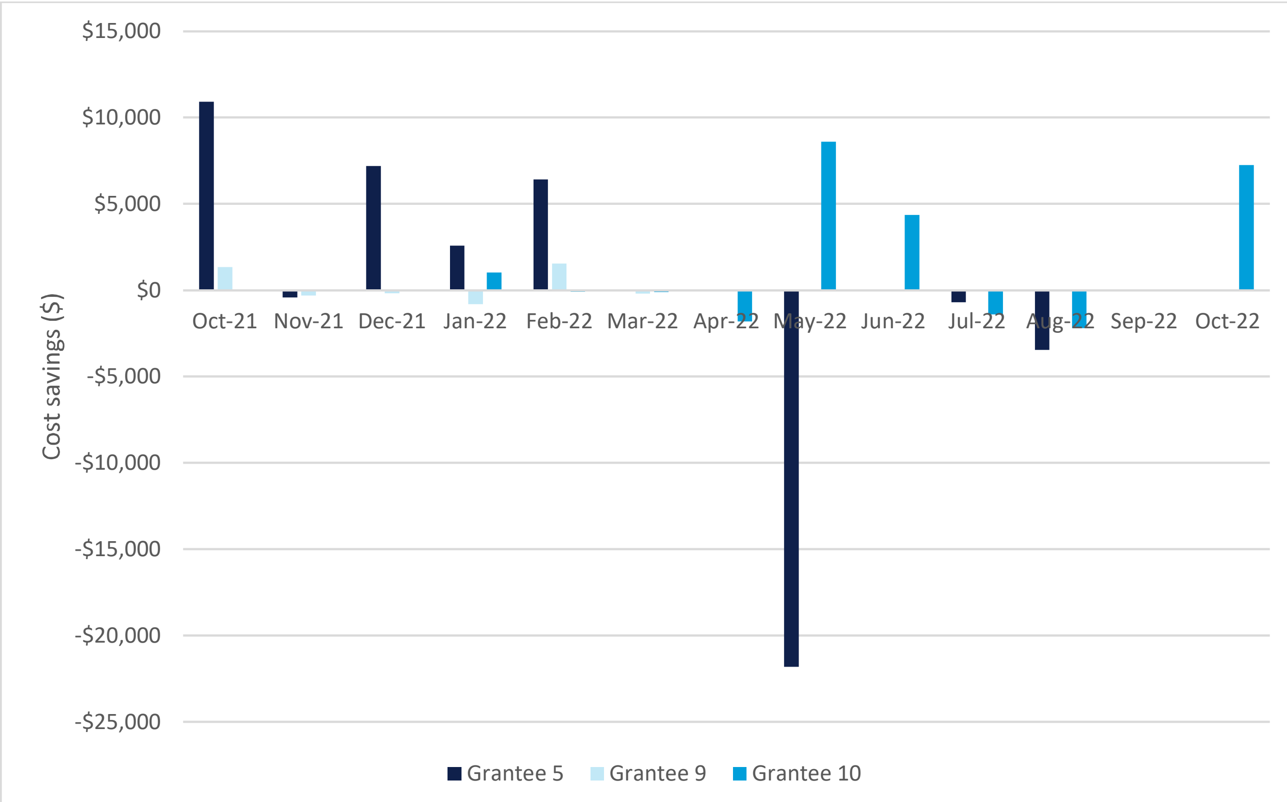
Table 3-11 shows the total peak demand reduction benefits accrued by the three Grantees reporting these benefits for this period.

Table 3-11. Peak demand reduction ACES revenue

Revenue Stream Criteria	Value
Analysis period	November 2019–October 2022
Number of Grantees reporting revenue	3
Total revenue	$35,391

Figure 3-17 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 3-17. 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

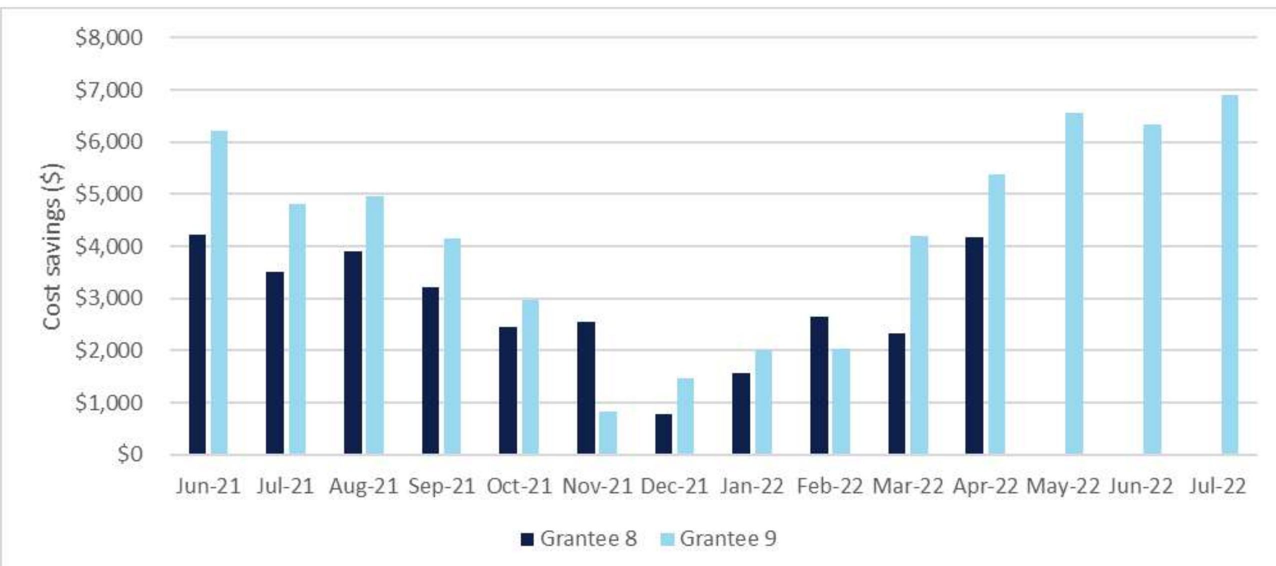
Of the 11 Grantees included in this report, 2 Grantees currently report revenues from the SMART program as a result of the energy storage adder. Both are battery projects co-located with solar installations (one ground-mounted and the other rooftop). One battery provides solar PV smoothing for the local 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–July 2022
SMART storage adder rate	$2.31 per kWh
Number of Grantees reporting revenue	2
Total SMART storage adder revenue	$161,684

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 3-18 shows the monthly SMART revenues achieved by the Grantees who pursued this end use.

Figure 3-18. 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. Additionally, Grantee 8 will report revenue values from May 2022 – October 2022 on their next operational report, which is not finalized at the time of writing this report.

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 11 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 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 $13,686 across 33 months. Table 3-13 shows the summary of Clean Peak Standard earnings achieved to date. While the Grantee has completed reporting for May 2022 to September 2022, CPEC revenues for that period are still estimates. Because the Grantee has reached the end of their reporting period, the estimated values are included.

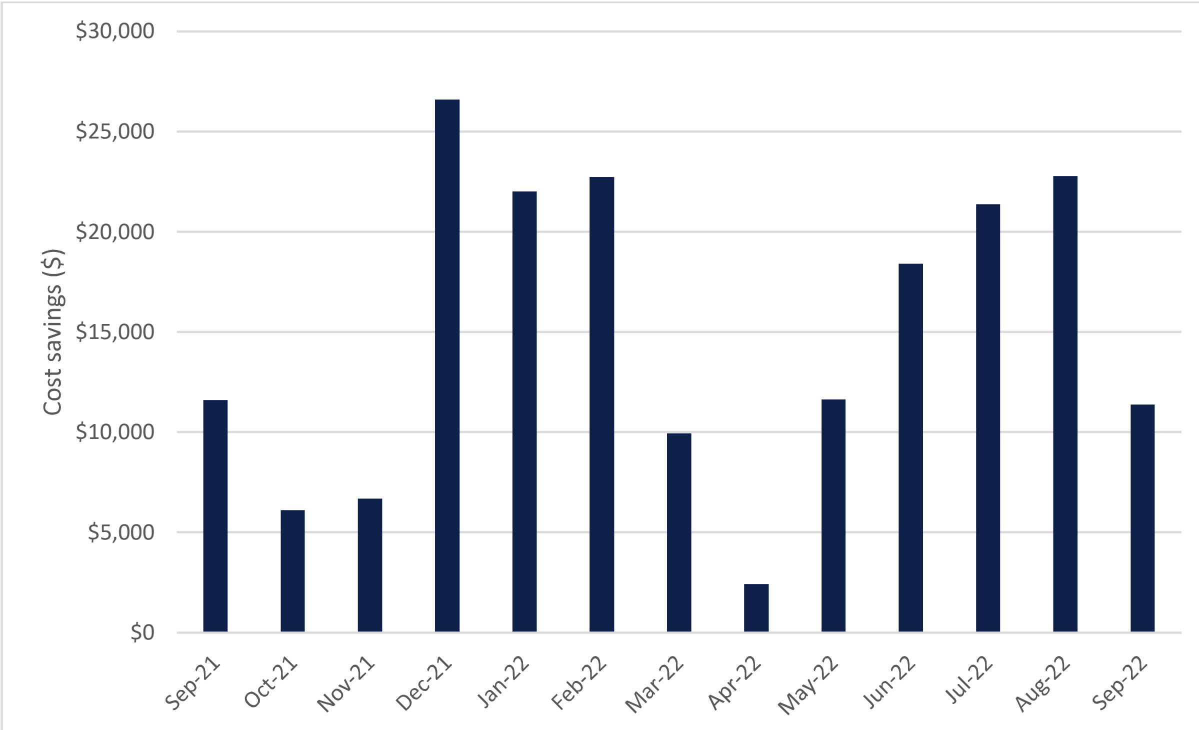
Table 3-13. Clean Peak Energy Standard ACES revenue

Revenue Stream Criteria	Value
Analysis period	January 2020–September 2022
Number of Grantees reporting revenue	1
Total revenue	$451,630

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 3-19 shows the monthly CPES revenues achieved by the Grantee who pursued this end use.

[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.

Figure 3-19. 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 can 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 its 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.

About DNV
DNV is a global quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable our customers to advance the safety and sustainability of their business. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil & gas, power and renewables industries. We also provide certification, supply chain and data management services to customers across a wide range of industries. Operating in more than 100 countries, our experts are dedicated to helping customers make the world safer, smarter and greener.