PLMA™

Load Management Leadership

Practitioner Perspectives™

17th PLMA Award-Winning Load Management Initiatives

A Compendium of Industry Viewpoints

Edited by
PLMA Award Planning Group
November 2020

PLMA Recognizes Leading Industry Load Management Initiatives

Each year, PLMA recognizes leading load management initiatives through a peer-led evaluation and selection process. In 2020 this process was made possible through the volunteer efforts of more than 20 judges from across PLMA's member organizations. The judging process requires judges to score of all of the submitted award nominations based on merit. Award recommendations are then provided to the Awards Planning Group for final review and decisions.

PLMA Load Management Leadership

Awards Program

Co-chaired in 2020 by Laurie Duhan of Baltimore Gas and Electric, Brett Feldman of Guidehouse, and Michael Smith of National Grid, the PLMA Awards Planning Group oversees the nominations and the judging process for PLMA's annual awards. PLMA welcomes staff from its member organizations to serve as volunteer evaluators each year.

To volunteer as an awards judge, please send an email to signup@peakload.org. For more information on the PLMA Awards Program, please click on www.peakload.org/group-overview.

The 2020 PLMA Award Planning Co-Chairs:

Laurie Duhan
BGE, an Exelon Company

Brett Feldman
Guidehouse Insights

Michael Smith
National Grid

Thank You to the Volunteer Judges of the 17th PLMA Awards Program

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PLMA (Peak Load Management Alliance) announced six winners of its 17th PLMA Awards in April 2020. These awards were presented during the *41st PLMA Conference Online* . They include three award categories that recognized outstanding load management programs, initiatives, and achievements in calendar year 2019, as follows:

Program Pacesetters

- Arizona Public Service and EnergyHub for their DER Aggregations Program
- National Grid and EnergyHub for National Grid's *ConnectedSolutions* Program

Thought Leaders

- City of New York, Department of Citywide Administrative Services for Building Operator Engagement
- CPS Energy for Public Engagement

Technology Pioneers

- Austin Energy for the SHINES Project
- Connected Energy Ltd. (U.K.) for Battery Recycling to Energy Storage in Belgium

The contents of this 17th PLMA Awards Compendium are transcripts from webcasts with the award-winning teams.

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Program Pacesetters

Arizona Public Service and EnergyHub for their Distributed Energy Resource Aggregations Program

Presented June 2020

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in June 2020. It highlights Arizona Public Service (APS) and EnergyHub for their award-winning program, "Distributed Energy Resource Aggregations (Rewards Programs and Solar Communities)."

The webcast discussion was moderated by PLMA Awards Group Co-Chair Brett Feldman, a Research Director with Guidehouse.

Brett Feldman: As we think about a distributed energy resource program that is succeeding in the desert of the Southwest U.S., it would be interesting to compare and contrast how utilities in very different climates deal with similar grid and customer issues. To do that, I am speaking with Tom Hines and Renée Guillory representing Arizona Public Service (APS) and Ben Bunker from EnergyHub. Let's start with APS.

Tom Hines: Thanks, Brett. I'm Tom Hines and I'm a Principal with Tierra Resource Consultants where I've worked closely with APS for many years now on their DSM strategy and program design. On behalf of APS, I would like to thank everybody at PLMA and all of the folks on the 17th PLMA Awards Committee for recognizing our DER program as a "Pacesetter." It means a lot to us, particularly as it comes from our fellow load management practitioners who we always look to for innovative new ideas.

Renée Guillory: Thank you so much and to echo Tom's gracious words, we really appreciate PLMA's recognition. I'm Renee Guillory, a Program Consultant at Arizona Public Service, working for our "Customer to Grid Solutions" team in APS' Product Development and Strategy division. Working with Tom on the programs that are recognized here, I served as the Project Manager for the various fleets that APS built out as part of the Rewards Program initiative, and I now support APS' strategic efforts to scale aggregated DERs.

Ben Bunker: Thanks, Brett and hello. I am Ben Bunker, a Senior Client Success Manager at EnergyHub working in support of the APS DER programs. Thank you to the PLMA team for this Pacesetter Award and also for the opportunity to speak today. To give you a little insight into my role here at EnergyHub, I've been supporting APS in achieving its DER strategy since last Fall, working closely with Tom, Renée, and many other folks at APS to

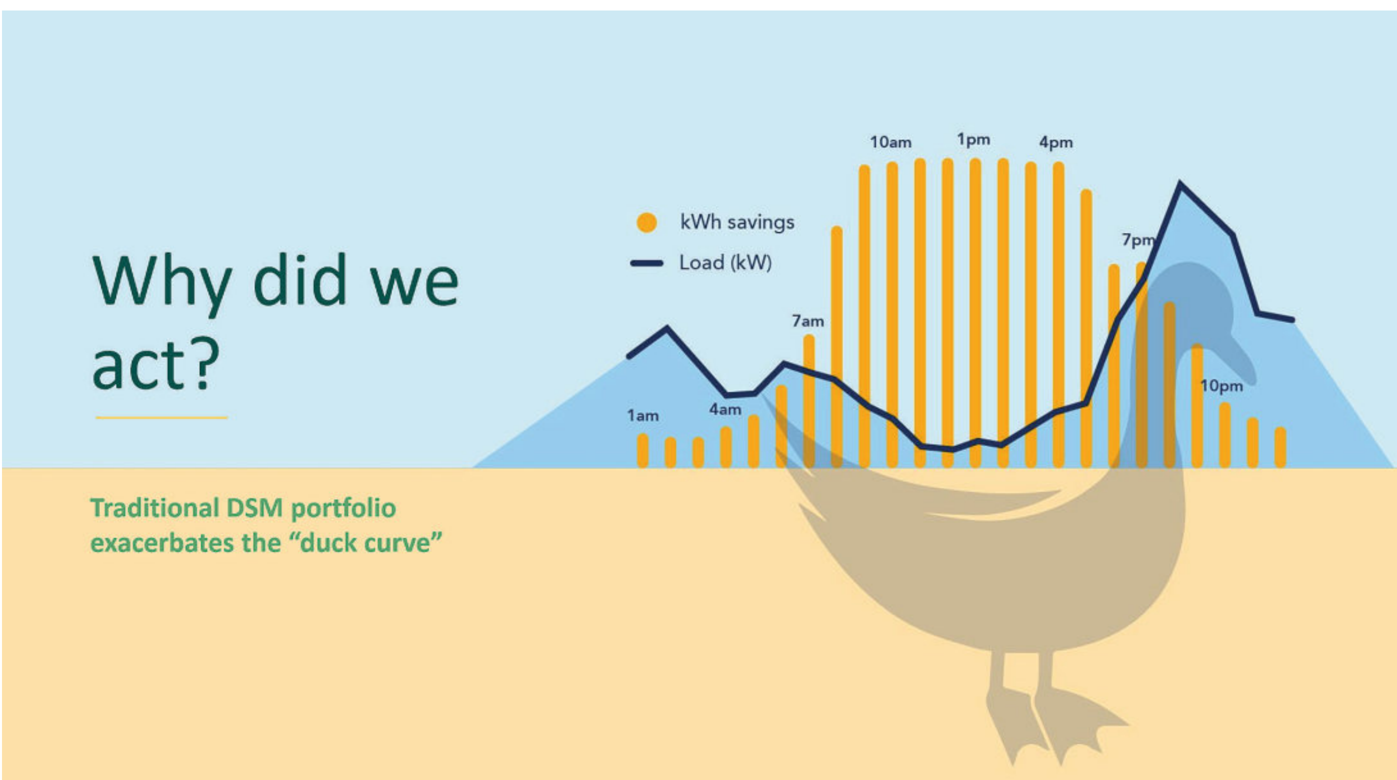


FIGURE 1 View Slide at: *https://bit.ly/3mlSW9N*

make that happen. A lot has been accomplished to date and an exciting future lies ahead for these programs.

Tom: Let's start with some background on the Rewards Program, which is a DER aggregation program that began in 2016. APS has a long history of promoting energy efficiency and demand-side management programs to our customers. But in 2010, the State of Arizona passed an energy efficiency standard with the goal of creating megawatt hours of energy savings. At that time, it didn't matter when energy was saved, the standard was all about creating total annual energy savings.

As you might guess, it didn't take long to see that with the penetration of more solar resources on our system, our friend the duck curve soon emerged in a big way in Arizona, both within our own customer base, and also in the regional wholesale power picture. Figure 1 is a fun graphic that shows orange bars to represent the kilowatt-hour savings we were getting in the load shape from our Commercial Energy Efficiency Lighting program. But as we look at this graph, it is clear those kWh saved were actually making our duck curve issues worse! This profile of efficiency savings was not aligned with our resource needs at all. Our conclusion? Many of our traditional EE programs were just not working, and they were making conditions worse at certain times of the day. We needed to do something different!

Fortunately, the opportunity arose to work with customers on some new DER programs that could help us to address the challenges being created by other DERs, most notably by rooftop solar. Hence began our partnership with EnergyHub which offered APS the means to work with our customers to determine which DERs we could aggregate. Today, we are proud to say we have aggregated thermostats, water heaters, battery storage, and solar inverters, and we have our sights set next on EVs and pools!

Initially, we implemented DER aggregation to address load shapes on the system. But I think more and more, we've found a new mission for DER aggregation. In January 2020, APS announced its goal of achieving 100 percent clean energy by 2050. As a result, we now think about our DER aggregation platform as a highly effective tool for working with customers to help shift our loads so they match when we have intermittent renewables on the system–a logical path to achieving APS' clean energy future.

Ben: Thank you, Tom. To give you a sense of EnergyHub's role in APS' DER aggregation initiative, let me tell you about the Mercury DERMS platform. This is a single platform that allows APS to dynamically leverage its portfolio of distributed energy resources, including thermostats, batteries, water heaters, and solar inverters, for an array of grid services that make it possible to proactively manage its load curve. This management can take different forms including demand response peak reduction or load shifting.

APS' Cool Rewards program is a smart thermostat program for residential demand response, targeting thermostats and reducing consumption on peakload days, obviously driven by high temperatures and HVAC load. This is possible because we have integrated all of the leading thermostat brands with our DERMS platform, and these represent the overwhelming majority of devices in the market, both in APS's service territory, as well as across the rest of the U.S.

We have also partnered with Rheem to create the Reserve Rewards program, a water heater program, and with Sunverge to provide a Storage Rewards battery program. Both of these programs help APS to put recurring load shifting into place by minimizing local evening peaks while absorbing the production of midday renewables. You can see how this works by looking at Tom's elegantly drawn Figure 1 duck curve; imagine the impact of really leveraging storage-based distributed energy resources in the middle of the day! Last, EnergyHub is also working with APS on a Solar Communities program which will make it possible for APS to conduct targeted management of solar resources in response to excess production and negative locational marginal pricing. This is made possible by modifying inverter settings.

As you can guess, the models for implementing each of these Rewards programs are all a little bit different from one another. With thermostats, it's a "Bring Your Own Thermostat" (BYOT) model, which EnergyHub has worked on for many years now, integrating with all the leading thermostat brands.

There are also direct install programs for the grid-interactive water heaters from Rheem, the residential batteries from Sunverge, and the solar smart inverters. We have implemented a combination of the "bring your own model" and the "direct install model" in which customers can buy their own devices and enroll them in the programs and APS can also seed the market with distributed energy resources. We can then bring them all together within the Mercury DERMS platform. To summarize, the idea behind the DERMS platform is to transform these variable and customer-constrained assets into something that's bankable for APS and helps it to achieve its goals.

Renée: Great set up for this next point, Ben. While there are many use cases, technologies, and customer types that we think are interested in participating in programs like Rewards, let's talk a little bit about scaling. There are important strategic outlooks associated with our DER aggregation, and really, with any program that we offer to customers. Of course, all APS programs must support APS' clean energy commitments.

As Tom described, the programs must all have a means of matching load with renewable generation. They also need to be affordable, and APS must be sure that we're providing real benefits, not just to participating customers, but to all customers. Reducing peak demand on the system is one way to do that; it helps maintain downward pressure on costs as we battle Arizona's extreme summer temperatures.

DER fleets also need to be reliable. We need to be able to build these resources over time with resource adequacy and equivalency. And we want to be able to measure how well and how flexibly we manage the load and continue to match the renewables coming on to the grid. The programs must also be customer focused. We have the benefit of having several rate plans for our residential customers who can now opt for time-of-use rates. This gives them an incentive to shift load in ways that help APS to better manage the grid, and there are other program participation incentives too.

In the case of Cool Rewards, we offer an annual participation incentive that allows us to manage our customers' thermostats. For Reserve Rewards, there are incentives to deploy heat pump water heaters that might be a little oversized compared to what customers are used to, but they facilitate good energy storage.

A combination of aligned rates and new technologies are very attractive to customers who are adopting a lot of these technologies on their own. The grid edge is expanding, and it's our job to harvest innovation on both sides of the meter. This is especially the case if we are going to achieve clean, affordable, reliable, and customer-focused energy programs and meet APS' 2050 clean energy goal.

Brett: So we've heard a little about different program approaches; some are direct install while some are "bring your own." How did APS decide upon the design for each of the different Rewards programs?

Tom: Part of our process was to look at best practices around the country, although in some cases, there weren't a lot of best practices to look at! We also looked at installing on certain distribution feeders. For both our battery program and our water heater program, we were targeting specific feeders that had specific needs. And in doing that, we believed a direct install approach was going to get us to our goals faster which was important because we wanted to achieve a lot of market penetration. In addition, it's always a challenge to engage a customer at just the right time on replacing their water heater plus adding battery storage—these are big upfront costs for most people.

On the other hand, knowing many customers are willing to adopt smart thermostats on their own, it's possible for us to take advantage of that opportunity with a BYOT program. That way, we can pay customers for the capacity they can give us while they purchase and install the thermostat technology that makes the most sense for them.

Brett: Ben, how has the DERMS platform had to evolve to support the different APS use cases? Clearly with all these different use cases, it's not necessarily one size fits all.

Ben: I think with all these programs and maybe more generally with anything at the grid-edge, there are complex devices and complex systems involved. When we began working with APS, we looked at the various devices and decided to build things from the ground up. We asked ourselves, "how do we build something to meet short-term needs, but also to evolve to be able to manage large numbers of these devices?" This is something EnergyHub has a lot of experience with and so what began with thermostats has now expanded to include many other DER classes.

As these programs grow, we always need to think about scale and size, and how to deliver increasingly sophisticated grid services to APS, and to other clients, so they can achieve their goals. For us, it comes down to figuring out how to manage that complexity while doing so in a way that is scalable.

Brett: Thank you, Ben. Renée, who are the different stakeholder groups engaged in APS' Results program, and what are some of the different drivers for those groups?

Renée: APS spent a considerable amount of time developing our internal stakeholders upfront, knowing we were going toward fully-scaled DER aggregations, and wanting to have what we often call a "single pane of glass." What I mean by that is the EnergyHub platform, which APS refers to internally as our "resource operating platform," has line-of-sight to all of our DER aggregations.

cybersecurity requirements, but in this case, on behalf of our customers. Even in a cloud-to-cloud space, these are important things to get right, both for the sake of grid operations and for our customers. Of course, we also included all of our usual stakeholders: procurement, legal, and regulatory.

Our marketing teams had to do a lot of communicating with customers to explain the details of a big variety of programs. Today they continue to educate customers as the programs mature and as we start to talk about results. It was very important to have developed a wide stakeholder group, and it was also challenging because in the energy sector, as every practitioner knows, we can sometimes have silos! But I will say that there was enormous sponsorship and stakeholder support across APS because of the strategic importance of this initiative. Plus, we were graced with a lot of great collaborators among our stakeholder groups.

Brett: It takes a village, huh?

Tucson, Arizona

Knowing we wanted these resources to be visible to the various decision makers at APS drove us to include many different stakeholder groups, whether they are in our marketing and trading space or from our distribution operations space.

Also, knowing that we wanted to look at locational targeting for some of our programs, specifically the Reserve Rewards and Storage Rewards programs, we also worked closely with our DER integration engineers to find the best locations to potentially improve local conditions on the grid while still ensuring customers in those targeted feeds had a great product. That is especially important because this effort also represents a partnership with our customers. Some of our programs leverage customer Wi-Fi, so we included APS' IT and cyber security teams to ensure we met our own strict

Renée: Yeah, absolutely. That's a hashtag: #ItTakesaVillage!

Brett: Let's move to a discussion of the communications protocol and transport media APS used between the DERs. Is OpenADR involved?

Ben: Great question! It varies by device class. For the batteries, we communicate with those via OpenADR 2.0. For the solar inverters, we communicate via IEEE 2030.5. And then we have APIs in place with all of our thermostat partners, as well as with Rheem (the hot water heater manufacturer), that allow us to control and manage those devices.

Renée: There are important requirements that must be met to ensure communications are stable and compliant. For example, with the water heaters, CTA 2045 is an important communication requirement. It leverages a customer's Wi-Fi but there are protections in place to ensure secure communications are going through the cloud. Similarly, with the storage batteries, we looked for the most reliable communications we could find for a utility-owned and -operated battery, just as we did with a utility-'shared' and -operated water heater. And with the batteries, we opted for dedicated cellular communications going up to the Sunverge cloud.

Ben: There's also communication to consider between the EnergyHub platform and the devices, and there's an interface within the EnergyHub platform that APS has access to. For smart thermostats and water heaters, this is how APS is able to set these up the way they want them to work. EnergyHub is also communicating with the devices, so as you can see, there are multiple layers of communication happening!

Renée: The stool has a lot of legs.

Brett: What advice would you give to a grid operator interested in implementing a DERMS platform?

Ben: Start with the value proposition for your customers. Customer value can often get lost in programs when there are important benefits accruing to the utility. A good first step is to align these two. Renée also pointed out the importance of assembling the right group of stakeholders and making sure they are aligned on goals.

Tom: It's also really important to think about your use cases. What are you trying to achieve with your DER aggregation or your DERMS? At the same time, don't get caught in the "analysis paralysis" phase. I think there are a lot of utilities afraid to proceed because of the huge capital investment required. The first step is to try to create a DER aggregation that makes sense, then take it one step at a time as you consider how you need the back-end to work. If you are working on DER aggregation, there's no need to boil the ocean on your first pass! A modular approach makes a lot of sense.

Renée: Good points, Tom. If we had started out requiring the aggregations to be 100 percent load building and based on automated triggers responding to grid or market conditions, there's a chance we would have got caught up in analysis paralysis. As I've heard you say before, Tom, the crawl-walk-run strategy is a really good approach. Even more to the point, start where your customers are. With the Cool Rewards program, we began by leveraging an existing pool of aggregated DERs. "Aggregated" in the sense that we knew these customers had participated in an energy efficiency program, plus we had a base of smart thermostats that helped us understand customer behaviors. This made it possible to posit what might change if we were able to shift that load around and manage the fleet in partnership with our customers.

The Reserve Rewards program was similar, in that we started where our customers were and leveraged the same way, but in a different direction. We all recognize the timeliness issue in which customers don't think about buying a water heater until their old unit fails. Knowing this, we had to find a different strategy for deploying water heaters plus a scaled DER aggregation to use water heaters for energy storage. Starting with the customer top-of-mind provides a strong direction for designing these kinds of programs.

Brett: That's a perfect ending to this conversation Renée, thank you. Congratulations again to Arizona Public Service and to EnergyHub on your PLMA Pacesetter Award!

Presenters:

Tom Hines
Arizona Public Service

Renée Guillory
Arizona Public Service

Ben Bunker
EnergyHub

Brett Feldman
Guidehouse Insights

The conversation above is from a webcast recording at https://www.peakload.org/dialogue--aps---energyhub

Program Pacesetters

National Grid and EnergyHub for National Grid's *ConnectedSolutions* Program

Presented May 2020

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in May 2020. It highlights National Grid and EnergyHub for their award-winning program, National Grid *ConnectedSolutions*. This discussion was moderated by PLMA Awards Group Co-Chair Brett Feldman, a Research Director with Guidehouse. It also includes Paul Wassink, Program Manager for Demand Response for Rhode Island and Massachusetts at National Grid, and Chris Ashley, Vice President of Utility Sales with EnergyHub.

Brett Feldman: Welcome Paul and Chris! I'm excited about this conversation because I'm not only a PLMA Awards Group Co-Chair, I'm also a National Grid customer. I personally participate in National Grid's *ConnectedSolutions* program using my own thermostat, sometimes to my wife's chagrin, but I haven't yet joined the storage part of this program. Maybe our discussion will encourage me to do so! Let's begin with an overview of National Grid's *ConnectedSolutions* program.

Paul Wassink: Thank you Brett, we're delighted to be here and very much appreciate the honor of receiving a PLMA Pacesetter Award! To explain the *ConnectedSolutions* program, it's important to first understand these three aspects: first, it's a pay-for-performance program; second, it maximizes customer choice; and third, is it has proven customer satisfaction outcomes.

The pay-for-performance aspect of the program refers to customer-owned batteries. These are behind the meter, not owned by the utility and not rate-based. They have no rate of return which makes them analogous to our bring-your-own-device thermostat program in which customers purchase their own thermostats with no upfront incentives, but they receive incentives when they allow the utility to control their device at peak times.

Here's an example: as you can see in Figure 1, this is a peak day in which the battery had been called the day before, so it is near empty as this day begins. As the sun comes up, the battery charges until it is fully charged around noon, then it just sits there waiting. A demand response event starts at about 5 pm and goes until 7 pm, during which the battery is discharged. The DR event then ends. We could have the same scenario again the next day if it's a sunny day; our peak days in the New England area are normally very sunny.

One of the benefits of this pay-for-performance approach is that it protects rate payers. We're not putting large upfront incentives out there for our customers to buy a battery and then have that customer not let us control the battery. Plus, the program operates in a way that solar installers are used to seeing, at least in our

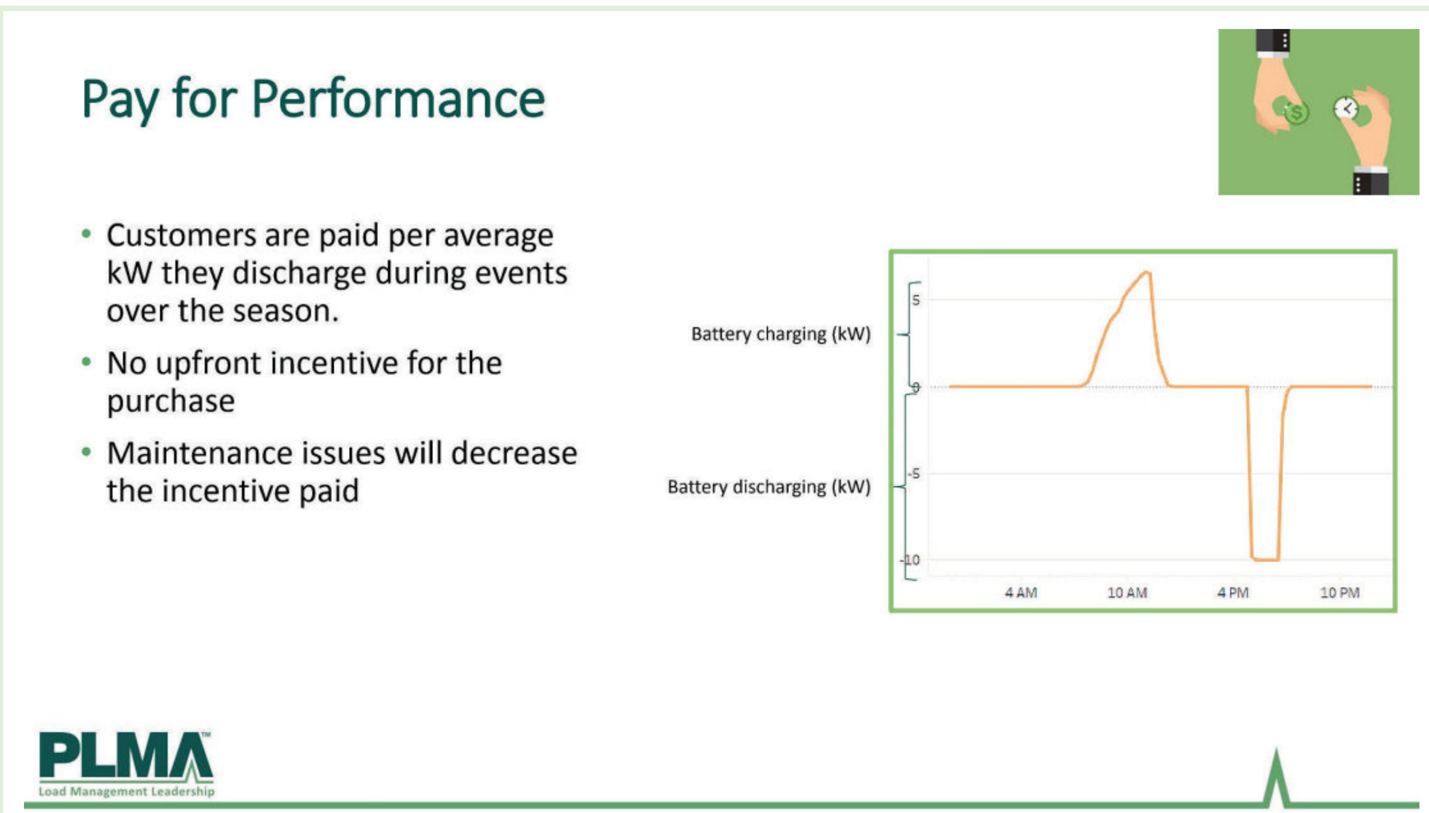


FIGURE 1 View Slide at: *https://bit.ly/3kQlIF5*

service area. Solar incentives are per kilowatt hour, which makes them also pay-for-performance.

The second key aspect of *ConnectedSolutions* is customer choice. We currently have four inverters for customers to choose from, not just one. Inverters control batteries so if you're used to thermostat programs, you already know how thermostats control central air conditioners or heaters. In the same way, inverters control batteries. Any qualified installer is able to install these inverters and some inverters also support multiple batteries. By focusing on the inverter, we think we're maximizing customer choice. Customers can choose their installer and choose their battery. We are also trying to add more new inverters to increase customer choice. In doing so, we're not picking winners.

ConnectedSolutions' third attribute is customer satisfaction. Ninety-seven percent of National Grid customers who responded to our survey said that they would recommend this program to a friend. Unfortunately, not enough of them have gotten around to recommending this program to Brett, so he's not a battery customer yet. However, we are seeing a steady uptake of customers, and I'm sure Brett will follow soon!

Brett: Perhaps I need some better friends! I hope I can be part of this program in the near future. Paul, what were the drivers of the *ConnectedSolutions* program for National Grid and how are you capturing value from it?

Paul: Our main driver was like the meat and potatoes of demand response, just peak load reductions. We realized that battery inverters can do a lot more than we currently have them doing, but this is our first foray into the battery world. Hence, we're using them just for peak load reduction, which for us is really hot, sunny, summer days.

Brett: Can you clarify how payment works; is it for kilowatt savings?

Paul: Exactly right, it's per kilowatt. For example, last year, the average performance over all DR events was five and a half kilowatts per battery. In Rhode Island, the incentive is $400 per kilowatt. So, $400 times five gives you about $2,000 per year in incentives. If anything happens to the battery, if the customer changes, if it's connected to WiFi and the customer updates their password, or if a customer just decides this isn't their thing anymore, that's okay for everyone. But because the program is based on pay-for-performance, that customer's financial incentive would also be affected.

Brett: Chris, what would you say has been the biggest barrier to program entry and how have you overcome that?

Chris Ashley: Initially the biggest barrier was primarily around getting battery partners on board with us while ensuring that the program was on track to be cost effective. In late 2017 and early 2018, it really was a challenge to get the battery companies to agree to participate. Their main question was about how this program would move the needle for their businesses and bring them new installations.

At the time, the customer incentive was lower and structured a little bit differently. With Paul's persistence, we got one battery company (at the time it was Sunrun) to agree to participate for the summer of 2018. That allowed us to get the program started. We had a handful of events that summer and lots of lessons learned. As we prepared for 2019, we restructured several things, including the program incentives, which we increased and made pay-for-performance. That change got the attention of the battery companies and several became interested.

Since then, we've shifted our focus to inverters in order to capture more inverter companies and in so doing, gain access to lots of different batteries and installers.

Brett: What made you choose the bring-your-own-device or "BYOD" route instead of a direct install model?

Providence, Rhode Island

Paul: Well, weren't the first ones to do this. We had some neighbors who also had a battery program and we learned from them. Their program generated some excellent results but we were concerned that if we focused too much on an upfront incentive, customers wouldn't have any continuing incentive to let us control their batteries and could easily just disconnect the whole thing. The solution was to make our program 100 percent pay-for-performance.

Brett: Is the *ConnectedSolutions* program targeted to provide load relief on specific local circuits? And if so, how do you market that to targeted areas?

Paul: Not yet. We haven't used this program for any of our non-wires alternatives yet. It is a system-wide curtailment event. We're doing this in both Massachusetts and Rhode Island, and we're calling the events at the same time. We are also working on getting this into our non-wires alternative areas, in a more localized format, but there are some regulatory issues holding that back right now. Fortunately, there are no technology issues. We do think customers would be open to this kind of program, and we didn't see any customer fatigue last year from the 40 or so events we called, so National Grid believes we could call even more events in order to capture both system-wide and local peaks.

Brett: This is not your typical peak-shaving program with just a handful of events per year. How many events have you called, and what does that frequency mean for the customer?

Paul: The 40 events we called last summer were primarily in July and August. When we call more events on sunny days, that's when we hit our peak. Less on cloudy days. That works pretty well with solar-charged batteries. We didn't see any customer fatigue, and as long as it's not a very cloudy day, we can recharge the batteries in time for the next day.

Brett: It's a new paradigm for customers and hopefully they don't feel a difference. Shifting to a technical question, what roles do OpenADR and other open standards play in the *ConnectedSolutions* program?

Chris: National Grid uses the EnergyHub DERMS to dispatch the batteries. They log into our software to run the control events. Between EnergyHub and the battery, we use an API-based OpenADR integration with the inverter company's cloud, where possible. They are not all OpenADR integrations, but that is the goal.

Brett: In the first year, the curtailment per battery wasn't that great. But in the second year it jumped considerably. What changes caused this improvement?

Paul: A key change in regulation that allowed batteries to export to the grid was the biggest factor. In our first summer, batteries could only displace the local load, which is less than a kilowatt per home, we learned! However, on average, the batteries can put out five and a half kilowatts. The regulatory change allowed us to displace the home loads and also export the additional renewable solar power to the grid. Before this change, we were really leaving most of the benefit on the table.

Brett: Nice when the regulators can provide some flexibility there, huh? As we pursue electrification, what considerations would you have for winter demand reduction programs versus summer?

Chris: Batteries are a flexible resource and they are not weather-sensitive, so the seasons shouldn't have much impact on their use. If anything, depending on a home's heat source, more of the battery may be available for load control in the winter than in the summer. National Grid's program is set up for both winter and summer demand response – the batteries are intended to offer flexible year-round resources. The only caveat I'd add is that National Grid's approach has been to tap into these resources when storms are less likely which means the customer might not be relying on the battery for resilience.

You can imagine in New England, in the winter, that power outages may be an issue during major snowstorms or ice storms. I would imagine that, over time, National Grid will have to consider what kind of buffers are needed to ensure customers aren't going to be relying on their batteries to ride through an outage. That's really the only consideration I can think of.

Paul: Exactly right. We do indeed have a program parameter where we don't call events before major storms because we know a lot of customers do indeed buy batteries for the purpose of resilience. We're trying to allow the customers to have their cake and eat it too.

Brett: Are there constraints on when the battery can be charged or recharged? What happens when customers want to use the batteries for their own purposes?

Paul: In our service areas, we don't have residential time-of-use rates. So, if a customer has a battery, except for during power outages, there are really no reasons, financial or otherwise, to do anything with it; it can just sit there. Now to get the federal investment tax credit, you do want to charge your battery with solar if you have it. I believe there's an 80 percent threshold. As a result, all the systems we've seen come in are paired with solar and are charging from solar. That does help the *Connected-Solutions* program because we don't see a snap back in the evening when we stop discharging. However, it's also a limitation. New England winters are typically pretty cloudy which may hinder us from calling more winter events because it's more difficult to discharge overnight or charge all day for back-to-back dispatches.

Brett: Is it a requirement in the *ConnectedSolutions* program that the battery be paired with solar?

Paul: It's not a program requirement, but the solar pairing is a requirement to receive a federal tax incentive, which is why customers are doing it.


Boston, Massachusetts

Brett: Who are your battery partners?

Chris: The inverter companies participating in the *ConnectedSolutions* program today are Tesla, Solar Edge, Outback, and Generac, and we are working to add others over the next several months.

Brett: I recently started seeing commercials on TV for Generac batteries and wonder if that will move the market as they become a more well-known name. Interesting to see them promote solar plus storage, in addition to the typical back-up generators.

Chris: Yes, this is a recent shift. In the beginning, we were looking at a mix of inverter companies and installers, as well as battery providers and batteries. We determined it's a fragmented market. You can't administer a program cost effectively that has dozens of different partners. The shift to focus on inverters was something suggested by National Grid, which was a really good idea. This approach mimics the thermostat model by capturing as much of the market as possible with the smallest number of the inverter companies.

Brett: And Paul, there was a question if C&I customers can participate or do you have other options for them?

Paul: National Grid has a similar C&I program that is also called "ConnectedSolutions." This program offers a slightly smaller incentive. If a system is generating over 50 kilowatts, it becomes part of our commercial program.

Brett: How long has the *ConnectedSolutions* program been approved for, and what's the plan for extending it?

Paul: In National Grid's Rhode Island service area, *ConnectedSolutions* is an ongoing program with no end date. In our Massachusetts service area, it is a demonstration program until the end of 2021. We are working with our regulators now to see if they like the program and if they want to convert it into an ongoing program. That will give National Grid, our customers, and installers the assurance that this is worth everyone's time. It is worthwhile for installers to learn about and get involved with the program. For customers, it's very difficult to commit to this large purchase if the window of opportunity becomes smaller every day. We're hopeful we can make that argument to the regulators.

Brett: Do the inverters prevent deep discharge to maintain system warranty, and how low can you go?

Chris: It is up to the participating inverter company to ensure that however the battery is being controlled is compatible with its existing warranties. We send the control signal to the inverter company's cloud, and it's really up to that company and their customers to determine how they participate in events when they get a dispatch signal, and to ensure that they're doing that within warranty or whatever other business frameworks are important to them. That's where pay-for-performance comes into play. The battery installer, the inverter company, and the customer all provision upfront the percentage of their battery they want to make available. That's also something a customer could adjust over time.

Brett: How are the program's incentives calculated and how do they work?

Paul: Here's a simplified example, although not a realistic one: let's say we called only one event for one hour for an entire summer. Let's take a battery in the program, which Brett, hopefully you will soon have! Over that one summer hour, the battery puts out an average of one kilowatt. We pay a customer $400 per kilowatt in Rhode Island, so that customer would get $400. However, as we've said, the average battery in the program generates more like five kilowatts. So, five times $400 is $2,000 per year.

As we consider the incentive for only one hour and one hypothetical event, it's important to note that the *ConnectedSolutions* incentive doesn't actually change when there are 40 events. If each of these 40 events lasted about two hours, we'd still pay the average discharge rate of that battery over the summer. So, if we mimicked the one hour performance incentive for 40 events, each lasting two hours or three hours, you can see how much the customer would get paid, as the incentive stays the same even with the increased number of kilowatts.

Brett: How do you combine DR programs like the batteries with the smart thermostats to enable multi-resource control orchestration?

Chris: This goes back to targeted dispatch. The resources are there in a single platform for National Grid to manage. The need today is really just about, for the batteries, those daily system peaks that National Grid is targeting, as opposed to more dynamic load shifting or optimization in which the utility is trying to shape load over the course of the day.

The *ConnectedSolutions* program is not doing that yet, but batteries are incredibly flexible. With some of our other utility clients, we are doing daily optimization, reflecting output of solar resources, and using batteries and other devices as storage to shift load into the times of day when the sun is shining. And then as peak load emerges, as peak solar goes down, using these storage resources to discharge at those times. But this is not National Grid's use case today.

Brett: Talk a little about the recruitment of customers and how they engage in this program. Is it hard for them to understand? What kind of sales process is required?

Paul: Batteries require a very different sales approach from our thermostat program. All the customers we've seen so far are pairing their storage system with solar, making the majority of installs the purview of local "mom and pop" solar installers in Massachusetts and Rhode Island. As a result, the sales process typically happens at the kitchen table between a customer and an installer. But these are person-to-person sales in which a vendor is explaining both solar and batteries, and this is time and resource intensive. National Grid has been working with local solar groups, stakeholder groups, to provide installers with education and the tools to help them understand and sell *ConnectedSolutions* to their customers.

Chris: A thermostat, after all of the available rebates, might cost a hundred dollars, or even less. A thermostat program incentive might be $20 or $25, so it's easy for customers to make a quick decision about participating in that program.

However, if a customer is looking at spending $15,000 or potentially more on a battery, they will evaluate the program opportunity much differently, and as an installer, I'm willing to invest the time and energy needed to explain the program to that customer. The person-to-person high-touch sales process is important. And while the *ConnectedSolutions* program is also a bring-your-own-device program, the customer enrollment experience is very different from the digital marketing pitch that often compels a customer to decide to participate in a thermostat program.

Brett: As a customer who installed solar a few years ago, I need to figure out what kind of retrofit opportunity might be available so that I can participate in your program. So, I'm open to a sales pitch!

Paul: Send me the specs on your inverter, Brett!

Brett: I'll have to look them up! But as this is a very unique program, what are some of the lessons learned?

Chris: An important recurring theme is one of flexibility. The way *ConnectedSolutions* is structured today is not how it was structured in its first summer. National Grid has done a good job of evaluating its program each year to figure out how it can be improved. Paul talked about the incentive structure going from fixed to pay-for-performance. We've talked about the shift from being open to different kinds of battery providers to focusing on the inverters today. We also discussed the regulatory framework and what it allowed in terms of battery discharging. This was the biggest issue in the first summer of *ConnectedSolutions,* and its resolution allowed the program to grow. Program flexibility is key.

Chris: Another important lesson learned is from the bring-your-own-device program approach, which does offer flexibility. However, BYOD doesn't mean battery marketing and enrollment will look the same as it does for thermostats. Instead, this sale is based on how a customer views their battery, and how they purchase and interact with it. This sales process embraces the discussion the customer expects to have with an expert before they will enroll in the program.

Brett: Thank you Paul and Chris for sharing this battery success story, and congratulations again to National Grid and EnergyHub for your Pacesetter award-winning *ConnectedSolutions* program!

Presenters:

Paul Wassink
National Grid

Chris Ashley
EnergyHub

Brett Feldman
Guidehouse Insights

The conversation above is from a webcast recording at
https://www.peakload.org/dialogue--national-grid---energyhub

Thought Leaders

City of New York, Department of Citywide Administrative Services, for Building Operator Engagement

Presented August 2020

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in August 2020. It discusses City of New York's award-winning public engagement efforts with building operators. This discussion was moderated by PLMA Awards Group Co-Chair and Executive Committee Member Laurie Duhan who also manages Baltimore Gas & Electric's demand-side management portfolio, including its direct load control and behavioral demand response program.

Laurie is joined by three guests from the City of New York's Division of Energy Management: Sergey Shabalin, Director of Load Management and Utility Affairs, Elizabeth Taveras, Energy Engineer for Load Management, and Martin Nolan, Energy Engineer for Load Management.

Laurie Duhan: I'm pleased to be speaking with Elizabeth Taveras, Martin Nolan, and Sergey Shabalin about their award-winning building operator initiative on behalf of the City of New York's Department of Citywide Administrative Services (DCAS). Please tell us about your backgrounds, your work with building operators, and how that has made a difference for the City of New York.

Elizabeth Taveras: Thank you, Laurie. My background is environmental engineering with a focus on mechanical engineering. I did some additional schooling and also have a master's in both Material Science and Engineering and in Sustainability Management. I've worked at the Division of Energy Management for one and a half years, although it feels like I started yesterday!

Working for the City of New York is very different from working in the private sector because our mission and all of our metrics are focused specifically on mitigating climate change, which is something I'm very passionate about.

Martin Nolan: I have a background that's an alphabet soup! I'm an associate engineer, like Elizabeth, in the Division of Energy Management, Load Management Group. Bachelor's: mechanical, Master's: electrical, PE, CM, CBCP and, from a prior career, I am also a CPA. I've been in the Load Management Group for about a year and a half and it's a very dedicated group of engineers focused on NYC's climate goals. The group also reviews other key goals, such as the Paris Agreement which uses the phrase "80 by 50" to describe a reduction in carbon emissions of 80 per cent by 2050. We all feel like we're on a mission!

Sergey Shabalin: I have been at DCAS for eight-plus years now overseeing operationally focused programs, such as a load management, real-time monitoring, and demand response. On behalf of our agency, I'd like to thank PLMA and Laurie Duhan for your gracious recognition of the impact of this program.

Laurie: Please share with us how the building operator engagement program developed and give us a little bit of a timeline.

Sergey: This effort started back in 2013, which feels like such a long time ago! That's when we took our demand response work in a new direction. We partnered with a company called NuEnergen in order to grow demand response and real-time monitoring programs for city-owned buildings in New York. This included almost 500 municipal facilities across 30 city agencies and organizations. Over time, the City's DR portfolio grew to over 100 MW of committed load shed. Today, almost 600 city facilities encompassing almost 60 percent of the portfolio's one gigawatt peak load are monitored in real-time for their electricity use. A subset of those facilities is also monitored for gas and steam. All this was made possible by NuEnergen which built a platform for us called "EnerTrac" to monitor all high-resolution load profiles around the clock, 24/7.

With this progress, we recognized an opportunity and launched the Load Management program in 2016 with one staff person. This program was rooted in our ability to partner with building operators, monitoring and responding collaboratively to evolving energy consumption patterns. For example, we did a pilot project in one city building, the DNA Lab building at the Office of the Chief Medical Examiner. On that project, we were able to save 10 percent in electricity and 22 percent in steam consumption, which translated to almost 600 tons of emissions and about $200,000 in annual savings!

That success story opened doors for us and made it possible to expand our program resources. Martin and Elizabeth were part of that expansion and are now leading the Load Management team into a new and exciting era.

Laurie: How does your program define load management? And how does that definition translate into the work you do?

Elizabeth: For us, the definition of load management really centers around load profiles. Sergey just mentioned the connection to EnerTrac, which is the software we use to analyze our load profiles. Beyond that, we collect, interpret, and optimize load profile data, and use that data to "re-tune" city buildings, implementing no-or-low-cost operational energy

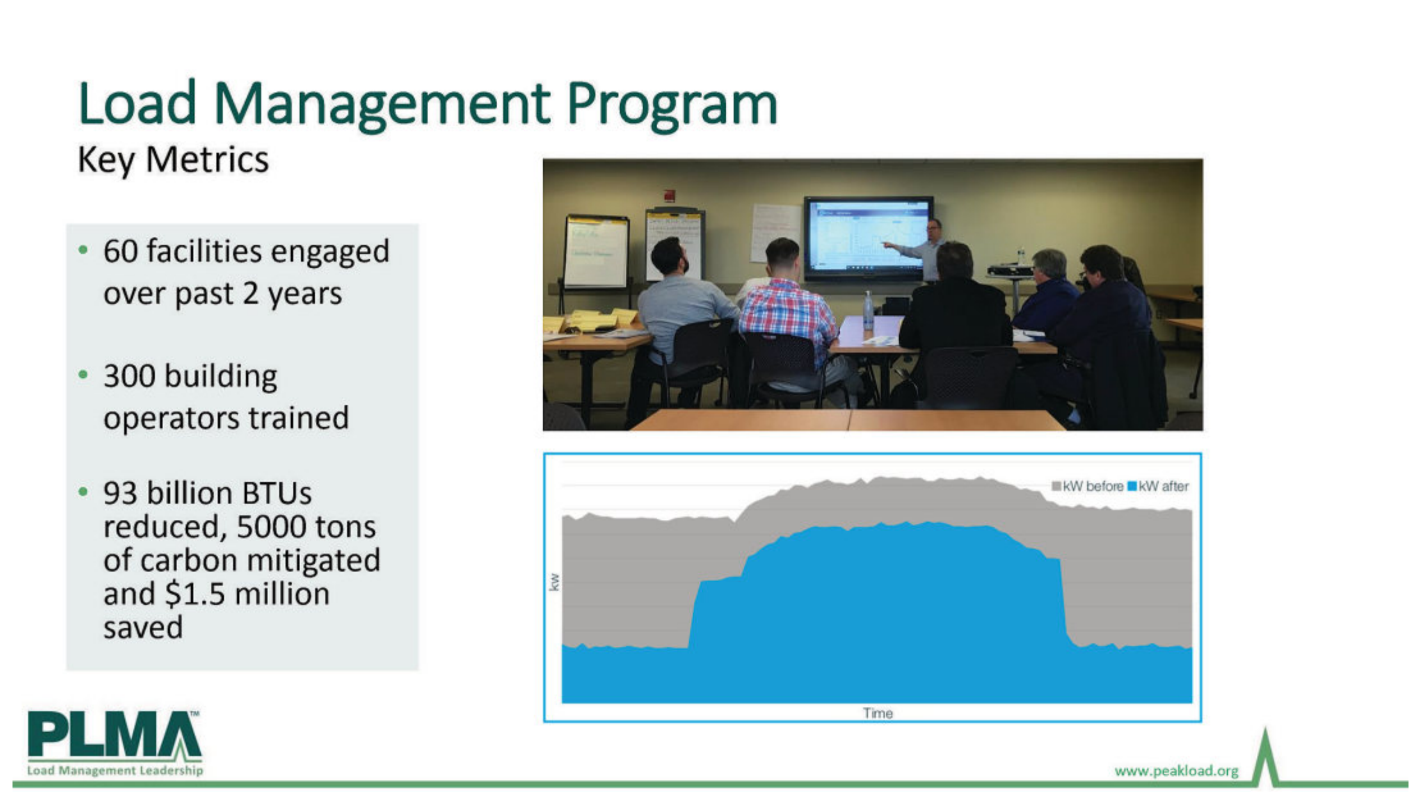


FIGURE 1 View Slide at: *https://bit.ly/383yigl*

efficiency measures. That's the core of the Load Management program, which evolved from the original project with the Office of the Chief Medical Examiner. All of our work relates to load profiles and is grounded in the invaluable research and analytics we get from NuEnergen's EnerTrac software.

Laurie: What has been your approach to working with buildings on load management?

Martin: It begins with finding "clients." These are the building operators we work with in a consulting relationship. Sometimes agencies will reach out to us for help too. In addition, we have a Quarterly Energy Forum gathering where we mix and mingle and talk, and this can also serve as the start of a new work relationship. To find buildings that are consuming energy outside of the norm for their building class, we study billing data. Our group sees the energy bills for 4,000 accounts which represent buildings that New York City owns, rents out, or leases. That's a big database!

New York City, like many other cities, also does bench-marking. We call it LL84. The buildings are required to submit their benchmarks every year, and about 33,000 buildings provide us with their energy consumption, square footage, and other details. What's great is these submissions are not just from municipal buildings, and this means we can compare how our own buildings are doing relative to private sector buildings and identify the "energy hogs." These buildings are the ones we reach out to and offer assistance. We also get clients through our load management training and coaching program, which Elizabeth runs.

Once we engage with a client, the task is one that requires diplomacy. Sometimes in business, we talk about the carrot and the stick, right? The building operators come to us because of a stick, but we want them to stay for the carrot. Clients also come to us because they're curious or interested and they stay because they trust us. So really, the whole process is about building trust.

A great example: a Brooklyn schools administrative building that was running its equipment 24/7. It ran so many hours because teachers must call into this building if they are sick and need a substitute. The building opens at 5:00 am, and stays open until 6:00 pm, every day. We began working with the building's operator. Of course, there is always hesitation at first, and operators will say, "Hey, are you going to take the calls when people start complaining?" We respond, "Our job is to get you comfortable with what we're doing so that there won't be any more calls."

We told the operator of the school administrative building that we'd put some data loggers around the spaces and try turning off the equipment overnight so that there would be a hard stop on Saturday at 2:00 pm. Knowing no one would be in the building till 5:00 am on

Monday, we suggest turning the equipment back on at 1:00 am on Monday morning. The building engineer said, "Whoa, Whoa, Whoa!"

Seeing his concern, we asked for his input, and he suggested turning the equipment back on at 10:00 pm Sunday night. We went with that, and told him with the data loggers, we'd be able to determine how many hours the equipment would need to run to hit the temperature set point. The building engineer and his boss liked that approach and from that point forward, they realized we were there to empower them with the information they needed to make the best decisions. Generally speaking, most people want to be able to do their job better. The operators all understand climate change, and they all understand saving money.

We also created a "Field Equipment Lending Library." That way, the building operators gained access to a repository of equipment, so that if for example, they need an anemometer, they don't have to spend $700 to a $1,000 to buy one. Instead, they can borrow it from our library. So now, the operators have the tools they need to do their jobs to the best of their ability.

Laurie: Tell us more about the training and coaching program that your team developed.

Elizabeth: Yes, this is part of our Load Management program. One of the most prominent trainings we currently offer is called "Load Management Training and Coaching." This class is geared toward building operators and finding ways to engage them in implementing the no-and-low-cost energy efficiency measures we've been talking about.

Of course, with the COVID-19 situation we're in now, energy efficiency is not necessarily our number one priority. We're more focused on improving system efficiencies. We want to make sure the City's buildings are efficient so when they transition back to normal operations, when people begin returning to work or returning to school, the buildings will be ready and in top shape.

The training is focused on collecting what we call "trend charts," which are essentially time series data of different building system points. With the trend charts, we can work with a building operator to explain what parameters are within the trend chart and where the faults lie. Together, we can then diagnose problems and implement appropriate solutions. We've had a lot of success with this approach and we found it really appeals to building operators.

We've also discovered the operators are using a lot of what they're learning beyond the classroom. And that's really our goal; for this to be sustainable learning. They bring what they've learned back to their building, back to their facility, and we hope they will also share it with colleagues and especially with their boss. We call these concepts "building re-tuning," which is adjusting a building's operations so it is working at its highest level of efficiency.

New York City, New York

Laurie: How had COVID-19 impacted the Load Management program?

Elizabeth: COVID-19 is the elephant in the room! It has affected our buildings in three phases. The first phase was a shut down of all nonessential businesses, starting March 22, 2020. While some buildings did not close because they are considered essential, many others did. Our main focus during that time was to work with our building operators in the buildings that no longer had occupants and look for opportunities to shut off equipment such as air handlers. We'd ask the operators if a handler needed to be running if it was supplying air to an empty room. In many instances, we were able to work with operators to turn things off and curtail a significant amount of energy. Of course, this is very specific to situations in which there are no occupants!

There are two examples that are both interesting and useful beyond COVID. The first is the Department of Education, DOE for us. We worked with their building engineers to curtail 40 percent of the energy used, compared to the previous year when school conditions were normal. That's a huge chunk of energy saved simply because we were able to turn things off. Turning off unnecessary equipment to produce big energy savings is a quick and easy solution to no-cost energy efficiency measures. As a result of DOE, we learned the value of just getting on the phone with building operators and engaging one-on-one.

The second case study was the New York Hall of Science where we realized 50 percent energy savings. Again, this was mostly about turning off unnecessary equipment, but the building operator realized that even during normal times, the building was unoccupied between 6:00 pm and the next day at 5:00 am. For several hours every day, the operator would be able to continue to turn off equipment post-COVID-19 to produce an ongoing and sustainable opportunity for energy savings.

The second phase is reopening. Recently we've been given the order that buildings can start reopening. The Load Management team is trying to understand what opportunities that represents. Of course, things are evolving in real time but one of the biggest things that has come out of this conversation is that system efficiency is a key component to sustainable energy savings. No matter the circumstances, having optimal, efficient systems is a top priority. So this is a theme we're continuing to play out, both within our training programs, and as we work with our building operators.

Phase three, which happens after the pandemic ends, hopefully soon, is also an evolving conversation. One we're still trying to figure out. Where will the Load Management program will fit within the broader context of the Division of Energy Management, but also for the City of New York?

Laurie: Turning things off is a really good way to save. What are your most common, or largest, energy saving load management measures other than turning equipment off?

Martin: Implementing occupancy schedules. And a lot of this has to do with just recognizing with an operator, for example, that over the last five years, two floors in a building have been rehabbed and are now being used for a new purpose. Hence, it's time to re-look at the whole energy situation. Back when I was a design engineer, I knew there was a process to get to commissioning turnover. But I was never there to tune a building after the fact. I designed for a 15 degree day in winter and a 95 degree day in summer. But when you get to the shoulder seasons, you don't need to start up the air handlers as early.

Adjusting set points and setbacks. Again, depending on the situation, sometimes you don't want to turn things off. In a laboratory, for example, the fume hoods will run 24/7. But a lot of times, they also want some air circulating in the laboratory, even though no one is there at night. Still, why have it at 72 degrees when you could set it back to 80/82 degrees in the summer and 62/65 degrees in the winter? That alone saves a lot of energy and money. Getting the correct outside air damper position, sometimes called an "economizer." If it's 60 degrees out, why cool the air? Why treat the air? Just use outside air. It's all ready to go.

At the Brooklyn schools administrative building, we noted there was nobody in the building when the building operator was doing the morning warm-up cycle to get to set point. The outside air damper can be closed. The code says "When Occupied." Well, you don't have to ventilate when nobody's there, so you could take the three-hour time period that's needed to reach the required temperature and reduce it to a two-hour process instead. There again, money is saved.

The other opportunity is optimizing the variable frequency drive (VFD) schedules. These are the motor drives used in electro-mechanical drive systems to control AC motor speed and torque. We spent a lot of money updating our equipment, getting VFDs, so that we can change the speed of the motors. However, optimizing VFDs takes some math and some engineering. As engineers, we can help building operators with this task. A good common example of this is cooling towers. If there are four fans on a cooling tower, plus four pumps to get the water up to the cooling tower, often they'll be set up as "Lead-Lag." This means that one pump ramps up to 100 percent, then the next one starts and ramps up to 100 percent. But if there was load sharing, it would be possible to run all four fans at 50 percent, which would consume less than a third as much energy, compared to two pumps running at 100 percent.

Laurie: How do you measure success of your program?

Elizabeth: This is also an interesting topic because it will probably evolve as a result of COVID-19. Historically, the way we've measured success was based directly on how much energy savings we were able to achieve in the buildings we worked on. Specifically, how many net MMBTUs of energy we saved relative to the previous year, normalized by the City-wide average, for all different energy types, for 12 months. Related to that is the measure of our GHG emission avoidance, and finally, the cost savings achieved. Unique to the City, the Department of Citywide Administrative Services pays all of the utility bills. So the money we save is real taxpayer money.

This historical approach to measuring the success of the program has propelled us forward and helped us expand the program. In the 18 months I've been here, we've added five new team members. That correlates to how much savings we've been able to realize through both the trainings, and also the one-on-one work we do with the building operators at City facilities.

It's important to note that energy savings are important and valuable to the Division of Energy Management, as that's what our mission is focused on. We also expect to continue the conversation about how this work will be affected by COVID-19, and even more generally, public health overall.

Laurie: There are lots of buildings in New York, overwhelming number of buildings! What are the predominant types your program comes across?

Martin: Most of what we work on is commercial office buildings. For example, a courthouse. It's really an office building, but it's different from an ordinary office building because it's got courts and it's got a small detention center. In the case of the police headquarters, that building is a big office too, but it also has a gym, a swimming pool, and a shooting range. The largest of all the agencies is the K-12 schools. Largest square footage by far, 1,200 buildings, and then under the current mayor, the addition of "pre-K for all" means there are also annexes at many schools.

Then there are also about 35 museums and cultural institutions, including art, history, children's museums, Carnegie Hall, the Botanical Gardens, the David Koch Theater at Lincoln Center. The "culturals" are not just museums, but a large variety of institutions. We also have 14 wastewater treatment plants within New York City, 11 public hospitals, there are laboratories, and we talked earlier about Office of Chief Medical Examiner. Interestingly, almost all of these buildings could potentially have a laboratory too, including the hospitals, the wastewater treatment plant which checks water, and the New York Botanical Gardens which has an entire building that's a laboratory. You can do your PhD there! I have a friend who did a PhD at the American Museum of Natural History. K-12 schools have science departments and so they often have laboratories as well.

Data centers are growing too. For a long time, we've had the 911 and 311 phone systems. The City is also growing its amount of data collection. The Mayor's Office of Data Analytics was recently created because we have so much data to manage. Now that the police have body cameras, that data must be stored. You can see there are massive amounts of data. I always like to joke that I never wanted to go to jail, but the Department of Corrections, Rikers Island, is my client. Last week, we saved 5,500 kW at a building on Rikers Island.

Each building presents its own opportunity because of its unique application. Plus, as the City works to become greener and more sustainable, some buildings now have solar. In others, we have ground source heat pumps and energy recovery systems. All of these systems must also be optimized for their operations. So you can see that working with such a diversity of buildings is a lot of fun!

Laurie: You hit a lot of my favorites, but you missed the Library, one of my favorite New York City buildings! Are there broader climate initiatives going on in the City? How does the Load Management program contribute to that?

Elizabeth: If you follow the City of New York's local laws and all legislation related to climate change, public buildings are now directly responsible for reducing GHG emissions via Local Law 97. Most recently, the Load Management program has become involved, as part of the Division of Energy Management, in an "Implementation Action Plan." This is a partnership with the company Wildan in which we are trying to find ways to implement what's being requested within Local Law 97. So that's one direct way in which Load Management has been involved in the broader climate change initiative.

More generally, the Division of Energy Management's mission is to reduce and mitigate climate change. I do think the metrics of the Load Management program speak volumes here. In fiscal year 2019, recently concluded, we achieved 67,000 MMBTUs in net energy savings for the buildings that we were able to work with. This translates to almost 3,700 metric tons of carbon dioxide equivalent. For those who like cost values, that is over $1 million in taxpayer dollars saved.

Laurie: A very impressive outcome! Thank you very much for sharing your accomplishments and your enthusiasm with us, and congratulations again to the City of New York, Department of Citywide Administrative Services, for your PLMA Thought Leadership award!

Presenters:

Sergey Shabalin
City of New York Department of Citywide Administrative Services

Martin Nolan, PE, CEM, CBCP
City of New York Department of Citywide Administrative Services

Elizabeth Taveras
City of New York Department of Citywide Administrative Services

Laurie Duhan
BGE, an Exelon Company

The conversation above is from a webcast recording at
https://www.peakload.org/dialogue--cny-building-operator-engagement

Thought Leaders

CPS Energy for Public Engagement

Presented July 2020

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in July 2020. It discusses CPS Energy's award-winning public engagement efforts, which helped the utility to manage two very challenging summers of extreme temperatures and peak loads. This discussion was moderated by PLMA Awards Group Co-Chair Michael Smith who serves in the role of Lead Program Manager for Demand Response with National Grid. He is joined by Justin Chamberlain, Manager of Energy Efficiency and Demand Response with CPS Energy, and Julie Cain, Residential Program Manager for CPS Energy.

Michael Smith: Thank you and congratulations to PLMA Award Winners CPS Energy, in the Thought Leadership category. CPS Energy is the municipal electric utility serving the city of San Antonio, Texas. Please tell us about yourselves and your work in public engagement.

Justin Chamberlain: Michael, it's great to be here! Let me start by saying thank you to PLMA for this award. Our team put a lot of hard work into this project and we really appreciate the acknowledgment. Our team focuses on a portion of our DSM portfolio that we call STEP, or the "Save for Tomorrow Energy Plan."

This plan is made up of four areas of focus: 1) energy efficiency, 2) demand response, 3) weatherization, and 4) solar. Our team focuses on the first two. Our goal was to accomplish a reduction of 771 MW by the end of this year, 2020, and we're happy to say that we actually hit it in 2019, one year early! In addition, we exceeded our goal by almost 74 MW and came in about $120 million under budget; a really outstanding performance. It was our demand response work especially that made it possible to achieve the energy use reduction goal early.

Julie Cain: Echoing Justin, thank you again to the folks at PLMA for this award, it's a great honor. I have worked in my current residential program role since 2017 and I can definitely say it gets better and better. No day and no summer are really ever the same. On a day-to-day basis, I oversee the operations of CPS Energy's residential DSM portfolio, including both our direct install and BYOT thermostat programs which have a combined total of over 150,000 enrolled thermostat devices. I also oversee our behavioral demand response program which has about 320,000 customers enrolled.

CPS Energy is the largest municipally owned utility in Texas with over 860,000 electric customers, and about 360,000 natural gas customers. We're a summer-peaking utility so our programs are focused on lowering the peaks in the summer.

Michael: Please tell us about CPS Energy's portfolio of demand response programs and how you're using them in the market.

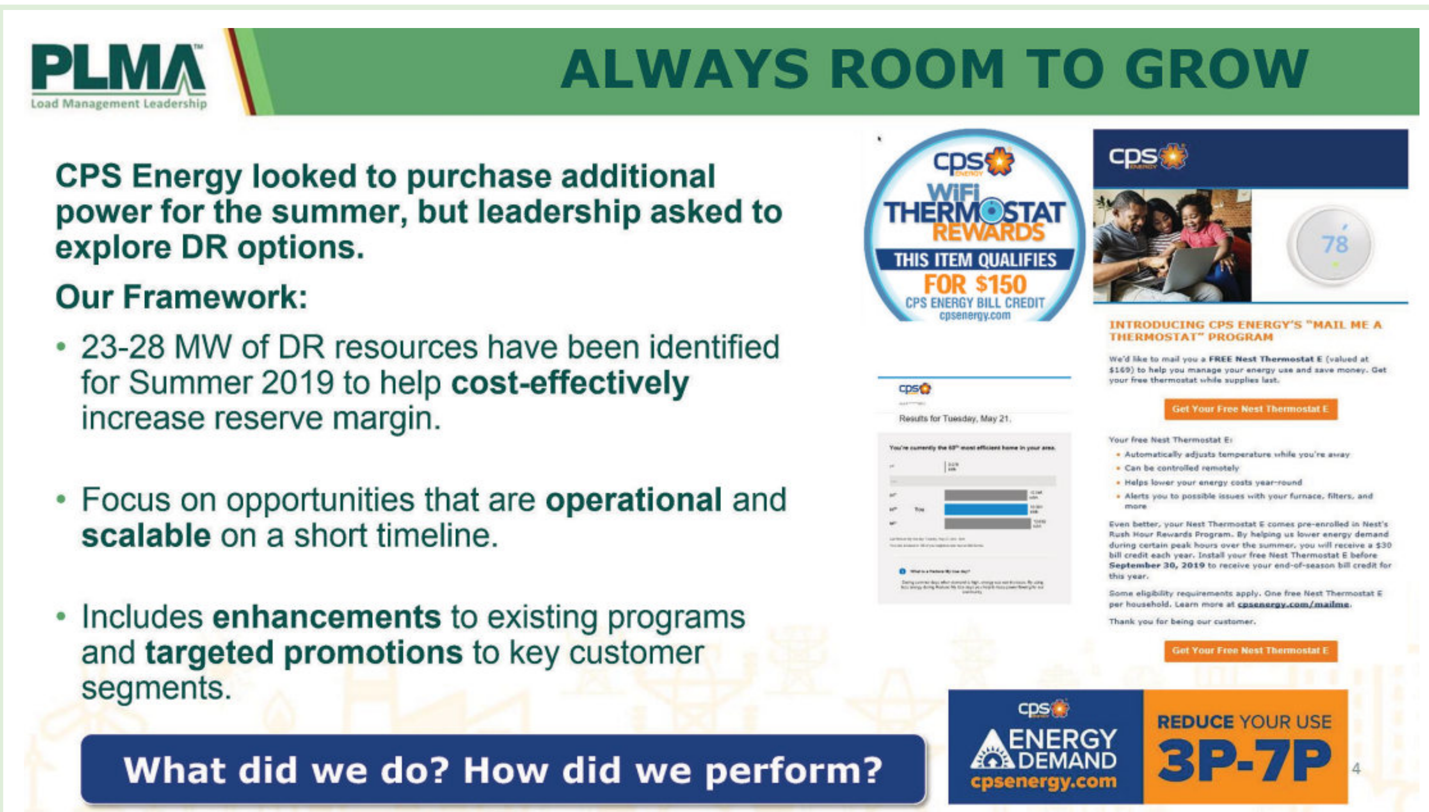


FIGURE 1 View Slide at: *https://bit.ly/3kS6HCm*

Justin: A large part of our DSM portfolio is called the "Save for Tomorrow Energy Plan" (STEP). CPS Energy began installing thermostats in customers' homes the year before I started, in 2003. Julie mentioned our residential programs in which we have about 150,000 residential thermostats, our behavioral demand response customers of which there are 320,000, and we also have about 755 commercial sites on the STEP program.

Putting that all together, CPS Energy has about 260 MW of demand response. During the summers, we generally call somewhere between 19 to 22 events, so we think of DR as an important resource. We're able to use it to help protect our customers against market prices and to be able to lower our transmission costs. Our main focus is to help lower energy costs for our customers. We actually called an event this past Monday when it was 105 degrees F here in San Antonio and deployed all of our resources to lower the peak.

Michael: With that framework in mind, tell us why CPS Energy launched the STEP plan.

Justin: Around the beginning of March 2019, ERCOT published a press release that spoke about high summer demand and tight margins. This meant the market cap would be $9,000 per megawatt hour. Pre-summer, we were looking at potentially really, really high energy prices, a lot of which was being driven by the fact that there was significant market retirement of thermal generation, which had been replaced by some non-dispatchable resources.

Our leadership team got together and said, "Okay, what can we do to help protect our customers from a very expensive summer of energy bills?" One idea was to buy more power to help protect ourselves. But leadership came back and said, "Before we do that, why don't we see what we can do with DR?" That was an exciting moment for us – leadership was recognizing DR as a resource that could be trusted to help protect customers. They came to us and asked for a plan for summer 2019.

Michael: Once you got that direction, did it come with a specific goal? What was the marker for success?

Justin: Leadership actually posed that question to us, asking what we thought was possible. Fortunately, DR is a mature program for CPS Energy, with a lot of customers and thermostats enrolled, thanks to the efforts of our account managers and residential team. We responded that we could identify about 25 MW in a short time period.

The short time period meant we had to get up and running and launched quickly. We couldn't try too many new types of programs. We had to figure out how to deliver even more results from the programs we had in place. We looked at the new outreach for our commercial customers, we thought about how could we get our thermostat program enrollment up, and we also looked into improving our support for behavioral demand response so as to add more customers there.

Michael: How did you approach residential customers in this project?

Julie: Around the time we were tasked with increasing our energy savings, we had already increased our BYOT enrollment rebate to $150, and that was up from our usual $85 for the enrollment. This was due to an annual holiday rebate increase that we do each year for about three months to really drive up enrollment. The quick hit for the summer of 2019 was to keep our thermostat enrollment up, so we continued with the increased rebate of $150 until the end of the summer, which really helped.

Another project developed into a hybrid, so to speak, of our direct install program and our BYOT thermostat program. And we named it, "Mail Me a Thermostat," where we targeted residential customers who had higher energy usage and emailed them an offer for a free pre-enrolled thermostat if they would install it themselves. We also married the existing energy efficiency and demand response program into a bundled offer that included our home energy assessment program and our low-income weatherization program. As a result, we provided valuable energy efficiency savings and offered free installed thermostats to qualified customers.

Moving on to behavioral demand response, we increased the enrollment from a little over 100,000 customers when we started, to about 320,000 customers. To support this growth, we also made sure there was proper support in place so that customer had the best possible experience.

A couple of interesting points: first, these results required a huge amount of customer communication. The behavioral demand response (BDR) program necessitated about six million customer notifications over the summer, including pre- and post-event communications. Plus, by combining our BDR enrollments with the thermostat program, we now have over a half of the CPS Energy customer base on a DR program. I thought that was a really great outcome of our increased efforts on the residential side.

Michael: Those are impressive numbers. Tell us about the public outreach campaign that facilitated these results.

Julie: We collaborated with our phenomenal Marketing and Corporate Communications teams on an awareness campaign that explained the concept of peak usage days to customers. In addition to BDR, our Marketing team also created billboards that said, "Tomorrow is going to be a peak energy demand day," or "Today is going to be a peak energy demand day." We also partnered with local news stations for a segment called "Energy Matters" that reinforced and expanded on the billboard messages, both before and after the events.

The news channels also did a follow-up segment with a thank you to our customers and provided the estimated demand savings that had resulted. That really helped us to drive home the message about the importance of peak energy demand days. When customers saw both the billboards and the news segments, the reinforcement helped them understand how the two pieces fit together. This understanding led them to making temporary changes in their homes to save energy.

Justin: We really appreciated the efforts of our Corporate Communications team and our Marketing team because before this initiative, all of our DR messages had been internally focused. Meaning, if you were enrolled in the program, you heard about an event, but if you weren't enrolled, you didn't receive any messages at all. This was the first time CPS Energy had really provided broad external outreach about our demand response events.

In addition, we tried to align the energy messaging with the commonly understood issue of San Antonio's aquifers, which everyone here follows as these provide our water. When the aquifer is low, we hear about it continuously on the local news. We believed the electric grid was a similar resource and wanted to be able to say to customers, "the grid is constrained today, can you cut back on your energy use to help the whole system?" We thought this was a great opportunity to reach out to the public and speak to them in terms they already understood and responded well to.

Michael: You've told us how you approached the residential customers. What did you do to achieve results on the commercial side?

Justin: There were two main focuses on the commercial side. One was just good old-fashioned outreach. We worked with our account managers who did a really good job last summer of getting out and explaining to customers what was going on with energy use. I am going to call out one of our account managers, Bob Nelson, who worked extensively with our commercial and manufacturing customers to let them know that we could use their help. His approach, and the one-to-one communications with our biggest customers, helped us achieve a lot of new enrollment. Robert Olivares and Joe Jones were equally as effective with our school customers, and we are working with the schools to make sure they can participate and help us during the summer.

To work with the schools and the manufacturers, we added resources, but we also provided something we called "DR Coaching." We knew we had customers, both new and existing, who would need some support to participate. We thought they may be leaving kW on the table while they were trying to figure out how to participate. We actually went to their sites, walked them through how to participate in events, identified key measures, provided them a report, and also offered them support to make sure they could consistently implement the measures that had been identified. Together, these efforts helped increase the number of commercial customers who sustained the program.

San Antonio, Texas

Michael: With all these efforts, residential customer engagement, a new public outreach campaign, a focus on commercial and manufacturing customers, how did the summer turn out for CPS Energy?

Justin: It was a good summer. We put in this effort and there was always the chance that cooler weather could have come in, that we weren't going to need all these additional resources. But it ended up being a very exciting season! We called 26 event days, which was a lot of event days for a typical summer, and we were able to hit all of our peaks for the summer. Plus, we were able to dispatch during two energy emergency event days.

As an aside, we did hit the $9,000 per MW prices. The day that happened, I was in a PLMA meeting. We had just sat down and had been asked to set our phones aside and focus on the meeting. Right away, my phone started buzzing with notifications that things were happening in our market! Fortunately, CPS Energy was able to respond quickly, dispatch our resources, get our customers reacting, and use all of our new resources to protect our customers against big energy prices. Thanks to the strong response from our customers, we succeeded in reducing ~269 MW last summer. Internally, CPS Energy also reached its operational goals.

Michael: Earlier, you mentioned 25 MW as an incremental project. How did you manage to do that on the front end of this project?

Justin: We set that goal and I am proud to say we exceeded it, plus we ended up with an additional 44 MW for the program. Nineteen of those MW were from our schools and manufacturing customers. Julie can expand on the behavioral and thermostat results.

Julie: Yes, that was a great summer! We saved about 17 MW through the behavioral side while thermostats saved another eight MW.

Michael: What do you think the biggest lessons have been for you and CPS Energy from this initiative?

Justin: The first one is that DR is a real resource. We've used DR for years to address peaks, which helps lower costs for customers. But last summer really was a big challenge! We had various power emergencies and we were able to counteract them by relying on our DR resources which could be quickly dispatched to help protect our customers from high prices. Another important learning was that we were able to really count on our customers and DR to deliver when we needed them. This initiative reinforced the value of CPS Energy's DR program.

We also learned there is room to grow, even with a mature program that's been around for a while. Sometimes we just have to take a step back and say, okay, well, is there a different approach we could try out in this program? We've done direct install for years, and we focused on a "Bring Your Own" model for a little while, but with our "Mail Me a Thermostat" program, we were able to mesh these two approaches together. We found this was a good way to capture customers who may not have gone out and bought their own thermostat but who were open to installing a new one that was all set up and ready to go.

Julie: Another important discovery that came from this initiative is the power our customers have to positively influence one another through friendly competition. I'm speaking more about the BDR program and the event notifications in this instance. The combination of BDR and the awareness campaign with the billboards and news outlets resulted in a huge social media presence from our BDR customers who posted their results and began conversations with others. This especially helped us to drive home the significance of peak energy demand days, what they mean, and how customers can really make a difference to the grid when they save energy.

Michael: I know this is a question that a lot of us have because we're all dealing with it and trying to figure out how it changes the way we do things: what impacts have you seen from COVID-19 so far?

Justin: It's still a little early in the season to be able to say what is COVID, and what's not. At present, we are seeing our peaks getting flatter. Normally about 91 percent of the ERCOT peaks are between 4:00 to 5:00 pm or 4:15 to 5:15 pm, but now we're starting to see peaks occurring closer to 3:00 pm, and then the next day, closer to 6:00 pm. We've observed a longer flat peak. Whether that's COVID, whether it's folks participating in demand response, or whether it's just weather (we have a lot of pop-up showers that come across the Texas Coast), we don't know yet – there's still a lot to learn.

San Antonio, Texas

However, we are looking very carefully at how we dispatch our programs, and to be sure, we're focusing on both those peaks, but also remaining aware of the need for customer comfort when we dispatch events.

This year, our terrific marketing team expanded our outreach to all of the local news stations, which has made it possible to message all the stations in English and Spanish to let customers know about pending events, and the need for their help this summer. We also encourage customers to stick with us and to not opt out of events. This past Monday, I was watching the Today Show and while they were presenting a weather update, a Peak Day Alert came up. It was great to see this message going out to inform a wide audience, and also encouraging more customer involvement.

Julie: I agree it is early in the season to determine the impacts of COVID-19, but we are seeing some wider variance in participation as more people are at home during demand response events. While I'm not seeing year-to-year variability or program opt-outs yet, I am noticing with more people home, set points are different. It will be interesting to look back at the summer of 2020 and compare the number of event opt-outs to previous years, and to note at what points in an event customers chose to opt out.

We're continuing to prioritize customer comfort when we call DR events, and reiterating what Justin explained, the variability of when peaks occur may, or may not, shift to later in the day. With that possibility, we do have to get a little more creative and think outside the box when dispatching events, all while keeping the peak in mind as well as customer comfort.

Michael: How will CPS Energy keep building on this success? Will you focus on what you've done so far, and further develop those ideas, or do you have other new big ideas to add to this portfolio? What's next?

Justin: This project focused on scaling up current programs: getting more customers enrolled in our thermostat programs, and helping more customers achieve consistent performance in our commercial programs.

CPS Energy is constantly looking at new programs. We think about the opportunities they present for our customers, the needs of the market, and where the gaps lie. If we see a gap, we look at it as an opportunity to be able to create a new program or bring something new into our portfolio.

We're currently exploring something we call "FlexSTEP," which will be about creating a flexible path with new types of generation. We also expect to explore some new programs that can help improve our DR program.

Julie: There is a real need for flexibility going forward, whether that comes from adding new programs, changing up our existing programs, or even expanding our existing programs. Key to achieving this is having the flexibility and communications to be able to collaborate.

Michael: Are there any changes to how residential DR works now that so many people are working from home due to COVID-19? Are you asking these customers to do anything different? Are you changing any of your business assumptions about them? Or are you running a traditional program model that you think that will work for customers, whether they're at home or at work?

Justin: Based on where we are now, I would say what we still need to prioritize customer comfort and if the peaks begin to push out later in the day, we'll need to keep customers' air conditioners cycling later into the evening, and that will take some balancing. Maybe we'll have to hedge our programs and call events earlier in the day for residential customers, later in the day for commercial customers.

We were already adjusting the way we were calling events, just to be sure we were hitting our peaks, meeting our operational goals, and keeping customer comfort in mind. We absolutely want our customers to be happy with our programs so they'll continue to participate year after year.

Michael: Do you have any final thoughts that you'd like to share on this project?

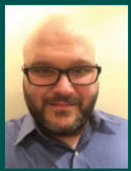
Justin: Thank you again to PLMA for the recognition. CPS Energy is a strong team that really comes together when we need them to. Our Key Accounts team, our Corporate Communications team – we appreciate their support and ability to deliver on these goals. I'd also like to reiterate the importance of strong partnerships within CPS Energy as a critical success factor. And of course, none of this would be possible without our customers. They have responded really well to our outreach efforts and have stuck with us through two very challenging summers.

Michael: Justin, Julie, a big thank you from all of us for sharing CPS Energy's award-winning customer engagement program. Congratulations again on being recognized as a 17th PLMA Award Winner!

Presenters:

Justin Chamberlain
CPS Energy

Julie Cain
CPS Energy



Michael Smith
National Grid

The conversation above is from a webcast recording at
https://www.peakload.org/dialogue--cps-energy-public-engagement

Technology Pioneers

Austin Energy for the SHINES Project

Presented July 2020

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in July 2020, which discusses Austin Energy's award-winning SHINES Project. This discussion was moderated by PLMA Awards Group Co-Chair and Executive Committee Member Laurie Duhan, a Demand-Side Management Portfolio Manager with Baltimore Gas and Electric, and features Anna Popp, a Power System Graduate Engineer with Austin Energy.

Laurie Duhan: It's a pleasure to be joined by Anna Popp of Austin Energy to discuss the Austin SHINES Project which was recognized as a Technology Pioneer at PLMA's 17th Awards. Anna works on distributed energy resource integration and optimization at Austin Energy. She began her career in a two-year leadership rotational program that provided her with experience in power production, rates, and financially regulated operations, as well as transmission reliability and power quality at Austin Energy. While most of Anna's time over the past three years has been dedicated to the Austin SHINES Project, she also collaborates with business units across the organization on evaluation efforts and the development of a strategic DER program.

Please tell us exactly what Austin SHINES is, what it does, and what technologies make it possible.

Anna Popp: First, on behalf of Austin Energy, thank you to PLMA for this Technology Pioneer Award. We are honored to have received it! To give you a little background first, the collective SHINES awards arose from a U.S. Department of Energy (DOE) Cooperative Agreement which originated in DOE's Solar Energy Technologies Office. The awards envisioned an opportunity to dramatically increase solar-generated electricity that could be dispatched at any time, day or night. The intended goal was to meet consumer energy needs while ensuring the reliability of the nation's grid.

However, Austin Energy's proposal and the grant we received evolved into something even more comprehensive. The Austin SHINES Project is extremely layered: at the highest level, it seeks to integrate solar photovoltaics, batteries energy storage, smart inverters, forecasting tools, and market signals all into a software optimization platform.

This platform is expected to optimally manage the assets for an electric grid in a high-penetration solar scenario. Figure One shows the Austin SHINES Project also produced a methodology to create a replicable platform template that can be adapted by other regions and market structures. In addition to the technologies involved, several project layers and assets were installed to help inform utility engineering, and to

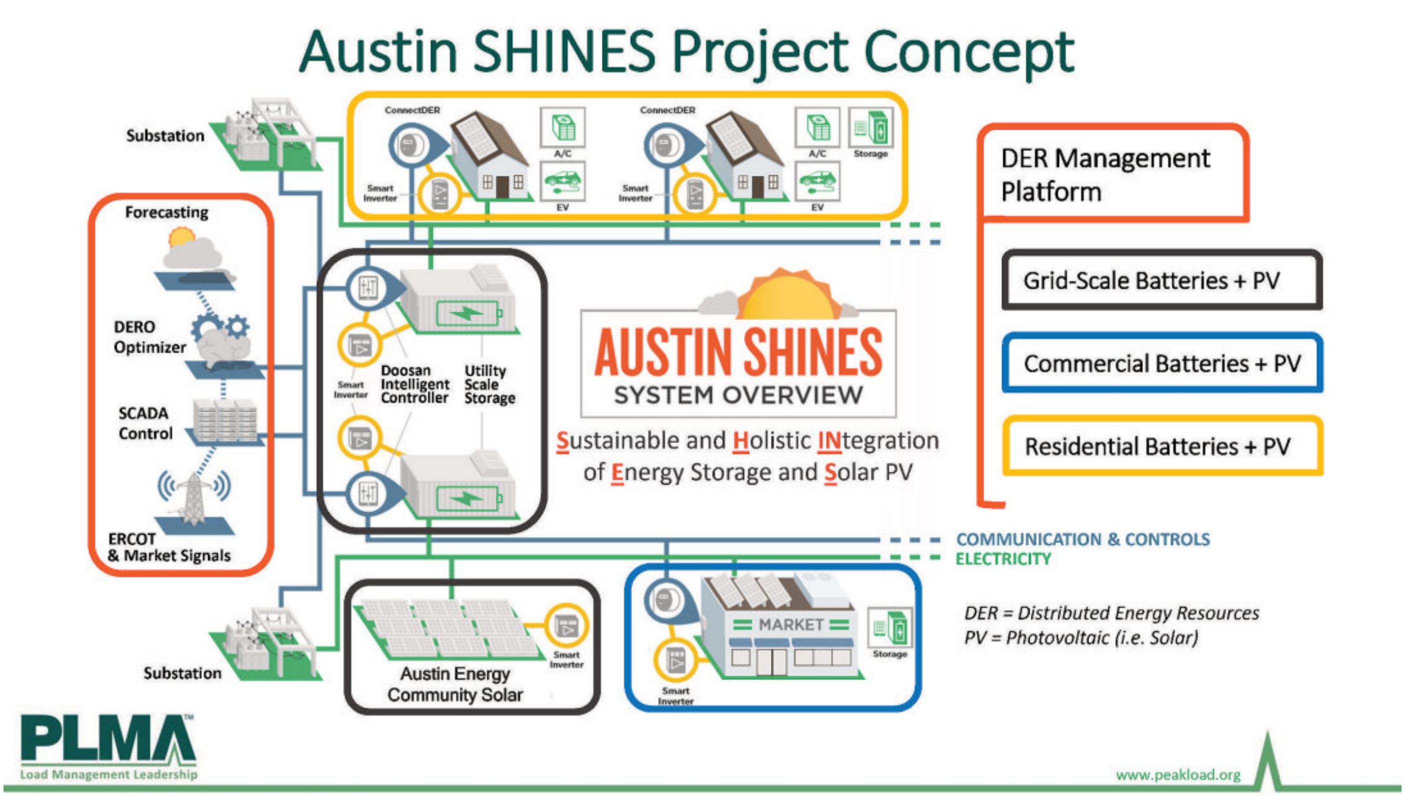


FIGURE 1 View Slide at: *https://bit.ly/3mTjlli*

test several types of operational control themes through the distributed energy resource management system, the "DERMS."

To summarize and define these elements, including the assets and operational controls, the types of ownership, and the DERMS applications, Austin SHINES had three scales of assets. They were 1) grid-scale commercial and residential resources, each containing some form of battery energy storage; 2) co-located solar, and 3) in the case of residential, a vehicle-to-grid component too.

We tested three types of operational controls: 1) no controls, which formed our baseline; 2) autonomous controls; and 3) holistic controls. In the no controls scenario, there was a rigid schedule in which DERs carried out very simple applications. Any changes in the operations of the DERs happened only according to pre-set schedules. This made it possible to maximize value based on parameters such as time-of-use rates, historical load profiles, or energy prices.

In the case of autonomous controls, DERs have local intelligence, and they responded to real-time, localized data like the power factor, or substation, or building load. But there was no coordination between assets that were at different locations or at different sites. With the holistic controls, the assets were able to carry out all the enabled applications, and they were coordinated and optimized by our DERMS Fleet Manager.

Next we have the three types of ownership and they were represented by: 1) direct utility control, so the utility is dispatching a signal to each asset, 2) a third party aggregator where a third party aggregates a fleet of assets, some utility dispatches, one signal for all, and 3) autonomous control in which the schedule operates the asset with visibility into performance only.

That brings us to the DERMS applications. From the original list of 19 applications, we built out six use cases. These were deployed within the utility-grade DERMS and included, 1) utility peak load reduction, 2) day-ahead energy arbitrage, 3) real-time price dispatch, 4) voltage support, 5) distribution congestion management, and 6) demand charge reduction. This may seem like a menagerie of experimentation, but I don't think SHINES would have gained the notoriety it has without this!

Laurie: Austin SHINES was a huge team effort within Austin Energy and beyond the utility too, as we can see in Figure Two. Who was involved with the project, both within Austin Energy and outside?

Anna: Austin SHINES touched almost every group in Austin Energy. The core internal work and deployment was led by our dedicated DER Integration team on the T&D side with critical input from our Energy Market Operations and Customer Energy Solutions team, which houses our solar and electric vehicle groups.

FIGURE 2 View Slide at: *https://bit.ly/3l1O4vT*

We had many different project partners and Austin SHINES' funding came from the federal, state and local levels of government. We felt especially good that our vision was universally supported. The company Doosan GridTech served as our systems integrator and DERMS developer. Stem, Inc. and Austin's own Pecan Street labs were our aggregators for the project's commercial and residential fleets respectively.

And with so many people involved, we had to share some technology principles between us to effectively guide the work. During the design phase, it was important for us to consider all resources regardless of type, age, ownership, or which side of the meter they were on. We wanted to use open standards because we felt those were critically important for scalability. Hence, we employed MESA, SunSpec, and OpenADR. In addition, we wanted to enable complementary technical and economic objectives. The best example of this is the six chosen DERMS applications, which were evenly divided between market and reliability functions.

Laurie: What was your own specific role and experience with Austin SHINES?

Anna: I started working on the SHINES team while I was still in the rotational program you mentioned earlier. Initially, I helped our Economic Modeling Working Group by calculating the value of a 4CP load reduction by the action of a DER on a SHINES circuit. Basically, I answered the question, "What is the dollar per kilowatt hour value for a 2020 ERCOT (our Texas ISO) peak load?" More specifically, what will be the potential savings that result from lowered transmission cost obligations?

This was accompanied by a lot of sensitivity analysis because it was 2017 and I was forecasting forward to 2020. In addition, I worked on modeling electric vehicle charging behaviors across different locations, for example, homes versus workplaces versus grocery stores, using information from our charging network. These results were fed into simulations for SHINES' vehicle-to-grid component where my availability models helped to determine the value of EVs in the DER mix.

These days, I serve as the chief editor for Austin SHINES' final reports to DOE; the reports are a grant requirement, and can be viewed on the Austin Energy website at https://austinenergy.com/ae/green-power/austin-shines/final-deliverable-reports.

My initial role in economic analysis provided me with the opportunity to fully understand SHINES' complexity. As a result, as an editor, I am very fortunate to understand all the project information, review the analysis, offer feedback to the contributors, and to develop cohesive answers to the questions we originally asked of ourselves.

Laurie: Can you define the elements which were critical to the project's success and to addressing ongoing challenges?

Anna: Two things come to mind. Over the project's 50 months, there were three phases and we spent nearly 40 percent of our time in the design phase, versus the deployment and demonstration phases. We used the concepts of "holistic" and "optimal" a lot in our conversations; essentially, we wanted an optimal solution to originate from optimal design. Of course, once a project reaches the deployment phase, you end up making some sidesteps, but our three-phased process was very educational, and so I'd say given the trifecta of time and money and resources, it always makes sense to invest extensively in the design.

Part of the design challenge was figuring out how to incorporate all of the project layers into the economic metrics outlined by DOE. Even though I started in this project working on economic modeling and determining metrics like system levelized cost-of-electricity formulas, this task took a lot of time for us to get consensus and understanding around, even within our own working group. Sometimes, we had to re-explain to ourselves what we did the previous week and make sure we had agreed on all of the graphical representations that served as the framework for building out the DERMS. It certainly shaped our results to adhere to this measuring system.

And, even if we decided not to continue using a particular framework, the measuring system allowed us to create proportional and comparative scenarios that helped us find the trends and characteristics of the technology. As a result, these are the pieces we'll use for "road mapping" going forward. Once there's a stake in the ground for evaluation, you can really learn a lot from it.

Laurie: Were there any theories or intuitions about DER that were supported by the project outcomes? Did you have any surprising results?

Anna: There are still a lot of theories and hypotheses about DER and its capabilities, and of course everyone is interested in seeing fully fledged demonstration projects. I believe the Austin SHINES Project validated intelligent system design and showed it should be executed by means of a step-by-step iterative process. But it should always begin with clear project objectives.

It's important to first know your functionality, then sizing, siting, and communications can follow. It's also important to know which groups have sophisticated or high-throughput hosting capacity analysis (or other DER-friendly modeling tools). The circuit analysis part of our simulations was a significant computational burden. To get a pulse we had to make adjustments, going from year-long to month-long type things. We still don't quite have that pulse on our territory for identification and then quick proposals for DER solutions, especially when we're talking about mixing technologies. However, I firmly believe that someone will become a master, a "Gepetto of Load Management." And it feels like I'm working to help Austin Energy leverage its institutional knowledge to address both utility and customer needs.

We had an intuition that the value of assets would increase when the amounts of deployed storage increased, but we were also able to see the rate of value would drop off with increased storage capacity. This suggested that even our holistic controls within the DERMS would hit a saturation point of return.


Austin, Texas *(courtesy of Austin Energy)*

Increasing in size from residential to commercial to utility, Austin SHINES proved economies of scale, but it was also balanced by finding out that utility-scale storage is going to be less expensive and a better value than a mix. The mixture of technology scenarios carried the combined characteristics of each individual technology. Therefore, in a way, residential and commercial were compromising what you could have, meaning if you have four megawatts of all utility-scale storage, that will not be the same as say, two megawatts of utility-scale storage plus one megawatt each of residential and commercial storage.

In the vehicle-to-grid scope, we learned the use of EVs for grid services is limited due to the low availability we found for any 15-minute interval. The value becomes even smaller after you start to apply variable availability and fixed availability modeling. I think at best we found it to be around 14 percent of a fleet.

With some of those examples, it was a relief to see outcomes matching expectations, but understanding the nuances and having data to support theories is really fun, and I am kind of nerding out on it.

Laurie: Kind of fun to nerd out! What was the largest challenge the Austin SHINES Project had to overcome? Do you feel the market outcome Austin SHINES generated, in terms of reduced operational costs and customer value to participate, can now scale, at least in Texas and within ERCOT?

Anna: Yes, I think this could easily be scaled. Even though there was a lot of modeling of single technologies versus a mixture of technology scenarios, the actual deployment phase of the project was very worthwhile. For example, for utility scale, we had two grid-scale systems. One was within a substation, which made siting a lot easier. This one was also co-located next to a community solar farm. The other grid-scale system, which was not in a substation, was located within a neighborhood development. It was placed there because that particular Austin neighborhood has the city's highest concentration of residential rooftop solar and we wanted to put the system next to the feeders that had the highest percentage of distributed rooftop solar.

In the commercial scenario, we initially had a lot of interested participants. The three participants we proceeded forward with were all nonprofit organizations with a strong interest in the technology and what it stood for. Fortunately, they all met the project's space requirements! For retrofitting, permitting, and codes, we agreed upon these step-by-step with the help of the Austin Fire Department. Residential was a little bit easier, especially with the help of our aggregator Pecan Street. The residential customers also had strong beliefs about solar and had their own good reasons for wanting to be involved. Still, there were hurdles we has to overcome together to achieve the results we did.

In terms of the market component, I look with dreamy eyes look toward a time when there are a lot more customers building out solar, and I like programs that have a lot of enrollment and involve load management. Right now, for batteries the question is one of viability. It's not that I think of batteries as a last resort because I do think there are plenty of use cases where they fit well.

But for broad-scale applications, to me, batteries do not represent "low hanging fruit."

Using a commercial example, SHINES hooked these customers up to a load profiler before we even had their systems up and running. As a result, many were able to see they could make very simple changes to their HVAC ramping and gain a lot of savings for their demand charge, and this turned out to the most valued application for these customers. And this was before we even switched them on! Giving customers, or even the utility itself, the leeway to explore those different pathways and then see how they use it, goes back to defining your functionality first, then really narrowing it down.

Laurie: Where can we learn more about Austin SHINES?

Anna: The Austin SHINES website (https://austinenergy.com/ae/green-power/austin-shines/final-deliverable-reports) includes our final reports to DOE, plus videos and additional information about the project. There are six reports total, and each has a "how to read this document" section to help readers determine if they are the right audience for the report. With six reports, I hope there will be something for everyone!

Laurie: It's clear why Austin SHINES is a PLMA Technology Pioneer Award Winner. Thank you for sharing your experience and knowledge of Austin SHINES, Anna, and congratulations again!

Presenters:

Anna Popp
Austin Energy

Laurie Duhan
BGE, an Exelon Company

The conversation above is from a webcast recording at https://www.peakload.org/dialogue--austin-shines

Technology Pioneers

Connected Energy Ltd. for Battery Recycling to Energy Storage

Presented July 2020

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in July 2020. It discusses U.K.-based Connected Energy Ltd.'s award-winning Battery Recycling program which the company established in Belgium. This discussion was moderated by PLMA Awards Group Co-Chair Michael Smith who serves in the role of Lead Program Manager for Demand Response with National Grid. He is joined by Mark Bailey, Connected Energy's Chief Commercial Officer.

Michael Smith: This discussion focuses on Connected Energy Ltd., one of two PLMA Technology Pioneer Award winners. Mark Bailey, Connected Energy's Chief Commercial Officer will explain his company's battery recycling project, which re-purposes "second-life EV batteries." Mark, please tell us more about yourself and about Connected Energy.

Mark Bailey: Thank you, Michael, it's an honor to be here, and I'd like to thank PLMA for presenting a Technology Pioneer Award to Connected Energy. I've been with the company since late 2018 and have the responsibility of leading our global commercial and business development initiatives. Connected Energy is an engineering-led innovator in energy storage. Our technologies, which make use of second-life electric vehicle batteries, are rapidly changing the way intensive energy users can access the benefits of low-cost, on-site storage solutions. As a company, Connected Energy recently completed a Series B round of venture capital funding, which makes us a relatively early stage company.

I've worked in the energy industry since the early '90s and did a lot of work at that time with Yorkshire Electricity (a regional electricity company in Britain) on pioneering demand response services to industrial and commercial businesses. I subsequently began a start-up that was acquired by Gaz de France in the U.K. and followed that with 18 years with the ENGIE Group of Companies, including 11 years in Paris at ENGIE headquarters, starting in 2007. Following that, I led ENGIE's global key program on demand-side management and energy storage.

To begin this story, it's important to note the client for this battery recycling project is an industrial customer in Belgium called Umicore. Umicore is a global materials technology and recycling group, whose activities include the recycling of EV batteries and the manufacture of battery components.

I first met Umicore in early 2018 when they shared their strategy with us for 2020. Their goals were to show clear leadership in clean mobility materials on recycling, and

FIGURE 1 View Slide at: *https://bit.ly/2GkClnl*

to turn sustainability into a greater competitive edge. In that regard, I think we're all seeing discussion trends today around the importance and value of the circular economy, and also the need to optimize the lifecycle of valuable, already-extracted natural resources.

Umicore's key objective for this second-life battery project was to establish a sustainable, secure, and competitive energy supply chain at their site in the municipality of Olen, in Belgium. The project, which is pictured in Figure One, was part of a broad solution to provide revenue generation and power quality on-site. It was also about effective recycling of electric vehicle batteries. Throughout the project, battery performance and battery degradation were an interesting and important variable.

Connected Energy's new E-STOR system helped to stabilize Umicore's grid and increase the utilization of sustainable energy solutions, including wind turbines and a combined heat and power (CHP) plant. The E-STOR system also helped Umicore to further expand its knowledge and expertise in the field of EV batteries in second-life applications.

This industrial second-life battery storage system, as you can see in Figure Two, consists of 48 used batteries from Renault's Kangoo electric cars, which together form one large storage battery of 1.2 MW or 720 kWh. Kangoos are small all-electric vans, popular in France. Each Kangoo battery's original energy content is 22 kWh. In this so-called second-life application, they still have 15-17 kWh of energy content left which means that on arrival in Olen, they still have two thirds of their original power. This is sufficient, through net balancing, to contribute another 10 years to both the circular economy and the energy transition.

Michael: What are some of the challenges you've had as you integrate EV battery modules into a stationary storage system? And what was your approach to solving these?

Mark: First, we don't penetrate the battery packs; instead, we take the battery packs directly from the OEM, which is the vehicle manufacturer. Connected Energy made this decision purposefully because we have long-standing relationships with a number of OEMs that trust us to manage their batteries in second-life applications.

We have a set of criteria and technical specifications that we share with the OEMs so that each of the battery packs supplied to us is certified to our specifications. Typically, certification is done through a third party before we receive the batteries. The real challenges are about the battery packs working with different OEMs, even from the same company. They can have different dimensions, and even though they have similar kWh ratings, the battery footprints can be a challenge in terms of economies-of-scale and building up the batteries in containers.

FIGURE 2 View Slide at: *https://bit.ly/2GkCInI*

In addition, battery cooling can be a challenge as some batteries are air-cooled, some are liquid-cooled. In terms of communications management, our power control module is really the IP within our E-STOR system and it is able to communicate with the CAN protocols of the OEM.

Michael: What is your process for evaluating the batteries and assessing their potential for use in the project? What criteria do you have and how do you determine whether they are a good fit?

Mark: Typically, we receive the battery packs at around 75 to 80 percent of their original capacity. Such batteries could have been in a vehicle for six to eight years, depending on the weather conditions where the vehicle was operating.

We have worked with the technicians at a number of OEMs for as many as eight years now, and especially with the Renault-Nissan Alliance and with Jaguar Land Rover (JLR). As a result, we're confident that the batteries tested by a third party meet our specifications. The OEM is also confident these batteries will be able to operate in second-life applications.

Michael: What are the considerations in play for evaluating the expected life of these second-life batteries once you do put them in place? Also, what is the longer-term performance of second-life batteries and how might that compare with a new battery?

Mark: That's a really good question, and one we're asked often! Connected Energy has 14 or 15 commercial projects that have operated for several years. What we're seeing, and the OEMs are also seeing this with all the data that we're sharing together, is that the batteries are performing very well in their second life, in fact, better than originally foreseen.

In terms of battery degradation, we are observing an almost straight line. Previously, a lot of people and technicians were looking to around 50 percent where you'd expect to see a "knee point" in terms of more rapid degradation. But now, we're seeing the knee point happen around 40 percent.

Two years ago, when we were first talking with Umicore about battery performance in second life, we were discussing a six- to eight-year timeline. Now, we're looking at second-life battery applications that can sustain for up to 10 years.

As we look at these second-life projects, Connected Energy always starts by considering the client's application, whether that is EV charging infrastructure support with rapid EV charges, or an example like this one in which the battery provides dynamic frequency response. Specifically, we evaluate how the batteries need to perform for the application they are being used in. So yes, we are seeing almost a doubling of battery life from the first life to second-life usage.

Mark: In this Umicore application, the batteries will be used for a second life, and then move to recycling. Today, I think there is a tradeoff between the cost of recycling, versus the value of recycling, versus using EV batteries in second-life applications. Because the recycling market will develop as EV batteries and EV usage increases, I expect there will be economies-of-scale that develop, and that dynamic will evolve over the next several years.

And yes, Connected Energy is also considering potential third-life opportunities, and the possibility of further re-packaging salvageable modules or cells. And again, there are companies already emerging in this field, which is interesting.

We have different arrangements with various OEMs in terms of where the responsibility ultimately lies for recycling. The batteries can be returned to the OEM, or that recycling responsibility can remain with Connected Energy. Obviously, in the case of Umicore, the energy storage project is on the property of a battery recycler, and so that is also an interesting business model too.

I think we are at the point where everyone accepts that electric vehicles, whether it be cars, buses, trucks, or something else, are on the way to experiencing a big increase in their market penetration. I also think the battery management model from first life to second life to recycling is an emerging one. I hope Connected Energy has provided a good case study with the Umicore model, one we can all learn from.

Michael: You talked a little about how the process and relationship might change from OEM to OEM. Can you say more about the relationship with EV OEMs, and how that plays into the recycling obligations of the project? Also, within a given project, what's going to be available in terms of suitable batteries, and then which ones will meet the end-of-life requirements for the economics of the project?

Mark: Yes, this is really important, especially in this interim time period before we have larger numbers of used EV batteries available for second-life projects. In terms of Connected Energy’s business model, from Day One, we’ve designed projects that will incorporate batteries from different EV manufacturers. I think it's fair to say we're battery agnostic. We already have different energy storage systems out there using different OEM batteries, and also batteries with different footprints from the same OEM, if that makes sense.

For Connected Energy and for our customers, this makes it possible for us to gain access to the largest possible EV battery feedstock. By having the best supply and best prices for electric vehicle batteries, we are able to meet the increasing demand for this kind of product. In addition, we are clearly offering an important route to market, and an important service, for EV manufacturers.

At this time, the electric vehicle market is still relatively nascent and emerging. The manufacturers are looking at the circular value chain to determine how to achieve the greatest value from an asset they’ve got a large investment in. These batteries are still very useful, and they can create significant value still. That makes it possible for the EV OEMs to defer their recycling costs.

Michael: From your point of view, in this emerging market, how do you think the supply chain looks in the near term? Do you think there's a point where Connected Energy will outpace its ability to source suitable batteries? Or do you think your approach will become the business model for OEMs? That they’ll look for this type of a partner for second-life battery opportunities? Are we going to have plenty of battery-secular projects? Or do you think there could be a near-term shortage?

Mark: Well, obviously, we work closely with our OEM partners. And in terms of feedstock and potential projects, it's important to have that shared visibility. For now, Connected Energy is satisfied with the level of feedstock availability. In addition, we continue to forge new relationships with EV OEMs, and we're also able to use new EV batteries and demonstrator-car batteries in our projects. As a result, we’re not limited to second-life batteries only.

I can also share that the batteries we are working with from Jaguar Land Rover are not second life, and they have not been used in demonstrator cars. Coming back to Connected Energy’s technology, our power control module is able to work with different battery packs, new and second-life batteries from different OEMs, as well as bus batteries, truck batteries, etc. Having this amount of flexibility enables us to have adequate battery feedstock.

Michael: Circling back to the Umicore project in Belgium, can you give some specifics around the load management services that your customer wanted, and how this capability was integrated into the design of this project?

Mark: It's important to note we worked very closely with the local business unit of ENGIE in Belgium – the Industrial and Energy Solutions team. This team has a longstanding relationship with Umicore, including high voltage maintenance and energy supply as you saw from the renewable assets and combined heat and power (CHP) that was also onsite. Connected Energy’s role was to provide the energy storage system.

In terms of demand response, there is some on-site optimization with the renewables and managing the local grid power quality as needed, and that is coordinated with the site and ENGIE. The principle revenue generation comes from the grid-balancing services to Elia, which is the Belgian transmission system operator. Since then, there has been an introduction of wider European balancing services, which is possible because of the well-interconnected grid.

Our second-life EV storage system provides dynamic frequency response. It ultimately forms part of an aggregated stack that ENGIE manages in Belgium. The interface to ENGIE is provided through their DERMS software platform, which was supplied by Kiwi Power, a U.K.-based company that Connected Energy has worked with on other projects. The DERMS provides all the software and control management to ENGIE’s Optimization team, and then to Elia (the TSO) through availability notifications. So it's a dynamic service.

There are also other opportunities locally: occasionally, there have been some strategic reserve opportunities in Belgium when the TSO has needed capacity volumes from the demand-side. ENGIE optimizes that for Umicore in order to maximize the revenue streams and pay back.

Michael: When you're working with grid operators in Belgium, are you having to meet any other regulations, or safety certifications for this type of technology? Or has it been relatively easy to plug into those market opportunities?

Mark: I would say it has been relatively straightforward. Again, what our energy storage system does is no different than any first-life storage system would do. At Umicore, we had to go through a local electrical appliance assessor for safety standards approval, which we did. In Belgium, there is no specific fire standard regulations for energy storage systems so we had discussions with the local fire service and detailed our fire prevention protocols. In this case, it's prevention, prevention, prevention, with all the monitoring and hierarchies we have within the system, and with Umicore addressing any fire suppression requirements needed. Nothing inhibited the cost of the project, and our product range is CE-marked and certified with the relevant authorities in the U.K. and Europe.

Michael: Would you like to share some final thoughts on this project and Connected Energy's work in EV second-life batteries?

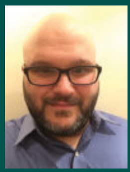
Mark: Yes, thank you Michael. This project was an important achievement for our client, and for us, because it was Belgium's first energy storage project using second-life EV batteries. In addition, it was Connected Energy's largest system to date, and played an important role in enabling us to access battery feedstocks through developing and extending our OEM relationships.

Going forward, we are now also launching projects at the front of the meter. We've got a project in the U.K., a smart local energy system project named "SmartHubs," which is an energy storage system that will take us to more than 20 MWhs. As the battery market develops, Connected Energy hopes to accelerate the widespread adoption of competitive and sustainable storage solutions, and elevate the understanding and benefit of re-using and re-deploying electric vehicle battery packs with projects like the one at Umicore. Together with our global partners, we look forward to leading the circular economy evolution to a carbon-neutral future.

Michael: Excellent and thank you again Mark. And of course, a big congratulations to Connected Energy on your PLMA Technology Pioneer Award!

Presenters:

Mark Bailey
Connected Energy (UK)



Michael Smith
National Grid

The conversation above is from a webcast recording at
https://www.peakload.org/dialogue--battery-recycling

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PLMA (Peak Load Management Alliance), a 501(c)(6) nonprofit organization, was founded in 1999 as the voice of load management practitioners. Today PLMA has over 165 utility and allied organization members, including private and publicly owned utilities, technology companies, energy and energy solution providers, equipment manufacturers, research and academic organizations, and consultants.

As U.S. and global energy markets evolve, PLMA strives to offer timely programming and training opportunities, well as a forum for its member practitioners to share dynamic load management expertise, including demand response and distributed energy resources. Member practitioners take pride in sharing their knowledge, experiences, and ideas with the goal of educating one another on a range of topics. These topics span load management programs, price and rate response, regional regulatory issues, evolving technologies, and much more.

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