Load Management Leadership

Practitioner Perspectives™

2020

Thought Leadership Discussions

PLMA's Industry Viewpoints Compendium

Published 2021

About the 2020 Thought Leadership Compendium

Welcome to the 2020 Thought Leadership Compendium! .This document contains the transcripts of 2020's most highly rated PLMA sessions. These sessions were drawn from sources including PLMA's 41st and 42nd Conferences and its Load Management Dialogue webcasts.

Within this Compendium the transcripts have been grouped into three categories within the table of contents: Pricing, Integration, and Evaluation.

For ease of access, PLMA has also provided the transcripts from this Compendium in the following formats:

1. As individual session transcripts, which have been included together with their session recording in the PLMA Resource Center;
2. As three separate 2020 PLMA publications covering the topics of a) Pricing, b) Intregration, and c) Evaluation.

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Why Is Electricity Pricing So Difficult? Between a Rock and a Smart Meter

Pricing

This document, which presents the contents of one of PLMA's most popular webcasts hosted in 2020, provides an engaging and easy-to-understand perspective on electricity pricing from two industry experts, Dr. Ahmad Faruqui of the Brattle Group, and Mr. Bill LeBlanc, Chief Instigation Agent at E Source. Together with moderator Derek Kirchner of Consumers Energy, who also serves as a member of PLMA's Executive Committee, their discussion provides additional insight about the everchanging landscape of electricity pricing.

Ahmad Faruqui
The Brattle Group

Bill LeBlanc
E Source

Derek Kirchner
Consumers Energy

Ahmad Faruqui: I am going to begin by sharing some perspectives from the field on why pricing is so difficult. I'm calling these perspectives the "Five Immortal Objections to Time-of-Use Rates." I'm using the term "time-of-use rate" very broadly here to refer to any kind of rate that varies across time, whether it is simply a seasonal rate, a time-of-day rate, or a critical peak pricing rate. In other words, some kind of dynamic element could be present in the time-of-use rates, or they could even be full-fledged real-time pricing rates.

I am calling them "immortal" objections because they have been around forever, and I suspect they are not going away, not even for another 10 to 20 years. They are deeply rooted in human psychology and when I say human psychology, I'm referring here not just to the utilities that obviously have to design and offer these rates, and I'm not just referring to the commissions and boards that have to review and approve them. I'm also referring to the customers who will ultimately be on those rates, and to all the stakeholders in the ratemaking process.

Of course, there are more than five objections, but let's start here. Interestingly enough, even though my career in rate design began in 1979, I can tell you that these five objections pre-date me. My father was an electrical engineer and my mom was an economist, so I ended up becoming an electrical economist, so to speak. In my father's collection of books, there was one book written in 1938 that caught my attention.

It's a British publication called "Costs and Tariffs in Electricity Supply" by D.J. Bolton. In it, the author states, "There's never been any lack of interest in the subject of electricity tariffs. Like all charges upon the consumer, they are an unfailing source of annoyance to those who pay, and an argument among those who levy them," and then comes the punchline: "There is general agreement that appropriate tariffs are essential to any rapid development of electricity supply and there is complete disagreement as to what constitutes an appropriate tariff." If this sounds to you like something that might be debated in today's British House of Commons (or in any U.S. rate-making process), we are on the same page!

Of course, this was written in England in 1938 before the Second World War. Here we are in the United States, a former British colony, in the year 2020, far into the 21st century, and Bolton's assertion is still correct. But why? Looking at Figure 1 which presents the time-of-use rates currently in place in the Canadian province of Ontario, it shows that for more than a decade, Ontario has had default, or opt-out, time-of-use rates.

Ontario's rates apply seasonally, and they apply within the day. There are three pricing periods: Off-peak, midpeak, and on-peak. Weekends and statutory holidays are entirely off-peak, and then there are periods at different times of day when there are different prices that apply, as shown in the figure. This is just one very simple way to

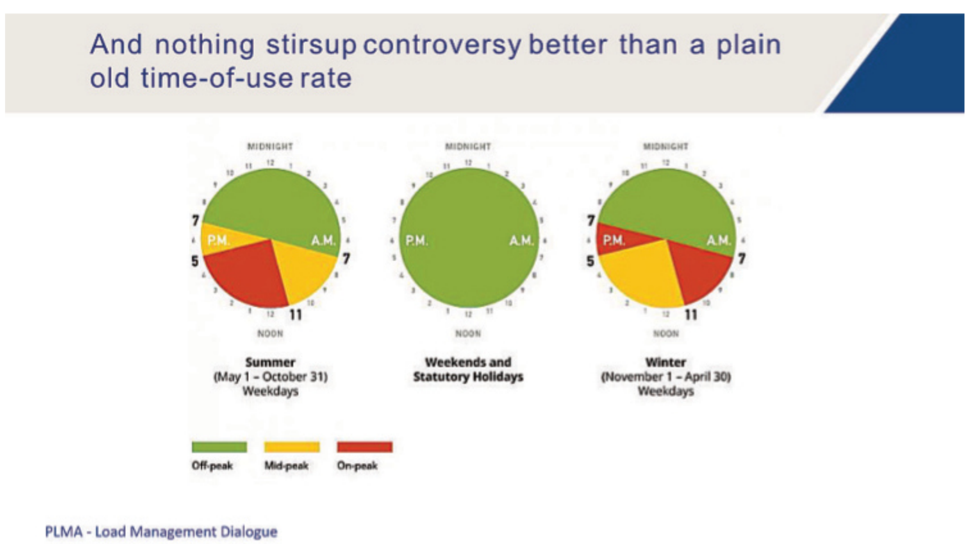

FIGURE 1. View Slide at: https://bit.ly/3iAVyoS

look at time-of-use rates. And because we now have digital technologies, including smart thermostats, digital appliances, smartphones, and smart consumers, we also have many more interesting possible combinations.

But for now, let's focus on Ontario as a point of reference because it make sense to first agree on whether we should have a simple plan or time-of-use rate before we move on to more complex pricing possibilities. For 10 years in Ontario, time-of-use has been the default rate available through regulation and there has been retail choice. A resident of Ontario can pick any other rate that retailers provide. But 90 percent of customers have preferred the TOU rate. When COVID-19 arrived, Ontario's leader, Premier Doug Ford, who was elected in 2018 and who had previously said he did not like timeof-use rates, got his chance to make history.

He said, "I don't like the TOU rate because my wife has to time her laundry for the off-peak rate, which is very inconvenient for us." He said this six months ago but once the pandemic arrived in March, Ford commented, "We're all at home now so I'm just going to set all electricity prices equal to the off-peak rate so as to give everyone a nice discount, and peace of mind." Clearly, he doesn't like time-of-use rates, and he has essentially suspended what many believed was one of the best TOU programs in North America. So why did he do this and why is his decision proving to be popular?

> "There is a mountain of empirical evidence that customers accept and respond to TOU rates, but skeptics continue to assert the contrary. That's why today in the U.S., only four percent of customers are on these rates, mostly simple time-of-use rates, but 80 percent have smart meters."
>
> *– Ahmad Faruqui, The Brattle Group*

The answer lies in the five immortal objections. There is a mountain of empirical evidence that customers accept and respond to TOU rates, but skeptics continue to assert the contrary. That's why today in the United States only four percent of customers are on these rates, mostly simple time-of-use rates, but 80 percent of customers have smart meters. The point of smart meters is to provide customers with the price signals they need to make efficient energy buying decisions.

There's a huge gulf between the 80 percent and the four percent. But when this year ends, if things go as planned, the nearly 80 percent of customers with smart meters will rise to 85 percent, but the four percent on TOU rates might still be stuck at four percent.

I got into a debate with a very respected and seasoned regulator about this when I wrote to him to ask why Ontario was going backwards in time when everyone else was going forward. This regulator said, "TOU rates are an exercise in modifying behavior with little chance of success. Even if successful, they will not yield any tangible reduction in electricity cost."I showed his quote to a former utility vice-president, and I said, "You know, I'm really disappointed in the regulators for taking this perspective. What do you make of this as a utility executive?" The utility exec said, "Well, I think dynamic pricing is just a fantasy."

There you go, right? One utility comment, one regulator comment. Now just by way of perspective, I have been keeping track of these frequently voiced objections to time-of-use rates since I joined the EPRI Rate Design Study in 1979. In those days, the big issue was lack of metering, but at some point, that problem was overcome. Now we have 80 percent of customers on smart meters, so I have removed the metering objection from my list, but there are five objections that remain.

Objection #1:

While time-of-use rates might reduce peak load, they will not lower customer bills.

Every customer says, "This is the utility's problem. Why are you making my life difficult? I only care about having a lower bill."

Here's my response: A well-designed time-of-use rate will yield savings to customers, even in the short term, as customers will reduce peak loads and shift their peak usage to off-peak periods. Off-peak periods are the chance to buy electricity on sale. People love to shop when there is a sale, and the off-peak period is exactly that – a sale! That's when we all need to focus our consumption and reduce our peak load as much as possible. Not everybody will do it, but those who do will come out ahead. In the long run, the savings will be even greater as customers install new digital devices, such as smart thermostats.

By the way, these days you can't even buy a "not-smart" thermostat, or a "not-smart" dishwasher! Even the dishwasher has a four-hour push button, so you can set it at 8 pm when dinner is over, and it will run at midnight, if that's when your off-peak period begins. That's what I do with my dishwasher. Additionally, as peak demands fall as more and more customers reduce their peak load, there will be less need for utilities to invest in peaking capacity, which will further reduce customer costs over the long run. With some minor modifications to your lifestyle, most of which can be assisted with enabling technology, you can really come out ahead on your electricity bill.

Objection #2:

Lower peak demand will not lower transmission and distribution costs.

This is because T&D do not depend on load, and this is where the T&D folks come in. Congestion is rising on distribution circuits. There are more and more people buying electric cars, installing solar panels, and lots of new big homes; some net zero, some not net zero. There are challenges now at the distribution circuit level, and you can relieve those by targeted time-of-use pricing. In addition, well-designed time-of-use rates can lower the need for T&D investments over the long run.

You can also encourage customers to charge their electric cars when there is no distribution peak. Right now, we have a million and a half EVs in the U.S., and that number could rise to as many as 20 million by 2030. Who knows? But we will need time-of-use pricing to3 Why is Electricity Pricing So Difficult? Between a Rock and a Smart Meter manage EV charging, and I'm sure that most ISOs and RTOs would welcome the demand response created by time-of-use rates

Objection #3:

Ongoing pilots with time-of-use and other time-varying rates show minimal customer reaction to price signals. Their load profiles remain unaffected.

Now this is hardwired into the DNA of many people and they will not accept any evidence to the contrary. We all tend to reject evidence that contradicts what we deeply believe. Psychologists call this cognitive dissonance. I have shared with PLMA and other audiences the evidence from almost 400 deployments of time-of-use rates around the globe. Every single one of them shows the same customer response: If the price ratio is two to one, you get a drop of five percent in your peak.

If the price ratio for critical peak pricing with dynamic tariff is much higher, like 10 to one, you'll get a much higher response. Customers do respond to time-of-use rates and lower their peak demands while shifting some of their load to off-peak periods. That's an empirical fact.

Objection #3 has no basis in fact, but that doesn't mean it doesn't exist. It's an emotional objection. One commissioner even said to me during a conference that if he ever moved his home to a time-of-use rate, his wife would divorce him. I looked at the respected commissioner and I said with a smile, "Your wife's probably going to divorce you anyway, so why are you blaming the TOU rate for your pending divorce?"

Objection #4:

Residential customers are apathetic about TOU rates.

It's said that families are too busy seeing their kids off to school in the morning, commuting to work, returning home to make dinner, et cetera, et cetera. Residential customers have no interest in TOU rates. My response is that while this is true of a third of customers, sound scientific research shows that on average, time-of-use pricing motivates many customers to modify their lifestyles in order to save money.

Oklahoma Gas and Electric has signed up a fifth of their customers for an opt-in program under dynamic pricing, which is mostly enabled with smart thermostats. On average, these customers are reducing their peak demand by 40 percent! Not 4 percent, but 40 percent, and as a result, they are lowering their bills by 20 percent. I have been to Oklahoma twice. Even the taxi driver and the man sitting next to me on the plane said they were on TOU rates, and they were positive and enthusiastic about it. Both were normal human beings. SMUD in Sacramento deployed default time-of-use rates without any hitch last year. Only one percent have opted out.

Fort Collins in Colorado decided to go to whole hog and they have mandatory time-of-use pricing. No revolt, no riots, no objections.

From what I understand, Consumers Energy is going to begin deploying TOU rates in June 2021. Xcel Energy in Colorado has filed to deploy default time-of-use rates this year in a case that's still pending. San Diego Gas and Electric has already done it. They have close to 900,000 customers on default time-of-use, and PG&E and SCE, the two big IOUs in California, will begin deploying TOU rates this October.

Objection #5:

In the developing world, people are too poor to support TOU pricing.

Many people in developing countries eke out a meager existence, and are so intent on making ends meet that they don't have time to focus on responding to time-ofuse rates. But here's an interesting riddle: The less money you have, the more important it is for you to save money! So the argument that low-income customers, whether in the U.S. or abroad, have no interest in wanting to save money is just not reasonable.

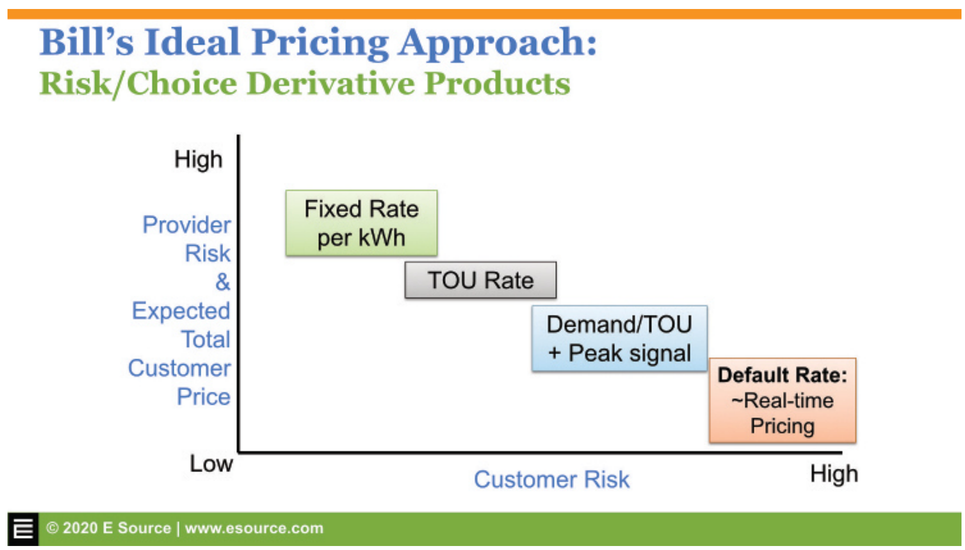

FIGURE 2. View Slide at: https://bit.ly/31XP91m

People want to lower their energy bills regardless of where they live, and the lower their income, the more they want to save money. While I cannot share with you much experiential evidence from developing countries on the efficiency of time-of-use rates, I can tell you there is a lot of evidence that a program funded by the World Bank and the International Monetary Fund (IMF) to improve energy efficiency in developing countries (in order to lower customer bills) continues to be very popular with customers. Clearly a time-of-use rate, if marketed properly and well-designed to lower customer rates, appeals to people in the developing world too.

Bill LeBlanc: My title is Chief Instigation Agent at E Source and that means I do a lot of product development. I have to figure out what's going to happen in the future and bring that back to E Source and say, "If we help our customers in these areas, I think we'll be in good shape." As you might expect, we get lots and lots of questions from our utility members.

Our work is primarily focused on helping utilities engage more effectively with their residential and commercial customers, where ever they interact. I have some questions that dovetail well with Ahmad's five immortal objections: Are the price signals right to create grid efficiency? Do retail prices reflect all the costs they really should? We also have the people side of the equation to consider: Do they perceive their electricity prices to be fair? I use the word "perceive" because it doesn't matter if the price is fair; it matters whether customers think it's fair. The number one thing we have discovered customers want most is fairness in their price rates.

If the net benefit to the grid of changing someone's rate is $50, but somehow the inconvenience for the customer exceeds $50, we have to ask, is that good for society or not? That's a policy question. Not all people want the same rate. One size does not fit all customers, and that's not what choice means. But customers do have to understand electricity rates in order to be able to perceive them as being fair and act on them accordingly. However, we've also got to consider policy, and this is where the arguments begin in earnest!

Does the rate meet equity goals? Does it meet the fairness goals that regulators or city council have set? Is it cost-based or goal-based? I'll use that as an example. In the case of a cost-based rate, if you're offering a time-of-day rate and the differential doesn't come up as big enough to drive and motivate any behavioral change, do you then move to a goal-based rate to make that differential big enough? That's a policy decision. You have to change the economics and you have to change the equations. You might then consider environmental goals, and that's where solar pricing comes in to create another big debate.

Does the rate enable customer choice and does it encourage the right investments by the customer?

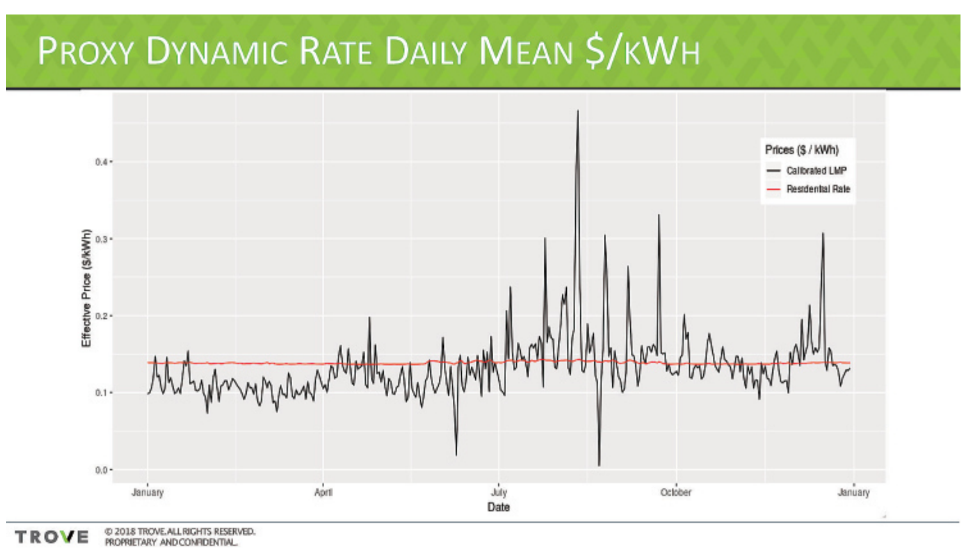

FIGURE 3 View Slide at: https://bit.ly/2ZavgID

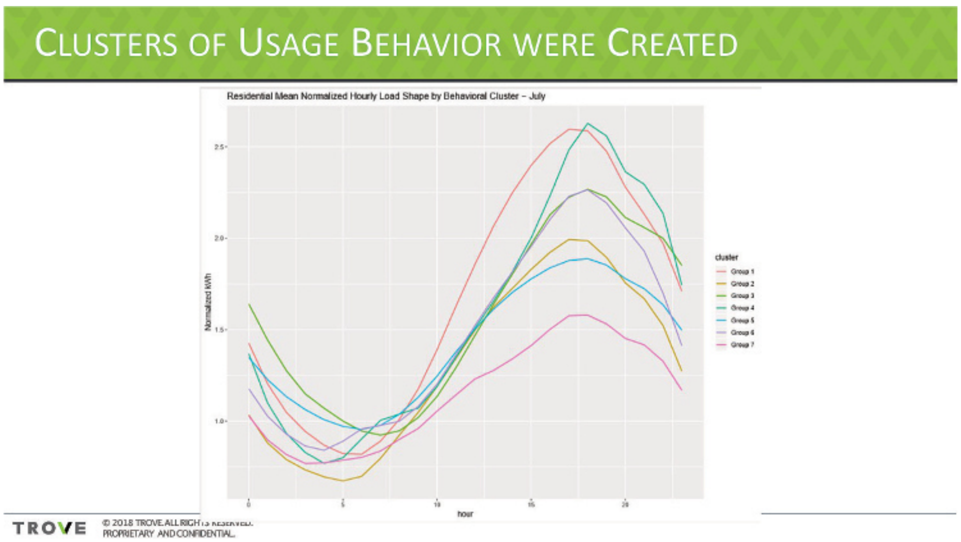

FIGURE 4. View Slide at: https://bit.ly/38A27DI

The analysis showed the RTO price in that region and compared it to what people pay for electricity on the residential side. In Figure 3, you can see the variations are all over the place, and in summer, you can see the peaks. You can also see how short the duration of these peaks are, and you can feel that the flat rate pricing isn't following any trend in particular.

Trove then did something really interesting: they clustered residential customers based upon their similar load shapes, and this resulted in seven different clusters that behaved in similar ways in their peakiness. This analysis, shown in Figure 4, leads us to conclude that these customers are either overpaying or underpaying. If the customer is super peaky, then they are probably paying not enough, and if the customer has a pretty good load shape, then they are probably paying too much. Sure enough, this is correct as you can see in Figure 5, which shows that on average, the customers with the decent load shape are paying almost $17 extra per year, while the peaky customers are underpaying their true cost of service by more than $21 per year.

The good news is that the differential over the course of the year in dollar amounts isn't that much. But then let's go back to the policy considerations around how and why we do customer segmentation. What this shows is that current rates are not fair because some people are over-paying and some people are under-paying. Unfortunately, we can't start with that argument! Let's move instead to the people side of the equation. We've

Meaning, does it help them to make good long-run investments – investments that are good for them and also good for the grid? We don't want customers to buy an expensive battery just because there's a new rate in place.

I've thought about pricing throughout my career and I've concluded that if I had the power to create rates, I would probably make the default rate something that looks a lot like real-time pricing. I would actually not expect very many residential or small business customers to stay on their rate because then, we would have what are called derivative products based upon risk and choice.

If you consider Figure 2, the X axis shows customer risk becomes greater as you move to the right, while provider risk and expected price both increase as you go up the Y axis. If you wanted the lowest possible price, you'd stay on real-time pricing, and you'd deal with it. However, many customers prefer to exchange a lower electricity price for pricing certainty. They want to trade off the risk. If they chose a TOU with a peak signal, or a demand rate with a peak signal, their risk would increase, but their price would decline. And, the utility would also end up with less risk. But instead, what we mostly see across the country is fixed rate pricing, which is the costliest pricing for the customer, and the highest risk for the utility.

E Source recently acquired a data science company called Trove. Trove did some analysis with a large utility based in the Midwest.

Equity Comparison

- >Overpayment is shown with positive values and underpayment with negative values
- >Cluster Group 1 under-paid their true cost of service by an average of $21.42 per year per customer
- >Group 7 overpaid on average $16.87 per year per customer

Group	Proportion of Customers	Daily Cost Delta – Mean ($)	Daily Cost Delta – Variance ($)	Annual Cost Deviance per Customer ($)
Overall	100%	0.0000	0.0565	0
Group 1	21%	–0.0587	0.0238	–21.42
Group 2	15%	–0.0036	0.0402	–1.31
Group 3	12%	0.0221	0.0480	8.07
Group 4	11%	–0.0137	0.0198	–5.00
Group 5	21%	0.0380	0.0713	13.87
Group 6	15%	0.0107	0.1179	3.91
Group 7	5%	0.0462	0.0733	16.87

TROVE

FIGURE 5. View Slide at: https://bit.ly/38EJHSf

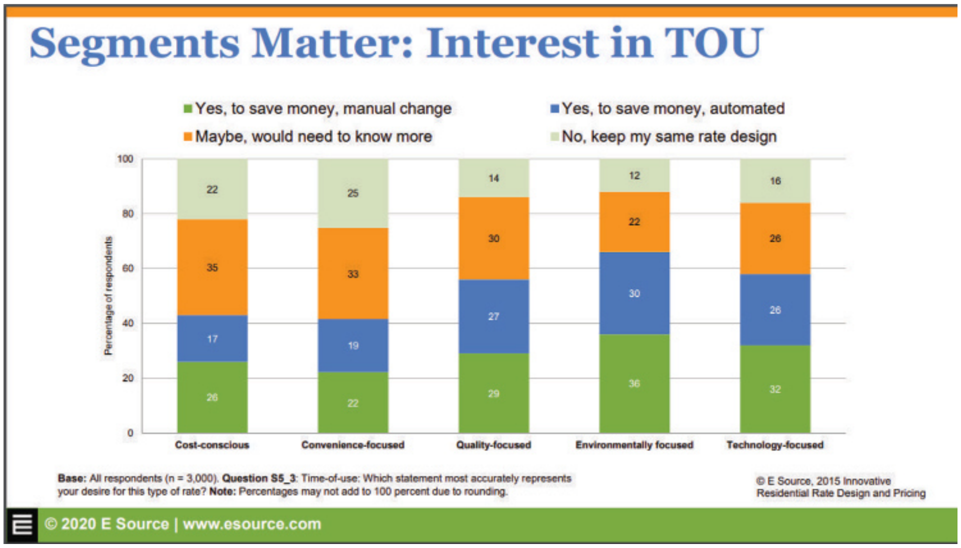

FIGURE 6. View Slide at: https://bit.ly/38BT9pq

done a lot of ethnographic research with residential customers, small business customers, and low income customers. We have had lots of conversations and one thing these customers never say is, "Hey, I wish my utility could give me more differentiated pricing on my electricity." No one ever says that! We have to remember that "differential pricing" is a utility construct; all our customers want is to save money.

In my power-walking video "research" some interesting observations emerge. When I ask a person on the street, "How much does a gallon of gas cost?", I get a fairly accurate response. But when I ask how much a unit of electricity costs, that is, one kilowatt hour, the range of responses runs from a few dimes to a few dollars. One woman told me she tries not to use electric appliances from the early afternoon to the early evening because she thinks that saves her money. However, she and her friend disagreed on whether they are charged more during those periods of time than they are at other times. She went on to say that when she looks at her bills, she doesn't really understand the usage graphs or how to interpret them. Interestingly, it turns out she was not on time-of-use rates, but she believed she was.

E Source did some market research a few years ago on rates and pricing within the residential sector. One of the segmentations we included was based on five different customer groups: cost conscious, convenience focused, quality focused, environmentally focused, and technology focused, as shown in Figure 6. We asked customers if they were interested in a time-of-day rate, and we describe what the time-of-day rate was in some level of detail. Interestingly, once they understood what a time-of-day rate is, a remarkable number no longer reject this pricing approach. As a result, we can conclude TOU rates are not something that people hate automatically, especially after they learn what these are and how they work. In fact, in this research study, about 75 percent of the customers we spoke to either wanted TOU rates or were willing to consider them.

The environmentally focused and technology focused customers are both much more likely to say yes to TOU rates. For cost-conscious and convenience-focused customers, the number interested in TOU rates is around 40 percent, and it goes up to about 65 percent for environmentally focused customers. These kinds of customers are likely to be very pleased with TOU rates. We also found that if you also describe a demand charge in clear detail, about the same number of customers are willing to consider it an option too.

In this same study, we completed another analysis in which we asked customers to essentially make trade offs between rate and pricing. As you can see in Figure 7, which shows results for six of the 15 scenarios presented, the plan that as many as 95 percent of residential

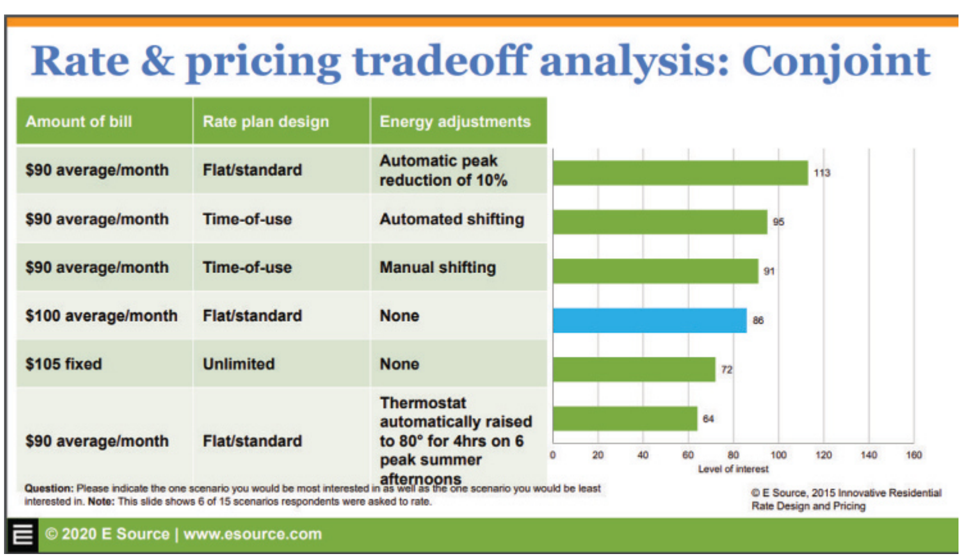

FIGURE 7. View Slide at: https://bit.ly/2Dg39cg

customers have today (the standard hundred dollar, monthly flat rate) is not the most popular! When we offer the timeof-use or peak reduction options, look at how their preferences change! In this case, the preferred option is the flat standard rate with an occasional peak reduction, and they pay $90 instead of $100.

What's even more interesting is that when you flip that around and the thermostat is automatically adjusted by the utility, customers hate the plan. Clearly, language matters! You can also see in the $105 scenario, the customer pays a five percent premium for "all-you-can-eat" electricity, but this is also not a popular scenario; it's just a more expensive flat rate.

In residential rate design, I like to talk about five critical design imperatives: a) engagement, b) choice, c) advice, d) localized, and e) rewards. How can we design rates to optimize for all of these imperatives? There's a utility in Colorado that's likely to implement something along these lines soon, recognizing that people love choice. Here are their three options: 1) one price all day, but this makes it hard to save any money; 2) demand pricing; and 3) "happy hour" pricing.

Now we're getting into the advisory aspect of customer service where we can say, "This is best rate if you're this type of person." Then we add to that localization and environmental choice. Plus we've included an optional local solar adder, so customers can get community solar. Ultimately, people also really like and want opportunities to earn rewards; they certainly don't want to be penalized! So now we can say, for a customer on time-of-day pricing and demand pricing, they will get an optional flash peak and flash sale. They will save more money. And, we wouldn't make these flash sales available to customers who don't want to take any risk. For those who opt for the predictability of one price all day, there's a premium to be paid. But ultimately, we can determine all of a customer's needs with an easy three question survey. These questions are as follows:

1. Are you willing to alter your use of energy in order to save money?
2. What large energy-using appliances might you be able to shift to operate between 9 pm and 9 am, and avoid using at other times?
    a. Heating / Cooling
    b. Pool Pump, Hot Tub, Spa
    c. Electric Vehicle Charging
    d. Gaming
3. Which of these most accurately describes you and your household?
    a. We want to lower our bills anyway we can.
    b. We want to lower our environmental impact.
    c. We want simplicity and don't have time to think about our energy use.
    d. We love the latest technology and are early adopters.

In another of my power-walking research videos, I told people on the street that utilities are considering implementing new rates called time-of-use rates, and I asked them if they'd heard of these. Most hadn't. One respondent said, "I just think you got to pay for what you use. Doesn't matter what time it is, time-of-day. I mean they want you to get up at two in the morning so your wife can do the laundry? Any time of the day when you're plugged in to something, it should cost you the same."

Another respondent asked if this meant customers would have to pay prime rates for using electricity during prime hours. She went on to explain that she'd experienced this while visiting the U.K. where her mother did the laundry at midnight to take advantage of non-peak hours. She found that irritating but then stated she also liked that it made her more aware of her use of power.

I also asked if it would make things better if the utilities referred to off-peak hours as "happy hour rates" rather than time-of-use rates. But this seemed to invoke references to free drinks. What I loved about all these discussions is that everybody I spoke to seemed to think time-of-use rates would require us all to change just one thing – when we do our laundry.

Moving to beneficial electrification and pricing, I observe we want the pricing plans we design to be economically efficient for our customers. We also want these pricing plans to be environmentally beneficial, as well as grid efficient. When these three things all come together, it turns out we can also lower prices for nonparticipants because we're reducing peak demand. Now everyone is a winner and the grid is better off too!

Derek Kirchner: Ahmad and Bill, do you have examples of effective ways to communicate with customers about time varying rates? We've talked a little bit about this from the utility perspective, and Bill's power walking videos highlight some of the misconceptions held by many in the general public. We know the rates that have worked and we know the reductions and the shifts that have worked, but how do we successfully tell this story to the general public?

Faruqui: There's a huge misperception that laundry is the biggest driver of an energy bill – witness the conversation I had with the regulator about his wife divorcing him, and what I've heard about Ontario's Premier Ford and his views on TOU. But here is the irony: Laundry is not a huge portion of anyone's bill! The washing machine consumes little energy. The clothes dryer does, but it only runs for half an hour to 45 minutes. In fact, the big ticket item on everyone's electricity bill is the air conditioner in most cases, or the space heater if you're in a winter-peaking area.

In terms of successful TOU marketing examples, Oklahoma and Arizona have it figured out. Arizona has a very hot climate, with a hundred days above 100 degrees every year. APS and SRP are two of the leading utilities in the time-of-use rate space. They tell their customers, "Here are your five major loads. It's your air conditioner, electric oven, electric range, electric dryer, pool pump; those kinds of things. Be thoughtful about when you use them and if possible, use them during the off-peak periods."

Of course, the air conditioner will run whenever it needs to run, but you can pre-cool the house, so then when the peak period arrives, the A/C doesn't have to run as much. I would say APS, SRP, Oklahoma Gas and Electric, and SMUD are doing well. I have not worked directly with SMUD on this issue, but I last visited them right before they transitioned to default time-of-use. What did I see? As I drove to Sacramento on the Interstate, I noticed a big billboard telling me SMUD is introducing time-of-use rates, but they did it in a way that was both simple and understandable. It explained that customers have a chance to save money by buying more power when it is on sale. Every American consumer can relate to that.

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>
> *– Bill LeBlanc, E Source*

Billboards aren't the only solution, but they can be helpful in influencing how we humans think. In the 1980s, Southern California Edison hired the actor George Burns as their spokesperson, and he said "Give your appliances the afternoon off." That was all he said. A very simple, understandable message that resulted in lower customer bills and a reduction of the peak load. George's message worked!

Clear messaging through social media, through billboards, and through word-of-mouth makes a huge difference. Oklahoma has been so successful at this that even the cab driver and the passenger sitting next to me on the plane were aware of their utility's TOU program. I have mentioned those examples to many other utilities who have only one or two percent of their customers on TOU rates and the response I get is, "Are you trying to shame us?" I say, "No, I'm just trying to give you examples of success from elsewhere." Their response is often, "Oh, we don't have a marketing budget. We can't do this, we can't do that."

As a customer, I now have solar on my roof, a storage battery, and an electric car. I had to try to figure out the best rate for myself, and you'd think I would know what this is, but no, I don't. It is just too confusing! When I called my utility, they didn't have my load shape for the prior year, so the customer service rep told me to wait a year for it to become available. I said, "No, I need to get on some kind of rate now." The rep explained that she had two of the same technologies that I had, but not all three, and so she couldn't say for sure what would work for me. I asked her why it's not possible to create an AI platform to simulate a future load shape for customers like me. Her response was, "Our customers are all asking this, but we don't have an answer for them." I said, "Get a budget and hire somebody." And she responded, "Oh, our management doesn't want to give us a budget."

These are very embarrassing statements coming from a big utility! We're effectively limiting our possibilities for want of some budget and a creative mind.

LeBlanc: E Source has done a lot of communications research, especially on solar rates, but remember, what people want is choice. They hate monopolies and if a monopoly tells them they have only one price option, they are immediately negative. So we always need to present customers with real, not fake, choices. Not by putting a tariff out there and saying, "Oh well, we have 11 choices or we have a hundred choices." No one takes these. Instead, we need a full-blown analysis of how to present the choices to each cluster of customers. How pricing fits a customer's lifestyle is another part of the story. Customers want to know what they can do to save, and then whether that particular option is a fair one. They want to know: 1) How is this price option fair? 2) How does it fit my lifestyle? 3) How can I save?

Kirchner: Excellent point. Have you found the five immortal objections hold through in other geographies or markets, for example in the EMEA (European) or APEC (Asian) markets? Aren't there varying levels of TOU adoption around the world, and to what would you attribute the higher rates of TOU adoption outside of the U.S.?

Faruqui: Having worked on rate design issues in a few countries, I can say it's the same old challenge. I was recently talking to a utility CEO, and I asked why is it so difficult for utilities to tell customers "this rate is more fair for you and it will help you save you money." He said, "Customers reject this approach immediately because they think of a utility as a monopoly and wonder, 'why would a monopoly try to help me? They're just trying to make more money from me.'" This is a huge perception challenge everywhere – from Australia and New Zealand to Hong Kong and the U.K. Retail choice does not solve this enigma either.

In the U.K. and Australia, retail choice has not worked out well for customers. When it comes to pricing, innovation has been limited. The last time I was in Texas, the representative of an energy retailer told me that about a million customers were now on time-of-use rates. But he was unable to share any data with me, saying it was confidential. Retail choice is not the magic bullet we hoped it would be. In 14 U.S. states with retail choice, most residential customers are still with the monopoly utility.

Kirchner: Given that most of the big loads are on the C&I side, what about dynamic pricing or real-time pricing for commercial and industrial? What's been the experience? I know most utilities have at least a non-peak and an offpeak bill determinant for demand charges, which in some fashion or another is a default time-of-use rate. You're trying to incent that behavior, but is there a way to take it a step further, and have you seen anyone be successful on the commercial and industrial side?

Faruqui: Georgia Power has probably the world's most impressive real-time pricing (RTP) program. They have more than 2,000 commercial and industrial customers on either a day-ahead or an hour-ahead RTP rate. It's a two-part rate structure: the first part is the customer's baseline load shape. If the customer does not change their load shape, they will pay the same bill they paid last year. In other words, they subscribe to their last year's load shape, but for any deviations, they pay the real-time price. I think it's a great idea and a good example of success, but it hasn't caught on with many other utilities for reasons that I'm still trying to understand.

The other example of a partial success is critical peak pricing. In California, they have deployed this as the default rate for C&I customers, going back about 10 years now. But for various reasons, customers have not been happy with it and there have been a lot of opt-outs. Many other utilities have time differentiated demand charges. Some also have time-of-use energy charges to go along with the time differentiated demand charges. Metering is not an issue, it's really more about getting customers excited and engaged.

LeBlanc: Success can depend on which group of C&I customers we're talking about. Large C&I customers are very sophisticated. They are likely to have energy managers, and they accept very complex rates, probably 2-part demand charges, 3-part energy charges. Smaller commercial customers often don't have the automation to make this work. It's a slow process, very similar to residential decision-making, but much more focused on the bottom line than residential customers tend to be.

For example, many residential customers are willing to pay a little more for comfort and convenience because energy is not that big a part of their overall budget, if they are in the top half of the residential sector. Small businesses are often looking to cut expenses. California has done a lot to move customers to TOU, and have done lots of early marketing and early education with small business customers. But remember, small business customers are looking for advice from trusted partners too. If the utility comes across as heavy-handed, they're automatically not going to like it. Utilities have to move in this direction by offering a partnership with their customers.

The other thing that I've often heard from utilities is they tell customers that the new rate isn't going to change their bottom line at all. This is a terrible message! If you're going to bother to do time differentiated prices, if you don't see any changes, then what's the point? Utilities need to couple the rate with an intelligent message about what they are working to accomplish in the long run. Once customers understand that their utility is not building power plants, but is instead focused on helping the environment and low income customers, they're now on board with the new rate.

Kirchner: The key is definitely in connecting the rate story to the bigger picture. That is, as utilities, we're not providing these rates just because we feel like we have to. We're doing it for a good reason. But boiling down an IRP into a 30-second marketing ad is hard to do! Still, we've got to get there.

Most of the TOU rate programs are default TOU. It's not an opt-in program, it's an opt-out. Are there any situations where you've seen opt-in working, or do optouts need to lead the way in deployments?

Faruqui: At Oklahoma Gas and Electric, it's opt-in. Same for APS and SRP in Arizona. Those are the three most successful programs today, and they have penetration rates between 20 and 57 percent. There have been incredibly successful opt-in programs. Opt-out will get you more customers, but you still have to do the marketing. Otherwise, there'll be no engagement, and without customer engagement, there will be no load shift. You can do both of them well, and you can do both of them poorly. It's all about your priorities.

One utility with an opt-out CPP rate for large customers hired me to figure out why it was not experiencing any success. I interviewed their demand response manager, the pricing manager, the customer service manager, and finally, the power supply procurements manager. Two of the four hated the CPP rate. The rate design people liked the rate for the job security it provided. The DR person said, "I need the megawatt savings." The supply person said, "Why are you paying them so much money? We can buy power more cheaply than we can get a customer to cut back." The customer service person said, "I really hate this. I tell customers who call us to get off this rate, it's terrible." That's four perspectives in one utility. That's the challenge. You need to achieve internal alignment before you'll be able to make these rates work externally with customers.

LeBlanc: There are a few utilities who have had achieved high market penetration for opt-in programs. Most TOU rates are not opt-out now. That's a relatively new phenomenon. If you look at the behavioral side and not just rate design, with opt out, you end up at above 90 percent penetration. If you offer opt in, you can chug along at three to six percent penetration for your whole life, unless you have an incredible marketing program. But, I wouldn't actually recommend either opt-in or opt-out. What I would love to see is every customer having the opportunity to choose between three or four different rate designs, and then follow the rules of risk and reward.

> "Load shape curves are changing with DERs and will change even more as electric vehicles begin to proliferate. For the first time, an EV is being seen as storage."
>
> *– Bill LeBlanc, E Source*

I would tell them do your lifestyle analysis, do a little survey, and based on this, choose the rate that makes the most sense, knowing you can change it later. This gives a customer some control and choice, which is what they're looking for. I think we'll find this is the beginning of a trend in which customers start talking with each other about energy prices, because that's what's happened at APS. When new people move into a neighborhood, their neighbors will update them on the TOU rates because this is now part of their experience and knowledge. So I recommend utilities offer a choice of very good rate options so that customers can select the best fit for their lifestyle.

Faruqui: I totally agree. No two people are alike, and so give them choices, let them pick. If you were going to a department store and they only offered one kind of shirt, you'd probably never go there again!

Kirchner: Some view time-of-use rates as anti-solar. While demand rates could be that, according to some, what has been your experience with TOU being anti-solar?

LeBlanc: It's very hard to blame a rate for being anti- or pro-solar. I could design a TOU rate that the solar people would love and a TOU rate that the solar people would pick. I think that it goes back to the question of what is, and is not, a policy decision. If your policy is to encourage local rooftop solar, then you may decide to subsidize it within the rate design. If you want to be absolutely fair, you can do that too. You just run the numbers and you're absolutely fair. That's a policy choice. I would not blame the rate design for being pro-solar or anti-solar.

Faruqui: Obviously, it depends on a state's policy objectives. If a state policy objective is high RPS and we want to promote supply-side as well as demand-side deployments of solar, then let's think of this as an opportunity, the same way we think of an energy efficiency program as an opportunity. Let's provide a rebate to subsidize the cost. We've had 30 percent and now 26 percent income tax credits for solar. Some states provide renewable energy credits for solar. In Austin and in San Antonio, Texas, the utility provides a cash rebate over-and-above the federal income tax credit. That's the way to incent the deployment of solar and other technologies.

Why should rates be used to subsidize customer investments? In my view, that's not a good approach. Whether it's for solar or low income customers, if there is a need for an incentive, offer it either through the tax code or a cash payment. We have food stamps. We could have energy stamps. We could have solar stamps, but the rates should be cost reflective. Otherwise, you get cross subsidies between customers. I don't think TOU rates are anti-solar by the way. Demand charges are viewed by some as being anti-solar. That's not true. If you think about all the incentives already in place for solar, the demand charges being implemented are for the purpose of creating equitable outcomes among customers.

Some customers have solar, some don't. But the reality is every state has to juggle these competing objectives, right? Efficiency, equity, and renewable energy. There is no easy answer. One utility told me about five years ago that the solar industry wanted time-of-use rates. They said they didn't want demand charges, so the utility was going to give them a time-of-use rate. But the time-of-use they were going to get from the utility would not be the one they wanted because of the duck curve. It would need to have a really late peak window from 4 to 9 p.m. rather than from noon to 4 p.m., which solar people would love. The reality is that if you make one customer happy, you're going to make the other unhappy.

LeBlanc: Yes, and we're in a very dynamic supply situation right now. Orders of magnitude greater than I've seen in my career. Load shape curves are changing with DERs and will change even more as electric vehicles begin to proliferate. For the first time, an EV is being seen as an appliance with electrical storage. So whatever we decide to set as the "expected" EV charge time, customers will learn this and remember it for the rest of their lives. It's both important and necessary to set expectations around the optimal charge times right from the very beginning because it will be brutally hard to change these later.

That's why I would recommend to utilities now that they skip beyond TOU as the next new thing and think much more about dynamic pricing. Similar to the process by which developing countries went from having no telephones to having cellphones in one step. If we're not already doing TOU rates, it makes sense to move to something much more dynamic right now because emerging technologies like electric vehicles will really shift these curves, and education is hard to do well. We also want entrepreneurs to work on this problem. The more our utilities can get on the same page around dynamic pricing, the more we'll see entrepreneurs jump in to help solve these problems for customers.

Faruqui: I agree a hundred percent with that. I really think the developing country analogy is perfect. Just leapfrog TOU and go directly to dynamic pricing. We have to do this because so many states want to be 100 percent renewable in 20 years. How is TOU going to help with that? We need 24/7 load flexibility and the only way to get there is through dynamic pricing.

> "Opt-out will get you more customers, but you still have to do the marketing. Otherwise, there'll be no engagement, and without customer engagement, there will be no load shift."
>
> *– Ahmad Faruqui, The Brattle Group*

LeBlanc: We should also be putting this capability onto smaller appliances. Air conditioners are pretty big, but going back to solar, when we explained to residential customers that community solar is 40 percent less expensive, and utility solar is half the price of rooftop solar, it shifted their interest from installing rooftop solar to buying solar from their communities.

Kirchner: Yes, this is very much about whether you set rates according to a policy decision or a pricing decision. Trying to move to dynamic pricing is probably the closest balance we have to getting to both of these without being locked into one or the other. If pricing could be tied as closely as possible to the real-time energy market or the real price of power, customers would have the flexibility to make their own economic decisions. In the long run, the load shape would adjust and a natural balance of the system would occur based on preference and not artificial design.

LeBlanc: One last video interview story. I asked a couple on the street, "Have you heard of real-time energy pricing?" When they said no, I gave a long and involved explanation of real-time pricing; that it has a lot to do with the loading order of the power plants because there are base-load power plants that are typically coal or nuclear, and then there are intermediate plants, and then there are peakers, which are often gas turbines. I explained that real-time pricing can give customers the information they need to be able to turn appliances off and on at the right time to help the smooth operation of the grid. There was a lot more to my explanation, but I said to the man, as he walked away, that with real-time pricing he could save as much as five percent on his energy bill. He and his wife weren't interested. They just walked away.

Perhaps it was my explanation?

Presentation slides available at https://www.peakload.org/dialogue--pricing-difficult

How Pricing Is Playing a Greater Role in Grid Solutions

Pricing

The following transcript is from a roundtable discussion held during the 42nd PLMA Conference, presented online in November 2020. It highlights pricing as a means to manage electricity supply and demand, as well as the role of pricing as a tool for alleviating grid stress.

This discussion was moderated by PLMA Executive Committee Member Christine Riker, who is the Director of Distributed Energy Resources for Energy Solutions. Christine was introduced by PLMA Executive Committee Member Andrea Simmonsen of Idaho Power and Chris Walls, PLMA Conference Co-Chair of Baltimore Gas & Electric. The roundtable speakers also included Derek Kirchner of Consumers Energy, Ryan Hledik of The Brattle Group's San Francisco office, Erica Keating of Southern California Edison, Rich Barone of TRC Companies, and John Powers of Extensible Energy.

Moderator
Christine Riker
Energy Solutions

Rich Barone
TRC Companies

Ryan Hledik
The Brattle Group

Erica Keating
Southern California Edison

Derek Kirchner
Consumers Energy Company

John Powers
Extensible Energy

Andrea Simmonsen: In the following discussion, we'll explore the ways in which retail pricing is being harnessed for load flexibility, including flexible capacity, and also for active demand management to alleviate grid stress.

Christine Riker: The electric grid continues to be stressed by causes that include extreme heat waves, massive wildfires due to climate change, and the increased penetration of renewable energy which operates much differently from traditional fossil fuel power plants. Each of these factors impacts electricity supply and demand.

In many other parts of our lives, supply is managed by changes in price. For example, around the holidays, when we're trying to travel to visit family and friends, the demand for flights or hotel goes up, but supply is limited. Hence, the price increases to help alleviate some of the demand.

This discussion explores the concept of electricity pricing as a means to help manage supply and demand, and the situations in which it can serve as a useful tool to alleviate grid stress. What are your organizations doing to facilitate time-varying pricing?

Derek Kirchner: Consumers Energy has run and continues to run residential DR programs including dynamic peak pricing and peak-time rebate programs that we use in support of our clean energy plan. About a year ago, working with our Public Service Commission, we began the process of implementing a mandatory summer time-of-use rate. We were all ready to launch it in 2020 when COVID-19 hit so we went back to the commission and together, determined it made sense to hold off until summer 2021 when summer time-of-use rates can support Consumers Energy's clean energy plan and long-term goals for a cleaner future.

John Powers: Extensible Energy is a software company. We make load flexibility software for small to medium commercial buildings so we are driving the automation of time-varying rates by helping our customers take advantage of whatever time-of-use or demand rates are available. We're also encouraging the adoption of a more realistic flow-through of wholesale rates to retail customers because with automation, it's possible to take advantage of the true time-varying costs on the system.

Ryan Hledik: My introduction to the wonderful world of rate design came about 14 years ago when I joined the Brattle Group out of grad school, right when a number of utilities were starting to explore investments in smart metering infrastructure. At the time, I worked with utilities to help develop those business cases and focused on understanding the benefits of new time-varying and dynamic rate designs. That is, understanding the benefits of reducing consumption during peak periods and what that translates into in terms of system value.

Today we're exploring a broader set of questions around how to price electricity fairly for customers with generation behind the meter, and how to price electricity in a way that encourages the use of all these flexible automating technologies John mentioned. We started with a narrow goal for advanced rate design and now that's expanded into a number of new and challenging issues to address.

Erica Keating: Southern California Edison transitioned our non-residential customers to TOU rates a number of years ago, and starting in 2019, we began doing the same with our residential customers. Our target is 2.5M customers by the end of 2022. We also have a real-time pricing program and a critical peak pricing program that, so far, has ~350,000 service accounts on it. We have options in place for both residential and non-residential customers today.

Rich Barone: TRC is building on its almost two decades of energy efficiency, demand response, and general DSM program administration expertise. We're combining this today with new technologies. For example, working with Marin Clean Energy, a community choice aggregator (CCA), we're deploying a battery storage program that provides some economic opportunity for customers as well as some resilience which is especially helpful in the face of increasing wildfires.

This program is rooted in a TOU structure that creates synergy between economic opportunities for customers, time-of-use rates, and overall system demand during those peak periods where Marin Clean Energy is exposed to high prices in the CAISO market. TRC's work on this project helps support the overall program design, as well as the information technology and partner ecosystem needed to deliver a full turnkey solution for Marin Clean Energy. It's a model we expect to expand for many other IOUs and CCAs in the years ahead.


Marin County, CA

Riker: What is your biggest hurdle within these programs or within your research or software?

Kirchner: Beyond the significant barrier of COVID-19, we look at this time as an opportunity to continue to engage our customers with information about pricing, something utilities are always doing. As a utility, we don't really talk about kilowatt hours, or rates, or shift, or even time of use. The customer conversation goes more like this: "Hey, there's a new rate! It's a default time-of-use rate. That means there'll be a price difference between your off-peak and your on-peak energy usage in the summer."

The discussion is not only about the rate; it's about the "why." This is not necessarily a challenge. It's just a matter of having that customer conversation and getting them educated, just like everything else in the world. As Christine mentioned, supply and demand are the same on the energy side. Our goal is to have our rates reflect our costs so that customers can best understand how shifting their behavior helps meet our clean energy goals. Talking to customers about rates, when done well, results in engaged customers interested in helping meet clean energy goals.

Riker: I think your biggest challenge, Derek, will be my parents in western Michigan! They're still trying to understand what these changes and clean energy goals are all about.

Hledik: A barrier we've come across in our regulatory work with utilities has been related to the fact that when you change a rate design, some customers will automatically experience bill savings while others will experience bill increases. It's the customers who end up with bill increases who become a concern for regulators, for utilities, and for certain stakeholders.

The question this brings up for me is what tools and approaches are available to address concerns about the subset of customers that could experience a bill increase and who may not have the means to afford more expensive electricity? The challenge we have is finding solutions for this subset of customers so they are well positioned to handle a transition to the new rates.

Barone: One of the biggest challenges I've observed, now from few different perspectives including that of a utility employee, is how do we establish energy pricing? What are the key contributors? It's one thing to look at supply and demand, but to what extent should we include locational considerations in pricing? Another constraint is the price of carbon. So what makes up a "price?" It's big question because there's no uniformity and it's not simple.

Speaking more broadly, as a customer, I have a rate and maybe it's clear and easy to understand my rate, which is ideal. However, I still don't necessarily know what to do with this information. What's at my disposal to allow me to take full advantage of this pricing information? I think customers really need some support to help them get over the chasm that exists between "understanding" the economic opportunity and "realizing" the economic opportunity inherent in their energy pricing.

Keating: Customer education and outreach is really about helping customers to understand what the new rate means. It is the single biggest hurdle we experience. As we've gone through waves of early residential defaults, we need to acknowledge these customers just want to be able to balance their normal expenses on a day-to-day and month-to-month basis. They don't really understand whether they are going to come out ahead or behind in a rate change, but they want to be able to stay on budget.

We don't make it easy for customers because the rates are complicated, and we're asking people to change their behavior at home in order to better adapt to a new rate. So how can we simplify the issues and educate customers so they can really understand?

Powers: It's important to simplify, but also to automate, because this is not the last wave of rate changes we'll have, right? The grid is changing quickly and dramatically, so the notion that a rate can be filed and that it will then stay in place for decades is long gone. I also think that we'll see another wave of complexity even after this one. So, the more we're able to give customers the comfort they desire, the more automation and software will be able to adapt faster than the rates change. That's the key to bringing customers on board. My organization works more with commercial customers than residential, but our customers have been willing to be more flexible than we've given them credit for over the last few decades.

Riker: What about the customers who are going to have higher bills? What can we do for them? What are some thoughts on technology and smart devices? Could these things help? What role can technology play in alleviating the potential impacts of dynamic pricing?

Hledik: Technology is one option through which we can automate responses to these new prices and that certainly helps with bill management. There's also the concept of providing a choices of rates to help customers manage this transition. Derek said that Consumers Energy is transitioning to default TOU rates. I assume that means customers have the option to opt out of the TOU rate and choose an alternative; possibly the continuation of their flat rate? Maybe it's some other type of rate design, ultimately one that encourages price response?

If we can give customers a menu of options and let them choose the rate that works best for them and that still provides an incentive to benefit the whole system, that is one good way to address some of these concerns.

Kirchner: I agree. It's not just a technology solution, it's a customer solution, it's a behavioral solution, and it's also on us as utilities to look at rate design because it's possible to design a rate to accomplish just about anything we want. We can encourage a change of behavior. It's all about how we incentivize it through pricing.

> "Customers really need some support to help them get over the chasm that exists between "understanding" the economic opportunity and "realizing" the economic opportunity inherent in their energy pricing."
>
> *– Rich Barone, TRC Companies*

For the customers who are experiencing higher bills, we can design a rate that says, "Okay, maybe you don't fit in this box, but you do fit in this other one, and we can help offset your bill increase and still get some savings and behavior change for those costs."

Powers: It's certainly not the zero-sum game it was when I was doing rate design, back in the day! The wholesale markets reward load flexibility so if utilities can team up with their customers to harness load flexibility, there can be an enormous impact on wholesale prices when energy is shifted from the most expensive peak periods. This is where the utility and the customer are on the same side. If they can tap the wholesale markets properly, they end up not with winners and losers, but with winners and winners.

Barone: Where there's a nexus of lower income customers disadvantaged by some of these rates, there are public benefits funds available that have, for years, focused on DSM and especially energy efficiency to help supplement or support them. To be more expansive about what that could look like, efficiency investments would be a huge part of this. That will bring costs down a little bit.

The evolution of pricing is going to get more and more complex, and without supporting technologies that allow for automated response to price signals, it will be very difficult to achieve meaningful results. Looking at this, and looking at public benefit fund investments that support energy efficiency as well as the buydown of some of these enabling technologies to make them more accessible, is a key consideration.

There's also the notion of customer choice which represents a huge opportunity. There are bill modeling tools that could make this simple. If we're going to create several pricing choices for customers, then let's allow them to look at what the different options might mean in their situation. That way, they can make informed decisions that align with their wallets.

Riker: Have we reached not a "tipping point" per se, but a changing point around technology? I like to think of a dream home in which the washer and dryer, the water heater, and all the appliances are able to communicate and pull in prices, then operate accordingly. As the homeowner, I wouldn't have to think about any of it, nor care if I'm on a flat rate or a dynamic rate. Is this a possibility?

Powers: The day of this dream home is getting closer and closer for those who can afford it. But there's plenty of risk in residential because a lot of folks will be left behind. Their homes will not have been heavily wired to be "smart," and these are not yet trivial investments to make. While the market is moving in the right direction, the equity considerations Ryan raised are important.

From the perspective of the commercial sector, it's a lot easier where you're just looking at a customer's bottom line and thinking about how they can improve it. You can make a dollars and cents investment in automation technology based on its payback time. I see the commercial market moving very quickly to adopt these kinds of technologies.

Modern House Concept

Hledik: Time-varying rates for residential customers create an opportunity for those who have automating technologies like smart thermostats and smart EV chargers that can save them money by responding in an automated way to price signals. But these rates also provide an opportunity for customers who don't have automating technologies to reduce their bills. For customers on a flat rate, the only thing they can do to reduce their bill is to conserve. But on a TOU rate, a customer can conserve, or they can shift their consumption out of the peak period and save money. That can be done through automating technology, or through a behavioral change.

Brattle has just wrapped up an evaluation of the first year of a TOU pilot in Maryland which evaluates how low and moderate income customers, as well as other customers, respond to time-of-use rates. In the pilot we've found there is a significant, almost identical level of response from lower income customers, even though they are less likely to have smart thermostats and smart chargers to capitalize on these rate designs. This shows that once customers understand the rate and the associated price signal, there are various ways they can respond to those rates, both automated and not automated.

Barone: It's one thing to modify your behavior when you have well-defined blocks of time and dollar amounts. But if we evolve to a point where rates get more dynamic for thinner slices of time, I would imagine it would get more difficult to employ behavioral changes? At that point, we'll be more reliant on some of the automating technologies for results. Is this accurate?

Hledik: That's pretty fair. In Illinois, residential customers have, for several years, had access to an hourly real-time pricing rate. Customers who are enrolled in this hourly rate do respond to the prices, but they treat this like it's a simple two-period TOU rate. They know, generally, prices are higher in the afternoon and lower during other hours and act accordingly. But they are not turning on the air conditioner in hourly intervals to respond to prices. So there's eventually a limit to what customers can accomplish through their behaviors and that's where automation really starts to kick in and add value.

The question is how to make this happen. Christine described a dream house in which technology responds to hourly or sub-hourly energy prices. Or, is it a very simple rate design, maybe even a fixed monthly bill for customers, so all of that automation, smart thermostat management, and EV charging is happening behind the scenes and being controlled by a utility or an aggregator or someone else? This is the tension that often arises when we talk about how to incentivize load flexibility.

Keating: We talk about this issue a lot at Southern California Edison. We've got traditional demand response event programs. We've also got a whole suite of dynamic pricing, which will continue to get more complicated and dynamic in California as time goes by. We talk about the hope that all of these technology builders, third party developers, and thermostat, appliance, car, and battery manufacturers will rally around this concept with us.

Hopefully, in 10 or 20 years from now, whether it's equipment pre-programmed to a rate that a customer chooses and downloads, or whether it's the utility that sends signals for something specific and discrete to occur, all these devices will respond together in tandem. Our fingers are crossed!

"Hopefully, in 10 or 20 years from now, whether it's equipment pre-programmed to a rate that a customer chooses and downloads, or whether it's the utility that sends signals for something specific and discrete to occur, all these devices will respond together in tandem."

– Erica Keating, SCE

Riker: We've talked about a scenario that's one rate, technology neutral, respond as you like. We've also seen moves across the country toward an easy specific rate. So a technology specific rate might work well with a larger energy consuming device. Is there an SCE electric vehicle rate and are there hurdles or successes that go with it?

Keating: SCE is one of the first utilities trying out EV rates and we have some early lessons to share. We went out with an EV1 rate a couple years back to serve residential customers who planned to charge their electric vehicles at home. Those were the early adopters of electric vehicles who would be willing to install a meter at home to get this specific rate.

Once this program was in place, we realized we were isolating the market because there are just not a lot of people who are both a) EV early adopters, and b) who can afford to install a meter. Plus, to install a meter, some of these customers would first need to have some work done to upgrade their electric panel. That led to a conversation about all the other technologies we see coming, plus those already here, including smart thermostats and residential batteries.

We quickly realized we needed a technology-neutral rate; one that will work for people who are electrifying things in their home, including their car and other widgets. As a result, we closed down the EV1 rate last year and moved to implement a technology-neutral rate so customers didn't have to choose between a rate for a battery or a rate for an EV and on down the list. We've proactively marketed the technology-neutral rate and have seen good adoption: it's grown about 25 percent in the last six months. We have ~22,000 service accounts on this rate, and this is growing by ~1,000 accounts a month.

Barone: I had a lot of debates about this at Vine Electric. I believe there's a time value of electricity and no matter what the technology, it will be used to help incentivize behavior in accordance with the economic signal. It shouldn't be technology specific. That doesn't mean you can't market to specific technologies or to specific customer segments, but that's more of a branding or marketing effort than it is an underlying price construct.

Powers: The EV issue is so huge that it doesn't just boil down to rates, does it? There's a lot written about smart charging, but not very much about demand charging, at home, in workplace settings, and at fast chargers on the grid. If EV adoption is going to continue at a high rate, there has to be a lot more automation and simplification of smart charging.

We're working on a project now that includes examining whether Auto DR is one approach to controlled charging or whether pricing a separate rate is its own approach. Early adopters are not showing high promise for that. As a result, we have to do something with automation or the very fast adoption of electric vehicles will create difficult planning issues.

We're all involved in planning the grid. DERs, which pose a fundamental change to the grid, are not being figured out by four guys in a Distribution Planning group anymore. Instead, customers are planning the grid when they install solar or big fleets of electric vehicles online. We must recognize this reality and create smart programs to address it. These could be DR, or pricing, or something else, but EVs are a special case. They are as significant as a house.

Riker: What about the small and medium businesses being left to the side? Are they really able to change their operations? Can they shift during the peak hours or do they need to remain focused on running their businesses?

Powers: Certainly they need to focus on running their businesses but with automation and good tools, they have a surprising amount of flexibility in their usage patterns.

This raises a good point about restaurants and other businesses that don't have much flexibility. As we talked about on the residential side, there will be people who benefit from changes in rates and others who don't. There are also some who have less flexibility which causes them to lose out. Engaging with small to medium buildings, and small to medium businesses, we'll find there's a huge amount of flexibility in office, retail, church, school, conditioned warehouse, and municipal buildings. There are all kinds of businesses that are not necessarily driven by a nightly dinner schedule. The messaging around rates has to be customized by the type of building and business, but there also a lot of flexibility in the small to medium commercial world.

Hledik: In the pilots that we've been involved in, automation is key for small businesses relative to residential customers or larger customers. There isn't nearly the same level of behavioral or manual response from those smaller customers. Technology automation is necessary to get demand response benefits from these customers. The reasons for offering these rates goes beyond demand response. There is also an issue of fairness and cost reflectivity in rate design.

Riker: We're not talking about traditional DR, like a four-hour event when a customer needs to turn off everything to participate. This is more about how we harness that little bit of flexibility that all these different customers have. A restaurant is going to be very different than a retailer in what can be harnessed, but there's still something there to harness. For utilities that get their energy supply from third parties, trying to prevent having their peaks match, that third-party peak, what mechanisms or critical peak pricing can help address the coincident peak?

Hledik: Some utilities do offer coincident peak-based demand charges which means after the peak season, at the end of the year, the utility looks back at its customers' loads during peak hours. A customer's load is used to sets the demand charge portion of the customer's bill which is a very accurate way of aligning customer charges with the cost drivers on the system.

A lot of utilities with this type of rate design provide customers with day-ahead notification of when they think the system peak might be set. There's no way to forecast that perfectly, but by notifying customers that tomorrow might be a system peak day, customers get some sort of actionable information rather than just finding out after the fact that their bill was higher because a system peak occurred mid-month, or similar.

Riker: Thinking about educating customers about pricing and time-of-use and a situation in which critical peak pricing occurs maybe 15 days out of the summer, how often are you connecting with your customers, talking with them, working with them to manage their demand in these situations? Any thoughts on ways to reach customers once they're in these programs?

Kirchner: For dynamic peak pricing (DPP) or critical peak pricing (CPP), Consumers Energy calls events by 6:00 pm the day before so customers can make the changes they need, whether it's adjusting the thermostat or doing the laundry today instead of tomorrow or waiting to run the dishwasher. We try to notify customers as close to real-time as we can. That way, we are avoiding over-communication or fatigue.

On the TOU pricing, we send a lot of information during enrollment. It's a more passive approach because the rate's a little more passive. The design is there to modify behavior but we're not in there every day, 365 days a year, communicating to the customer, "Hey reminder! Today is a time-of-use day." That would be a little much!

Keating: SCE tries to notify customers at the beginning of each new season through messaging aimed at getting the attention of those already on DR. For CPP, we do our best to try to get customers to opt-in to those communications, hoping that will increase their success on the rate. We have seen a lot of program notice opt outs as time goes by. Our best guess as to why so many opt out of event communications is perhaps customers forget they're on this rate and then think they're getting spammed by us because we email and call them with event notifications.

Ironically, one of the big successes we had with customer communication this summer during the system emergencies was through SCE's demand response app available on Android and iPhone. We saw ~30,000 downloads during the week of the August emergencies and a record high number of downloads and views of alerts and messaging in the app.

Customers can customize these alerts by program and by the type of messaging they receive too. For utilities considering an app, I highly recommend it. Apps are very customizable and make it easy for customers to get information quickly. SCE will be using these more in the future.

Riker: What is your top solution to increasing price-responsive rates, to harnessing this flexible demand?

Hledik: To pilot these new rates with a plan for full-scale deployment. We often see new rate designs get stuck in the pilot phase. My advice would be to assume the pilot will be successful and go into it knowing how you will scale it up. Don't just test it then wait to do something bigger once the pilot wraps up.

Kirchner: Educate customers. It still comes back to customers understanding their energy use as well as knowing what energy actually is in order for them to be able to take advantage of "kilowatt" and "kilowatt hour" charges. Helping customers to understand how these things work is key to getting them to shift their usage and behavior.

Barone: To harness flexibility, we need three things. First, to understand how to establish granular dynamic rates and incorporate all of the disparate value elements. Secondly, automation, automation, automation! Not relying on individual customer responses to those signals is the best way to ensure you can get the response you want. That could be done through algorithmic optimization for economics, for example. Third is customer education, specifically helping customers understand the economic opportunity plus the rates and the automation that support that economic opportunity.

Keating: Build a pilot that really can be used in the real world. SCE has had some growing pains when we had pilots that couldn't be operationalized quite right, or that were not cost-effective when they became programs. There's a lot that goes into these programs and a lot to think about.

Simmonsen: Thank you panelists for a great roundtable discussion!

Perspectives on FERC 2222

Pricing

The following is a transcript from a Load Management Dialogue (webcast) presented in October 2020. It reviews FERC Order 2222 which addresses the opportunity for distributed energy resource (DER) aggregators to participate in wholesale electric markets.

This discussion was moderated by PLMA Awards Co-Chair Brett Feldman of Guidehouse Insights. Participants include Anja Gilbert, Principal, Pacific Gas and Electric Company; Marcus Hawkins, Executive Director, Organization of MISO States; Jay Morrison, Vice President, Regulatory Issues, NRECA (and as of January 2021, Chief Legal Counsel at ElectriCities); and Matthew Sachs, Senior Vice President, Strategic Planning and Business Development, CPower. Together, they represent the viewpoints of an investor-owned utility, the MISO states, a cooperative utility, and a DER aggregator.

Brett Feldman
Guidehouse Insights

Anja Gilbert
Pacific Gas & Electric Company

Marcus Hawkins
Organization of MISO States

Jay Morrison
NRECA

Matthew Sachs
CPower

Brett Feldman: About five years ago, I hosted PLMA's webinar on FERC Order 745 which made it all the way up to the Supreme Court, and here I am again!

On September 17, 2020, FERC issued Order 2222 which it has acquired several descriptors so far, including FERC 22-22, FERC two by four, and as a college football fan, I especially like the "double Flutie" in honor of Doug Flutie who wore number 22 for Boston College in the mid-80s.

In summary, FERC Order 2222 allows distributed energy resources (DER) aggregators to compete in all regional, organized wholesale electric markets. The order's goal is to level the playing field for new technologies to participate with existing ones in wholesale energy markets, further enhancing competition, encouraging innovation, and especially, driving down energy costs for U.S. consumers.

Each Regional Transmission Organization (RTO) must allow distributed energy resource aggregations to participate directly in RTO markets, which establishes DER aggregators as a new type of market participant. Aggregators must be allowed to register their aggregations under one or more participation models, and aggregations cannot exceed 100 kW.

RTOs must address locational requirements, distribution factors, bidding parameters for aggregations, information and data requirements, metering and telemetry requirements, and ensure coordination between themselves, the aggregator, and the distribution utility, as well as any relevant retail regulatory authority. The RTOs must also address modifications to the list of resources in aggregation, as well as market participation agreements for aggregators. Finally, they must address the utility opt-ins and opt-outs, based on the size of the utility. The order goes into effect on December 17, 2020 and the RTOs have 270 days to submit their plans, which means we won't see anything for another nine to 12 months.

There have already been several requests for clarification and re-hearing of FERC Order 2222, so we'll see if it goes to court as happened with FERC Order 745.

Generally, I'm skeptical of FERC's impact on the markets with these types of orders. In the case of FERC Order 745, it feels like a counter-factual occurred. At that time, if either FERC or the courts said demand response was not allowed to participate in the markets, that would have been a huge deal. But in the end, we got the status quo with some incremental improvements.

The process that gave us FERC Order 2222 started back in 2016. In the four years since, most of the RTOs have held their own DER proceedings, so it'll be interesting to explore if this order is incremental or more transformational. FERC's recent order on energy storage, Order 841, may have been more impactful because it focused on one type of resource, rather than this very broad DER order.

Anja Gilbert: I work at Pacific Gas & Electric in the Integrated Grid Planning and Innovation Group. My focus is on how DERs help flatten the load curve, looking primarily at the supply side of wholesale markets including demand response integration and other DER pathways, like rates and standards, as well as FERC 2222. However, the perspectives I am sharing here are my own.

My initial reaction to FERC Order 2222 was, "Good. Now we can have more minds working on this." In California, our ISO, the California Independent System Operator (CAISO) is always innovating and has had a market model in place since 2016 that largely mirrors what FERC Order 2222 will require of all ISOs and RTOs.

So how have things been going? We haven't seen participation in CAISO's DER aggregation model quite yet. I think that's largely because the ball is in the state regulator's court as far as developing corresponding retail rules.

If you read all ~300 pages of FERC Order 2222, you'll notice FERC deferred some aspects to local regulatory authorities, and for good reason. There are new systems required and when we have retail customers acting as suppliers, this requires coordination between ISOs and state regulators. With a wholesale product, rules must be established by the state related to interconnection, billing, metering, customer protection, and in California's case, capacity evaluation and accounting.

In addition, FERC 2222 will require huge upgrades to our systems, including investments in IT systems and communication platforms. It may mean that new systems are needed for visibility and control, like increased supervisory control and data acquisition systems (SCADA) and a distributed energy resource management system (DERMS). You'll see this play out in utility rate cases.

It's worth taking a quick look at the history of integrating retail load into markets. As Brett mentioned, although FERC issued their demand response order (Order 745) five years ago, it has taken ISOs and states a while to integrate demand response. In California, it's taken about 10 years of regulatory work, collaboration with stakeholders, and system build-outs to fully develop the demand response model, and we're still refining it today!

A lot can be leveraged from the process of integrating retail load, and FERC Order 2222 is much more complex in so far as it also allows load to be exported. I believe there are three issues to consider here. First, complexity is costly. DERs are being positioned to participate in the market in a way the grid wasn't designed to accommodate. That is, transitioning from a one-way flow of power to a world in which DERs become both sources and sinks of power. Adapting for this change will require distribution grid investments including both upgrades and enablement systems; SCADA and DERMS for visibility and control.

We've had pilots in California that have looked at this more closely, but more needs to be done. The grid doesn't always operate as it was studied; the grid is dynamic and sometimes there are issues out of our control. For example, when a car hits a pole, circuits are often reconfigured. Sometimes for days and at other times, for months. This means that export that was once safe, as studied, may not be under these new abnormal conditions.

Second, DERs go where money flows. Currently in California, market-integrated demand response has been more attractive because there's a capacity payment. It doesn't require 24X7 participation and it has rules that allow non-resources to also be a part of that load. If more attractive alternatives are introduced in the future, such as real-time rates or other programs that pay more, it may mean this model is no longer used as much. From a policy and ratepayer perspective, state regulators will need to examine which DER pathways provide the greatest benefit and cost while still enabling these resources.

My third and final point is: capacity is king. As the largest source of payment for DERs, if FERC Order 2222 and CAISO's model which mirrors FERC Order 2222 are to be attractive, we'll need to figure out the capacity piece. From a planning perspective, we'll need to understand when these DERs will be acting as a wholesale resource versus a retail resource. From an operational perspective, we'll need to establish requirements for reliability. We'll also need to determine what will be compensated based on these two factors.

In summary, these are the policy issues I believe will require further discussion in order for FERC Order 2222 to connect customer abilities with grid needs.

Marcus Hawkins: I'm the Executive Director of The Organization of MISO States (OMS), and we are the regional state committee of all of the commissions within the MISO footprint. There are 15 state regulatory proceedings going on around various subjects related to FERC 2222 at the different state commissions within the MISO footprint. OMS also includes the province of Manitoba and the City of New Orleans within our membership. I want to be clear that I'm not speaking on behalf of the OMS Board in this discussion, although I may reference some of the positions the board has taken. However, the following is my own perspective.

OMS has been involved since 2016 in the DER aggregation discussion. We have coordinated with the Midcontinent Independent System Operator (MISO) to bridge the gap between the state jurisdictions and FERC, or the wholesale jurisdictional components of DER aggregation. MISO's state regulators have been forward-looking in their efforts to ensure we realize the most efficient and reliable means to integrate DER at both the retail and wholesale levels.

> "The [FERC 2222] order's goal is to level the playing field for new technologies to participate with existing ones in wholesale energy markets, further enhancing competition, encouraging innovation, and especially, driving down energy costs for U.S. consumers."
>
> *– Brett Feldman, Guidehouse Insights*

MISO and OMS have issued a set of joint priorities that spell out some front-end work for how the commissions will work with MISO to coordinate several aspects of Order 2222. We've especially tried to better understand the touch points between retail and wholesale rates, and where the value for DER aggregation will come from. As you peel back the layers of this onion, and there are endless layers, it gets really complex.

Overall, I think state regulators are happy with Order 2222 in terms of the level of control and flexibility afforded to the RTOs in order to comply with it. A lot of the value for DER is still primarily at the local level and will be determined by the retail rates and the structures set by the commissions. In MISO where there is no centralized capacity market producing a meaningful capacity price, the rates set by the state commissions will determine how a lot of DER is able to integrate into the system. OMS has specifically focused on the information and data requirements for how information from the retail side or the distribution side is fed into the MISO market, and where the balance lies between requiring too much information versus too little in order to maintain bulk system reliability.

If too much information is required, state metering or interconnection may prevent it from being technically possible. If it's too burdensome, all that DER will participate only at the retail level. Our goal is to strike a balance. OMS hopes to shape a unique process in MISO to ensure that all stakeholders and perspectives are at the table to coordinate this complex process. We especially hope to include more demand-side perspectives, although these are not typical MISO or RTO followers.

Jay Morrison: As the Vice President of Regulatory Issues for NRECA, I've been following the FERC issues as well as DER issues for over 20 years. DERs have been an important resource for over 40 years; co-ops and other utilities have used them as an important tool for providing energy to their customers at stable, affordable prices. DERs are a risk management tool, a market management tool, and an operational tool that's incredibly valuable to the utilities that are able to access them. As an example, one midwestern co-op says DERs help it control 50 percent of its load because they can operate off-peak heating, water heaters, irrigation pumps, and customer-owned generation, making DERs a significant portion of their portfolio. With more digitization in both the system and the tools available to us such as high-speed communications, the potential value of DERs just grows. NRECA is excited about distributed energy resources but not necessarily as excited about 841 and, to a certain extent, 2222.

There are two related trends I'm seeing at FERC. One is an ongoing shift of all aspects of state and utility resource decisions being moved from local policy-making and planning to the centralized RTO markets. I see 841 and 2222 as very similar to what we're seeing in the eastern RTOs with respect to buyer-side mitigation in the capacity markets. The arguments over where decisions are being made, whether it's at FERC, in the RTO stakeholder processes, or whether it's with state regulators and utility boards of directors, the situation is very similar between these two areas.

Second is an effort by some stakeholders to try to use federal policy and wholesale market design to force shifts in the way energy services are being made available to retail consumers, and not to enable state and local decision-makers to implement their own policy and resource decisions.

It's not just about providing DER access to the wholesale markets. It's about providing access to retail customers to wholesale players even in places in which those retail customers are being served by traditional utilities, in states that don't have retail competition.

I do want to thank FERC in Order 2222 for creating this opportunity to make a wholesale leap down this path, pun intended. They did include an opt-in for small electric utilities, which is something we pushed really hard for, and think is incredibly important for our members. FERC also showed some deference to the states on interconnection and safety issues, and also said they planned to show deference on some of the economic issues. However, there are already re-hearing requests on Order 2222 challenging FERC's decision to provide that deference to states, challenging FERC's decision to provide the opt-in. There's also a collateral attack in MISO by one aggregator that is challenging the deference FERC provided in both 2222 and 719 in asking for the opt-in opt-out from 719 to be thrown out. I expect we'll spend a lot of time litigating the question of where decisions about serving retail customers should be made, and about where decisions about risk management should be made. However, this is not about DERs because we all agree about the value of DERs. As the technology improves, we're all looking for better ways to leverage DERs for the benefit of customers. The question really is, where are those economic decisions and policy decisions going to be made?

Matt Sachs: As CPower's VP of Strategy and Business Development, my lens on FERC 2222 is more strategic and less regulatory and legal. We are fairly optimistic and excited about this order, which has the potential to act as a catalyst to getting more DERs involved and to spur conversations across most regions. Our optimism is based on our belief that the order has benefit for both customers and for the grid.

Many of our customers, and everyone else's, have been installing DERs anyway. FERC 2222 will help these organizations find more value for what they are already doing. It will also support these organizations which we believe will bring greater resilience to the grid. This applies to behind-the-meter assets, but also to the grid-tied assets located within the distribution grid.

On the grid side of the equation, FERC 2222 creates a path for better utilization of the generation and transmission infrastructure. In some regions, this equipment has been operating for just hours a year at the highest peak. FERC 2222 also facilitates a path to greater renewables by filling in some of the intermittent gaps. However, while there's a net benefit, there will be a lot of challenges to achieving it. Distribution utilities and their regulators will need to address assets that are physically located in their grids, as well as those that will be injecting. Still, with good market design, I think this will benefit everyone through better pricing, cleaner energy, and increased grid reliability.

On the question of opt-out, this is big. Is demand response a component within it? What are these DER aggregations? Is it still subject to FERC Order 719 which is the opt-out? This needs to be clarified. Market design is also a big question; how granular will this be? The larger the aggregation, the more flexible it is; the smaller, the riskier it becomes. But there are also advantages in being able to access more localized energy. A PJM capacity-type structure or demand-response-type structure works, where you can aggregate at the zone level, dispatch more granularly in zip code, but that's just one thought and there's a lot to work through to determine what will work best.

The last question I have is how FERC 2222 will change interconnect quadrants into the distribution utility. Many utilities are already striving to do better, and if we add more pressure to them, are we expecting better results without taking the time to understand their concerns?

Feldman: Is FERC Order 2222 more incremental or more transformation for the markets?

Gilbert: From the perspective of a distribution utility, I see FERC 2222 as transformational given the amount of change that will be required from distribution utilities for the systems to see these DER resources when they're participating in the market. My point earlier about going from one-way power flow to two-way represents a huge change.

> "The ultimate goal is for customers who have installed distributed energy resources to make the most of those resources and be able to pay for the systems they've installed."
>
> *– Anja Gilbert, PG&E*

Hawkins: Depending on where some of those legal challenges end up, FERC 2222 could be either transformational or incremental. Where the final line eventually gets drawn around resource visibility, whether or not there's an interconnection requirement to the RTO, if the RTO deems it's not reliable to participate unless on the distribution side, interconnection is fundamentally changed. There's a slippery slope to ending up with a bigger transformation than intended – one we hadn't anticipated.

From a market perspective, I don't see FERC 2222 as hugely transformational. There are a lot of limitations within the market clearing engine technologies at the RTOs that may limit some of the capabilities to optimize the system and to integrate as many small resources as some are thinking about. An example is MISO's battery storage compliance with FERC 841. It has already dropped to the 100 kW threshold, and MISO is not complying until 2022. Just because of the sheer number of resources involved, it won't be possible to include them all until there have been some significant technology upgrades. Together these are the things that may hamper the level of transformation possible.

Morrison: Marcus is absolutely right; it's a "maybe" kind of answer for a couple of different reasons. One, we don't yet know how much DER is going to be out there. Some parts of the country have enormous penetration, some don't. Is DER going to be the type of resource for which prices just keep coming down and consumer value just keeps going up? Will there be an electric vehicle in every garage?

If there is, FERC 2222 becomes more transformational because there's that much more resource for the market to pursue.

On the other hand, is FERC 2222 going to limit opportunities so that only the largest commercial and industrial customers can participate to a significant extent? In that case, it may be transformational in areas where that's a significant portion of the load, and much less so in some co-op territories, for example, which are mostly residential. We saw with retail competition that folks weren't really excited about aggregating rural residential customers. Will it be the same in this case? We don't know yet.

The second question is about where we'll ultimately find the value for DER. Is it distribution value? Is it for the retail providers and their risk management? Is it behind the customer's meter? If any of these are so, there won't be a lot of value to aggregating into the market. The retail services are going to out-compete the wholesale aggregation services, and customers are going to participate more in net metering, for example, than they are in wholesale aggregation. We don't yet know how that will turn out.

On the legal issue, if the lines FERC drew on where decisions are being made stay where they're drawn now, it's going to be less transformational than if they slip and we start rolling down that slope toward increased federalization and wholesale "marketization," to create a new word, of things that have traditionally been managed at the state and retail level. We don't know where that line's going to end up, but we do know it's going to be litigated and it's going to impose a lot of cost. If we do end up with a significant penetration of resources, if we see significant aggregation, like California has, then yes, this will be truly transformational on the distribution system, and extremely expensive for a lot of distribution systems. If it's a lot slower to move, then it will be a lot less transformational in other parts of the country.

Matt Sachs: I think it depends on your vantage point. From the perspective of an RTO ISO, FERC 2222 will be a little less transformative and more progressive or incremental. There are wheels in motion already in many markets. Referring to back to FERC 841, NY ISOs, DER participation models are another good example of resources that are already here and headed in this direction.

From a distribution utility standpoint, it is certainly transformative. It requires more visibility and more understanding of what's going on at a more granular level than has ever been needed before. That's where we'll see innovation happen but I don't know if that's good or bad news for distribution utilities. It should result in a need to deploy more infrastructure which I would think they can add to their rate base. On the other hand, none of this is simple. It will take a lot of stakeholder meetings to work through.

Still, there are a lot of positives. FERC 2222 brings all the stakeholders to the table and we're going to get better rules as a result. I think ISOs and RTOs will eventually learn from each other, improving their learning curves; we've seen that happen before. Investors will benefit from increased visibility across the market. We know there will be value for some of these assets' grid services. Maybe we won't know the exact value, but it will equate to a little less risk and either more available capital or less expensive capital, which again will make the economics better for all.

Gilbert: In California, in PG&E's service territory, we have approximately one in four of the country's solar rooftops, and about one in five of its EVs. With Governor Newsom's recent proposal to ban all fossil fuel vehicles in the future, we see those numbers increasing, which adds some additional context: creating these DER pathways will be essential. The regulators will decide the pathways, whether these will be transformational, and if that is the preferred approach. Alternatively, it could be retail rates that become more dynamic and more real time, instead of direct wholesale market participation.

Will we end up with a distributed energy resources aggregation model, like FERC Order 2222 has, or could it be something more like demand response? In California, demand response has been the preferred pathway to date because it has capacity value, doesn't require 24X7 participation, and because it's just load. It doesn't have an immediate need to coordinate with the distribution system, like an exporting DER will.

Feldman: FERC Order 719 and the opt-out allows states to not allow DER aggregators, and that hasn't been clarified within Order 2222. How might this play out in the future? Is there a difference between demand response and DER aggregation?

Hawkins: The opt-out has been getting whittled away bit by bit by FERC going back to energy efficiency resources and then by FERC Order 841 on storage. Surprisingly in Order 2222, FERC held the opt-out for third party aggregation for demand response only. Following up with FERC, we understand this to mean that Order 2222 includes any aggregation that includes any component that is demand response.

If a state is barring third party aggregation, that will apply to all aggregations that have demand response within them. MISO is challenging this. The core question in all this is who gets to participate at the wholesale level? More than 10 percent of MISO's current peak capacity is demand response, load modifying resources. And if third party aggregation is going to displace what's already in existence at the state or retail level, is that a net positive, or is it just different? Different people providing the resource? So while this is timely, I'm unsure where it will end up, given the current legal challenge to FERC Order 719.

Morrison: FERC Order 719 is preserved in FERC Order 2222, both an opt-out and an opt-in. The opt-out is for the regulator of utilities that sell more than 4,000,000 megawatt hours in the year before. The opt-in is for those regulators for utilities that sold less than 4,000,000 megawatt hours in the year before.

That opt-in applies now to all DERs, including storage, if they are aggregated. Storage large enough to be bid directly into the market without being aggregated doesn't get the opt-in or the opt-out, it has the right to participate under Order 841. So there's demand response opt-in opt-out; large storage directly bid in; and then the rest of DER, which is opt-in. So why is this important? There's a big picture policy reason why the opt-out,opt-in is important, and there's a practical reason why the opt-out, opt-in is important.

> *"The way a DER interconnects into the distribution system will be set by each state's interconnection standards; they may not be uniform and this is not a FERC jurisdictional matter."*
>
> *– Marcus Hawkins, The Association of MISO States*

Let's start with the big picture policy piece. It's up to state and local regulators, or the state legislature, to decide what the retail electric delivery model is going to be in that state. Is it going to be retail competition or vertical integration? And there's a lot of disagreement among all of us in the policy world about which is better.

Are retail markets better or is vertical integration better? That's the state's decision to make and if the state has chosen vertical integration, then it is trying to take advantage of what it sees as efficiencies of scale, scope, and integration which are available to a vertically integrated utility for managing cost, volatility, and the risks of providing a bundled retail electric service for all consumers.

One of the utility's tools to provide that service is the management of DERs. These make it possible to manage distribution risks and costs, transmission risks and costs, and power supply and market risks and costs.

If the regulator has chosen vertical integration, the opt-in opt-out allows it to protect that model and ensure the risk and portfolio manager, the utility, has all the available resources it needs to meet demand. That means no free riding and no cherry picking.

The opt-in opt-out permits the regulator to ensure nobody's going to come in and take a resource that provided a lot of value to the system as a whole, bid it into the market, and have it no longer available to the portfolio manager for managing its portfolio. The opt-in opt-out permits the regulator to ensure that nobody is going to increase the system's overall risk because there's now a large load (or collection of loads) with greater uncertainty because they're no longer within the control of the utility. So, that's the big picture policy reason. Are you relying on the utility to manage risk in the portfolio or are you going to have somebody else doing it through the market?

The practical solution is the one that Anja's been talking about. Third party aggregation can be complicated and expensive, and will require a lot of stakeholder work at the RTOs to figure out. When you talk about a small electric utility, you may be talking about a co-op with 10 employees. They cannot send somebody to an RTO stakeholder process. They don't have the resources, they don't have the expertise, they don't have the time. How are they going to describe what their needs are for the integration process? They've only got so much capital they can use to invest in the system. Are they going to be investing in all the back office and middle office tools required to enable safe, reliable, and affordable third-party aggregation? Or, are they going to wind up being unaware of what's happening on their own system because they simply can't afford the tools that would give them the visibility they need to be able to provide good service.

They could be much better off hiring a company like Matt's (CPower) to manage this for them. Or they could use old-fashioned tools like radio signals to manage load. Maybe they don't need that much visibility to manage load because they are making use of simpler tools for simpler needs rather than investing in the expensive tools required for third party aggregation into an RTO. Hence the opt-in is really important for those smaller utilities that don't have Anja's resources at PG&E to make sure they can serve their customers affordably and effectively.

Sachs: Opt-in opt-out is a complex issue. I'd like to be sure each market develops a means to allow these loads to be recognized, whether that comes from FERC or comes through the distribution utility. This is because they have different objectives. I'm not necessarily against some of the opt-in opt-out provisions, however, I would like to make sure that an honest dialogue has taken place and that we find a way to make the system cleaner and more economical for all. FERC 2222 is one way to get there, but it's not the only tool we have for using DERs.

Feldman: Looking at the data and metering requirements, what role will AMI play and who is responsible for DER metering?

However, AMI allows for greater flexibility, particularly for demand response and traditional curtailment. Still, many utilities have found it challenging to get AMI out there, especially if automatic meter reading (AMR) is already in place, which makes it hard to present a cost argument for implementing AMI. We do expect more AMI to come as revenue-side applications can be used to justify the upfront cost.

Hawkins: In MISO, states could make different determinations about the need for AMI and the investment it would require. This could lead to a patchwork of metering and data availability throughout the RTO footprint. My organization (the Organization of MISO States) focuses on how to accommodate the variety of capabilities throughout the market for doing M&V or settlements. The MISO States need something that works for all states and there's not just one solution. Finding an umbrella that will work for the largest number of resources is a challenge because the resources are not uniform, and they won't be when it's time to comply with Order 2222.

Gilbert: I am not a metering or AMI expert, but the rule is that ISOs and RTOs establish metering rules. That means the distribution utility and local regulatory authority have a role there. You'll see the rules related to AMI and metering will most likely play out in rate cases. However, if an ISO or RTO has more stringent standards than what the distribution utility or the state regulator has, there's likely going to be a delta which may result in a pay-to-play scenario. In that case, DER will need to have different systems in order to participate under FERC Order 2222.

Sachs: From an aggregator's point of view, this is a difficult question and I'm also not an AMI expert. Much of the country does not have AMI but it's working fairly well in California. Many of these devices have their own meters and we don't need to come up with a baseline for everything. If a battery is discharging into a meter, it's pretty easy to tell how much energy or capacity is being provided in a given amount of time.

Sachs: That's a great point. One far out question: can some of the DERs provide some of the infrastructure that is missing but that is needed for an omni-directional grid? Can some of these devices that are being deployed, and for which we are already paying to roll trucks, provide that infrastructure to give greater visibility? That is, can they help provide an additional layer of valuable data back to the utility? I don't know but I hope so.

Morrison: This is going to be a different challenge in different parts of the country. If we plan to bring back a tremendous amount of data from some of the market products in a very short timeframe, we will absolutely need high-speed Internet. However, much of rural America and even some urban areas don't yet have high-speed Internet. In these cases, more than just fiber is needed to back-haul the kind and amount of data the RTOs might need for some services, and that's not something an individual DER provider will be able to do. It’s just too expensive to run new fiber to a customer.

On the other hand, if that kind of network is in place, but there are 15-minute meters and an aggregator wanting to provide a service that requires five-minute data, what will it cost to upgrade the 15-minute meters to five-minute meters while also creating the required storage and DERMS to move from 15-minute data to five-minute data? That's a huge amount of additional data.

In summary, there are big cost implications here, depending on what folks want to do, and when and where they want to do it. It will be critical that state and local regulators get some say in whether or not those costs are incurred, and by whom. I am a little concerned if FERC is worried about its markets, then it’s not worried about its statutory obligation to local customers and their local distribution system needs. So, we're going to need to make sure that state and local regulators continue to be able to make the determinations they are accustomed to making. That is, local regulators with the expertise and knowledge should continue to hold the statutory obligation to be concerned about all of the implications of these situations.

> “Customers want a system in which today’s wholesale market efficiency and reliability is maintained… If there’s a lot of variability, they end up with inefficient dispatch that’s also unreliable; a worst case scenario!”
>
> *– Marcus Hawkins, The Association of MISO States*

Feldman: What is the jurisdiction of the interconnection of DER at the FERC level, or at the retail level?

Hawkins: State commissions, depending on their enabling legislation, could just set their interconnection standards for the distribution system by writing it into a law somewhere. The states within MISO that I'm most familiar with are looking at upgrading interconnection standards to IEEE 1547. Already there are a couple of states on the leading edge of that.

The way a DER interconnects into the distribution system will be set by each state’s interconnection standards; they may not be uniform and this is not a FERC jurisdictional matter. FERC was clear that it’s not necessary to go through the typical generator interconnection (GI) process, be studied, and have a proforma Generator Interconnection Agreement (GIA), or similar, on the books for other resources connecting to the transmission system.

If the RTOs decide that a given aggregation needs to be studied as injecting, it will be interesting if they set up a unique study for this aggregation to determine its reliability. They might set up their own process to do this, and I believe flexibility exists around how the interconnection of the aggregation works and what it looks like at the RTOs, but it won't be the distribution-level interconnection standard. That will remain state jurisdictional and will likely be non-uniform.

Morrison: Marcus is right about what's in the regulation and I worry about litigation. Imagine you've got a storage unit at a facility that was studied and interconnected under state law for behind-the-meter use. Now the facility owner wants to sell into the wholesale market. The state says, "That will need to be restudied for that purpose." And the facility owner says, "This is a state rule that interferes with my ability to participate in the market. The FERC Small Generator Interconnection Procedures (SGIP) should apply,” and as a result, they go to court.

I don't know how the court will rule, but I expect something like this will be litigated at some point and it could become a transformational issue. Do the states decide all of the issues that are in an interconnection agreement, including who bears what risks? Who bears what costs? What studies are, or are not, permitted?

Numerous decisions having to do with the safety, reliability, and power quality on the local system are now being made at the local level. Will those have to be litigated at FERC instead of locally? We don't know the answer to that yet. We know what FERC says the answer is, but I think that one will go to court.

Feldman: What’s the benefit for customers in all this, from a participation standpoint and more broadly, in terms of cost savings, prices, reliability?

Gilbert: The ultimate goal is for customers who have installed distributed energy resources to make the most of those resources and be able to pay for the systems they’ve installed. The ultimate goal is to have enablement pathways, but is this through FERC Order 2222? Is it through other programs? Is it through real-time rates?

Customers are not policy wonks. Their goal is their bottomline and they prefer to keep things as simple as possible. At PG&E we think about automating these changes and making them imperceptible to customers so the customer experience becomes seamless. At the end of the day, customers want to realize the benefits of owning their DERs.

Hawkins: Customers want a system in which today's wholesale market efficiency and reliability is maintained. Whether there are increased levels of coordination needed with the demand side, the wholesale market can ensure that the dispatch of all the variable generation out there can be smoothed out and coordinated in a way that maintains economic efficiency and reliability.

Certainly customers don't want variability at the transmission or distribution level. If there's a lot of variability, they end up with inefficient dispatch that's also unreliable; a worst case scenario!

Morrison: We should always be asking about customer benefits and impacts, so this is an excellent final question. The goal is to seamlessly provide customers with benefits so they continue to have their current quality of service, and possibly even better service. Whether FERC Order 2222 gets us there or not, I don't know yet. There are a lot of uncertainties, but I hope we can find the pathway to this preferred outcome. Respecting local decisions as much as possible will help get us there.

Sachs: There is real value in helping an individual customer find the best way to market and benefit from their DER investments and the way they operate them. For society at large, there is an economic gain if we do this well. That is, if we design the right program and we listen to all the stakeholders, we can achieve an economic gain, and possibly a slightly more diverse grid.

As we all know, when a big power plant goes down, there's a huge impact. But when an aggregation of DERs has an issue, we may lose just a few percent off the top because we lost only one asset out of a whole aggregation. DER aggregations are interesting resources with both strengths and weaknesses that can help diversify the whole generation stack.

Feldman: Thanks everyone, great conversation, and to our audience for all the terrific questions!

The Promise and Progress of Integrated Energy Efficiency and Demand Response Programs

Integration

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in March 2020. It highlights the enhanced grid flexibility and customer benefits that arise from fully integrating energy efficiency and demand response. The webcast discussion was led by PLMA Executive Committee Member Olivia Patterson, Vice President of Opinion Dynamics, speaking with Tom York from ACEEE and Craig Aubuchon from Ameren Missouri.


Dan York
ACEEE


Craig Aubuchon
Ameren Missouri


Olivia Patterson
Opinion Dynamics

Olivia Patterson: As we examine integrated energy efficiency and demand response programs, a topic near and dear to my heart, current regulatory policies in most jurisdictions and the siloed nature of many utilities prescribe separate approaches to funding EE and DR programs, which complicates the measurement framework.

The siloed framework represents a growing missed opportunity to holistically engage customers in energy management. This missed opportunity will only continue to grow costlier for utilities over time as demand flexibility becomes a critical tool for supporting increasing penetration of distributed energy resources onto the grid. Fortunately, innovations like smart thermostats and smart meters now allow us to leverage one piece of technology or additional types of interventions to capture multiple customer value streams.

We're privileged to be joined by Dan York of the American Council for an Energy-Efficient Economy (ACEEE) and Craig Aubuchon from Ameren Missouri. ACEEE's recently published a review of the current landscape for energy efficiency and demand response integration which revealed that Ameren Missouri offers one of the only fully integrated energy efficiency and demand response programs in the country. In my role at Opinion Dynamics, I'm happy to serve as an evaluator of this program.

Dan York: ACEEE's interest in the integral nature of energy efficiency and load management demand response goes way back. We know that saving kilowatt hours affects power demand quite possibly at peak times; conversely, the technologies and measures used to reduce peak power demands can also save kWhs, as well as help to manage energy within homes and businesses. Meanwhile, the vast majority of customers don't really distinguish between saving a kWh or a kilowatt. They want are low utility costs, reliable power, and good quality customer service, which increasingly means greater choices. It also means establishing a working relationship with their utility.

Integrated approaches to energy efficiency and demand response are nothing new. I was involved in an ACEEE project in 2005 that looked at this and it wasn't a new idea then either. There are clearly numerous benefits, both for customers and for the grid, from integration. Yet energy efficiency and demand response programs have largely remained separate. Only in the past few years have we really seen a surge in interest and movement toward integrated programs. To characterize the landscape of integrated EE and DR in the U.S., ACEEE reviewed the program portfolios of 44 of the largest electric utilities in the country, both public and private power providers. We actually started out with a set of 52 utilities that are part of our utility scorecard, and we had enough filings and program information for 44 of those. We found that despite the potential benefits, there are still few fully integrated energy efficiency demand response programs.

Of this set of 44 portfolios, we found just five programs operating at the highest level of integration. There were 22 programs with some degree of integration and most of them were residential, which surprised me a bit but we also identified some commercial and industrial programs. This is likely not news to many of you, but it seems smart thermostats are prevalent for residential integration. Clearly, they are the gateway to integrated programs and services for the residential sector. We also discovered that integration is a many splendored thing that consists of four distinct levels.

The first level is basic recognition of EE or DR capabilities, like a shout across the wall saying, "did you know about this one?" The second level consisted of cross-promotional programs in which there's some active recruitment for other services and programs happening via the utility. At level three, there's administrative coordination going on between the programs. Finally, at level four, there is a single, fully integrated program.

Looking in more detail, we found some programs are using creative ways to combine energy efficiency and demand response value streams. Examples include: AEP Ohio's ***It's Your Power Program*** offers an energy management app for homeowners; PG&E's automated DR program offers additional energy efficiency incentives for participation in its ***DR Customers*** program, and Southern Company's ***Smart Neighborhoods*** is a true pioneering effort. It goes above and beyond energy efficiency and demand response by aggregating a full range of DERs. Then there's Ameren Missouri's ***Peak Time Savings*** program, a residential program that enables customers to save energy with a smart thermostat while also enrolling them in an automated DR program.

We didn't find many integrated commercial industrial programs but we did find three examples at the administrative coordination level. Xcel Energy Colorado's ***Energy Management System*** program offers incentives for both peak demand and energy reductions. Some of Oncor's third party administrators for their load management program also offer energy efficiency incentives and services. And Southern California Edison coordinates its EE and DR programs. The one fully integrated CI program that we found was NV Energy's ***Power Shift Commercial Energy Services***. There, with a single appointment, customers can receive rebate offers, get a site assessment, get smart thermostats, and enroll in demand response.


St. Louis, Missouri

Our high-level takeaway is that in order to increase the number of integrated programs, there will need to be organizational changes and support for barrier-reducing regulation.

In another effort, we examined the degree to which AMI is being used to leverage customer energy efficiency programs. And here's a spoiler alert: we found AMI is vastly under-utilized for customer energy efficiency savings.

We have organized and are facilitating a Working Group of utilities and program administrators interested in grid-interactive efficient buildings or GEBs; a new acronym. GEBs are the evolutionary endpoint for the integration of energy efficiency, demand response, and other DERs. Let me know if you're interested in joining this group, which is a peer-to-peer network of program managers sharing their experiences and learning about GEBs.

Craig Aubuchon: My name is Craig Aubuchon and I am the Manager of Energy Analytics at Ameren Missouri within our Customer Energy Solutions department. This department is responsible for all of our customer energy efficiency programs, as well as all of our renewable energy programs. A key lesson from this effort for us has been to design programs with the customer experience in mind.

Before I delve into our ***Peak Time Savings*** program, here's some context: in 2019, Ameren received approval for the 2019-2021 program cycle for the largest energy efficiency and demand response program in history of Missouri. Ameren was proud of what we were going to be able to do for our customers, which included funding for residential, business, and income-eligible programs. It also offered several "firsts" including new delivery channels for income-eligible customers living in single family homes, a multifamily home channel for market rate programs, and a greater emphasis on programs that help maximize customer participation through behavior and education programs.

The ***Peak Time Savings*** program was the first DR program we launched and is now at the end of its first year. Smart thermostats serve as the program's gateway with a primary focus on the integration of the smart thermostat with Ameren's ***Cooling Load*** program.

With a focus on customer experience, we've made it possible for customers to enroll through two different channels: 1) a bring-your-own-thermostat channel, or 2) our online marketplace channel. Currently, the program accommodates three different manufacturers. And while we have worked to set this up as one integrated customer experience, we've found the subtle differences between thermostat manufacturers, and between how a thermostat arrives, means that at times we're actually running six programs!

Customers receive a $50 rebate for purchasing their thermostat through Ameren's Online Store. They then get an additional $50 rebate when they sign up for the demand response program in their first year, plus a $25 incentive for participating in the program after that. We also estimate our participating customers save ~$180 a year in energy bill reductions.

This program was implemented by Franklin Energy and Uplight provided us with the algorithms for the energy savings. In 2019, we were able to call four different three-hour test events because we had a cooler summer than expected. In Missouri, the regulatory environment makes it possible for the utility to receive a performance incentive and an earnings opportunity for the program as a whole, based on achieving several metrics. Our earnings opportunity includes pay-out rates for both energy savings and demand savings across all the programs we offer. However, in the 2019-2021 cycle, the payout rates and the performance incentive for DR are based solely on megawatt savings.

> "The utilities' separate, silo-ed teams for energy efficiency and demand response tend to have different goals. Their budgets, funding, and business cases have been very distinct which make it difficult to coordinate and communicate across programs, and to get the customer messaging right."
>
> *– Dan York, ACEEE*

Finally, Ameren also has a custom *Business Demand Response* program, which is focused on peak demand more so than on integrated energy efficiency savings.

Patterson: Thanks, Craig and Dan for highlighting an integrated residential program. Let's talk about the effects of COVID-19 and how it's affected 2020 programs.

Aubuchon: COVID-19 is clearly front and center for all of us, and utilities across the U.S. are concerned with keeping their workforces healthy so we can continue to provide reliable service and the critical lifeline that keeps hospitals open. But what does COVID-19 mean for energy efficiency? It's important to remember the value that energy efficiency programs are able to provide to customers, and as the pandemic has become more widespread and severe, the economic value of energy efficiency is even more important. We've also got to remember the upfront capital costs that come with investing in EE technologies and programs, and how we can help customers to continue to do this in difficult economic circumstances.

In evaluating these programs, it's also and always important to keep in mind what's going on in customers' lives. I expect we'll need to be more creative in how we seek customer feedback on how our programs are working because in-person surveys are likely to be cancelled, whether it's on-site or in the store.

York: On the implementation side, programs in which there's direct customer contact have been curtailed, suspended, or rolled back. Clearly the utility's ability to deliver customer programs and services will slowdown, along with the rest of the economy. That will need to be accounted for and clearly the evaluations and some program approaches will have to change.

Patterson: From a research perspective, Craig spoke about engaging with customers. We certainly expect to see some interesting exogenous shock in terms of consumption across the residential and commercial sectors. And that might also have implications for measuring impacts. Prior to COVID-19, what were the most common barriers to integrated programs and how can we overcome them? Were there any surprising barriers that showed up in your research?

York: As part of our research, we spoke with front-line program managers who deal with program problems and challenges. As expected, some familiar themes popped up: the internal organization of most utilities, which has historically been made up of separate silo-ed teams for energy efficiency and for demand response. These teams tend to have different goals. Their budgets, funding, and business cases have been very distinct which make it difficult to coordinate and communicate across programs, and to get the customer messaging right so its not conflicting or confusing.

Certainly there are some regulatory hurdles when evaluating cost effectiveness. I think we're now all realizing that every call or hour saved is not equal. Time and location are increasingly important as we have more renewables and distributed resources coming onto the grid. How do you handle those distributed resource value streams? As ACEEE has researched rate structures and funding, we've looked at how advanced metering infrastructure (AMI) is being leveraged to increase energy efficiency savings. To make sense from a customer perspective, some DR measures require time differentiated rates to ensure real savings.

Data access also came up as an issue, especially for people trying to use big data capabilities to identify and target customers who might most benefit from specific programs, or even from having third parties and non-utilities get into the game. There are conflicting objectives around saving a kilowatt hour versus saving a targeted kilowatt. On surprising barriers, we've got all this gee whiz technology that can do amazing things, but yet this very same benefit was cited as a problem because many of these systems can't talk to each other! When you add in the complexity of grid connection, things get really messy. These are the problems holding back progress.

We are having to evaluate each device and each channel because of data interoperability standards in which each device manufacturer has a slightly different energy savings algorithm, and a slightly different definition of their control and treatment groups. It's been a challenge to fully separate demand reduction from the energy statements.

On the evaluation, we found it was easier to take a conservative view of more energy saved and less demand saved because it's difficult to separate those out on a DR event day. Going back to our regulatory structure, that would tend to hurt us because we'd miss an opportunity or performance incentive. However, that risk has been addressed by enrolling more customers than expected. Design with the customer in mind was really one of the best ways to address all the back-end data and business complexity challenges.

Patterson: Let's spend some time on harmonizing Ameren's kW and kWh objective. What are some of the implications of the so-called "loading order" on program


Kansas City, Missouri

design, customer experience, and evaluation? How does the regulatory environment shape these decisions and will this change over time?

Patterson: That's a good and helpful list! What are the lessons we've learned about the customer experience in terms of upfront design choices and how these affect the implementation and evaluation of integrated programs?

Aubuchon: Technology is both an opportunity and a challenge. By designing a program with the customer in mind, by letting people bring in multiple devices through multiple channels, Ameren has tried to make enrollment as easy as possible. It seemed to work as our customer participation rate was much greater than we forecast. When we surveyed customer experience and satisfaction, we also found high levels of satisfaction. Making it easy for people to enroll and easy to participate definitely pays off. The flip side is that it creates additional challenges on the back-end, both in implementation and evaluation.

Aubuchon: In Missouri, our regulators judge our performance based on demand savings. By adding in the savings from EE, integrating both becomes about doing the right thing for the customer; extending the extra value proposition to save people money. And this is what has led to higher-than-expected participation.

As we consider how this might evolve over time, regulators may eventually consider the option of running these programs beyond the current three-year program cycles. The question becomes how can the utility create more value for those programs by guaranteeing they'll be available to customers for six or 10 years? This makes it more likely that we will capture the right value, at the right location on the grid, at the right time, and be able to lock-in that impact for future investment decisions.

York: Regulators decide how we'll harmonizing kilowatt hours and kilowatt objectives, and this varies from state to state. Generally, kilowatt-hour energy savings have driven most programs although I've seen programs and goals presented in terms of overall power demand and capacity reductions. In addition, there's now a rapidly growing focus on the reduction of carbon and greenhouse gases, which adds complexity to some of the overarching program goals.

Regulators will have to establish new priorities and may need to rethink some of the traditional regulatory policies and practices. Again, they need to capture the full value of packaged energy-efficiency-demand-response bundles, and that has to be recognized and applied in program design evaluation, as well as in system planning and resource optimization.

Things are getting more complex. We've mentioned the need for regulators to work with customers and the energy industry to set guidelines and standards so all of the new technologies can readily work together and deliver integrated services. Plus there's the need to be ever-vigilant about data security and customer privacy, and the requirement to support technologies like AMI. Rate structures will have to be designed with those change objectives in mind.

And as if regulators don't have enough to do already, they also have to keep up with the rapid changes occurring with technologies and markets. Utilities are not a fast moving group, so exciting innovations have taken time finding their way into utility business models and those of supporting businesses.

Patterson: When considering a regulatory perspective on time and location, evaluation and technology innovation, if you could travel five years into the future, what will these programs look like? What innovations do you think will occur?

Aubuchon: One of the biggest challenges for the industry and where we need to be five years is the ability to provide some certainty to these programs. Demand response is different than our traditional energy efficiency measures. If you install a light bulb you know with reasonable certainty what the effect will be. Right now, if your DR programs are approved for three years, you know with certainty that you'll be able to sign customers up for the next three years, but what happens in year four?

When we start to talk about things like the location value of demand response, or value to the grid, having that additional certainty, that additional line of sight, being able to know that you'll be able to offer your program in year four, or five, or six and so on, will be increasingly important. Certainly being able to integrate these with new rate structures is going to be critical.

Ameren has some proposed time-of-use rates in our current rate case. We'd love to be able to integrate our current offerings with those time-of-use rates. We've learned a lot about what it takes to integrate different technologies, such as thermostats, with different software and different algorithms. Being able to scale up will be very important as we add smart, connected devices in the home whether those are water heaters or electric vehicles.

> "Regulators need to capture the full value of packaged energy-efficiency-demand- response bundles and that has to be recognized and applied in program design evaluation, as well as in system planning and resource optimization."
>
> *– Dan York, ACEEE*

York: Integrated residential programs based on smart thermostats are going to grow those residential marketplaces. Smart thermostat programs have really caught on and customers are looking at the marketplaces as "trusted sources" from which they can get devices and program services, and have them tied together in a nice package. Those are going to grow. Part of that growth will need to come from home energy management systems that are able to integrate multiple DERs including EVs, battery systems, and customer renewables. Home energy systems are going to be more complex but will also offer a lot of new options that customers will value.

I'd like to think that in five years we'll see some growth in the C&I sectors. There's great potential there, especially for demand response, but I'm tying that with energy efficiency. I think the technology leaps need to be bigger but as the systems are inherently more complex, getting all these advanced controls talking to each other and working with the grid will continue to be a challenge. They will all need to function seamlessly and that includes communications with grid operators.

As we've worked with these grid-interactive efficient buildings, we were expecting to see more of that going on, but to date, there have been only a few demonstrations. However, this is where we'd like to see our buildings of the future go. We also need regulatory innovation to capture the full value of bundled services. Utility programs will only get us so far. Some innovations will occur on the margins and there'll be private providers and non-utility, independent businesses emerging, as they already are.

Patterson: For homes that might have multiple controllable devices, say a smart thermostat, a smart water heater, and home storage, what are the pros and cons of controls that connect directly to each device versus control through a hub that goes out to multiple devices? We are talking about the interoperability and the complexity of many of these technologies. Was there anything in ACEEE's research that supported one approach versus the other?

Columbia, Missouri

York: We didn't dig deeply into how systems are operated in the home. But it seems thermostats certainly got at the main energy-using system in most homes, which is the HVAC system. I'm not really sure how much some of the other systems are being incorporated and integrated, such as rooftop home photovoltaic systems and storage batteries but certainly there's rapid movement to develop integrated home management systems.

Aubuchon: One thing we've learned with the BYO thermostat program is that customers will show up with devices they've purchased for their own specific reasons or because of other attributes (such as brand or layout), and these might not always work well with energy efficiency. In a perfect world, you might prefer having one individual hub that controls all the devices. That would certainly be simpler. However, a key lesson for Ameren has been the importance of accommodating complexity. What customers bring to us has proven to be very valuable in the long run.

Patterson: A lot of the integrated programs we're seeing are being driven through market demand for specific enabling technologies. What ends up in our homes reflects what customers wants. Although we're talking about integrating energy efficiency and demand response, we can also integrate distributed energy resources or incorporate other strategic goals like beneficial electrification with energy efficiency and demand response. Will the barriers or lessons learned to date also apply to DR plus DER, or EE plus DER?

York: An important consideration is the location of savings. Looking at a utility-wide system we can estimate the kind of results we'll get, but this becomes even more important as we reach limits with the transfer of electricity at different places. Handling the distribution loads and getting the demand response to relieve those loads is ever more critical.

This is another one of those things, especially with regulators, we have to get comfortable with where we're going to have more targeted DR and try to build some energy efficiency into that too. That's a rapidly emerging direction for the non-wires alternatives.

Patterson: Is Ameren working on anything in the programmatic space around integration?

Aubuchon: The lessons we've learned integrating smart thermostats and cooling mode provide guidance for how to scale other electrification and DERs. The obvious cliche answer that's worth repeating is don't underestimate the time and effort that it takes to integrate new technologies!

A lot has to happen on the back-end to pull in all that data and make the difficult choices about how to handle different baselines so it's important to prioritize accordingly. Good ideas are coming faster than we can implement them day-to-day. That's not a bad thing, but it does mean that we need to take a step back and try not to under-estimate the time and effort it will take to integrate these and move them forward.

For me, this conversation has highlighted the old proverb, which is if you want to go fast, go alone. You can storm ahead and get a lot done. But if you want to go far, go together. It's vital that we take the time needed to have discussions with stakeholders, regulators, and customers, and then all of them together! We'll be able to go a lot farther than if we just plow ahead alone.

Patterson: Let's talk about customer experience, needs, and the technology, and also what we can measure and claim value for. Craig and I have had many conversations about where to put energy efficiency and where to put demand response when customers are trying to do both. How do we allocate appropriate baselines? For the Ameren program evaluation we had the luxury of having all of our vendors design randomized controlled trials for both the energy efficiency optimization and the demand response effort, except in cases where there was a system peak event.

That helped us with estimating impacts for the program, but it also created some interesting decisions that we had to make about where we wanted to allocate benefits on event days. It is interesting to think about where the value lies for the utility and where it lies for the customer.

> "…Any risk, any evaluation is always going to be easier if you have really satisfied customers and you've been able to exceed your enrollment goals."
>
> *– Craig Aubuchon, Ameren Missouri*

Aubuchon: The trade-offs are always going to be informed by the regulatory structure, and for us as well, by how the earnings opportunity works and how it balances with the customers' savings. Second, following Olivia's comments, how any risk, any evaluation is always going to be easier if you have really satisfied customers and you've been able to exceed your enrollment goals.

York: In trying to determine the value stack of all these multiple benefits, cost-effectiveness would historically account for some amount of demand reduction, but it was hard to tell if that captured the full value of reducing a kilowatt during a peak demand event. There's work to be done on this still. As a non-evaluator myself, there's another side to the rapid growth of technology and that is we're getting increasingly better at measuring energy use at times and locations. And since those will be important in the mix of things and in determining where we want to direct resources to, where they're the most valuable, those capabilities will help with program evaluation as long as we can manage the big data they entail.

We have a challenge in front of us, but we also have technologies and analytical methods developing in parallel that can help address some of those difficult questions. If we saved this kilowatt at this location on a really hot summer day, then here's its value. As these capabilities become more accessible, they will be important additions to the evaluators' toolbox.

Patterson: The amount of data and the new tools we have are wonderful for researchers, and for being able to think about programs from a more integrated and holistic perspective. We all need to work together to make sure that data access is possible and that the right tools and strategies emerge to deliver meaningful and timely impact. Thank you to our excellent presenters today, Dan York of ACEEE and Craig Aubuchon of Ameren Missouri!

Presentation slides available at https://www.peakload.org/dialogue-promise-progress-integrated-ee-dr-programs

U.S. Department of Energy's Future Connected Communities: Validating Buildings as a Grid Resource

Integration

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in April 2020. At that time, the U.S. Department of Energy (DOE) was preparing to issue a Request for Information (RFI) in order to inform its planned Funding Opportunity Application (FOA). The FOA was published in October 2020 with a final submission deadline of March 3, 2021.

This webinar transcript provides a valuable perspective on Connected Communities, grid-interactive efficient buildings, and DOE's goals in advancing the development of these across the U.S.

About "Connected Communities"

A Connected Community (CC) is a group of grid-interactive efficient buildings (GEBs) with diverse flexible end-use equipment and other distributed energy resources (DERs) that collectively work to maximize building, community, and grid efficiency. Under this FOA, DOE will select a portfolio of "Connected Community" projects totaling up to $65 million in varying climates, geographies, building types, building vintages, DERs utility/grid/regulatory structures, and resource bases. Through funding these projects, DOE hopes to find and share technical and market solutions that will increase demand flexibility and energy efficiency. *(source: U.S. Department of Energy)*

Validating Buildings as a Grid Resource

This discussion was led by PLMA member practitioner Allison Hamilton, a Senior Principal, Markets and Rates with the National Rural Electric Cooperatives Association (NRECA). She was joined by:

David Nemtzow, Director of Building Technologies Office, the U.S. Department of Energy (DOE);

Mary Ann Piette, a Senior Scientist and Director of the Building Technologies and Urban Systems Division at Lawrence Berkeley National Labs (LBNL); and

Teja Kuruganti, a senior member of the R&D staff and a Program Manager for sensors and transactive control in buildings with at Oak Ridge National Lab (ORNL).

DE-FOA-0002206
Connected Communities

Anticipated Schedule:

FOA Issue Date:	10/13/2020
Submission Window for Concept Papers:	10/13/2020 - 02/17/2021
Submission Deadline for Concept Papers:	2/17/2021
Concept Papers will be accepted on a rolling basis until the Concept Paper deadline. Applicants must submit a Concept Paper by 5:00pm ET on the due date listed above to be eligible to submit a Full Application. Concept Papers will be accepted starting on the FOA issue date above and encourage/discourage determinations will be sent within seven calendar days of submission. **Applicants are encouraged to submit Concept Papers as early as possible.**	
Submission Deadline for Full Applications:	03/03/2021
Submission Deadline for Replies to Reviewer Comments:	05/04/2021
Expected Date for EERE Selection Notifications:	07/01/2021
Expected Timeframe for Award Negotiations:	Fall 2021

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

FIGURE A. Anticipated schedule for DOE's Connected Communities Funding Opportunity Application


David Nemtzow
U.S. Department of Energy


Mary Ann Piette
Lawrence Berkeley National Labs


Teja Kuruganti
Oak Ridge National Lab

Allison Hamilton: This conversation is all about gridinteractive efficient buildings and Connected Communities. Thank you to our guest speakers for providing their perspectives and observations on this important project.

Operationally advanced high performance buildings seem to constantly evolve with the emergence of new building capabilities, as does the way we described them, with terms like "smart," "intelligent," and "connected." Your office, David, DOE's Building Technologies Office, has further defined these as "grid-interactive efficient buildings," with a group of these buildings referred to as a "Connected Community." What is the Grid-interactive Efficiency Building Initiative? What are the unique characteristics of these buildings?

David Nemtzow: I thought you'd never ask! DOE's Building Technologies Office is looking at both the opportunity and the challenge presented by our nation's 125 million buildings. Buildings in total consume just over 74 percent of U.S. electricity. In most of the country, an even larger share of that energy at peak is building-related. As a result, our building stock generates about 35 percent of the country's carbon dioxide emissions, plus, the total bill to heat and cool and power all of these buildings in 2019 was over $414 billion! I expect everyone in the PLMA family already knows a lot of that energy is wasted. But clearly, this situation represents both a challenge and an opportunity for all of us.

We call Grid-interactive Efficient Buildings "GEBs" and in them, we are working to move beyond traditional energy efficiency. Not just in how we find energy efficiency opportunities, but in how we implement them in ways that are helpful to the grid, to peak load management, and to demand response. We evaluate all the ways we can contribute to technology, integration, and business practices so that buildings can become more demand flexible and more grid-interactive.

At the same time, we want buildings and their owners and occupants to get something out of this deal too. We'd like the grid to be more friendly to buildings and we hope that together, your work and ours will result in buildings that are more dynamic and flexible, and that they can serve as dispatchable grid resources whether it's to trim peaks, to shift time, or to "fill the bellies of ducks." This is needed to improve building resilience, reliability, and affordability, and to reduce emissions.

We are also looking forward to the grid being able to send signals; these may be direct communication signals, price signals, or some other kind. These signals would go to both buildings and building operators to let them know when it's most valuable to trim their energy use, and how to do it in a way that will have optimal impact on the affordability of their energy use.

You can see this in Figure 1 which is a schema for a commercial grid-interactive efficient building. We are looking into how we use advanced sensors and controls; how we incorporate the existing thermal mass of buildings to act as de facto energy storage; how we add batteries for dedicated storage; and how we control the HVAC in a way that is sensitive to the occupancy of the space and also the actual population, making HVAC demand-sensitive. The question is how to do this in a way that connects buildings to the utility grid but also remains cognizant of other potential opportunities such as PV on the rooftop or central station, and EV charging. That's how we're thinking about the proposition of making all these buildings more integrated. DOE has published additional GEBs information at www.energy.gov/eere/buildings/GEB.

Allison: If you walked into one of these grid-interactive efficient buildings today, what kind of advancements and operational capabilities would you find? And, what might you find in five or even 10 years from now?

Mary Ann Piette: One exciting thing we're seeing today is how controls are changing the way we think about the use of energy in buildings. For example, we might see a smart thermostat in a home, or a control system in an office building that's able to reset the zone temperature when signals come in from a third party. There's a lot of new technology being developed that allows us to respond to signals to enable interactions between the electric utility and the building owner, which is typically done at the individual building level. Maybe it's a heat pump for space or water heating, or HVAC controls and smart thermostats.

Teja Kuruganti: Physically, you'll see smart devices like efficient heat pump water heaters and HVAC systems with variable frequency drives, solar panels with energy storage systems, and electric vehicles. The key difference is you'll be seeing more sensors that can measure environmental parameters, and that can also show the quantity of energy being used by these devices. HVAC and water heaters will have more data and control interfaces that will make it possible to network them together.

What you won't see, but that also exists, is smart automation that lets buildings function as virtual batteries, and that optimizes the operation of individual homes, and also of whole neighborhoods on the grid. In 10 years from now, smart homes will be ubiquitous. We'll likely be using artificial intelligence and machine learning to embed intelligence into our homes so that they can continuously improve their efficiency and their interactions with the grid.

David: If I had to pick one technology that I think has promise in this setting, it's thermal energy storage. There's been a lot of exciting progress in storage in recent years, despite the fact that thermal has been around forever! We now see opportunities to use the existing thermal properties of buildings and their thermal mass for water heaters and HVAC, or to serve as dedicated thermal storage. Thermal applications are great at "coasting." You can over-cool or overheat when power's cheap and abundant, and then you can cut back later. I hope thermal will be an increasing part of the mix in coming years.

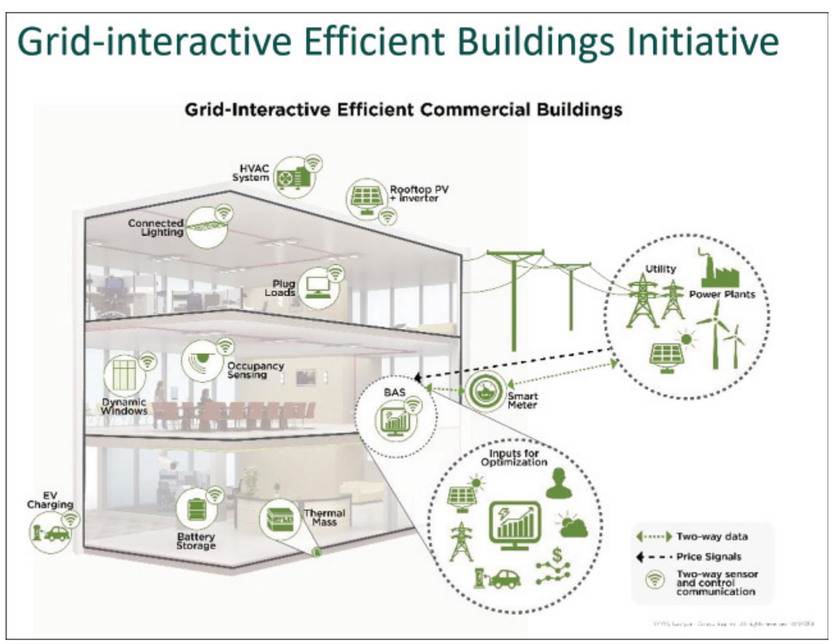


FIGURE 1. View Slide at: https://bit.ly/3b9M02U

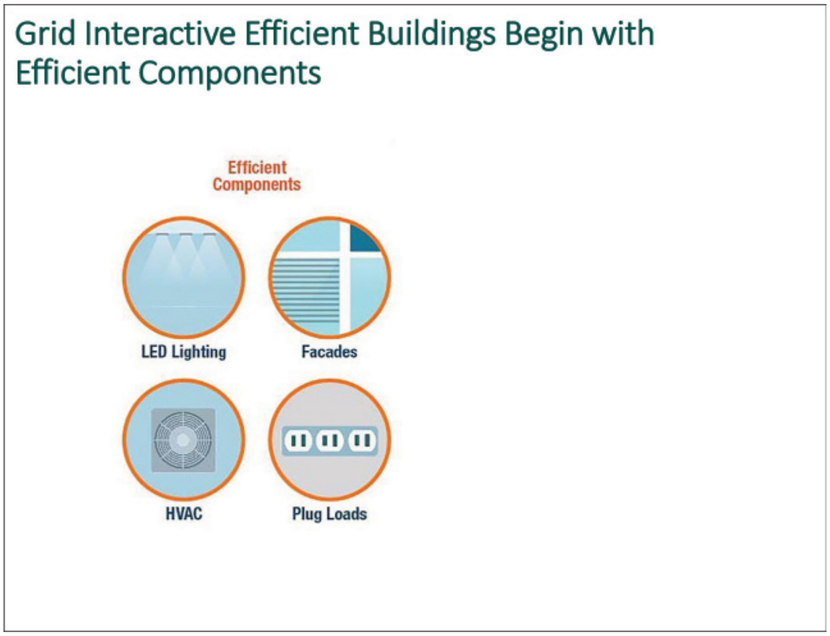


FIGURE 2. View Slide at: https://bit.ly/35abFEO

Allison: Can you describe some of the research developments in your current projects that are enhancing energy efficiency and demand flexibility? I understand you have a few testbeds of grid-interactive efficient buildings already set up?

Mary Ann: Yes, as you can see in Figure 2, as we move toward Connected Communities, we begin with the components. We have a long history in the building research community, both at DOE and at the National Labs, of developing low energy technologies, dynamic facades, dynamic HVAC systems, energy efficient equipment, and plug loads that can clearly show how energy is being used.

Historically, we've oriented a lot of research toward using less energy anytime. What's changed is that now, we want to understand not just how much energy we are all using, but when we're using it. In Figure 3 you can see that more measurement is the key. We're understanding the thermal environment, the HVAC environment, the lighting environment, user comfort, and what the facade is doing. There's a lot of ongoing work around whole-building systems, way beyond widgets. Figure 4 shows the extent to which we're focused on making sure these whole-building communication devices are actually communicating with the electric grid so that building owners and homeowners are benefiting from both energy efficiency and grid integration.

One of the big research challenges is how to ensure there is synergy between achieving homeowner value and grid and utility value. Figure 5 presents the revolutionary nature of the Connected Communities concept: it's not just about a single building, but a whole group of buildings interacting together. Figure 5 shows an existing residential building retrofit project called "EcoBlock" which is underway in Oakland, California. It's a good example of an advanced, connected community that has been built from the ground up, starting with deep energy efficiency retrofits, to which solar PV and portable tanks have been added. Once you've done the efficiency work, you can put in a smaller set of portable tank systems. This one will have shared storage, but it's also possible to have behind-the-meter distributed energy resources like portable tanks and storage, or even these community-scale systems. Both of these are examples of Connected Communities, which may be community-scale solar and storage, or behind-the-meter DER integrated over the set of buildings.

A unique aspect of Connected Communities is the way they are controlled as a system. We're looking at the aggregated electric load for a group of homes or a group of buildings, and in the Oakland EcoBlock example in Figure 5, electric vehicles are part of the shared resources too. This project is led by Dr. Sascha von Meier at UC Berkeley. Lawrence Berkeley National Lab is a partner, and project funding was provided by the California Energy Commission. It's a very exciting example of an emerging Connected Community.

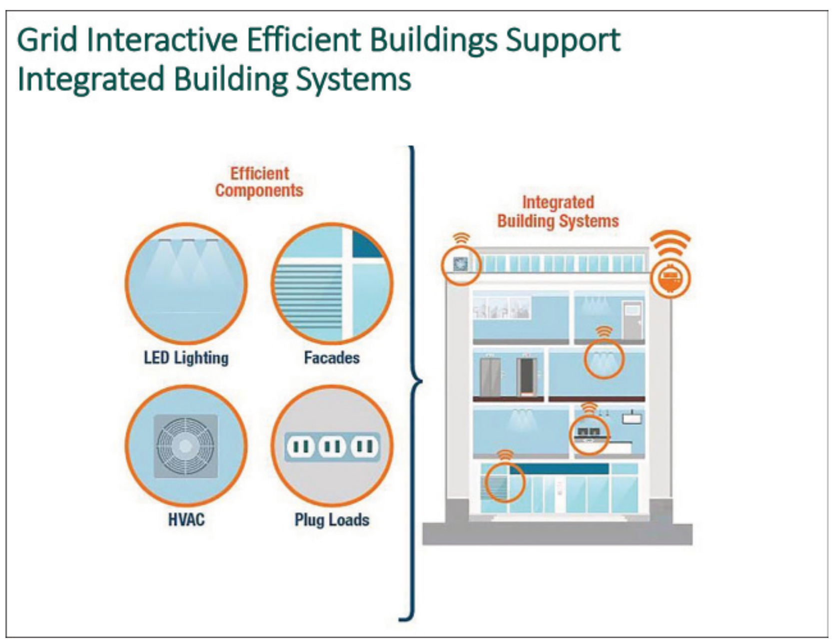


FIGURE 3. View Slide at: https://bit.ly/2Lolecp

Teja: Oak Ridge National Lab is working on two testbeds to serve as a living laboratory for our researchers. We are doing this in partnership with Southern Company, Alabama Power, and Georgia Power, together with DOE's Building Technologies Office. We are exploring two possible futures for neighborhoods: distributed energy resources 1) at community scale, and 2) at the residential level. Both of these testbed neighborhoods include homes with highly efficient envelopes, plus loads that are capable of responding to grid needs while also maintaining occupant comfort. This is achieved through smart automation which accommodates models and optimizations that, in turn, coordinate energy generation, storage, and consumption.

Optimizations benefit both homeowners and utilities. For homeowners, the focus is minimizing energy cost and maximizing comfort. For the utility, it's facilitation of a high penetration of DERs with a minimal impact on the distribution circuit. In Figure 6, you can see the 62-home neighborhood that was developed in collaboration with Southern Company and Alabama Power. Each home has a controllable heat pump water heater and a variable frequency drive-enabled HVAC system. All of these homes were built with high efficiency construction techniques and have HERS scores of about 45. Next to the neighborhood is its power system: a microgrid with a PV system of about 300 kW, an energy storage system of 680 kWh, and a 400 kW natural gas generator.

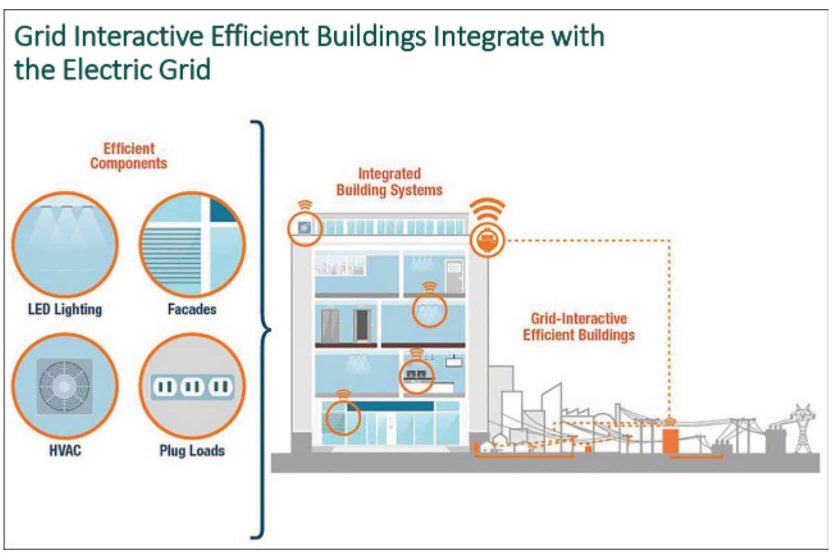


FIGURE 4. View Slide at: https://bit.ly/2LrGOfR

On the right you can see a second look into the future in which each individual home has roof top solar, energy storage, and a controllable load, all under one roof. How do you control the load? How do the homes connect to the distribution system, and what does it take to optimize the operation of these homes together with grid operations? The Alabama Neighborhood, which we've operated for the last 18 months, is pictured in Figure 7. This neighborhood was built with the goal of demonstrating real-time building-to-grid integration while still focusing on energy efficiency.

As shown in Figure 8, all of ORNL's research is driven by use cases that address specific questions, including: 1) Can we quantify the value to the grid of operating microgrids with controllable loads? 2) Can we use these 62 homes to generate macroscopic load shifts that maximize the use of the community microgrid's DERs while also maximizing homeowner comfort? 3) What kind of price or incentive signal do we need to accommodate these new technologies in the mix? Key to this living laboratory demonstration is the question of system-level architectures. Are they scalable? Can we deploy these systems ubiquitously as we implement control at scale for all 62 homes? And, could we potentially scale this to 62 million homes?

Scaling requires a hierarchical approach to controls. At a residential level, we've coordinated operations to focus on the homeowner as you can see on the left side of Figure 9. Then we have interfaces to communicate this optimization at a neighborhood scale. Finally, across the bottom of Figure 9, with the grid providing four key services, namely energy efficiency (a primary motive), adaptive load shape, reliability response, and regulation response, we ask, "Can efficiency be optimized as the equipment degrades, and as operational usage patterns change? Can we reliably demonstrate the generation of adaptive load shift? Can these assets provide reliability responses and regulation responses?" Data is key to developing this model of optimization.

Another important highlight is inter-operability and cybersecurity, which go hand-in-hand. They need to be addressed in the early stages of defining requirements for a project like this. Once a project is at the predeployment stage, they're baked in because many data and control interfaces are already in place.

Allison: What are the differences between the Smart Neighborhood in Alabama and the one you unveiled over the summer? What are some of the key lessons you're hoping to learn? Are there any revelations to date? Have there been any unexpected successes or failures?

Teja: We learned that we can actually deploy efficient construction at the individual home level, and both the technologies and the integration of these technologies, at scale, in the real world. We learned significant load flexibility is available because we pre-heat and pre-cool the homes to ride through peak events. We also learned to do this in a way that reduces back-up generation, reduces storage requirements, and uses thermal mass.

Another key lesson was the need for a scalable, coordinated control framework. Customer education is key and so is tapping into the experiences of our early adopters to learn what went right and what went wrong in the scaling process. In this neighborhood, we've seen ~44 percent energy savings and a ~34 percent reduction in peak demand.

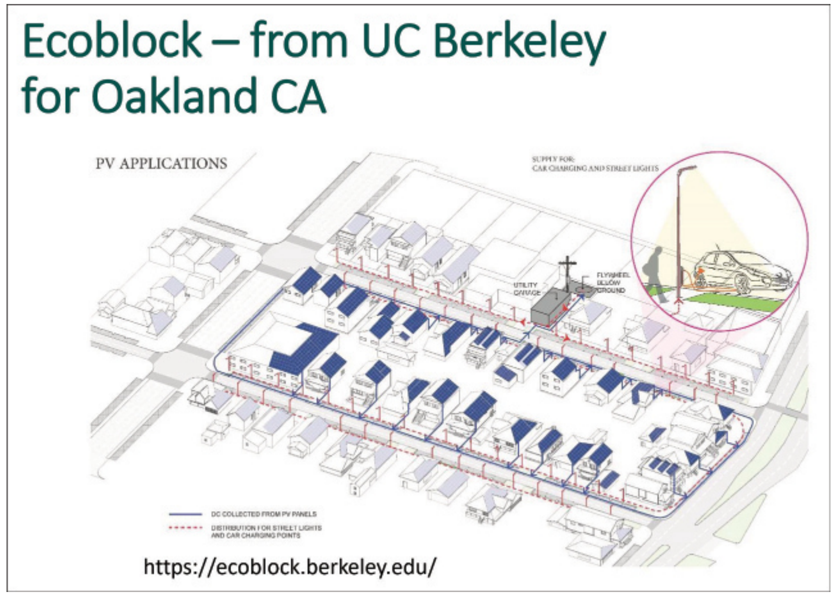


FIGURE 5. View Slide at: https://bit.ly/39iClET

Allison: What is the next research investment in these Connected Communities? David, you flagged the value of including diverse building types, industry players, geographies, climates, and so forth. How does DOE plan to build more of these? Are you looking for utilities in ISOs to lead these projects, or do you see developers or even local municipalities taking them on?

David: The short answer is all of the above. In Figure 10, you can see a collection of Grid-interactive Efficient Buildings; homes obviously. What can we do with a group of them? DOE's working assumption is the whole is greater than the sum of the parts, and that's what we're testing and field-validating in these projects. We want to document economies of scale, and whether the diverse loads within a community can be used synergistically, especially if a neighborhood or community includes buildings other than just single family homes. Additionally, we want to understand potential infrastructure savings and viable business models.

Figure 6 shows two projects. The one in Alabama has single family homes with a microgrid, community solar, and community battery storage. The one in Georgia has townhomes with rooftop solar. There are similarities and differences. The Alabama project has been very successful. We have a full year of data from the real human beings living there whose energy savings were 44 percent compared to a standard home of the same size and climate conditions in Birmingham, AL. Some of that's traditional efficiency but a lot is due to grid interactivity "smartness."

DOE's hopes that through the competitive grant opportunity of the FOA, we can establish more Connected Communities. Communities that include diverse neighborhoods all over the country, and not just in the hot, humid South which has the attributes of capacity and variable renewables. These could be residential communities, and we'd like to see mixed use and commercial communities too. We're interested in campuses where several buildings are owned and controlled by one party, whether a corporate or a healthcare campus or a university. Different kinds of utilities too; they could be co-ops or munis or investor-owned utilities. Certainly, we'd like to look at the nation's 125 million existing buildings, not just the million or so new buildings being built every year. The ability to retrofit existing buildings will continue be important.

FIGURE 6. View Slide at: https://bit.ly/38goNuf

Geographic diversity matters to DOE. We think we'll be able to support four to six new projects in partnership with utilities, home builders, researchers, and technology providers. We'd love to see the results of creating a Connected Grid Interactive Community in Phoenix for example, with its hot, dry weather and its high degree of variable renewables. Also in the Pacific Northwest which is quickly outgrowing its hydro-electric systems. And in Maryland which is also AC-dependent and has an increasing degree of variable renewables. Chicago, et cetera. In a diversity of conditions, we are interested in what can we learn, and in what can we demonstrate.

When this is done, we don't want it to be just a fabulous science project. We want everyone who works for a utility, a technology provider, or a PUC to say, " This approach really works and it provides value. Let's try it in our service territory!" DOE wants to see increasing demonstration, increasing validation, increasing communication, and then hopefully these communities will one day be commonplace.

David: Mark Martinez asks the question, how can a building property respond when, as is often the case, utility retail rates and wholesale market signals are at odds with one another and send conflicting signals?

Mark, you live in the heavily regulated world of California, and yes, price signals are very imprecise in this country. I don't have to tell the PLMA members this, but only about two percent of U.S. residential and small business electricity customers have time-sensitive rates. Just about all of them have the opportunity to opt-in to TOUs, but only two percent, plus or minus, actually have them.

Prices are not sending the right signals to many consumers about what electricity is worth at any given time, so what then is the value of saving or shifting or shedding that electricity?

However, what is also important, is that signals are sent to customer outside of just their retail rates. These may be incentives for technologies, incentives for actions. They may be revenue recovery incentives. Southern Company has gotten some revenue recovery for their investments by working with their PUCs. It could be a policy signal that is sent to a retail utility by its PUC or by its state government such as, "Utility, you shall have more renewables, you shall have more storage." Down the road, there may be a policy signal sent that you should do more on grid-interactive buildings. You'll respond using the tools that you have, incentives, and/ or technical assistance. We have to look at the whole series of signals and interventions together.

Currently, we're looking at building codes and how these can be made responsive to electric vehicles, to PV and, I hope, to increasing grid-interactivity. I don't know that we're going to see TOU retail rates that solve this, and I do think we'll need to look at all the other mechanisms to make sure they fit and make sense.

Mary Ann: Most of the last decade's demand-side management has been based on energy efficiency, that is, using less energy, so program evaluation metrics are well developed in this area. As demand response programs have evolved, and there's been a lot of DER activity around the country, the metrics have shown themselves to be very different. Historically, they've focused on peak capacity, hot days in the summer. But now we're looking at loads that can shift peak demand, not just shed it.

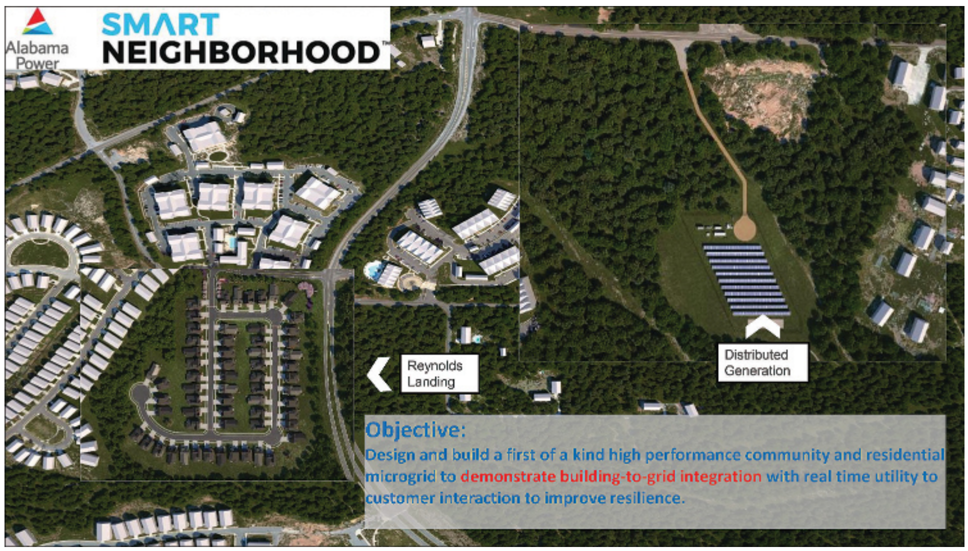


FIGURE 7. View Slide at: https://bit.ly/3hLy9kB

Load shift is very important when we consider renewable integration on the grid, and even metrics such as greenhouse gases. We've been developing metrics around reducing kWh, reducing kW, and we're also considering metrics like greenhouse gas reductions as part of evaluating a Connected Community.

There's also the cost of service. What does this mean for a utility? With base costs and marginal costs, the electric utility evaluation framework around Connected Communities is of considerable interest to DOE as it determines how to advance these new business models and aggregate these portfolios of investments beyond the traditional EE and DR portfolios.

Allison: How will this effort be different from traditional demand-side aggregations and what is the value proposition for the building occupants and for the utility?

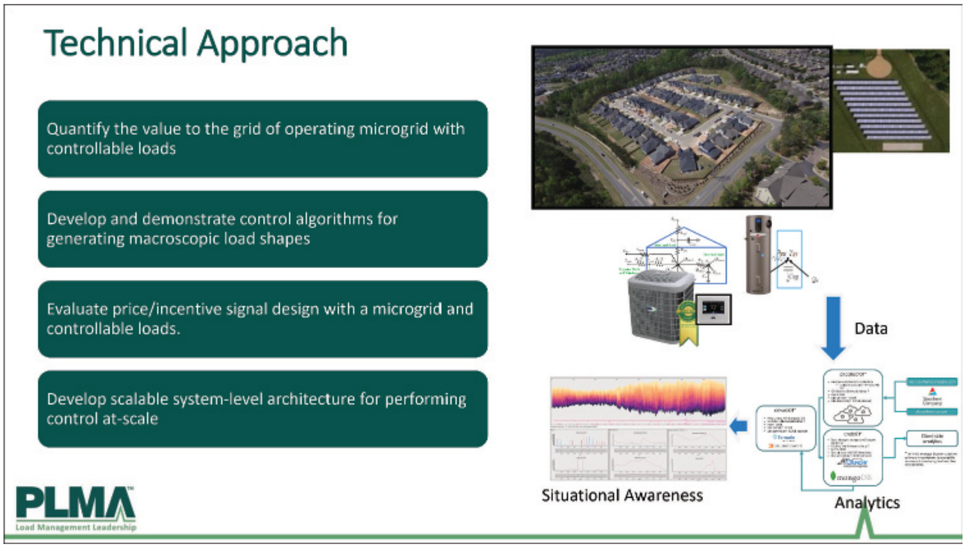


FIGURE 8. View Slide at: https://bit.ly/35eAijL

David: How many hours do you have for Mary Ann to wax poetic on this topic?!

Mary Ann: The Connected Community is really exciting because it is trying to bundle these offerings which always begin with energy efficiency. A lot of DOE's and LBNL's work is looking at the relationship between energy efficiency and demand response. Where they compete, and where they have synergy. We see customer value when we see utility value, but there's a lot of innovation that needs to happen in the business models for aggregated technology offerings, similar to Teja's residential examples from the Southeast.

For homeowners, this value has to do with lower and perhaps more predictable bills so they can make choices about when to use energy and how much storage they might want. Homeowners may also benefit from knowing how their community system is doing, and how they're performing as part of that bigger system.

The utility gets a package of technologies that help create a smarter, more connected, more modern grid which helps it ensure supply and demand are better integrated. It also means the local system can be resilient and made "islandable." In this case, if there's a power outage or a storm, the islanded community may have some value in operating. But it doesn't have to be islandable, right? Some of these connected communities will be and others will not. We're working on ways to value resilience as part of a Connected Community.

Allison: As you've all worked on aspects of these projects for years, what do you think is the most exciting opportunity for the Connected Communities Funding Opportunity Announcement (FOA)?

David: The Connected Communities FOA represents a multi-million dollar investment in these communities. The FOA was designed by DOE's Building Technologies Office, together with others at DOE who work on solar, electric vehicles, and electricity issues.

What I'm most excited about are the business aspects of this project, even more than the technologies. Diversity is key, and I am looking forward to seeing how Connected Communities can best be applied in different situations, different geographies, different service territories, different climates, different building types, different rate structures, and levels of variable renewables penetration.

I am also excited about the opportunities for new teams to come together. Teja spoke about the teams they built in the Southeast, which included a major utility and a national lab. The Atlanta community was built by Pulte Homes, the nation's fourth largest home builder. The Alabama community was built by an important regional home builder and included Rheem and Carrier water heaters, plus other technology providers. Building teams is essential to the future of Connected Communities. We

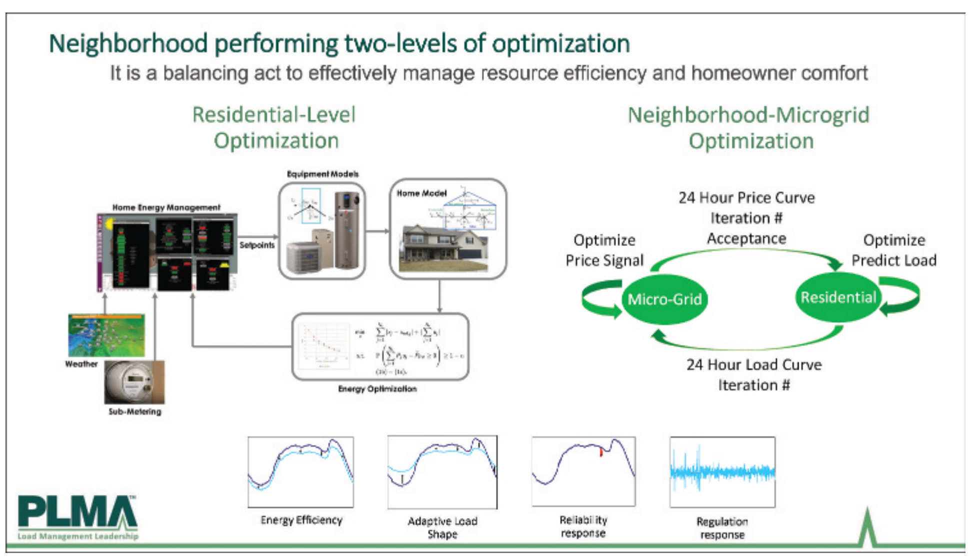


FIGURE 9. View Slide at: https://bit.ly/3naPc0E

don't want these to be the work of just the Department of Energy, or just the State of Michigan, or just one private sector company, for example. We want them to be team initiatives because we think that's the way of the future.

Mary Ann: This is also an exciting time in the building controls business because of AI and machine learning, as Teja said. We can now collect a lot more data than we could 10 or 15 years ago, due to the help of the Internet, and due to improvements in our measuring abilities. There are a variety of methods on the control side. One example is "model predictive control," which is a model that looks at what a building may want to do over the next 24 hours about its heating and cooling needs, water heating needs, and lighting needs, while also taking into consideration the outside temperature, the number of people in the building, and the price of electricity.

These machine learning model predictive control systems also try to take into account the mass of the building, whether there's a portable tank on-site, and if there's a storage system. They can create a sequence of operations and set points that try to minimize energy use, minimize the utility bill, and minimize the peak demand. Think of this compared to today. Currently when we run a building, we switch systems on and off, and we lack real-time energy feedback as part of the controls. We just use what we want and we pay the bill a month later.

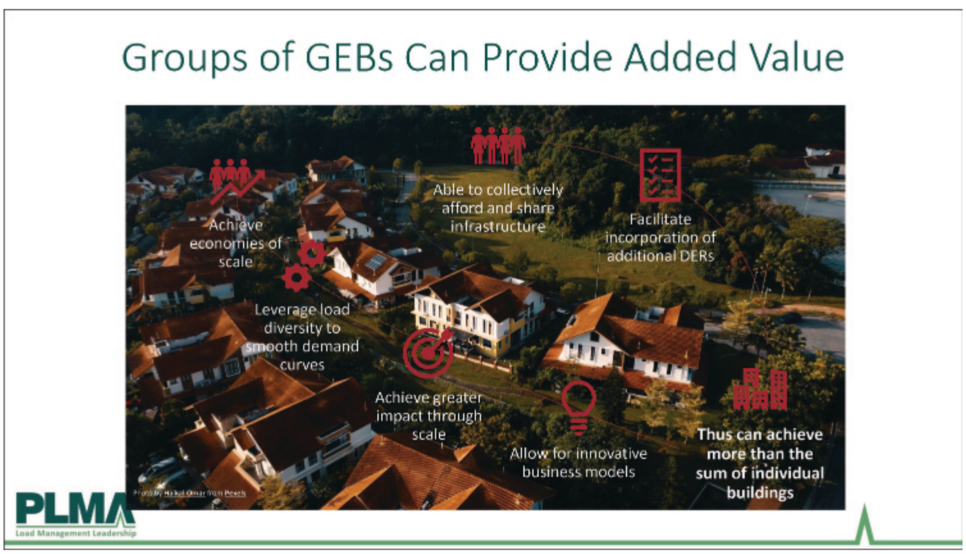


FIGURE 10. View Slide at: https://bit.ly/3pR99vg

There's another type of control called "agent-based control." The agent-based control does not provide global optimization, but it may optimize a local system and then decide how to participate in the larger optimization. Cybersecurity issues need to be worked out, but there are encryption and authentication systems that enable these transactions and a lot of the interoperability standards to be cybersecure. The National Institute of Standards and Technologies (NIST) and the national labs are working to ensure machine learning model predictive control systems are cybersecure and interoperable.

When considering direct current (DC) power with a battery and photovoltaics, homeowners may also want to use DC lights or a DC refrigerator. They will save energy because there's no need to convert electricity with an inverter from DC back to AC. There's about 10 percent energy savings to be had by using a DC power source and a DC demand-side system.

Teja: I believe Connected Communities represent a transformation. They have the potential to enable our traditionally load-following grid to engage buildings, with their large energy footprints, to participate in grid activities. This will improve convenience, comfort, and grid operations, but it will also improve resilience. There are also new value streams that arise apart from comfort and convenience. The flexibility we can create in the large building footprints will enable the integration of clean, renewable energy with minimal impact on distribution, especially as we move toward 10, 20, and 30 percent PV penetration.

We'll also see continuous optimization driven by learning, and an increasing number of sensors and controls that make it possible for buildings to become aware of their own energy consumption. There are traditional ways of controlling buildings; if you have 100 buildings in a zip code their operations can be controlled by the outside degree temperature. They click on, then the temperature adjusts at the same time without coordination. If we can dispatch that operation in 15 minutes without impacting households, we can also reduce peak load in the same area.

Mary Ann: Let me make a quick comment about aggregators. A lot of aggregator programs provide demand response to utilities into wholesale grid services, but not energy efficiency. This is an opportunity to combine EE and DR. We want the Connected Community models to be scalable. I think that's one of the biggest challenges when we think about issuing these federal monies to understand this technology, and also the business models. How do we scale these systems to create a bigger national opportunity?

David: One question is do these communities have to be geographically contiguous? That's one approach.

But is there another market-based, aggregation-based approach in which geography isn't a constraint?

Mary Ann: Another question related to the value proposition is whether a Connected Community in a grid-constrained area can help defer an upgrade to a distribution circuit because we've instead invested in local load shape management?

Teja: If we defer investments in distribution upgrades, as Mary Ann just said, but also successfully facilitate more DERs, there's clearly a lot of value there. The research question becomes how does this decision translate into controls and deployment? We have learning to do about how these controls get deployed, but if we require the homeowner to be technically involved in a lot of decision-making and deployment, that may be a deterrent to their participation. So how can we make this process as seamless as possible? What is the software infrastructure that is needed to scale this?

With the flexibility we're talking about, we need a system that is as simple as providing a homeowner with a battery they can operate. How can I make this thermal battery that David was talking about deliver a response so there's no need to depend on alternative sources to generate it? Creating robustness requires a lot of research both in valuations, as Mary Ann said, and in bringing in thermal storage, as David was talking about.

FIGURE 11. View Slide at: https://bit.ly/2XcGQuT

A lot of these elements have to be addressed at the system level. Whole system integration goes hand-in-hand with the business model of who benefits and how this business model expands. The big challenge lies in developing robust and replicable integration and deployment architectures.

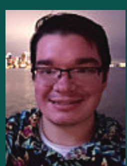
Allison: Thank you again to our panel of experts, David, Mary Ann, and Teja, for sharing your insights and expertise. We'll look forward to hearing more about Connected Communities after the FOA closes and new projects get underway!

Presentation slides available at https://www.peakload.org/dialogue--validating-buildings-as-grid-resource

Bridging the Gap Between DSM and Grid Operations

Integration

The following is a transcript of a 41st PLMA Conference session held in April 2020 which provides a perspective on bridging various resources at different times of the day. The discussion, introduced by PLMA Conference Co-Chair Bruce Brazis who is an Account Executive with Arizona Public Service (APS), was moderated by Tyler Rogers of EnergyHub and includes Michael McMaster and Tom Hines, both of APS.



Michael McMaster
Arizona Public Service

Tom Hines
Arizona Public Service

Tyler Rogers
EnergyHub

Bruce Brazis: Welcome to our moderator Tyler Rogers, a Senior Director of Utility Sales with EnergyHub, based in Reno, Nevada. Tyler manages the utility business west of the 90th meridian. And he can explain where the 90th meridian is! When he's not talking DERs, he enjoys talking ice cream, cowboy boots, and/or best practices in wrangling his two-year-old daughter.

Tyler Rogers: Thank you, Bruce and to ensure we accurately cover this increasingly relevant subject, we are joined by Tom Hines and and Michael McMaster of Arizona Public Service. The point of this conversation is to talk through an interesting reality that has surfaced in Arizona around the need to bridge the gap between traditional DSM organizations and operations. Tom Hines and his colleagues in distribution operations, who are emerging as an important load management voice, will help us understand the future of resource allocation in AZ.

For me, this story begins in 2017. I happened to be reading APS' 2018 DSM Plan, like all of us do to enjoy our evenings! We sit down and study DSM filings to keep ourselves entertained. As I combed through this document expecting to see all the normal residential, commercial, and lighting programs, I was surprised by the opening section and said to myself, "Wait, APS is planning to cut back on its energy efficiency programs because these don't make sense given the reality of their grid!?"

Tom, that plan had your fingerprints all over it, and was an "Aha!" moment for me. Why did APS write this plan? What was going on to cause this reality in which you had to completely reinvent or rethink the way that traditional DSM, energy efficiency, and DR are being implemented in Arizona?

Tom Hines: As APS' DSM program strategy guy, which I've been for a long time, I'm going to represent the DSM part of the bridging the gap while my colleague Michael McMaster will talk about the system side.

Historically, DSM for us, like it has been for so many utilities, has been about compliance. It's been about kilowatt hour savings, and from a compliance perspective, those kilowatt hour savings were valued equally in our metrics. It was a kWh energy standard that said no matter what time of day, or time of year you saved a kWh, it was equally valuable.

Enter the duck curve, as you can see in Figure 1. You'll notice Arizona ranks among the top three states no matter what metric you use to think about the penetration of rooftop solar. We have over 100,000 APS residential customers with rooftop solar today, out of a residential customer base of just over a million. That represents over 10 percent of all residential households in Arizona. They also tend to cluster in neighborhoods.

With this amount of solar, Arizona is facing the reality of a growing duck curve. The big midday trough, the result of so much solar coming onto the system at that time of day, and what we're overlaying on top of it, is the actual savings profile of APS' commercial lighting program.

You can see how the savings are maximized during the time when we have the least need for resources. As a

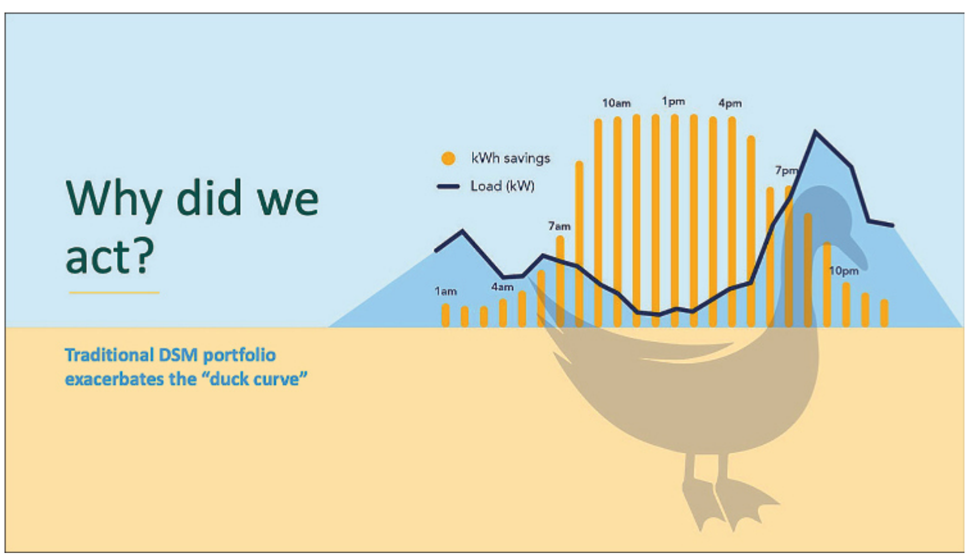


FIGURE 1.

result, we had to rethink how our DSM portfolio can provide value beyond just compliance. That is really all about aligning the state's resource needs, even as they change, with our portfolio and evolving the portfolio to become a valuable resource for Arizona.

Rogers: Was it challenging to get APS' DSM team onboard with the idea of rethinking how we're doing DSM?

Hines: We have built a large infrastructure around the traditional model, and this discovery was very eye-opening internally, and again when we spoke with stakeholders and external regulators. Initially it may have seemed like we were moving away from value for customers when in fact, we were trying to move toward better customer value.

Rogers: If APS has over 100,000 rooftop solar systems, this must create its own set of engineering problems from the utility's distribution side. Michael, at this point in the story, there was loose connection between DSM and distribution operations. How did distribution operations approach this problem? Was it an issue to have all these grid-connected DERs come online? Or was it an opportunity?

> "Everything is scoped out to accommodate a traditional amount of energy need for each customer. However, what now have is renewables and solar coming in earlier in the day than when we need them, based on customer energy demand. "
>
> *– Michael McMaster, Arizona Public Service*

Michael McMaster: Initially, this was a problem! The utility saw the world as it has always been: electricity flows from generation to distribution. A lot of our grid is designed with the wire size to . . . oh wait a minute, before I go full nerd, let me simplify this a little. Everything is scoped out to accommodate a traditional amount of load, to accommodate a traditional amount of energy need for each customer. However, what now have is renewables and solar coming in earlier in the day than when we need them, based on customer energy demand.

That's almost like adding an electrical pump, if you will, at certain points on the grid. So, all of a sudden we were putting in more energy in areas where we didn't expect much, so obviously, we're going to size it down. Think of it like a tree where the energy's coming from roots and it distributes out to its leaves. If all of a sudden all that energy is back-flowing from the leaves, you can experience problems. So we have to update some of our infrastructure, and that ultimately gets passed along to our rate payers, and we do want to be good stewards of our grid and costs. While we're certainly aware of this connection, DSM on the demand side, implied through load manipulation, has proven we can turn this from being a problem we're trying to address into an asset that can help us defer additional work in the future.

Rogers: Tom, you wrote the plan and the gap started to get bridged through that process. What types of questions emerged on your DSM side of the house? Was it something like, "We really do need to reach out to Michael's crew and distribution operations to think about this holistically?"

Hines: The first step for us, one that a lot of utilities still haven't made, is to actually look at the hourly impact of everything we do in terms of customer programs. We evaluated every measure in our DSM portfolio. We had about 600 different measures across different segments and different opportunities for customers and end users. We needed to define what was valuable energy efficiency and what was energy efficiency that was actually making some of our GND system issues worse. In Arizona in 2019 there were 90 days in which we were able to purchase carbon-free, renewable energy for negative prices on behalf of customers in the regional market.

We want to be able to serve our customers reliably, affordably, and with clean energy, and when we put all that together it made sense to take a harder look at our DSM portfolio and pay attention to the hourly load shapes of every measure. In doing that, we began to have more dialogue at the feeder level and at the distribution system level, because as Mike was saying, a lot of things were showing up that none of us had seen before. Our focus became to address those issues while at the same time, better understanding the tools that we had in our toolkit to do so. In the past, our conversations were about annual savings and sometimes the coincident peak impact from any given measure. But now, we could actually show an hourly shape of the savings and compare those against any other resource in the portfolio. That was a game changer!

Rogers: What jumped out as the types of measures that were exacerbating the problem?

Hines: The example here is one we used in our filings: commercial lighting.

If you think about the typical business day for a commercial customer, as you can see by the yellow bars in the Figure 1 chart, most of the savings occur when we have a minimum load situation, as a result of all of the solar energy on the grid. So we repeated this profiling analysis with every single measure in the portfolio. Commercial lighting definitely looked the worst across a lot of measures. Then things that focused on summer peak, things that were more demand response related, but also a lot of things that we tried to do to move energy toward the middle of the day to help flatten system load shapes, to flatten load shapes at the feeder level and take advantage of free or even negatively priced renewable energy. That helped flatten the system load shape.

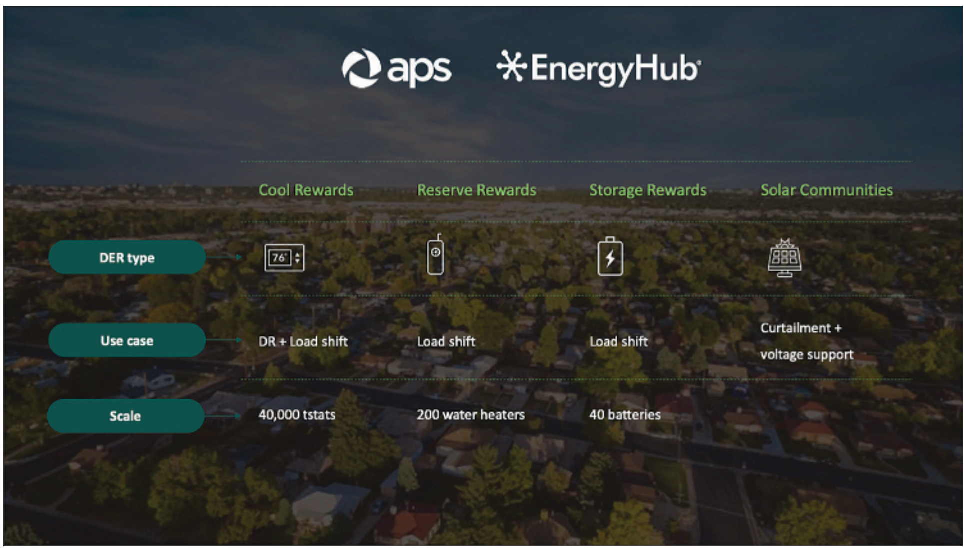


FIGURE 2.

Rogers: What we're talking about from a DSM perspective is proactively influencing customers' behaviors through traditional DSM portfolios and efforts. Was that easy for your side of the house to say something like, "Let's partner to create programs that can actually influence how DERs are coming onto the grid?"

McMaster: Yes, there was an appetite for this as we're working with a lot of renewables. We definitely wanted to accommodate them, but the majority of our energy demand is later in the day when there's less solar available. We could meet that energy demand by buying it on the market later in the day, but traditionally that energy would come from nonrenewable resources. So while we'd be addressing the early evening load, it would be via resources that are not as clean as they could be. So the value-add of demand response lies in synchronizing customer load to the time of day when solar is most prevalent. Without load shifting, customers would be consuming energy later in the day, when the energy tends to be less clean, and solar tends to be a smaller percent of the portfolio.

We'd like to be able to say, "Our current solar generation is flexible when paired with demand response, but inflexible without it. Is there a way we could use that solar energy and shift the energy needs so we could utilize our renewables more efficiently?"

One approach to this is pricing. APS wants to be able to accommodate renewables better and pricing is one way to do that. On the engineering side, we want a stable grid so we can smooth out the load profile. That would mean we wouldn't have to do as many upgrades, which would reduce our operational costs. We're also able to adopt more renewables, which is ultimately helpful from an environmental and policy perspective, so it this is a welcome approach.

Rogers: There are a lot of us working on the mission of getting more renewables onto the grid. Let's move on to a "second chapter" in this conversation which is all about implementation. Based on our conversation so far, it seems like APS' DSM and distribution operations groups had a really good reason to start talking with each other. So let's dig into those conversations.

The 2018 Demand Response and Energy Storage and Load (DRESL) filing was approved and APS was able to stand up rewards programs ranging from thermostats to water heaters, as you can see in Figure 2. What was included in the portfolio and how did APS determine the best technologies to solve this problem?

Hines: APS set out to create a platform on which we could aggregate distributed energy resources to make them an asset on the system, versus having them be an uncontrolled cause of challenges on the system. In collaboration with the Distribution Operations team, we thought about this as "a single pane of glass." Meaning if we are going to use DERs for the benefit of customers, they had to be accessible and easily acted upon, which meant our Distribution Operations Center had to have them all aggregated in one place.

In Figure 2, you can see the whole DER portfolio, which is connected to the EnergyHub platform. APS now has a goal of deploying 40,000 thermostats. Today we have just over 20,000 of them in our *Cool Rewards* program, which is a DR element of the program and also contributes a significant load shift component to it. This is because we're doing a lot of pre-cooling to help address our extreme temperatures over a five-hour on-peak period. It really helps if we can pre-cool customer homes and by doing that, we are also moving energy use to the middle of the day and taking advantage of the peak solar production curve.

The DERs in the *Reserve Rewards* program had a very different use case, related to over 200 Rheem-connected heat pump water heaters, which provide customers with bill savings plus load shifting. Water heating gave us an opportunity to do something with loads in the non-summer seasons when we're actually seeing minimum loads on feeders. This is more about what we call a "solar sponge," meaning the ability to absorb solar energy in the midday by storing energy in water heaters.

The original filing was intended to be built around storage. W tried to make the argument that there are lot of ways to accomplish load shifting, load management, and storage that look like something other than chemical batteries. However, we did also include about 40 chemical batteries in the *Storage Rewards* component of the program based on doing load shifting, and on a daily basis around customer on-peak rates.

The other noteworthy observation is that over two thirds of APS' residential customers are on time-differentiated rates. We've tried to build this in a way that provides value to customers if they load shift around our on-peak and off-peak rate periods. The *Reserve Rewards* and *Storage Rewards* components of the program are targeted at specific feeders where we have high solar penetration, and so they are specifically designed for load flattening at the feeder level. We are also implementing a *Solar Communities* program, which gives us the ability to do curtailment and voltage support with APS-owned and -operated inverters.

Rogers: I can't remember the last time the phrase "voltage support" came up at PLMA so it's exciting to hear more on these topics. It's also interesting that the different customer engagement models you've used, like bring your own thermostat, tap into the reality that there are a lot of thermostats out there. APS has also realized it needs direct customer engagement to find opportunities to install water heaters and batteries. Does the utility own the battery?

Hines: The utility owns and operates the batteries, yes.

Rogers: Ownership of the water heaters is actually passed to the customer, right?

Hines: Yes, the ownership passes to the customer but the utility operates the water heater on the customer's behalf. Neither of those is likely to be a scalable model for the future, but this initiative was for APS to learn more about the customer and grid benefits of these connected devices. Hence, it made good sense for this pilot to focus on aggregating them as we targeted specific feeders.

Rogers: Mike, I think we all look at this through the lenses of DSM and DR practitioners, but as a distribution operations engineer looking at Figure 2, when I look at the set of tools at your disposable, I am curious about what excites you most about how these can be used from a distribution side? I'm also curious about the importance of the feeder targeting in this program, and how that voice came through from distribution operations.

McMaster: To clarify, while I'm not in operations anymore, I certainly can speak to it because we've worked closely on this. There's flexible load and flexible generation, and our current generation with curtailment will be able to get some flexibility in the output. The advantage of the *Rewards* program is if it's behind the meter and there are different rates for both on-peak and off-peak, we can help our customers save AND help smooth out the load. As the utility, we don't care as much about where that energy comes from, whether it's additional energy or a reduction in the load. What we care about is smoothing out our profile so operational costs are minimized and not passed on to our customers.

What really helps make this possible is the *Rewards* programs, which provide different resources for different times of the day. For example, if a customer cares more about the load shift than the temperature shift from the thermostat, they have the option to achieve load shift through their water heater. There's a lot of flexibility.

From an operational standpoint, while it is APS-owned, one of the limitations we have is a limited amount of DER resource we can incorporate onto a given feeder; that's called our hosting capacity. Beyond that limit, the system obviously needs to be upgraded and the cost to do that is shared across everyone's rates. One of the advantages of curtailment is, if we have flexibility in our load, if we have flexibility in our generation, can we work with these to accommodate more renewables onto our grid? From an operations perspective, what was a liability along the lines of, "Hey, we've got these fluctuations now," to an asset of, "Hey, we can reliably move some of this excess solar energy into a time of day when it benefits our customers and us."

Rogers: APS has one of the most awesome feeder names: the one that we really like is "Roadrunner!" I challenge any other utility out there to share your feeder names and see how they compare with APS' feeder naming scheme!

Hines: I think Roadrunner is the most advanced feeder in the U right now in terms of what we're doing on it!

Rogers: As we're talking about how these tools can be used, I would like to focus on APS' lessons learned.

Looking at Figure 3, we now see a camel! Tell us more about that.

Hines: We've made a big deal about the fact that we don't have a duck curve in Arizona. For those who know Phoenix, I'm sitting here in the shadow of Camelback Mountain, and we've realized we do have different use cases around what we are trying to do versus what other utilities are trying to do. Our partnership with EnergyHub has worked so well because they've been very flexible and understanding about APS' needs.

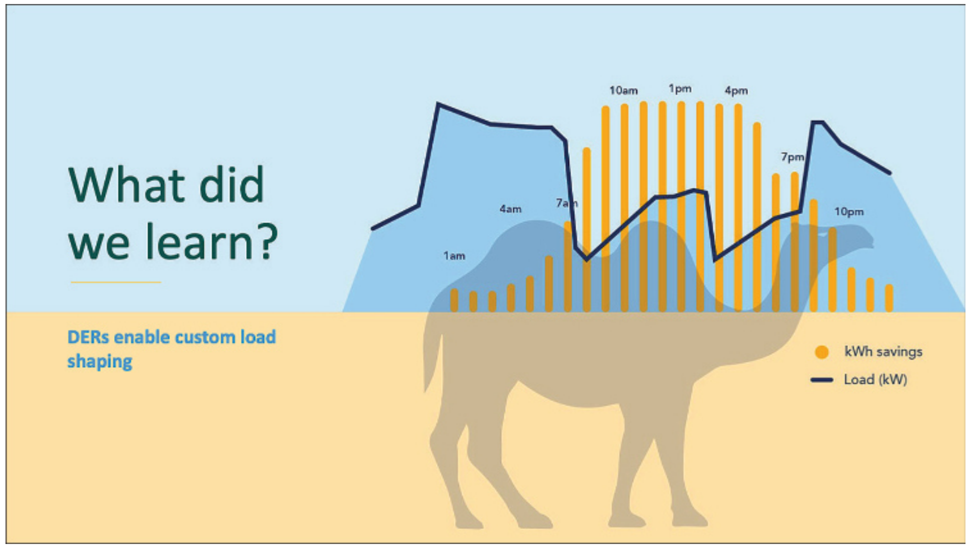


FIGURE 3

We are thinking hard about what we call a "do no harm" approach to programs when we have customers who are on demand rates; demand-based rates or time-of-use based rates. As I mentioned, over two thirds of our residential customers are on time differentiated rate plans today. Of those, about 20 plus percent of them have opted into demand-based rates. We've leaned pretty hard into demand-based rates as an opportunity to drive value for customers who can provide value back to the grid.

With the load shape getting peakier, it's been about trying to get customers to understand that if you can move load off those hours, you benefit everybody on the grid, and APS is willing to share that benefit with our customers through our rates.

In the camel curve, you're looking at some of the events we've done within the *Smart Thermostat* program. At the beginning of the blue line, you'll see we're increasing load by pre-cooling before our demand response events. This helps with customer comfort and it also shift a lot of load to the middle of the day when we can absorb that solar energy and actually reduce emissions too.

Our on-peak rate starts at 3:00 pm where you can see we're really starting to drop that load, but we're not initiating a demand response event yet, and the reason is we wait until typically 6:00 pm to start a two-hour demand response event. When we are releasing thermostats, it's after our on-peak period so we're not creating a demand impact or a time-of-use impact for a customer. The result is this camel curve which has been extremely valuable in terms of doing the right thing for our customers and our system, and for providing more value than we could have in any other configuration. In the camel curve scenario, we've achieved clean energy, reliability, and affordability.

Rogers: Let's talk about scalability. In Figure 4, we can see in the past few months, APS has joined a lot of the other utilities around the U.S. in stating a very aggressive goal to get to 100 percent clean by 2050. There seems to be a lot of safety in including grid-edge DERs as part of that solution. Is that true and does APS see grid-edge DERs as part of its pathway to 100 percent?

Hines: It's incredibly exciting to have spent my whole career working on this and find it is now an extremely valuable tool in the toolkit! Obviously energy efficiency helps by just reducing total consumption, but way more importantly, and we're doing a lot of modeling around this, it's about aligning our loads and our demand with our intermittent generation of clean resources.

The more that we can overlay those two things, the more we're absorbing them and integrating more renewables. We won't get there without significant inputs from all types of DERs, whether from storing energy for later use when clean energy is available, or from load management that's moving energy to be coincident with when intermittent renewable energies are available.

Rogers: If you're successful in getting all of these grid-edge devices onto the grid then Michael's life is going to get a lot more interesting! Michael, what does operations look like when you have hundreds of thousands of grid-edge devices that need to be used? How does that happen within the utility and who cares about it?

McMaster: First, there are a lot of groups who care. There's the "market layer" asking questions like, "If I've got all these DERs in aggregate, how is that supporting pricing? How is that supporting the overall cost of energy?"

At the feeder layer, which I like to think of as a distributed layer, they are asking, "From the operational standpoint, how is this impacting the feeder? Am I soaking up that solar? Am I shifting it later?" If you paired demand response or a lot of these grid-edge devices with solar, you almost have a pseudo-battery on your system, which is not something a customer's likely to notice. You're not dealing with any of the chemicals, or other means of storage, but you have a very effective method.

At the customer layer, which is behind the meter and which creates a lot of our load, giving them flexibility and encouraging them to adjust when loads peak and decline really helps out where from an operational perspective, we are controlling them en mass right now and obviously there are a lot of incentives to our programs to encourage customer adoption. The paradigm shift is moving from utilities disturbing customers to utilities partnering with vendors and customers to try to create a better load profile. I believe that will be the key to carbon-free power.

Rogers: What's one nugget from each of you to the audience on key things to keep in mind in standing up a customer DER program?

Hines: I'm going to give you a bonus; I've got two! One is always think about the customer. Keep the customer forefront. What do they want to connect? How do they want to use it? What are their use cases? Then, think about ways you can actively influence those use cases to get what you want for the greater good of everyone on the grid. But always think about the customer value proposition first.

As we scale, it's not going to be about one DR program, it's a diversity of different programs and we can feather-in different products to meet different needs: emergency response, or value on the trading floor, or rate responsiveness and two-hour versus five-hour products. There are different ways we can use all these to create a diversified portfolio of opportunities for Mike and the folks in Distribution Operations.

We also need to think about true load shaping around snapbacks and other issues so that we are creating a truly flexible resource for the grid and working closely with the guys who are actually operating it in real time.

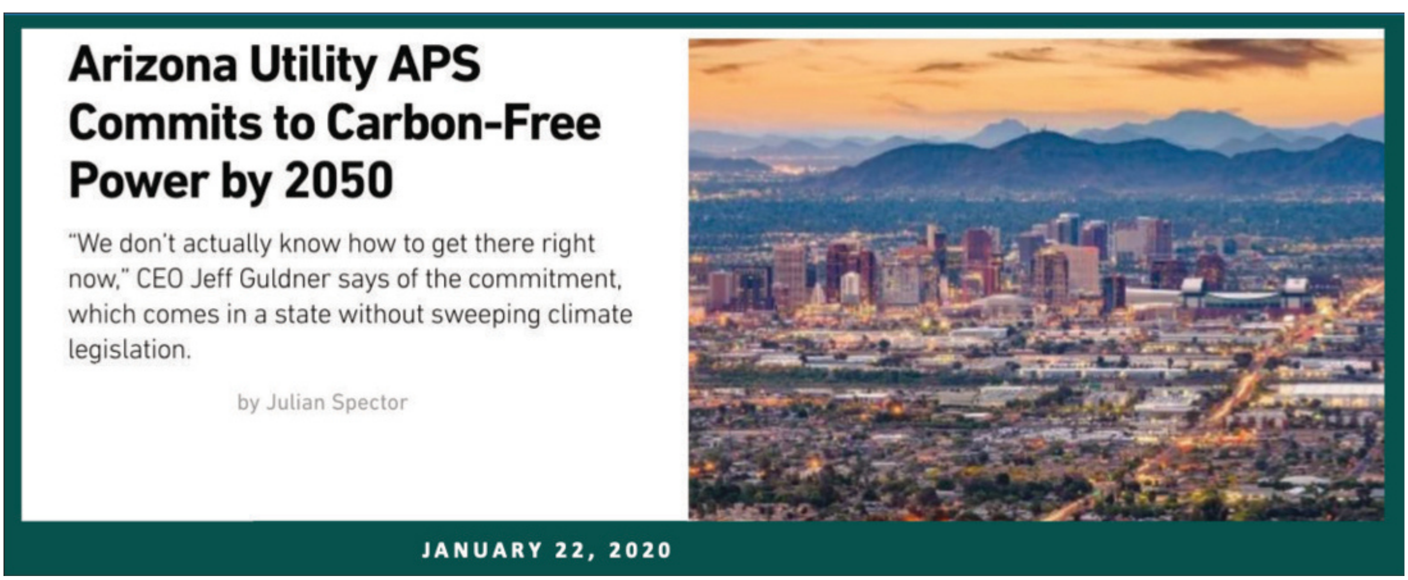
McMaster: As Tom said, clearly our customers need to be the main focus. It's also important to try to balance what your operators are dealing with. As you start to aggregate DERs, you'll see an impact to the bottom line. It's important to keep in mind your marketing and trading floor might be interested in this as well.

I also love the KISS principle: "Keep It Simple, Stupid!" APS has done a wonderful job on this because certainly we're aggregating a lot of things. It's very tempting as a nerd to want to get super- granular and control every individual device remotely. However, the advantage of aggregation is the flattening of your load profile for your operator, even though there are diminishing returns on the benefits of DR.

Brazis: Tom, you spoke about 600 or so measures that were EE measures, and they didn't align. Were there some EE measures that did align in terms of value?

Hines: Yes, it's not really surprisingly that even with all of our HVAC-related measures, we've almost doubled down on them, and even duct repair. We think a lot about EE now, not in terms of just the energy efficiency it provides, but the ability it provides to homes to be more flexible resources on the grid. For example, we have completely repurposed our *Home Performance* program to work with contractors so they are thinking about thermal envelope in the context of putting someone on a TOU or a demand rate, then programming a smart thermostat to pre-cool around that rate, effectively rate-optimizing for them.

We've found contractors are able to give a customer a 10 percent savings on their bill with energy efficiency alone. But they can deliver a 30 percent savings on the bill if we combine energy efficiency with the right rate and the



Arizona Utility APS Commits to Carbon-Free Power by 2050

"We don't actually know how to get there right now," CEO Jeff Guldner says of the commitment, which comes in a state without sweeping climate legislation.

by Julian Spector

JANUARY 22, 2020

FIGURE 4.

right device. That's the future! It's about helping customers make their home's flexible grid resources in ways they don't even notice; making it easy for those homes to interact with the grid, providing greater comfort for the occupants, and delivering greater value to the grid overall.

Brazis: Which specific DER technologies are part of APS' programs?

McMaster: For APS' *Cool Rewards* program, we're controlling HVAC. We've also got our "smart" water heaters in place which have different efficiency modes depending on whether they work on a heat pump or an electrical mode. Energy efficiency obviously reduces the load but it also means the delta in the load is going to be quite different compared to an electrical mode. You load shift less with a more efficient mode.

We're using Sunverge batteries which use a traditional lithium ion chemistry and a more traditional type of energy storage than we are used to seeing, but these provide a lot more granularity and smooth control for the customer's load profile. For *Solar Communities*, we're hoping to curtail some of our APS-owned solar so we can accommodate some of the negative pricing to reduce our customers' rates and give them a bonus.

We're also interested in curtailment just because of the potential it gives us to accommodate more renewables on the grid. When we talk about capacity, it's usually about a worst-case scenario and it could be for just a very brief moment during the year. As a result, we're looking into the flexibility of our generation load and how can we accommodate it.

Hines: EV load management, which we filed in the 2020 DSM Plan, will be one of the new DER resources we want to manage and control through the *Rewards* operating platform. We're also looking more at retrofit controls for existing hot water heater tanks and there are a lot of these out there! We believe we could use them like batteries.

Rogers: Don't forget those pool pumps, Tom. You guys always love to talk about pool pumps.

Hines: Yes, we do indeed have 280,000 pools in the APS service territory! Does anyone care when their pool gets pumped as long as it's clean? They don't, and so the point is it's a very low touch DER that we could take advantage of to potentially pump all those pools right in the middle of the day when there lots of free solar energy available to do it.

Christine Riker: When you talked about the heat pump water heaters and the batteries, you said you started off with a smaller number to test this out first. Have you started to think about how to scale that approach?

Hines: We've thought a lot about it! What we see right now is a one tenth (or less) cost per KW that we canmove with BYO smart thermostats, which customers are rapidly adopting. As the price for chemical storage comes down, I think we'll be able to do more. We believe heat pump water heaters have a strong future, and certainly in the builder market. Also in the builder market we've identified an opportunity to put the same kind of connected controls onto standard electric resistance water heaters.

We can do that for a fraction of the cost of the heat pump water heater, get a lot more builders interested in the program, and get a lot more bang for our buck in terms of the load we can manage. We don't get as much value in terms of the energy efficiency savings, obviously, but we have a lot more value because we can scale.

Arizona has a lot of master-planned communities so we can get immediate scale by working with builders to add a connected module onto a standard electric resistance water heater. These provide other customer benefits like leak detection so builders really like this approach. Customers aren't necessarily ready to spend a thousand dollars more for a heat pump water heater, so we've thought a lot about scale and the a diversity of things that we can do to bring us scale, as well as how we stagger them according to the technology and the costs.

McMaster: I agree there's a lot of value in batteries. If you have reliable storage, which helps at large scales, they are very good for load shifting. But when you consider batteries from a customer perspective, you recognize they have some other devices already available to them, such as water heaters, and especially in Arizona, an HVAC system. But a residential battery can represent an additional cost and it takes up space in a house.

It's also important to understand from a customer's perspective how installing a battery is to their benefit. The big positive we experienced in the *Rewards* program pilot was that load shift can be achieved through HVAC and water heaters. Load shift is the main value of the battery. Now, you don't have the pure granularity of a residential battery, but as you aggregate them up to the feeder level, or up to your system level, the utility can see a smoothed out and reliable load shift, which is what you would hope to gain from a battery.

When I mentioned keeping it simple, I believe we already have the technology available in a house to help us with load shift. That's where a lot of our resources are going to come from: behind the meter.

Brazis: Thank you everyone!

Presentation video available at https://vimeo.com/410358493/0860aba2b1

Calculating Cost-Effectiveness for Energy Efficiency and Demand Response Impacts

Evaluation

The following is a transcript of a PLMA Load Management Dialogue (webcast) presented in May 2020. It highlights the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NESP for DERs), published in August 2020. The webcast discussion was led by PLMA Board Chair Michael Brown of NV Energy, speaking with Julie Michals, Director of Clean Energy Valuation at E4TheFuture.

Julie Michals
E4TheFuture

PLMA Chair Michael Brown
Berkshire Hathaway
NV Energy

Michael Brown: Julie Michals joins us today to discuss her work as the project coordinator for the 2020 NESP for DERs manual. This manual is an expanded version of the original National Standard Practice Manual for Energy Efficiency (NSPM for EE), which was published in 2017. Julie is here to provide us the background on these efforts, lessons learned, and a summary of the NSPM for DERs, released in August 2020. Please tell us more about the National Standard Practice Manual.

Julie Michals: Thank you Michael. I'm here to give you a short overview of what is involved in this National Standard Practice Manual, and then to dive in a little bit deeper with some questions around the pertinence and application of this new manual as it relates to demand response and load management as seen in Figure 1.

The National Standard Practice Manual for Energy Efficiency (NSPM for EE), published in 2017, had the goal of providing new guidance for the cost effectiveness analysis of energy efficiency. It took into account the realities on the ground, based on experience across states, where traditional tests often do not, and have not, captured pertinent jurisdictional policies; those policies that are trying to dictate or reflect the intent of the investments in efficiency. There has been a historical lack of clear principles and guidelines on how to apply some of the traditional cost-effectiveness tests to efficiency, plus basic challenges around the application of these tests as well as a lack of transparency in benefit-cost analyses.

In 2016, a group of stakeholders informed the development of the NSPM for EE, which is now used in multiple locations around the U.S. Its focus is efficiency, and yet there remained interest, largely from regulatory staff and some practitioners, for a broader guidance document on distributed energy resources more broadly, including efficiency and other other resources, as seen in Figure 2.

The NSPM for DER is comprehensive. It lays out a common benefit-cost analysis (BCA) framework to help jurisdictions to analyze the cost-effectiveness of DERs by means of a consistent primary cost-effectiveness test. It also focuses on each DER type and discusses the key factors that affect the impact of each type, whether an identified impact is a benefit or a cost, and which use cases, technology characteristics, and operational profiles of the different DERs should be considered.

For each resource there are different factors to consider: for example, the case of efficiency versus distributed PV. In addition to chapters on each resource type, the NSPM for DER also addresses multi-DER analysis, both onsite multi-DER considerations like grid-interactive efficient buildings, as well as non-wires solutions.

The NSPM for DER provides case studies to illustrate how benefits and costs are affected, and in multi-DER cases, where one needs to account for factors such as interactive effects. It also demonstrates how to go about identifying what these interactive effects might be.

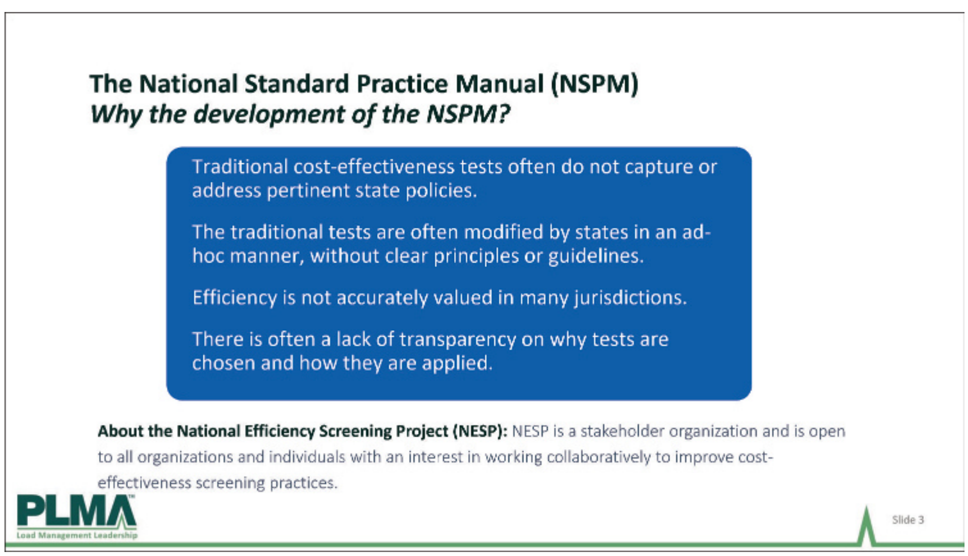


FIGURE 1. View Slide at: https://bit.ly/3qwGjkl

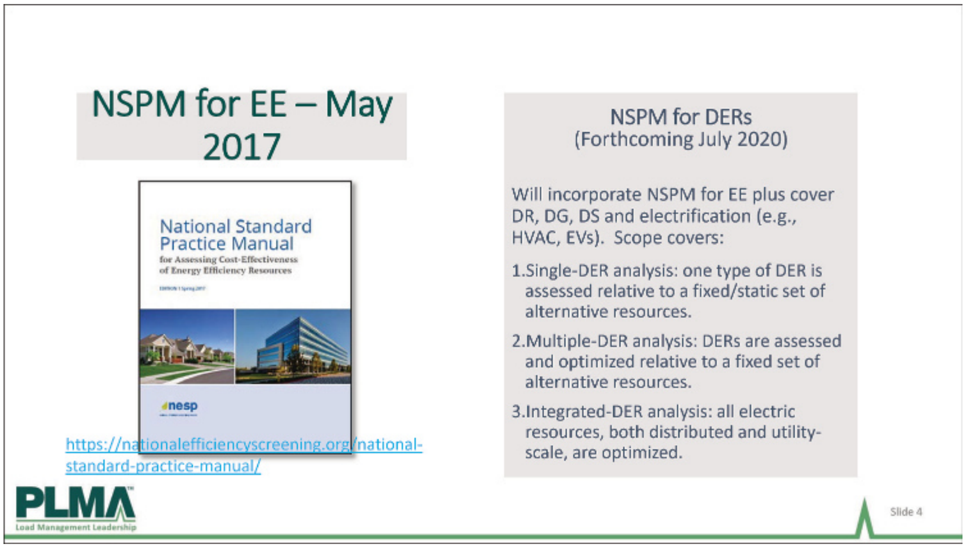


FIGURE 2. View Slide at: https://bit.ly/3pxmYOA

In the section on integrated DER analysis, which is much more complex and comprehensive, the advisory group of stakeholders recommended we learn more before providing written guidance. Still, integrated DER analysis is addressed at a high level and points to developments in the industry as a means of evaluating all electric resources, both distributed and utility scale, in an optimized modeling approach.

The NSPM for DER was funded primarily by E4TheFuture and by the U.S. Department of Energy through Lawrence Berkeley National Labs as shown in Figure 3.

In Figure 4, you will see the NSPM for EE's inventory that highlights where we are seeing states take interest, or where states have used the NSPM as a process to review their current testing practices and make modifications to them based on that process.

Figure 5 shows the basic elements of the NSPM for DER's benefit-cost analysis framework, built on its predecessor NSPM for EE. It includes a set of principles, a multi-step process for developing a jurisdiction's primary test, as well as guidance on the use of secondary tests for the situations when these are appropriate or needed. This framework is fundamental to the NSPM.

The policy-neutral, fuel-neutral NSPM principles, which are not in any way controversial, provide a process for a jurisdiction to say, "we're going to review our current cost-effectiveness testing or valuation practices, whether it's for single DERs or a multi-DER situation relative to these principles and see how we do."

The NSPM can be used to assess the benefit-cost-analysis to programs, procurement, or pricing mechanisms. It focuses more on administrative cost-effectiveness analysis of DER programs, but the concepts and these principles apply more broadly to procurement and other investment strategies.

The principles really help to guide the process of developing a primary test, ensuring that there's alignment as a test is developed, and the relevant costs and benefits are identified based on the jurisdiction's applicable policies.

The second principle – alignment with applicable policy goals – is fundamental to the NSPM. If a jurisdiction has clearly stated goals for its investments, the associated impacts should be accounted for. If specific goals are not stated, then one can make the case that that's not a purpose of the investment. Advocates can make the case through a statute, or through other venues for identifying what the value of these investments are. This can help with the identification of relevant impacts to the cost-effectiveness analysis process.

The third principle-- ensuring symmetry across costs and benefits--is critical. This has been a major challenge with the Total Resource Cost Test around the country. This has been especially so when accounting for participant impacts and where costs are included, but non-energy

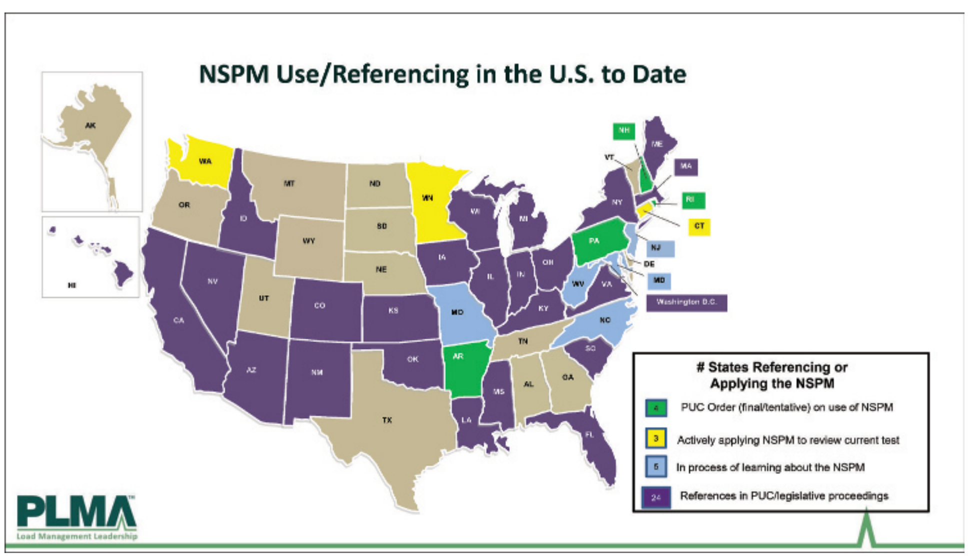


FIGURE 3. View Slide at: https://bit.ly/3dorTPD

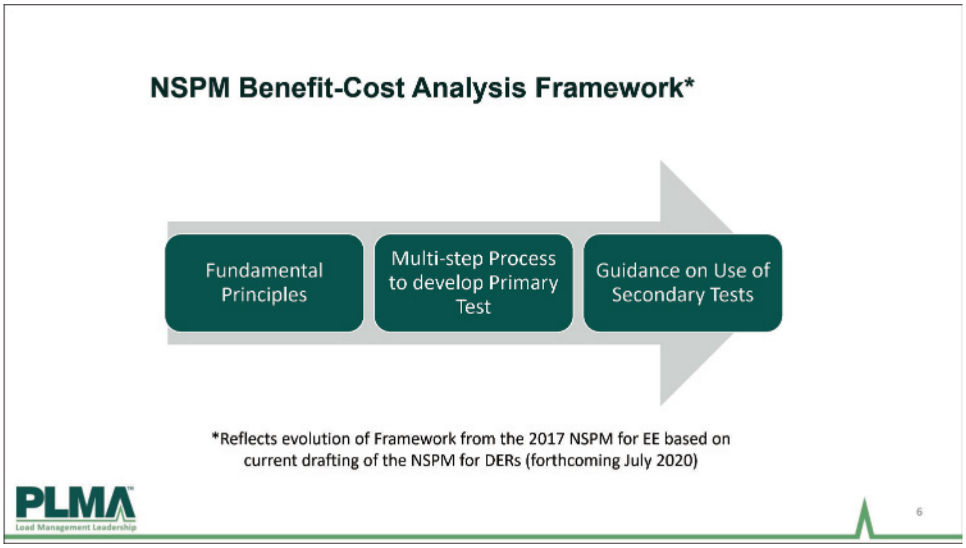


FIGURE 4. View Slide at: https://bit.ly/37roPhP

benefits are not included. The NSPM indicates that asymmetrical treatment of costs and benefits leads to a test that is skewed. However, it does not recommend that all non-energy benefits be included, rather it says if you're not going to include all the non-energy benefits, you shouldn't include all the costs.

The State of New Hampshire passed an order to use NSPM to update their cost-effectiveness tests in which they decided to remove all participant impacts. The state made this decision because it was not willing or able to spend the resources necessary to conduct studies to value these types of events. And therefore, to stick with the symmetry principle, they are taking out the cost.

Principle number eight, the final principle, is important because it comes up throughout the NSPM. It differentiates between benefit-cost analysis versus a rate impact analysis. If you are familiar with the world of cost-effectiveness, you know that some states use the Rate Impact Measure test. And while rate impact analysis and bill impact analysis are both important, they answer different questions and therefore should be evaluated separately. They are complimentary and can inform each other, but they really are separate analyses. So this important principle was added to the NSPM for DER, as you can see in Figure 6.

The NSPM provides a multi-step process for developing a jurisdiction's primary test, which identify which resources have benefits that exceed cost, and therefore merit acquisition or support on behalf of customers. A quick

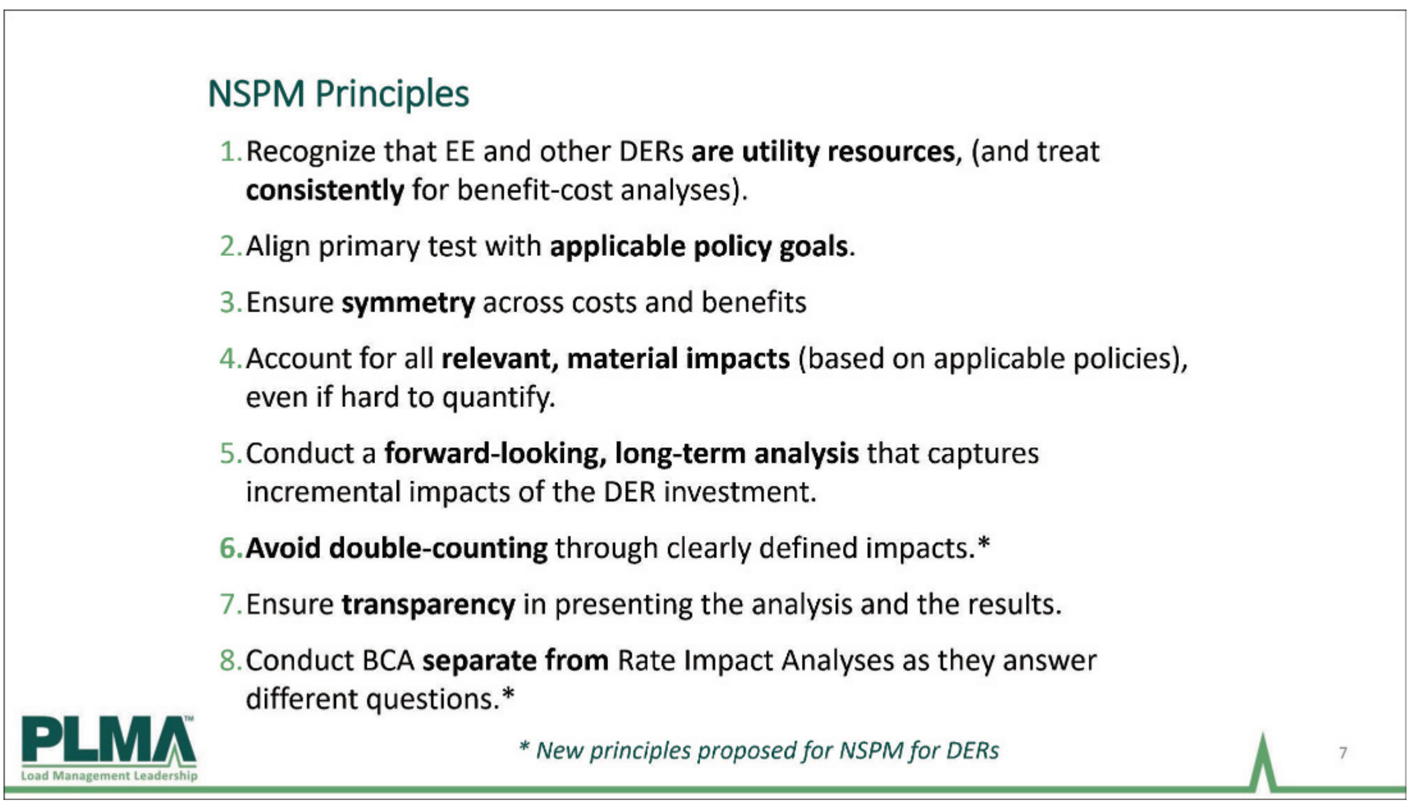


FIGURE 5. View Slide at: https://bit.ly/2ZsfvWz

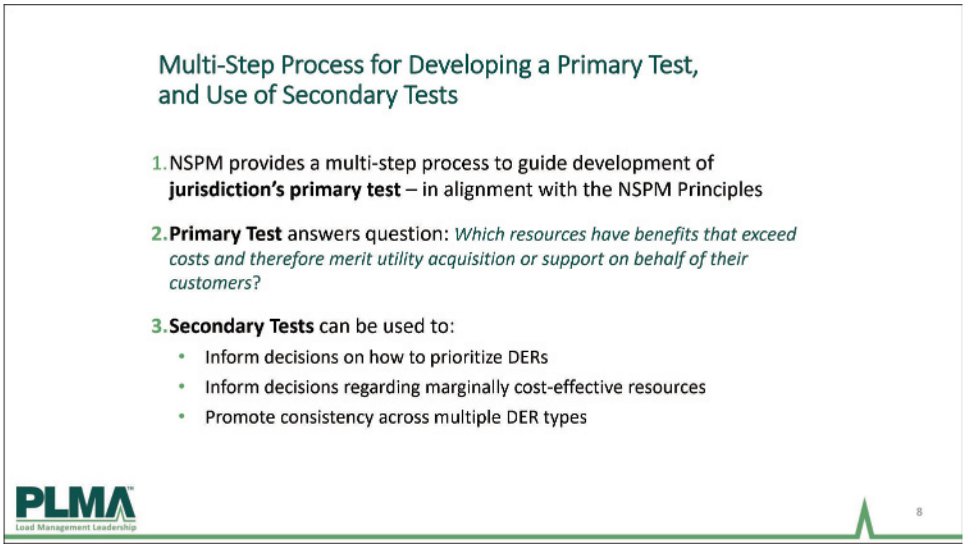


FIGURE 6. View Slide at: https://bit.ly/2M1NWQR

clarifying note: throughout the NSPM the authors refer to utilities and to regulators, but the definitions are broader than that and are not just narrowly applicable to investor-owned utilities. They can be applied in other situations to include energy providers and power system needs too.

In Figure 7, on secondary tests, the NPSM provides guidance on how these can be used, how they can inform decisions on prioritizing DERs and informing decisions about marginally cost-effective resources, and helping address consistency across multiple DERs.

The NSPM for DER also introduces the regulatory perspective which builds on the underlying perspectives of the Utility Cost Test, the Total Resource Cost Test, and the Societal Cost Test. These are the traditional test perspectives which we are all familiar with. The important differentiation is that from the "regulatory" perspective, (and regulatory is in quotations because again, it can represent a different range of decision makers), it reflects the intent for investing in the resource.

It's possible that the regulatory perspective, using the NSPM in developing a primary test, may be aligned with one of the traditional test perspectives. But importantly, it may not be. It may actually be that a jurisdiction develops a test that is unique to that jurisdiction. And that's what we saw, for example, coming out of New Hampshire which has named its test the "Granite State Test."

In Figure 8, you can see four examples, three of which indicate that if you apply the NSPM and develop a jurisdiction-specific test, you may end up with a test that aligns with one of the traditional tests based on the applicable impacts identified using the NSPM multi-step process. Those are the top two, and lower-right pie charts. The lower-left pie chart is one in which a jurisdiction's primary test is not aligned with a traditional test, and it really is unique to its jurisdiction based on the alignment with its policies.

E4TheFuture had an excellent team of consultants working on the NSPM for DER, including Synapse Energy Economics, the Smart Electric Power Alliance, Pace Energy Center, ICF, and the Energy Futures Group.

Brown: Thank you for introducing the whole NSPM team! It certainly takes a number of experts to pull together a practice manual of this magnitude!

PLMA has many member practitioners working on new demand response programs and we're seeing DR programs are evolving to include solar, storage, and electric vehicles. You mentioned the NSPM for DER has different chapters to address these new types of DERs, and you've mentioned interactive effects and other key factors. For our PLMA members who are developing these new programs, can you share some of the manual's recommendations for managing these, and particularly the associated benefit-cost analyses required to get program approval?

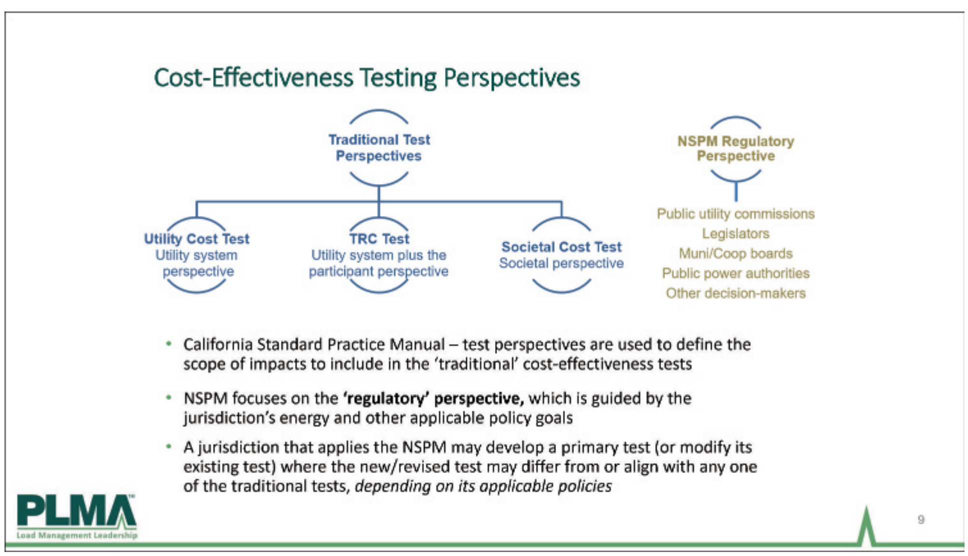


FIGURE 7. View Slide at: https://bit.ly/2NEpwxa

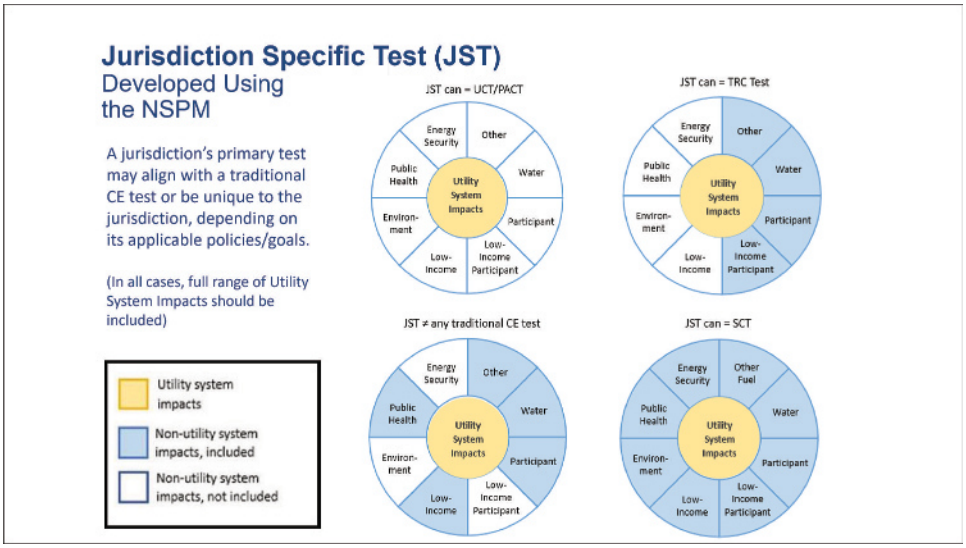


FIGURE 8. View Slide at: https://bit.ly/3avBxhy

Michals: Let's take demand response as an example. The DR chapter of the manual starts by identifying costs and benefits, including utility system impacts, host customer impacts, and potential societal impacts. Each DER chapter identifies factors that might affect whether an impact is a cost or a benefit, and the relative size of the impact. In the case of DR, understanding the technology characteristics of a given DR program is key to the benefit-cost analysis, as well as the operational profiles.

It's important to consider the speed, precision, and duration capabilities, as these have direct effects on the type of grid services. Understanding whether a program is based in simple or more advanced DR, and whether it's grid-interactive or a one-way energy flow, makes a difference to grid impacts also. Ownership and control of the resource – whether by a customer or the utility – will affect impacts too. The NSPM provides use-case examples and highlights the factors that should be considered for each.

In the case of interactive effects, this will come up in the context of multiple-DER benefit-cost-analysis where the benefit or cost of a certain resource may vary when combined with another resource. For example, there is typically a greater benefit for solar-storage due to the interactive effects between the two, while for a DR and efficiency multi-DER cost-effectiveness analyses, there can be a lower level of DR savings due to the increased efficiency of the equipment.

Brown: Several PLMA stakeholders and members who are actively developing new DER programs are pointing out that a big challenge can occur around the formation of these new programs. In many states, there can be different funding mechanisms that could potentially be silo-ed. For example, rebates for storage that may not have to pass cost-effectiveness tests, but then DER programs that leverage those new storage devices for dispatch. So this idea of cost allocating the different types of DER benefits to one particular program or funding mechanism arises. Is this a separate issue or does the NSPM for DER offer guidance around these kinds of cost allocation issues?

Michals: That's a really good question. This situation presents an inconsistent treatment of DERs from a cost-effectiveness testing standpoint. NSPM principle #1 indicates that all DERs that are supported by public or ratepayer funds or through pricing mechanisms should be treated consistently using the same benefit-cost-analysis framework. This consistency would then address the issue of how to allocate the costs and benefits of the specific DERs and any interactive effects.

The challenge is the industry is not there yet in terms of breaking down the program funding silos and the associated benefit-cost-analysis practices for different DER types. The intent of the NSPM is to help jurisdictions understand the importance of removing these silos and barriers to DER investment, and improving the cost-effectiveness assessment of the resources, ideally using a multi-DER analyses.

Brown: You spoke about locational benefits. PLMA collaborated with E4TheFuture previously on a publication of case studies about non-wires alternatives. In it, we saw there are utilities that are starting to use benefit-cost-analysis approaches for non-wires alternatives analyses. We're also seeing that due to the proliferation of DERs in our industry, there's a requirement to merge previously disparate utility planning approaches. Groups are starting to work more closely together; distribution planning with the DSM folks. Historically, they have had different analysis techniques and maybe even tool sets.

You mention one of your guiding principles is related to the consistency of input assumptions across DER analysis. Can you talk about other key factors that need to be considered with DER analysis or non-wires alternatives analysis?

Michals: We often see different terminology being used by different groups. Consistency across input assumptions is key, especially around items like avoided costs and other utility system and non-utility system impacts. The NSPM can helpful here in guiding jurisdictions to ensure they are aligning their policy goals across all of the different planning functions.

SEPA's non-wires solutions report, published some time ago, highlighted the need for creating consistency and harmonizing various analytical tools, and I think we have a way to go on that front. The upshot was that utilities aren't there yet. As many of you know, there are different ways to calculate NWS impacts and there's a need for greater consistency. In addition, there's a lack of transparency in the benefit-cost-analysis for the NWS, as SEPA noted in its report which documented a range of case studies.

The NSPM for DER can provide guidance on the appropriate process for identifying the best input assumptions, in terms of relevant costs and benefits, and can also point to some key resources around analytical tools and methods for calculating impacts.

Brown: A few key themes have surfaced from our long list of audience questions, including integrated demand-side management. Does the NSPM for DER address best practices for how to value programs that are essentially achieving EE and DER benefits together, such as "The Smart Thermostat Program Evaluation"? That's one of the specific use cases coming up. How can we best accomplish this? In addition, what about non-energy benefits evaluation?

Michals: On intrgrated demand-side management (IDSM), the NSPM for DER provides use case and case study examples that include a range of DERs and describes these in the context of grid-interactive efficient buildings and for a NWS scenario. By the way, grid-interactive efficient buildings include smart thermostats as a measure. These case studies consider the temporal, locational, and/or interactive effects of the combined DERs.

On the non-energy benefits, you saw earlier the principle that if you've identified a certain relevant impact that is hard to quantify, its value should not be zero. However, that's what we see in practice; jurisdictions will walk away from accounting for a particular impact because it's hard to quantify or they don't trust the numbers. The premise is that if it's relevant and it aligns with a jurisdiction's policies, and even if it's hard to quantify, the NSPM for DER provides guidance and approaches on how to go about quantifying this kind of impact.

These approaches can include primary research and conducting a study. Expensive, but perhaps more accurate. They can include using a proxy, which we often see; some percentage adder. In some cases, jurisdictions borrow information from other jurisdictions, but this is not always appropriate. And then in other cases, we see jurisdictions use alternate thresholds to account for certain non-energy benefits for certain types of programs when they conclude they can't capture or quantify all the impacts. They then reduce the 1.0 BC threshold to a lower level. This often happens around low-income customer impacts.

Brown: Julie, thank you to you and the whole team for your work on this important manual. The DER guidance is very welcome!

For more information about the National Standard Practice Manual for Benefit-Cost Analysis for Distributed Energy Resources (NESP for DER), published August 2020, please see the following resources:

NESP Website:
www.nationalenergyscreeningproject.org/national-standard-practice-manual/

- To download the NSPM for DER Summary - https://bit.ly/2ZmMyvj (20 pages)
- To download the full guidance document, NSPM for DER - https://bit.ly/2ZgT0E0 (302 pages)
- To download the NSPM for DER Presentation https://bit.ly/3ajtuEu (45 slides)

Presentation slides available at https://www.peakload.org/dialogue--calculating-cost-effectiveness

Beyond the Pandemic: Future Strategies for Meeting Commitments, Satisfying Regulators, and Evaluating the Whole Thing

Evaluation

The following transcript is from a panel discussion held during the 42nd PLMA Conference that was presented online in November 2020. It highlights pivots and changes forced by COVID-19 and examines how these might evolve in a post-pandemic world.

Moderator
Jenny Roehm
Schneider Electric

Moderator
Brett Feldman
Guidehouse Insights

Peter Bergeron
CPower

Tom Hines
Tierra Resource Consultants

Laura Small
Opinion Dynamics

Kenneth Weiland
Ameren

This discussion was moderated by PLMA Thought Leadership Co-Chair Jenny Roehm of Schneider Electric and Awards Co-Chair Brett Feldman of Guidehouse Insights. Panelists included Peter Bergeron of CPower; Tom Hines of Tierra Resource Consultants; Laura Small of Opinion Dynamics; and Kenneth Weiland of Ameren.

Jenny Roehm: Welcome to Beyond the Pandemic, a discussion about how COVID-19 has impacted all of our businesses. We're going to explore this subject from several different levels, including the utility level, the program level, and also the customer level.

Brett Feldman: We're speaking with Tom Hines, a Demand Side Management Portfolio Consultant with Arizona Public Service (APS); Kenneth Weiland, an Energy Efficiency Program Supervisor with Ameren Missouri; Laura Small, a Managing Consultant of Data Analytics at Opinion Dynamics; and Peter Bergeron, one of our 42nd Conference Co-Chairs and the General Manager for Utility Programs at CPower.

Tom Hines: Let's talk about staying focused on our long-term goals despite the 2020 course corrections that have resulted from COVID-19. I am going to begin by screaming (just a little bit!) that the beginning of 2020 was one of the most exciting months of my 30-year career as I began promoting clean energy. On January 22, 2020, APS committed to a goal of achieving 100 percent carbon free energy by 2050. We're not sure of all the technologies we'll need to get there, but we are going to do it affordably, reliably, and with a focus on our customers' needs, as you can see in the Figure 1 graphic.

If you consider all the demand side management and demand response tools in our toolkit, APS has been front and center with customer programs. As a result, we started 2020 thinking about customer programs in new ways that could really promote clean energy.

We looked at this problem in a multi-level way. Of course, energy efficiency helps reduce emissions by reducing energy impact across all hours of the year. We also thought hard about the particulars of the APS system and saw there is a 2024 hourly marginal carbon intensity for what we forecast the APS grid will look like in 2024. In every month of 2024, there's a stark difference that resembles the duck curve with all the renewable solar energy in the middle of the day and significantly less carbon intensity during those days. The more that we can shift energy away from that peak period, the better we do on reliability, affordability, and in our case, on TOU rates. Together, these help us toward our clean energy goals. The bottom of Figure 2 is about one third the marginal carbon intensity of the peak.

We've used this as an approach to load the value we get from programs, demand response, and load shifting, but also to address APS' net emissions impact. Figure 3

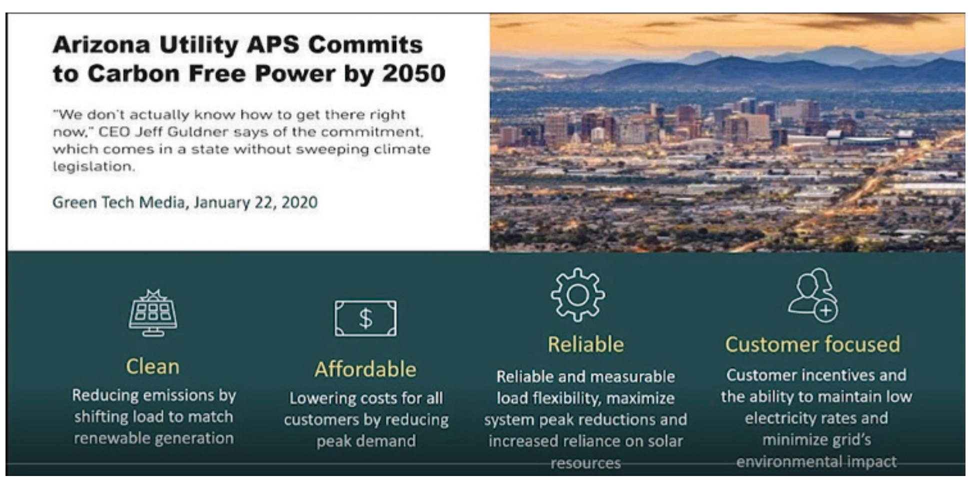


FIGURE 1.

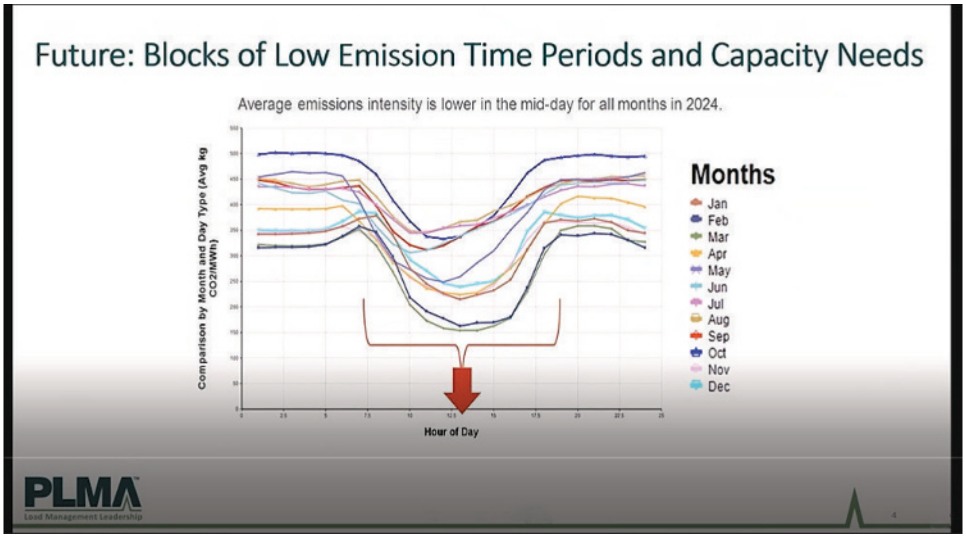


FIGURE 2.

shows example of an average *Cool Rewards* program; our smart thermostat residential program. Whenever there's a demand response event, we typically pre-cool homes for three hours before the event. That's because we're in Arizona and have an extreme climate! What we find is that we're able to shift energy for customers but also help them maintain their comfort during extreme afternoon temperatures while reducing APS' peak. In addition, with this approach, we are able to reduce our net carbon impact by about a third of a kilogram of carbon dioxide per customer, per event. With 20,000 to 30,000 thermostats per event, this is a significant carbon reduction.

We've had some controversy in the state of Arizona around the need to realign our DSM portfolio for new resource needs. To address this, we worked with our stakeholders to refile our DSM Plan, which had not been approved for three years—this is the same DSM Plan we filed in 2018, 2019, and at the beginning of 2020. We recognized we had a real emergency on our hands and the opportunity to provide some unique support to customers through DSM. This helped to connect the dots for our portfolio. We really focused on increasing support for limited income customers, but also for the tribal communities that were particularly affected by COVID-19. We believe that in Arizona, when your HVAC fails in the summer, it is an emergency; especially in the 2020 climate and economy. From APS' program perspective, one of the most important things we could do was adapt to help customers facing true emergencies as a result of COVID-19.

For our nonprofit and small business customers, we believed that doing HVAC tune-ups and energy audits would help delay the need for emergency HVAC replacements. We took a lot of action to provide new emergency support for customers.

The new aggregated DERs and demand response efforts have been in our filings for the last three to four years. These DER and DR efforts let us work with stakeholders to present a plan that made sense for everyone; the utility, its stakeholders, and our customers. It included several newly expanded virtual tools and services: an online marketplace, a new *Home Energy Reports* program, and virtual energy checkups, all of which help customers right now. We filed our DSM Plan in May 2020, and it helped us overcome a big block we'd had around energy policy issues in Arizona.

As some of you know, APS also had goals for our summer 2020 demand response program. The biggest goal was to expand our demand response program to an operational scale, and to reaffirm its reliability even if it became necessary to tap it for several consecutive days. This is something we've been very reluctant to do so far. However, the summer of 2020 turned out to be unprecedented with record-breaking temperatures across the entire region, regional fires, and COVID-19, all of which created some unique challenges!

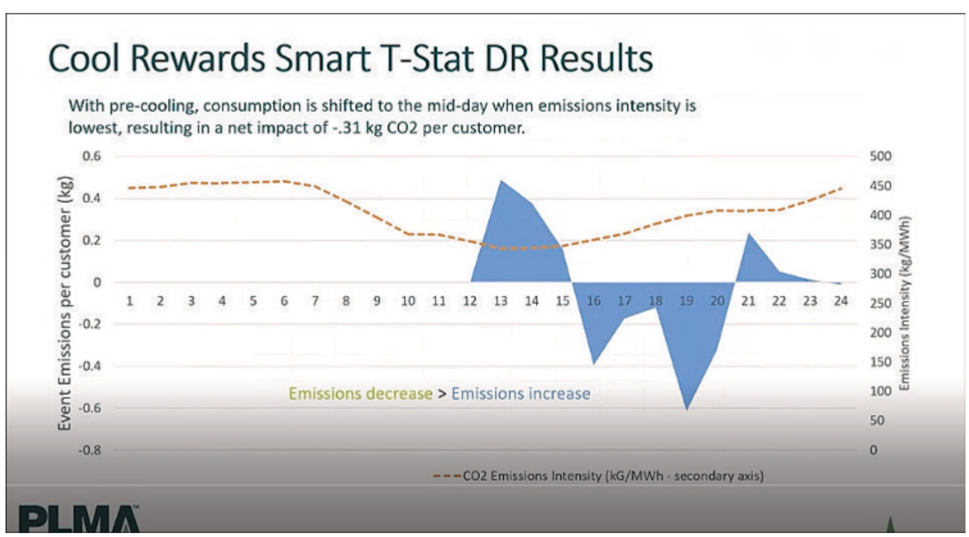


FIGURE 3.

In this literal "trial by fire," our grid resources were stretched to the limit. Our last peak was in 2017, and we destroyed it this summer by ~300 megawatts. At the same time, we also saw wholesale market prices spiking to as much as $1,500 per megawatt hour. States across the Southwest experienced emergencies and rolling blackouts. We were lucky to avoid rolling blackouts in Arizona thanks to our demand response resources. Looking back, APS and our regulators realized we had run a successful DR test in circumstances that exceeded our wildest expectations, and we were able to prove the value of demand response.

In summary, we began 2020 announcing our ambitious 100 percent carbon-free energy target for 2050 and added goals to our *Rewards* programs. We still believe DSM includes a number of valuable tools that will help us achieve these. This summer's crisis helped us partner in a unique new way with stakeholders to finally achieve a DSM Plan approval from our regulators in October 2020, and that's helping us to accelerate the development of all distributed energy resources and technologies. At the same time, it showed us the value of increasing our focus on energy affordability across a lot of different stakeholders, plus the positive effects of targeted outreach to limited income customers, a hard-to-reach and vulnerable group. APS recognizes we won't achieve our goals unless we reach all of our customers. We also instituted a lot more virtual products and services.

In a world where we're trying to do more to clean up our planet, there are synergies among initiatives including virtual energy audits, and even virtual evaluation and verification of installations. These help to reduce carbon and add customer convenience. Finally, the unpredictability of 2020, which strangely enough helped us to prove the value of APS' DR programs, plus the stakeholder support we received, amounted to a huge shot in the arm for APS as we continue to scale our DR programs.

Kenneth Weiland: Ameren Missouri's Demand Response program is now in its second year. Our program events are called either a) from our system operator, or b) if we reach 99 percent of our peak load through the season, which is May through September. To date, none of these triggers has happened although we've had four test events; two in 2019 and two in 2020. In addition, our goal doubled from 2019 to 2020, and we went from 53 participants to over 280, which has increased our data and our base of customer experience.

In late March, early April of 2020, we knew that working with our existing customers would be key. We also thought that schools would be re-opened and the stay-at-home orders would only be measured in weeks instead of months. In addition, we considered offering early payments to our customers to entice them to participate in the program.

Laura Small: As we've all realized, shelter-in-place policies to control the spread of COVID-19 disrupted business operations, but they also offered a unique research opportunity. We wanted to look at Ameren Missouri's business DR program and examine how this year's volatile business operating conditions impacted customer base loads, DR event performance, and baseline calculations. We also wanted to see if this research could provide any guidance to DR program administrators on how their programs may have changed in 2020.

Looking at Figure 4 for baseload differences, we can see the average hourly load for the same customers in 2019 and 2020 during the month of August, excluding any event days and presented by the day of the week. The blue line, which represents 2020, is below the 2019 line for many of the hours in most days of the week. However, this graph smooths out variability between 2019 and 2020 since it shows average hourly loads for weekdays and weekends for the entire month. The differences between 2019 and 2020 can be greater when you compare individual days.

Comparing event performance between 2019 and 2020, the two graphs in Figure 5 show average event performance for the same accounts in the two August audit events in 2019 and in 2020. In these graphs, the purple line is the baseline. The baseline is calculated using weekdays before the event and is what we think demand would have been on the event day if the DR events were not called. In other words, they're the

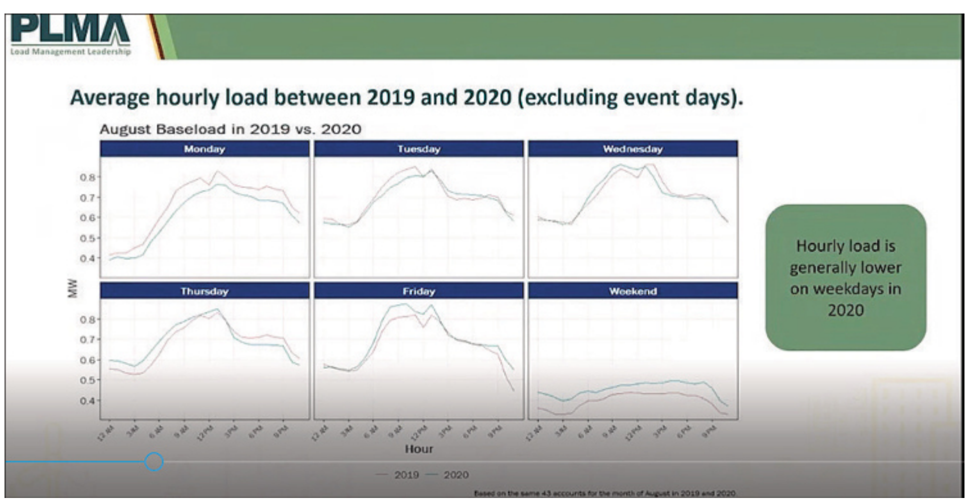


FIGURE 4.

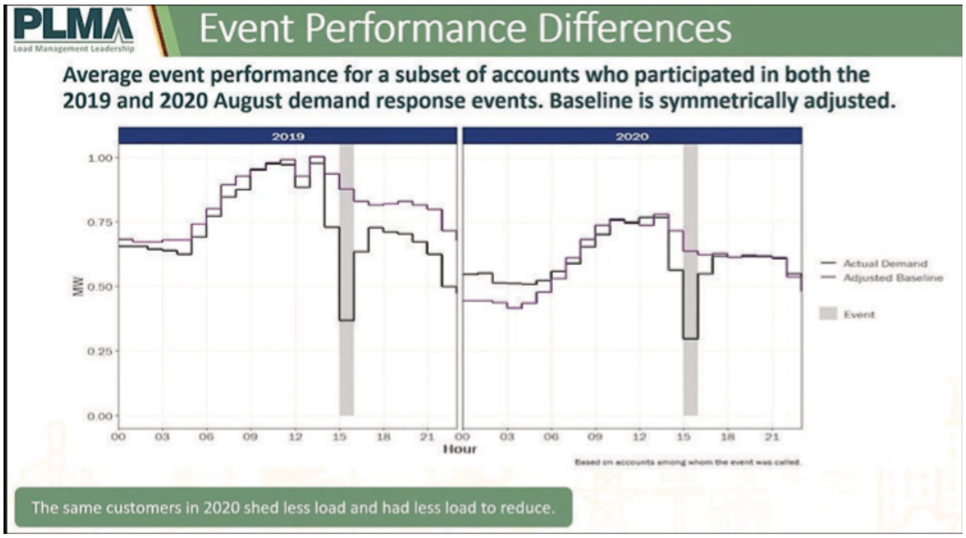


FIGURE 5.

counterfactual. The black line is the actual demand on the event day and the gray box is the event hour. Event performance, or how much each customer reduces demand during the event, is the difference between the purple and the black line in the gray box.

You can see that 2020 has a lower baseline than 2019 and consequently, lower event performance, even though average demand during the event hour, if you look at those black lines, was similar between 2019 and 2020. Even as these customers did their part to reduce demand, because their demand was already lower, judged by the baseline, it caused them to have less event performance. Please note Figure 5 does not indicate total event performance for this program; it only represents average performance for a subset of customers who participated in both 2019 and 2020.

Let's also consider the differences in baseline predictive accuracy, or the ability of a baseline to predict actual demand, between 2019 and 2020. We do this by comparing a baseline estimate of demand to actual demand on a proxy event day. We express the baseline predictive accuracy as the baseline divided by actual demand. So if the baseline perfectly predicts demand, baseline accuracy is 100 percent.

In this analysis, shown in Figure 6, we compared three types of baselines, a 4/5, a 10/10, and a 5/10, all with the symmetric adjustments. A 4/5 baseline, for example, represents the four days with the highest demand during the event hour out of the five most recent non-weekend, non-holiday, non-event days prior to the event. A 10/10 baseline would be all of the most recent 10 days using the same logic, and a 5/10 baseline is the highest five of the most recent 10 days.

The graph is Figure 6 shows 2019 baseline accuracy on the X axis, with 2020 on the Y axis. Ideally, you want all results to be clustered at the point where 100 percent on the Y and X axes meet, which would mean that the baseline perfectly predicted demand in 2019 and 2020. Observations above or below 100 percent, in either axis, are over or under prediction. There are more over-predictions in 2020 than in 2019 if you look at the number of observations over 200 percent in the Y axis. Interestingly, most of the points over 200 percent on the Y axis represent manufacturing customers. There's also one customer in 2019 that the 10/10 baseline drastically under-estimated as you can see way off to the left on the X axis. This is a mining customer.

Overall, the 10/10 baseline had the least variance in predicting demand between 2019 and 2020, and did a better job of predicting demand in 2020. It's important to note this analysis only included a small customer sample so these results may not hold true for all programs.

We found that baselines were a little bit less reliable in 2020, regardless of baseline methodology. Event performance for the same customers was also

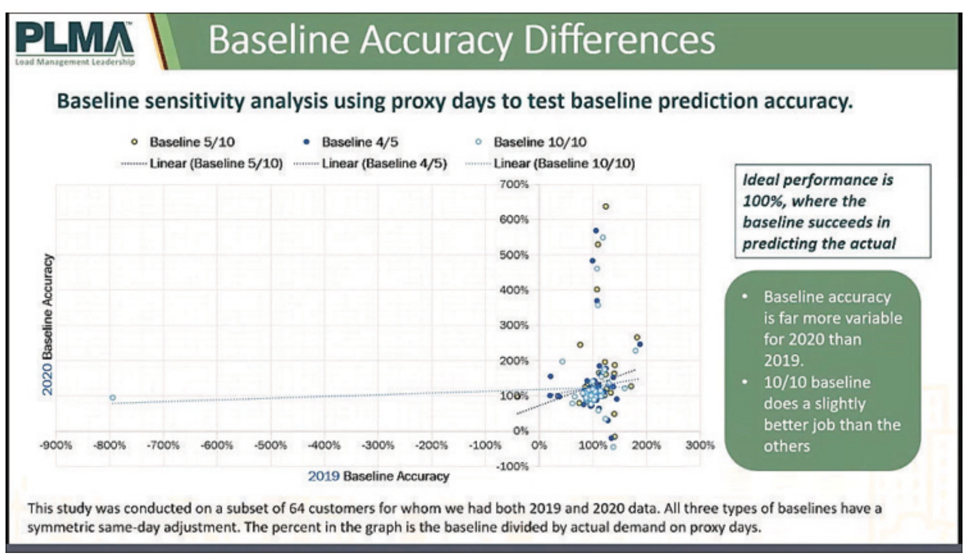


FIGURE 6.

diminished in 2020. However, some baselines performed better before COVID-19 policies, such as the 4/5 baseline, and some performed better during COVID-19 policies such as the 10/10. In addition, we found that results differed by sector. Big box retail had reliable event performance and consistent load, regardless of COVID-19, whereas manufacturing load was less predictable. Please note again, our sample size was small and may not prove true for all programs.

Weiland: One aspect of COVID-19 we didn't anticipate was 11 megawatts of expected performance that had been signed up for in DR contracts turned out to be unwilling to participate in curtailment. We work with every customer to verify the accuracy of their contact information, the name of the person responsible for curtailment, and that this person would be onsite to perform curtailment, when required.

We also uncapped the contractual performance at the top end so customers could bring as much capacity as they possibly could. Larger customers with over one megawatt performed consistently. Our other interesting data point was the schools, which we thought would perform well. One school group performed 50 percent over their previous year's results, while another performed at 50 percent of their previous results.

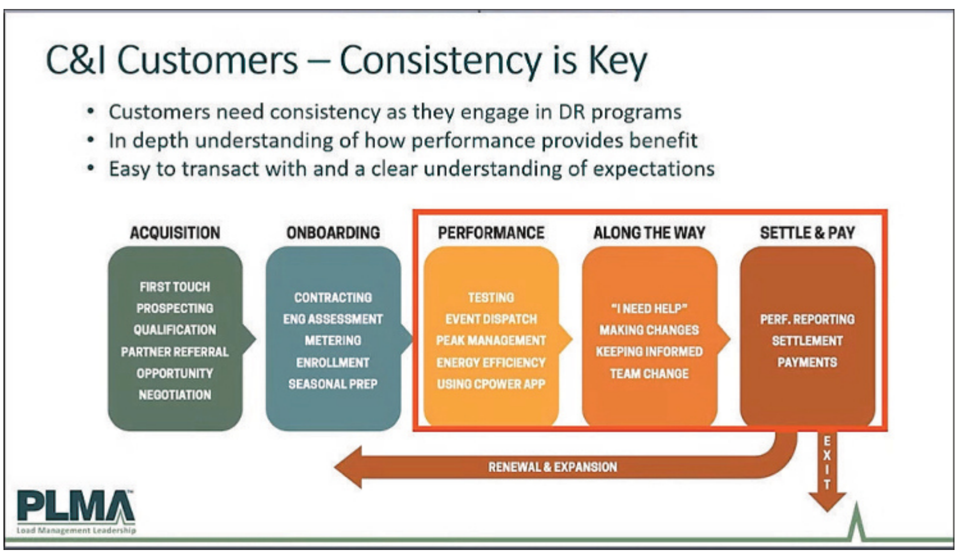


FIGURE 7.

To mitigate 2020, we also opened up the program and sold over 65 megawatts of performance just to get a little bit over 30 megawatts of goal that we needed.

Peter Bergeron: It's encouraging to hear the APS team is looking for opportunities to push its DR agenda by leveraging some of the COVID-19 impacts! It's also commendable that Kenneth and the Ameren team, and Laura in support, have started to think about how to meaningfully quantify what we're seeing happen among our customers. Clearly, there are impacts at the grid level, at the program level, and in program design. On the other hand, most customers are not thinking about demand response but about the interruptions to their lives and businesses.

As we navigate a post-COVID-19 world, we'll need to think comprehensively about the strategies needed to engage C&I DR customers. At CPower, we've identified a few things that customers consistently need. First on that list is an in-depth understanding of how their energy performance provides them with a tangible benefit. Second, the entire energy transaction needs to be easy even though it's difficult to explain DR to all customers in just four or five minutes. In Laura's example, even customers within the same segment can be handled a bit differently and have different resulting impacts.

Once customers are signed up for a DR program, we really focus on their energy performance, what happens along the way, and the final settlement. This is important because at the conclusion of each season, if a customer hasn't received a level of consistency in the interaction, or they don't have an understanding of how their actions resulted in an equitable benefit, they exit the program saying, "Geez, this really isn't worth it." On the other hand, when we consistently meet customers needs, and they clearly understand the benefit of a program, they renew and sometimes even expand their participation.

We see customers fitting into four groups, as shown in Figure 7. We've got customers that have increased demand, and with that, increased curtailment capability. In the case of the distribution and warehouse vertical, their loads are up and they actually have an increased curtailment capability at the moment. I think there are other industries with increased demand moving to the second segment, but they have lower than normal curtailment capability. Healthcare should probably be at the top of that list. They have been limited because they've been so stressed supporting the current COVID-19 situation which means their ability to curtail has been drastically reduced. Not all vertical segments are the same.

Manufacturing has increased demand but with both increased, and potentially lower, curtailment. Not all segments have been treated the same; for the neutral demand, neutral curtailment section, a few customers have no impact. The good news is distributed generation, whether that's typical assets or perhaps storage or more sophisticated assets, has not been impacted that much.

There are many customers that fall in the category on the far right of Figure 7. They have some decrease in their demand which is driving a lower level of curtailment capability. As Laura so eloquently stated, a customer took the same set of actions but based on lower demand, they're reaping a lesser benefit for the same participation. And that's really what, as a group and as a community of utilities and demand response providers, we need to be aware of: that we're setting the right expectations for our customers. And while all customers are a bit different, every single one has some impact.

If we focus on the customers who are most likely to be dissatisfied, it is the category on the far right of Figure 7 where there's a reduction in demand. This likely means that customer has a greater sensitivity to achieving their program cost savings while at the same time, they are competing against the trend toward lower curtailment capability. Stated another way, for completing the same actions, these customers with current financial sensitivities are going to see a lesser benefit from these programs. So it's incumbent upon us to get out in front of them to help reset expectations, and maybe more importantly, to think about what strategies we can leverage as a community to make sure these customers remain engaged and don't exit the program.

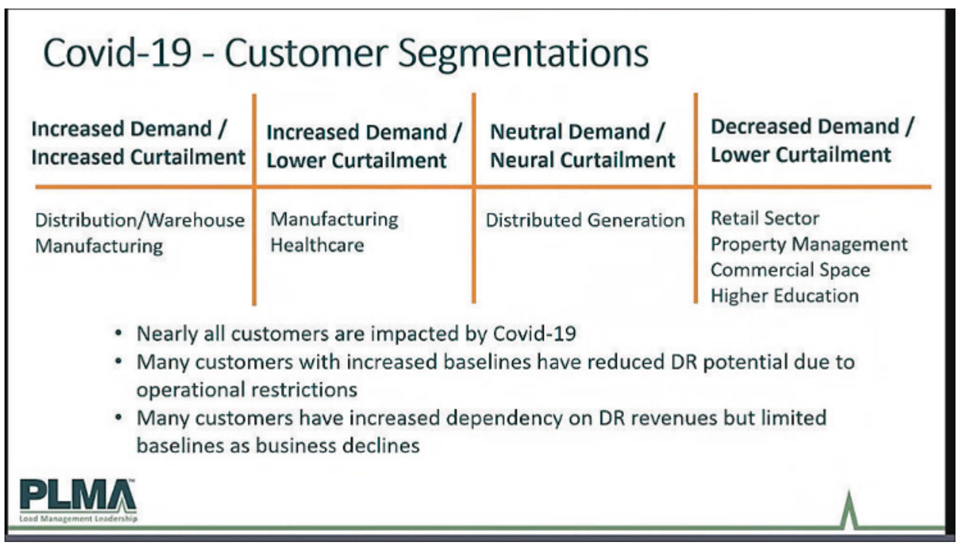


FIGURE 7B.

With that in mind CPower has a handful of items that many of you are likely already acting on, but it never hurts to talk about customer experience and share best practices. The first is curtailment plans and the engineering analysis or assessments that happen at facilities. We've dedicated a lot of time to making sure our customers receive comprehensive reviews. This includes documenting the strategies our customers plan to use to participate in DR programs, plus all the strategies that are potentially available to them.

A great example is higher education. Many U.S. colleges and universities have been forced to close. With little to no occupancy on campus, their ability to shed or curtail load where it's not supported through generation has been greatly reduced. However, by taking a more comprehensive view of curtailment planning and really looking at all available strategies, we've been able to partner with this customer segment to bring on loads that were previously precluded from participation. A perfect example is in labs. Many universities and colleges have them and labs often contain highly sensitive equipment that renders them off limits for energy curtailment. However, with no one on campus and those labs not operating as normal, we were able to activate an additional curtailment strategy. This helped those facing financial hardship to participate meaningfully, and at near pre-COVID levels in this COVID world.

Laura mentioned the retail sector. With stores closing down, we went back to the drawing board to reassess how we could interact with this sector to ensure there was still some benefit in curtailable load achieved. In a post-COVID-19 world, performance management will be important as we engage with customers. Often, customers are not focused on DR in their day-to-day operations, instead, DR is more of an interruption. Helping them to identify problems and opportunities is important. Across our community of providers, I encourage folks to think about all of their available avenues to offering customers meaningful energy performance feedback on a timely basis.

There are plenty of programs in which a seasonal review used to be accurate. But now, it's clear we'll need to engage with customers much sooner to provide performance coaching that correctly sets expectations and enables discussions about what adjustments might be needed so they are willing to remain involved in our DR programs.

The third item is portfolio balancing. As a result of the very diverse impacts experienced across different vertical segments, we found an opportunity to reallocate some of the low commitment within our portfolios. We may reduce the retail sector as many stores are currently closed and we'll shift their commitment to distribution or warehouse facilities that now have increased capability. As much as possible, we have to consider the program design and setup aspects of our own operational processes, and our ability to potentially shift load between two customers thereby preserving what we believe is a positive experience.

Finally we have automated load control to consider, which I think helps me sleep a little bit better at night! Are the solutions we're deploying to customers flexible enough? We all need to think about the customer experience we're offering and to question old strategies. At the end of the day, we may need to reevaluate how we're operating to ensure that customers have a great experience while also performing well in our programs.

To recap, in the years ahead we'll be evaluating 2020 against more "normal" years. From a program design perspective, we need to think about increasing flexibility for customers. Utilities and program managers will need to consider how to design flexible programs that benefit customers. Are the marketing and customer acquisition strategies that we used two and three years ago, and even early in 2020, still applicable? Will they still resonate with customers? Are customers getting a consistent experience? Do they understand their program benefits? Do they see the connection between their participation and these benefits?

> "At the end of the day, we may need to reevaluate how we're operating to ensure that customers have a great experience while also performing well in our programs."
>
> *– Peter Bergeron, CPower*

If we set up the operational expertise internally, and portfolio balancing is a great example, the hope is even in a post-COVID world we'll be able to demonstrated strong energy performance via a suite of comprehensive solutions.

Roehm: As we look at COVID and wonder what's going to happen next, do you have a timeline for how long you'll keep your special COVID-related program elements in place? Do you think some of those changes might be permanent?

Hines: That's a really interesting question, one we're asking ourselves a lot right now. APS' DSM Plan, filed in May 2020, assumed our COVID incentives would run through the end of 2020. In our approval, we requested they continue until further action in the PSC. Our concern was as we missed this summer, how do we enable retroactive customers to apply for rebates? Looking ahead to spring 2021, we already know we've got some big challenges coming if equipment like HVAC fails in our hot desert climate. So we've focused on making sure we keep the incentives in place, at least through next summer. Then we'll take another look.

We do believe virtual energy checkups and other virtual services are here to stay. APS believes these are better ways to serve customers more cost effectively.

Feldman: How do the different types of baselines affect different customers?

Small: We've found that in 2020, for manufacturing customers, the baselines had more trouble predicting their demand accurately. In 2019, the 10/10 baseline was far off for one particular mining customer. For most other types of customers, while different baselines do have varying predictive accuracy, the discrepancies are insufficient to make conclusions.

Bergeron: In a post COVID-world, baselines will continue to be a struggle. We've seen increased variability in customer loads that previously didn't exist. At this point, we've got a suite of over 120 baselines, and with the exception of regression analysis and some heavy statistics, I question whether we'll see any of those baselines increase in accuracy. It seems there will be a negative trend as it relates to baseline accuracy and we'll need to work hard to correct it. Regulators will continue to be sensitive to this issue so we'll need to demonstrate why various baselines are an acceptable means to determine performance.

If you think about programs in which there's not a baseline but customers agree to reduce their energy use below a certain point, some customers got a bit of a free ride this year due to their facilities being partially or fully closed. Beyond baselines, going back to program design and structure, there will be additional variability that we'll need to think through with all stakeholders. Overall, our historically "tried-and-true" methods may be in need of reevaluation.

Roehm: Customer goodwill is really the demand response resource. Do you have any anecdotes or insights about ways customers viewed demand response during the 2020 COVID-19 summer? How did they respond?

Hines: A if 2020 wasn't challenging enough, Arizona experienced our 144th day of the year when the temperature was over 100 degrees. Now in November, temperatures are still in the hundreds. In Phoenix, we've had 55 days this year over 110 degrees! This year broke every record for the hottest summer in Arizona's history. As everyone sheltered in place for most of the summer, we had significant concerns. As we have a lot of residential demand response with smart thermostats, we worried there would be some customer fatigue which did actually happen the week of August 15th when the whole region experienced extreme weather conditions. We called four events that week–the most we've ever called in a single week.

With people home the entire time, we saw opt-out override rates go up a little bit. However, we also maintained fairly consistent per-thermostat impacts throughout those four events. This experience helped us solidify demand response as a resource we counted on, even in extreme circumstances. As DR is voluntary, we consider the customer participation and results to be a success story for the summer of 2020.

Bergeron: I agree, customers really do want to do the right thing. In California this year, we've seen several unprecedented scenarios, including on the supply side, in the weather, and also with this year's fire season. There have been public calls for demand response, as well as some supply shut offs, blackouts, and brownouts. Still, most customers are trying to figure out how they can be part of the solution. Even with many DR events happening, we saw some large and significant customers double down on their efforts to bring as much curtailment as they could to help out the whole community. This difficult year has cemented the fact that demand response is a valuable resource that customers are willing to work with, for the benefit of all.

Feldman: When considering C&I impacts, what's going to happen with those load shapes going forward and how do you expect to redesign those programs? You mentioned the possibility of paying customers early in the season to participate and commit, somewhat like a PPP loan for demand response. What was the response? Will we have to change incentive structures going forward to address this need?

Weiland: We found C&I customers were willing DR participants so we didn't end up needing that kind of mitigation strategy. Still, it will be interesting to see what the "true up" will look like, since most customers underperformed from the baseline.

Hines: On the residential side, APS launched its online customer marketplace in October. Just this week, we turned on demand response pre-enrollment with Google Nest thermostats. We're planning massive promotions to customers who are at home and shopping online, especially over the holiday season. You may have seen Google Nest just released a new, lower priced thermostat. Normally we'd pay a DR rebate next summer, but instead, we're going to move those forward by pre-enrolling those thermostats and offer a pancaked rebate with our EE rebate; we'll offer a $105 incentive on $129 thermostat.

Roehm: Do you currently calculate the impacts and benefits of APS' TOU rates on emissions today? Is there potential to use a smart device to further optimize energy use with the rates?

Hines: We do, although right now, most of the TOU impact on emissions would be actually captured within the load forecast. Within our DSM planning model, we include incremental savings that we believe are available when we combined rate with good education and with the right enabling tools. For example, our last DSM Plan included rate-enabled smart thermostats, connected pool pumps, and connected water heater controls that we believe could all be optimized around those TOU rates to provide ongoing bill savings, ongoing carbon savings, and ongoing peak reductions.

Feldman: Tracy Schmidt from TVA asks for your low income customers, have you had issues with offering virtual audits? Have these customers had the access they need to smartphones and tablets?

Hines: APS' research indicates that most of our limited income customers have access to a smartphone somewhere within the household and only need a phone for the audit. However, we also offered the option to handle some of the virtual audit questions using regular phone service. The same team that's doing the virtual energy checkups has spent the last year working with our Community Action Agencies (CAA) statewide. They are conveying a lot of the same information in a train-the-trainer format to the CAAs' outreach staff. No one approach works for everybody but the virtual energy checkup has works across a broad swath of our residential customers.

Roehm: Looking at APS' 2050 carbon-free goal, will President-elect Biden's 2045 goal help you achieve that?

Hines: While APS is not yet sure how we're going to get to our 2050 goal, it's a positive step forward that we've been able to make a voluntary commitment that aligns us with Arizona's clean energy goals, and possibly federal energy goals too.

Roehm: There'll be a lot of presidents between now and 2050, and I expect we'll have many opportunities for course correction one way or another as we move toward these ambitious goals!

Feldman: Peter, Craig Sherman asks do you assign a baseline to each customer or use the same baseline for a whole customer segment?

Bergeron: The task of operating across 60+ DR programs throughout the U.S. requires a variety of baselines and that's part of the challenge CPower works to overcome. Some programs limit customers to a single baseline, some programs offer a suite of baselines. It's really a combination of the two. Our goal is to work effectively within a program framework, and we have experience to date with 100+ baselines from both the software and customer implementation perspective.

Roehm: Will ongoing *Rewards* program incentives continue to recruit customers who have good DR awareness following this summer? Or is a larger one-time upfront incentive likely to be more successful?

Hines: APS is looking at different approaches and we'd like to try both to see how each resonates with customers. Having the "carrot" of ongoing incentives gives us an opportunity to keep customers engaged and continuing to keep their devices online. It's definitely a balance as we think about incentive design.

Feldman: Laura talked about the different baselines and I'm curious why you think the 10/10 baseline worked better?

Small: We've experienced more variability in demand in 2020 than we did in 2019 and particularly more days with low usage than in 2019. We think the 10/10 baseline performed better in 2020 because it doesn't drop days with lower demand and therefore it may better capture demand volatility. The other baselines do drop days with lower demand and it seems those lower demand days are important in accurately estimating actual demand.

Roehm: Mark Martinez asks if demand response integrates more renewables with load up?

Hines: We've asked this ourselves a lot! One aspect of our DSM Plan that was approved was "reversed demand response," the ability to dispatch loads, particularly in the middle of the day for us in Arizona, when we appreciate having access to California's renewables, usually in the form of negatively priced energy. We take full advantage of this on behalf of our customers and it helps balance the Western grid too. Essentially, we are using demand response in a different way. You can also see this in the way we do pre-cooling and other more traditional peak-reducing demand response.

> "Reverse demand response is a new opportunity in which we'll work with customers to sub-meter individual dispatchable loads to take advantage of those renewables. This will make it possible to integrate more renewables on the whole western grid."
>
> *– Tom Hines, Tierra Resources*

We try to move energy prior to the peak. Our 3:00 pm peak time is important because we move that energy to right before the peak, right into the peak solar production curve. Reverse demand response is a new opportunity in which we'll work with customers to sub-meter individual dispatchable loads to take advantage of those renewables. This will make it possible to integrate more renewables on the whole western grid.

Feldman: Nice, and you can take advantage of California, right?

Bergeron: A little negative pricing to drive some new behavior.

Feldman: Does CPower have any early data on overall increases or decreases in participation at the system level?

Bergeron: We're fortunate that performance at the macro level was actually pretty close to flat. We're still tabulating final results and completing the M&V process but it won't be more than a couple of percentage points in either direction. Individual sectors and individual customers did see pretty big swings one way or another. At the same time, programs saw ups and downs based on their composition. Net-net across all of the programs we support, those differences offset one another. We're all waiting pretty anxiously to see what the new normal will be for 2021. I think we're all holding our breath on what's coming through the winter and into next spring and summer.

Feldman: How did weather play into this COVID analysis?

Small: Opinion Dynamics tested accounts in the analysis to see if their demand was weather-sensitive and we found they were not. As a result, we didn't take weather into account when selecting proxy days. However, we did ensure that we compared the same days of the week between 2019 and 2020, and we restricted our analysis to August data.

Weiland: Ameren's events were on mild days for Missouri. We're hoping that there'll be some heat late in the summer so we can really understand how our customers are able to perform.

Feldman: Dana DeRemigis asks if ecobee is in APS' marketplace and thermostat program?

Hines: Yes, we offer all thermostat brands and we use EnergyHub as our DER aggregator so we promote all of the brands available on that platform. Google Nest was the first device that we completed pre-enrollment with, and we are now underway doing pre-enrollment with ecobee. We've also got pre-enrollment online for Honeywell and Emerson in early 2021.

Feldman: Are there any specific program design elements that have helped customers adapt to changes due to COVID-19?

Bergeron: Of the program design elements, very few, if any, will change. Unfortunately, the supporting regulatory processes take time. What we did see however, was a shift in how customers are curtailing load. Maybe worded another way, the individual curtailment strategies customers are leveraging to achieve success definitely changed.

Feldman: How are the utilities and the vendors planning for next year, given the changes we expect, including a COVID-19 vaccine, a possible return to schools and places of work, more hybrid models of learning and working, and so on. How might this play out?

Hines: APS has to file a 2021 DSM Plan in about 45 days and there are a number of things we believe will continue into the distant future including virtual energy checkups that now make good sense. There are a number of rebates that we increased, some by a factor of five from the normal rebate level. And so we've been ordered by the PSC to address how we'll step those down over time. The preliminary thinking is we should be keeping them in place through our very extreme summer season, then (hopefully!) elegantly scale them down afterward.

Weiland: Ameren's programs were set in place for 2021, so for DR, it's business as usual.

Bergeron: Customers find consistency to be very valuable. They also value an in-depth understanding of how their actions ultimately benefit their bottom line. But we have no conclusions yet. We'll need to stay up-to-date with current events and plan to operate programs dynamically, coming up with new and innovative solutions as additional problems arise. Customers seem to have an increased sensitivity to these programs relative to some other financial impacts that may be adding pressure to their budgets.

Roehm: Thank you so much to the panel and to my co-chair, Brett Feldman.

About the Peak Load Management Alliance

PLMA (Peak Load Management Alliance), a 501(c)(6) nonprofit organization, was founded in 1999 as the voice load management practitioners. Today PLMA has over 160 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 their expertise in dynamic load management, demand response, and distributed energy resources. Member practitioners take pride in sharing their knowledge, experience, 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, technologies, and much more.

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