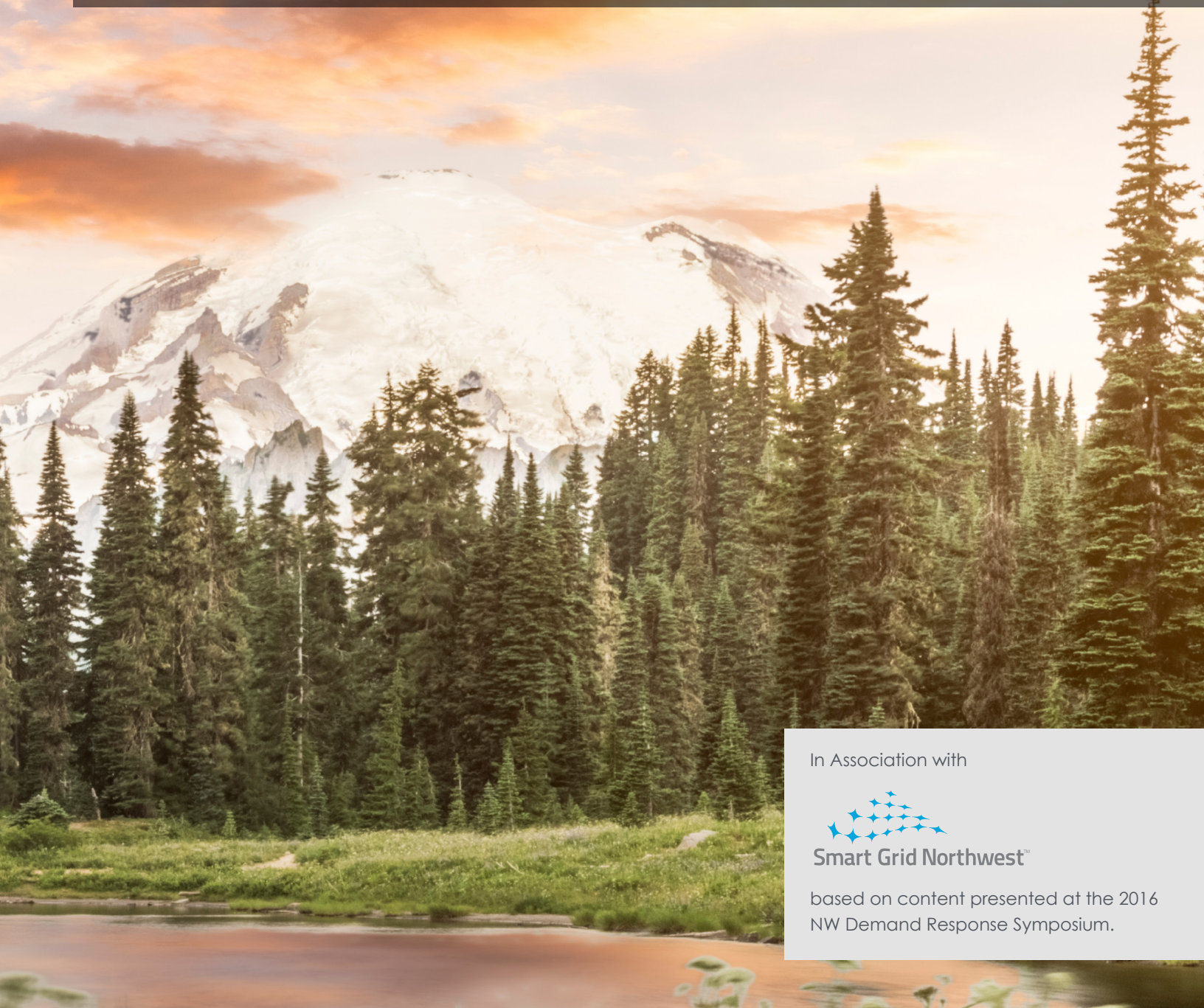
CADMUS

DEMAND RESPONSE IN THE NORTHWEST

A Summary of the Regional Cooperation Event Presenting The Northwest Power and Conservation Council's Seventh Power Plan Demand Response Objectives and Industry Best Practices for Demand Response Resource Acquisition

SEATTLE WASHINGTON



In Association with

Smart Grid Northwest™

based on content presented at the 2016 NW Demand Response Symposium.

DEMAND RESPONSE:

Demand response refers to the capability of technologies to target and reduce electricity use during timeframes when grid demand is highest. These targeted peak reductions can reduce the strain placed on the electrical grid and decrease the need for high-cost generation peaking resources, allowing utilities to optimize generator operations. Consumers participating in demand response activities are generally compensated for the service in the form of incentives or good will. When a utility issues a call for demand response, consumers do not necessarily have to take an action themselves; the utility can simply send a signal to smart-capable equipment or appliances that take action based on preprogrammed consumer preferences.

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Smart Grid Northwest™

Smart Grid Northwest is a trade association with a mission to promote, grow, and enable the smart grid industry and infrastructure in the Pacific Northwest. The association nurtures an environment that encourages smart grid industries to thrive and promotes the deployment of smart grid solutions across the Northwest. It does this through educational events and publications, advocacy for regional public policies, and programs that drive implementation of smart grid concepts and technologies. The organization has a diverse member base of 70+ organizations including regional utilities, energy and technology leaders, growth companies, national labs, universities, and others. Learn more at www.smartgridnw.org.

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INTRODUCTION

Six-hundred million watts of demand response proves cost-effective in the Seventh Power Plan, according to John Ollis, a power systems analyst and member of the Northwest Power and Conservation Council (Council). To put this in perspective, six-hundred million watts equals 10 kilowatts from each of the 60,000 participants in the Pacific Northwest Smart Grid Demonstration Project (PNWSGD). Ten kilowatts approximately equals the draw of a large home or a substantial part of a commercial load.

This raises the question: is the answer to the Seventh Power Plan simply returning to the demonstration project participants and requesting them to drop from the system at peak times? Perhaps. But solutions for demand response—as we know—are far more complex and require much more planning, not to mention that such a load drop may be much more than demonstration participants are willing to give. The Pacific Northwest Demand Response Symposium—held on September 28, 2016, at the Pacific Tower in Seattle, Washington—was the first of its kind. Among other demand response topics, it explored the requirements for developing demand response resources in the Northwest.

Comments received from the participants included the following:

- "Well worth the trip from the East Coast!"
- "This is just the beginning of something big!"
- "Interested to see how demand response will integrate with infrastructure, sustainability, transportation, and electrification."
- "Model for success in establishing relationships."
- "Public-private partnership with value proposition and outcome/results for all interested parties."

Enthusiasm for the demand response topic became widely evident throughout the symposium, as was a lack of understanding regarding the many issues on both the policy side and the operational side of administering demand response programs. The symposium greatly aided in reducing uncertainty on the subject, but this dialog clearly must continue.

Emerging symposium themes included the following:

- Demand response education is greatly needed to provide visibility of benefits, to gain customer acceptance, and to justify financial investment support.
- Leadership is needed, and there are drivers and evidence making a case for demand response. Utility program designs should fully exploit the nexus between energy efficiency and demand response.
- Successful customer engagement is the foundation of demand response.
- Millions of consumer devices all working together—the Internet of Things (IoT)—requires the glue of interoperability standards.

Speakers from a very diverse group of disciplines addressed these themes, but did not necessarily answer each one fully. Demand response clearly remains a work in progress in the Northwest, as it does throughout the country.

BACKGROUND ON DEMAND RESPONSE

Demand response education is greatly needed to provide visibility of benefits, to gain customer acceptance, and to justify financial investment support.

WHAT ARE THE REGIONAL DEMAND RESPONSE NEEDS?

The Council's outlook on demand response offers an important start in educating parties interested in demand response: specifically, how the Council determines the amount of demand response required in the region to satisfy load capacity growth. John Ollis walked the audience through this process.

Basically, determining capacity products has been difficult as past Council regional portfolio expansion modeling did not explicitly consider capacity needs. This changed for

DEFINITIONS

Distributed Energy Resources: Energy supplies and power sources that tend to be smaller than the typical utility-scale sources and are usually positioned closer to demand centers, frequently co-located with customer sites and composed of the following:

Distributed Generation: Power generation at or near the point of consumption. Generating power on site (rather than centrally) eliminates the cost, complexity, interdependencies, and inefficiencies associated with transmission and distribution. Typical examples include rooftop and ground-mount solar, combined heat and power plants (co-generation), small biogas, and wind.

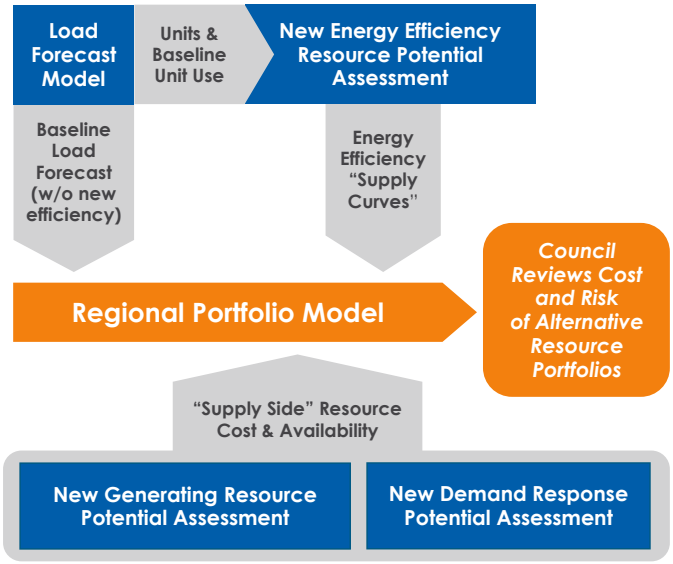
Demand Response: The capability of technologies to target and reduce electricity use within timeframes when grid demand becomes highest. These targeted peak reductions can reduce the strain placed on the electrical grid at key times and can decrease the need for high-cost generation peaking resources. Consumers participating in demand response activities generally receive compensation for the service. When a utility issues a call for demand response, consumers need not take action; the utility can simply send a signal to smart-capable appliances that take action based on preprogrammed consumer preferences.

Energy Storage: The capture of energy produced at one time for use at a later time. Devices that store energy are called accumulators or batteries. Energy enters storage devices in multiple forms (i.e., radiation, chemical, gravitational potential, electrical potential, electricity, elevated temperature, latent heat, kinetic energy). Energy storage involves converting energy from forms difficult to store into more conveniently or economically storable forms. Pumped hydro dominates bulk energy storage, accounting for 99% of global energy storage. However, new battery technologies are emerging for convenient electricity storage. Typical energy storage examples include lithium ion batteries, vanadium flow batteries, ice storage, and water heater storage.

the Seventh Power Plan, which now includes an explicit capacity model. Ollis explained that the current model can examine 800 scenarios with four demand response cost bins that include seasonal shapes.

The regional portfolio model (RPM), illustrated in Figure 1, estimates the system costs of regional resource strategies to address 800 future conditions (e.g., different loads, wind, gas prices, CO_2 prices). RPM targets a least-cost resource strategy, which includes a buildup of energy conservation, bulk generation, and demand response resources. Demand response can be considered a dispatchable resource, akin to generation, but it also compares to energy efficiency in that it does not produce power—it saves power by lowering output or shutting off devices at specific times. The RPM can show economic and least-cost demand response acquisition, but, more likely, dispatches demand response when peak capacity is insufficient to meet system peak demand. Inputs for this analysis include seasonality, cost, summer peaks (e.g., due to irrigation pumping and space cooling), winter peaks (e.g., due to space heating), and/or year-round peaking issues. Four cost bins include only firm demand response resources and delineate resource selection. Firm resources refer to resources that utilities can deliver reliably and model assumptions may include stiff penalties for non-delivery.

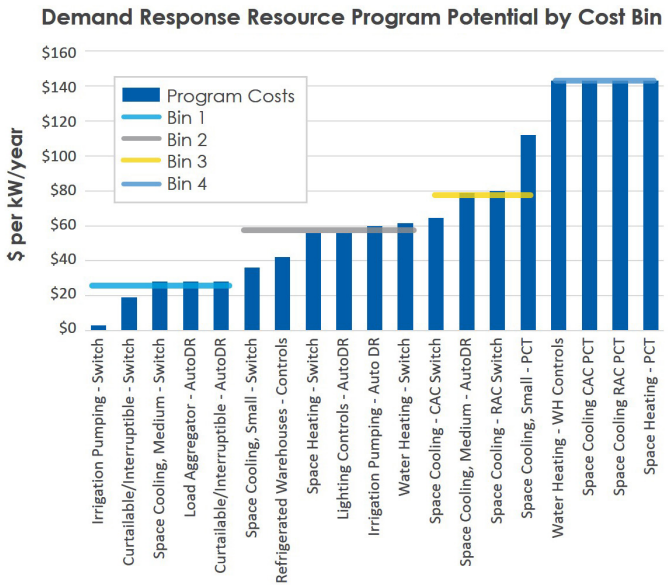
Figure 1. The regional portfolio model (RPM) process flow



The model also relies on a potential study developed by Navigant (shown in Figure 2), which ranks the costs of various measure types (with residential automated

demand response ranked as the most expensive). Large industrial demand response programs make up the least expensive demand response program block. Ollis pointed out that the RPM model does not determine demand response potential, but uses Navigant's potential study as an input. Ollis chose to cluster demand response programs into blocks. The RPM modeling assumed 10 MW blocks of demand response, which Ollis characterized as not necessarily realistic, in terms of how demand response is acquired, or sufficiently granular to show all the benefit of right-sizing the resource. Ollis also said that the Council used a public process to vet the study.

Figure 2. A potential study developed by Navigant aided in cost bin development



In the Council's analyses, resource adequacy served as an important guide. A regional loss of load probability in 2021 indicated that regional stakeholders should consider this more of an issue for winter than for summer. This appears to imply that utility program designers should focus efforts on demand response in winter. Most demand response efforts around the country tend to focus on cooling in summer, making the program design challenges much less prescriptive and more customized for Northwest demand response efforts in winter.

Ollis pointed out that, over all 800 scenarios observed in each of the different model runs, 600 MW of demand response was cost-effective in all but the no-demand response and increased market availability sensitivities. Results also showed that over 1,300 MW—the expected value (i.e., what Ollis calls a robust response)—was cost-effective in almost all of the sensitivities. He summarized the modeling results, showing demand response as a worthy resource to explore for the Northwest.

The RPM demand response model offers a key benefit in deferral of new transmission; however, the model offers an important distinction in that the analysis does not include deferral of new distribution system equipment. As a result, the estimated capacity benefits of demand response in the model is a conservative estimate.

For utility program planners, the Council's modeling shows sufficient value to pursue a minimum of 600 MW of demand response. The total range is actually much larger, the RPM purchased from 600 MW to nearly 2,700 MW in most of the sensitivities. The expected value was over 1,300 MW, so utility planners should consider the benefits of the larger expected value target.

The Council's modeling only covers demand response generation and transmission benefits. As utilities evaluate their own positions regarding demand response development, they should consider distribution system benefits in addition to the Council's benefits. Many in the industry believe demand response's true value arises from distribution system benefits, such as substation and feeder equipment deferrals, as well as indirect benefits such as strengthening utilities' relationships with their customers.

Work must continue to evaluate demand response valuations across customer segments. The Council's reliance on the Navigant report should be evaluated in the context of winter peaking needs, which industrial loads may or may not be able to provide when most load studies point to residential loads as a key driver for winter peaking.

People interested in becoming active in the regional demand response planning dialogue can follow the Council's Demand Response Advisory Committee, whose first meeting is on December 1, 2016.

DEMAND RESPONSE POLICY AND LEADERSHIP

Leadership is needed, and there are drivers and evidence making a case for demand response. Utility program designs should fully exploit the nexus between energy efficiency and demand response.

At the symposium, leaders in government, utilities, and technology acknowledged the value of demand response resources, and that they likely will provide many solutions required for a low-carbon, efficient power grid. Much work lies ahead, however, in addressing the following:

- Establishing key value drivers
- Valuing these drivers properly
- Finding compelling incentives for power customers to establish their own "requirements of operations" for their homes, businesses, and facilities that support grid operations (and do not run counter to efficient grid operations)

Leaders and policymakers must continue the important work of taking engineering operating priorities for an environmentally healthy grid and making them into a highly desirable and motivating movement for change by developing an incentive structure that is carefully designed for the optimization and coordination of abundant distributed energy resources.

REGULATORS AND OTHER REGIONAL ENTITIES

Representatives from Washington, Oregon, and Idaho regulators offered their perspectives on demand response in the Northwest.

Washington Utilities and Transportation Commission

Phil Jones—the Commissioner of the Washington Utilities and Transportation Commission (WUTC)—expressed pleasure that the Seventh Power Plan included a need for demand response, energy storage, and mentioned the potential impacts of electric vehicle (EV) charging. He stated that the WUTC recently approved an EV charging tariff. The WUTC also recently approved a demand response request for proposal (RFP) from Puget Sound Energy (PSE) to investigate the obtainment of 121 MWs of demand response.

Jones mentioned other drivers for demand response such as the growing technology innovation occurring in relation to distributed energy resources and greater concerns about the power system's reliability. He considered the tension between technology and the regulatory paradigm as good and healthy. Customers are increasingly becoming engaged with the power system as they want greater control over their generation choices (e.g., Tesla's battery power growth and more devices supporting smart-home development).

Ultimately, Jones considers climate change as a key driver for demand response, with the U.S. Environmental Protection Agency (EPA) setting parameters around energy policy and potential carbon pricing. WUTC approaches these changes by introducing small policy changes (e.g., approving the PSE RFP and assisting with the growth of transportation electrification).

Oregon Public Utilities Commission

Jason Salmi Klotz—the Climate Change lead at the Oregon Public Utilities Commission (PUC)—offered the Oregon PUC's take on key drivers of demand response, as well as insights into the regulators' perspective on demand response in terms of resource planning, program delivery, and interoperability of products.

Klotz agrees with Jones (WUTC) that climate change serves as a primary driver for demand response in the Northwest. NEST—a leading vender of home automation technologies—revealed that 8,000 homes used 600 hours of air conditioning (AC) alongside 600 hours of heating, demonstrating an increased electricity demand that places stress on peak capacity. Klotz reminded the audience that "it is IRP (integrated resource planning) time at the PUC," offering a good opportunity to discuss coordination between energy efficiency and demand response programs. The Oregon PUC anticipates more robust discussions on market roles for utilities, the Northwest Energy Efficiency Alliance (NEEA), the Energy Trust of Oregon (ETO), and other stakeholders.

Moreover, Klotz cited good practices for utilities submitting program filings to regulators:

- Long-term strategy for demand response (due to a long-term investment life of 20 years)
- Resource and program characteristics
- Special conditions that programs must communicate to customers and contractors
- Program participation requirements
- Customer outreach and engagement as part of programs
- Coordination with non-utilities (not just contractors, but measurement and verification [M&V] plans and so on)
- Benefit/cost analysis (helped by coordination)

Although the regulators' main role is to approve programs and answer utilities' budget requests, Klotz urged utilities to engage with regulators on important issues related to demand response. For example, some Oregon PUC commissioners had yet to grasp the full meaning of interoperability; regulators also need education on demand response.

Idaho Public Utilities Commission

The Idaho PUC presented Idaho's demand response experience from a regulator's perspective. The PUC generally acts in a reactionary fashion and has one mission: keep rates low. In the realm of demand response, the PUC already has seen several mature programs within its jurisdiction, compared to some other jurisdictions in which utilities are still in the early stages of developing demand response programs. Starting in 2004 with 0.5 MW of residential AC cycling, Idaho Power—a summer-peaking utility—has deployed 370 MW of demand response (30 MW residential, 35 MW commercial, and 305 MW irrigation).

When planning for mature demand response programs, utilities must consider potential over-deployment of demand response and its valuation. In response to these concerns, the Idaho PUC established these guiding principles for mature programs:

- Use existing demand response resources when possible
- Include demand response offerings for all three customer classes
- Keep costs as low as possible and re-evaluate as IRP changes
- Provide consistency in dispatch requirements for all three programs
- Investigate load following, operating reserves, emergency reliability, and flexibility
- Take a long-term outlook to achieve viable, long-term demand response (programs must continue operating and evolving in the short term)

In summary, although Idaho Power decided not to expand its demand response, it has emphasized a long-term outlook value for the resource. Regardless, running short-term demand response programs is necessary to continue to build the solid participant base necessary when ramping up demand response for the long term (e.g., for irrigators).

Other Regional Entities

In addition to the regulators in the region, there are other important regional entities whose representatives shared their opinions on demand response at the symposium: the Northwest Power and Conservation Council, the Bonneville Power Administration (BPA), and the ETO.

In addition to sharing the estimate of the region's demand response needs, the Council was also represented by a Council member at the symposium. Tom Karier—the Washington Council Member of the Council—pointed out that EVs offer great potential in the Northwest, so great that not including EVs in a demand response metric would be an oversight. Although load growth in the Northwest has remained flat, EV growth could dominate increased electric loads in the near future. This also presents some significant demand response opportunities for EVs, such as dispatching and controlling their charging times. The issue at hand is behavioral—one does not know which behaviors are best for certain types of technology. However, with good policy regarding EV growth, industry participants may be able to direct behavior in a grid-productive manner (e.g., limiting or incenting customers to charge cars only in non-peak hours).

Richard Génecé—vice president of energy efficiency at BPA—explained that BPA is focused on the deferral of

transmission and has issued a request for offers (RFO) for non-wires alternatives to upgrading various congested transmission zones. The agency prefers an integrated demand response strategy, and the RFO appears promising if proliferation of distributed energy resources provides more cost-effective and competitive solutions to expand the bidder pool, thus driving down costs. Génecé believes in the value of integrated demand side management (IDSM) and increased commercialization of distribute energy resources. He cited a Con Edison project that avoided a billion-dollar transmission project through a successful non-wires alternative (NWA) project.

ETO—an independent nonprofit serving 1.5 million customers of Portland General Electric (PGE), Pacific Power, NW Natural, and Cascade Natural Gas—focuses on energy efficiency resource acquisition. Spencer Moersfelder—senior program manager—drew attention to the growing importance of demand due to growing loads and constraints on the hydropower system. He also reminded the audience that some existing energy efficiency programs offer ancillary demand response benefits, which could be calculated from annual electric and gas savings and peak coincidence factors. The ETO's role in demand response is partnering with utilities to develop programs where energy efficiency and demand response overlap and provide additional value to ratepayers. For example, ETO and PGE coordinate the NEST thermostat promotion of incentive bonus (see the Implementation section for more details). All in all, ETO serves as a key player in the region, supporting and connecting utilities to aid marketing of demand response programs across service territories.

UTILITIES' PERSPECTIVES AND ROLES

As the title of the symposium suggests, successful demand response in the Northwest requires collaboration among all players in the region. Operationally, partnerships are important between utilities and third-party demand response providers. However, another kind of partnership exists between all regional players: the sharing of best practices and lessons learned. Three utilities—the Eugene Water & Electric Board (EWEB), PSE, and Idaho Power (via a representative from the Idaho PUC)—set the example by sharing barriers and strategies for developing their demand response programs.

Nevertheless, these utilities acknowledge the difficulties of regional partnerships. Both the representative from EWEB and the Idaho PUC emphasized that their utility territories did not have much in common. The Idaho PUC said its standards of success may be different from those of others in the region. Both agencies, however, remain interested in other regional players' demand response actions. PSE emphasized that discussing the approach used for determining winter peaking baselines is important at the regional level, and that PSE is also generally open to regional partnerships.

Eugene Water and Electric Board

Though a relatively small urban winter-peaking utility, EWEB is Oregon's largest customer-owned utility. From largest to smallest, EWEB's considers three resources for meeting future growth: energy efficiency, conservation, and demand response. Of the various types of demand response, EWEB first relies on energy efficiency measures with coincident peak reduction, then considers behavioral demand response and dispatched automated demand response.

EWEB has operated demand response pilots in residential and commercial and industrial (C&I) sectors for five to six years. This has resulted in two immediate lessons learned:

- Establishing the metering and telemetry systems is expensive and not yet cost-effective for small loads
- Turning pilots to programs requires many mechanisms other than the technology

Consequently, EWEB is building an automated metering infrastructure to bring down metering and telemetry costs.

Because of historically weak economic or market signals, EWEB took the position that utilities must have the foresight to begin growing demand response incrementally over time. If they do so, utilities will be prepared when resource adequacy—combined with strong price signals from BPA or the California Independent System Operator (CAISO) in the future—compels use of demand response.

The utility also identified barriers that arise with adding a new resource within an existing portfolio of resources. For example, existing back office systems (e.g., customer information systems) do not adapt easily to new practices (e.g., new billing calculations). EWEB is addressing this barrier by issuing an RFP to replace its legacy billing system. More generally, adding demand responses competes with other departments for

resources, which may require a new manager or other organizational changes.

Puget Sound Energy

PSE—Washington's oldest local energy company—covers about 6,000 square miles of service territory. In its 2011 IRP, price comparisons between demand response and supply-side management characterized demand response as not worthwhile. PSE's 2015 IRP, however, showed that 121 MW of winter-peaking demand response would prove cost-effective, making demand response both a resource and operational need. In particular, PSE considered deferral of infrastructure investment as a prime benefit of demand response. Therefore, PSE currently is developing some firm demand response programs while looking ahead for price-based and behavioral programs. For the 2017–2021 cycle, PSE will release two RFPs that address this need.

Similar to EWEB, PSE believes that the utility's existing organizational structure may pose a barrier. Based on the results from a few pilots, PSE identified some communication and technology issues, the most important of which was the lack of experience exhibited by customers and operators. This partly resulted from not fully understanding demand response capabilities. Operators must see demand response as a stable resource, and on the customer's side, PSE must conduct stakeholder engagement even before issuing program implementation RFPs. As customer outreach coincides with program implementation, a continuous learning process must be established to achieve further improvements.

PSE also raised issues regarding cost recovery: even if demand response proves cost-effective, who pays for it? If considered a non-dispatchable resource (as with energy efficiency), demand response should be funded under a rider (again, as with energy efficiency). If considered dispatchable and reliable, demand response can be funded through power and transmission and distribution budgets.

On a brighter note, PSE echoed EWEB's point that attention to demand response enhances a utility's potential participation in CAISO. In addition, developing demand response programs has enabled PSE to connect staff from system dispatch—the supply side of the utility—to those on the energy efficiency or demand side and provide a new perspective on integrated operations.

David Mills—PSE's vice president of energy supply operations—emphasized demand response's greater operational value more than simply its resource value. By growing the capabilities of demand response resources, PSE is trying to bridge the gap between a fully capable energy efficiency resource in the region and the real-time value that system generation provides. Demand response's role in grid management and renewable resource integration presents an important area for continued exploration. The more refined ancillary services provided by demand response can go a long way toward decarbonizing the grid. Not only can demand response reduce the need for constantly spinning fuel-powered generation, it can provide the ramping capabilities necessary to offset wind or solar variability. Gas plants are not designed to be particularly environmentally friendly when powering up; a large number of these generator starts in a short time span results in very problematic emissions.

To replace traditional gas generation, however, demand response must be dependable and provide a reliable level of "firmness" that dispatchers can consistently count on when needed. Dispatchers need to know that when the demand response switch closes to provide resources to the grid, such resources are neither temporary nor unreliable. Though rapid advances in technology and efficiency can help to overcome this, so can the demonstrated, statistically reliable demand response MW capacity performance achievable with continuing program growth.

Mills also shared concerns that the Council misses an important demand response benefit by not including the deferral of distribution equipment; local benefits offer a very substantial driver to demand response adoption. Regarding implementation, Mills believes that utilities should partner with vendors more to avoid disintermediation concerns.

Idaho Power

At the symposium, the Idaho PUC shared some lessons learned from Idaho Power.

A summer-peaking utility, Idaho Power has—contrary to EWEB and PSE—mature demand response programs. Started in 2004 with 0.5 MW of residential AC cycling, Idaho Power currently deploys 370 MW of demand response (i.e., 30 MW residential, 35 MW commercial, and 305 MW irrigation).

Also in contrast to PSE, Idaho Power claims it has effectively educated its operators at the dispatch center on the operational value of demand response. Continued interaction and best practice sharing between PSE, Idaho Power, and all Northwest utilities will aid in educating operators' strategies for the integration of demand response into their current operations.

TECHNOLOGY VENDORS AND SCIENTIFIC COMMUNITY

Technology Vendors

Leaders in the technology vendor sector discussed various topics related to demand response.

Sunverge Energy seeks to strengthen both the grid's and utilities' relationships with customers by delivering customer-sited solutions. Sunverge CEO, Ken Munson balked at the notion of a utility death spiral. He sees the grid as a social good; if the industry continues to innovate, new technologies can integrate with the grid and assist renewable integration. Developments moving in slightly different directions have siloed demand response and demand-side management (DSM). IDSM with devices removed from manual, hands-on requirements allow demand response grid management to seamlessly interact with DSM techniques. Platform energy services can accomplish this and deliver value to consumers, businesses, and to the utility. This allows integration and concurrent management of traditional DSM, EVs, and plug loads in a facility, enabling utilities to provide a "new user experience" to customers.

Michel Kohanim of Universal Devices (a leading manufacturer of affordable, Internet-accessible, home automation, energy management, and conservation products and solutions), discussed what the IoT means to demand response. He considers IoT devices as part of a solution and of an ecosystem that must be integrated with communications to create easy implementation of demand response goals for utilities or campus energy managers.

The OpenADR communication standard represents the future of IoT. Demand response has a long history of providing grid benefits, primarily on a seasonal peak basis. That relied, however, on consumers being sufficiently concerned to set their thermostats and manage their appliances manually or with limited programmability. The next phase relies on a more intelligent method, where devices communicate with one another and with grid resources. Operating with a communication standard (such as OpenADR), devices use a common language and common commands. This allows a wide array of devices to communicate their current state or their current environment, thus providing coordinated responses among devices. Eventually, this will help facilitate transactive energy, which allows devices to automate energy resource purchases and sales.

Graham Horn of Enbala, a firm dedicated to harnessing the power of distributed energy—and in keeping the renewable-friendly grid in balance 24/7—questioned automation's pervasiveness and the degree to which human interaction serves as a component of automation. He believes manual controls always play a role and much innovation remains to determine how that role looks and functions.

A fast-acting system (e.g., the grid) poses a challenge: automation must be required at multiple levels. To maintain safety and reliability at the grid level, grid-connected devices must follow specific standards that allow them to work in concert with other grid devices. Achieving this may require the utility to oversee device operations or require preset functions, conditional upon grid frequency or voltage maintenance.

At the customer level, automation means operating for convenience, at price or comfort presets that reflect an owner's desires. For examples, as clouds move over solar arrays, power levels dip, and other power sources from the grid or energy storage must move in to provide replacement power. The speed of this process and the convenience required makes automation a necessary requirement.

Scientific Community

Robert Pratt of Pacific Northwest National Laboratory (PNNL)—a government-funded lab that advances the frontiers of science and engineering in service to the nation—said demand response will move toward Transactive Energy, which perhaps symbolizes demand response's potential flexibility. He considers demand response developments as more than managing peak load capacity, given the nation's lessening peak load growth. Though new developments move away from direct load control, substantial growth and development remain for such controls, now focusing more on balancing wind, dealing with the solar duck curve, and shifting value propositions.

Renewables do not exclusively drive value propositions; EV's greater influence and customers' desires for power independence and other factors also move the value-proposition needle. PNNL has found that customers respond to broad forms of incentives, not just energy price.

Transactive Energy's design seeks to create a real-time marketplace with value incentives, not just prices; so resources respond in highly flexible, beneficial ways for grid operations. Development and implementation of dynamic rates for utilities proceeds at a glacially slow pace. If the power system waits for such developments, demand response growth will take too long and create more and more issues that must be solved by central generation or other supply-side methods. Rapid demand response development requires solving the measurement and valuation problem and determining the best marketing approaches to move towards real-time incentives rather than real-time prices.

Future Demand Response Applications

These technology vendors and the scientific community each brainstormed some exciting demand response (DR) applications in the future. Pratt from PNNL thought DR applications will move towards ancillary services driven by renewable penetration. Starting in California, the duck curve—the new market instrument used by ISOs—will sweep through the Northwest, providing opportunities for customers and ratepayers to make money by solving the evening ramp created when the sun sets in California.

Graham Horn of Enbala thought that, with grid modernization, distributed control systems will become important providing self-healing and more cost-effective feeders; but customer, regulatory, and utility innovations will remain important to drive those changes. Kohanim and Munson followed with transactive energy and virtual power plants, consisting of coordinated distributed energy resources (DERs) offering consumer and grid operator benefits.

Duck Curve

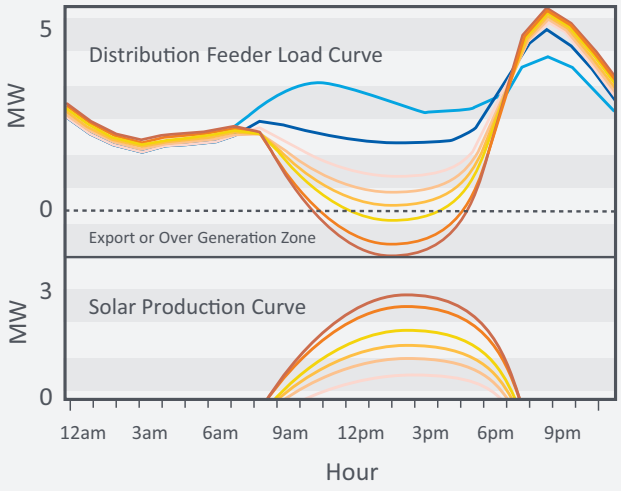
When examining future scenarios for net load curves, CAISO—when tasked with operational responsibility of the California power grid—coined the term "duck curve" to show deformation of a conventional load curve by the introduction of distributed solar resources (which generally produce maximum power around noon each day). During this time, overgeneration may occur as a large number of solar arrays pump maximum solar power into the grid, requiring grid operators to reduce or stop supplying conventional generation. As the sun moves farther west, solar power output drops until, at sunset, solar arrays stop producing power. Human behavior, however, continues into the evening hours, producing continued cooling loads and cooking loads until creating a late afternoon or evening power demand peak. The rapid ramp-up from full solar power to no solar power in the evening peak requires other resources to rapidly replace the lost solar power. The neck of the "duck" shows this ramp-up—a challenging situation for grid operators to manage using conventional power generation to fill the solar gap.

Demand response can help the duck curve in two ways:

- By increasing demand around noon each day to reduce overgeneration
- By slowing the ramp indicated by the duck neck and reducing evening peak by curtailing loads during those times

Energy storage can also help mitigate the duck curve: combining storage and demand response presents the optimal way to manage this situation.

Figure 3. How the duck curve is formed



INDUSTRY SUMMARY

In comparing these different industry actors' perspectives on demand response, suffice it to say that interest in demand response remains high, but so is the level of effort required to develop demand response into broad-based dynamic energy resource. The questions for the region: is there sufficient leadership, a compelling enough business case, and a strong enough will to drive demand response development to the point of providing a substantial viable capacity resource?

Climate change and changes to peak demand serve as the main drivers for demand response, and CAISO's energy imbalance market helps generate the topic's momentum. Regulators generally express interest in learning more about demand response and remain open to discussing their roles, whether developing the guidelines for demand response planning or supporting the mainstreaming of smart grid standards in the industry.

Most importantly, regulators and utilities acknowledge that demand response requires a long-term outlook and commitment that may have fuzzy initial benefits. This translates to an immediate need to jumpstart the investigation and development process, while allowing demand response programs to steadily grow incrementally over time. Following this mindset, utilities may be able to adopt a piecemeal approach in answering questions such as "How will demand response change organizational structures and operations?" or "How will demand response interact with existing energy efficiency programs?" This will allow the slow and steady resource growth that will take years to accumulate enough capacity to be noticeable at grid scale.

The bulk of program implementation resides with utilities working with technology vendors and customers. Some of demand response's most pressing issues to reach grid beneficial capacity involves customer engagement. A general consensus emerged that customer engagement is required to run any successful demand response program. Some utilities have put a positive spin on this by saying demand response provides them with another opportunity to engage with customers. Conversely, demand response may also provide an opportunity to connect demand-side and supply side operations, enabling utilities to regain a holistic view of their business.

As energy efficiency remains the top priority in the Northwest, any demand response progress will build on and run in conjunction with energy efficiency. Utilities can exploit existing customer relationships through energy efficiency programs to promote demand response, but must avoid pitting one tactic against the other or creating siloed departments.

IMPLEMENTATION

Successful customer engagement is the foundation of demand response

Once leadership and policy makers and analysts have determined capacity targets, cost parameters, and opportunities and barriers, teams of program development professionals can use this information to design compelling customer programs.

This section begins by presenting a model of idealized program design—an exemplar of demand response programs. A frank discussion follows regarding the challenges of moving demand response from a customer benefit program to a grid-scale operation with a trading floor. To satisfy the trading floor's requirements (i.e., the size of the demand response resource), the resource's timing and location becomes important, though not more important than assuring resource availability (often described as firmness). Verified results lead to determining firmness—a task directed by M&V processes.

In particular, this section explores these topics:

- An exemplar of demand response programs
- The trading floor and M&V
- Residential programs
- C&I programs
- Engaging broad deployment, beyond the pilot
- The nexus of energy efficiency and demand response
- Marketing of programs

AN EXEMPLAR OF DEMAND RESPONSE PROGRAMS

Steve Hambric of Comverge, a leading third-party demand response provider for utilities, represented his company at the symposium. He described lessons and best practices from Comverge's general experience

and a project conducted with Central Hudson in the bullets shown in this section. This full-service demand response project included designing the program, acquiring customers, implementing devices, coordinating with other DSM activities, and co-marketing the services with other stakeholders. Comverge was also closely involved with evaluation, measurement, and verification of the program to determine how the program operated and performed, and if it achieved its cost-effectiveness goals.

Comverge developed the following best practices based on its experience:

- Build internal support for the programs
- Take a broad view of program benefits
- Request outcomes, not features
- Pay for Performance, not activity
- Design with scale in mind (i.e., be realistic)

A brief discussion of each best practice follows.

Build Internal Support for the Programs

Management and trading floor staff must know whether demand response resource is reliable.

Building internal support often proves challenging when programs are new, slow to grow, and the outcomes are unknown. There is large element of uncertainty, primarily due to the randomness of human activities, and utilities have to rely on modeled/predicted loads for consumers' trends and habits at work and home. Notably, utility trading floors have not experienced problems with scheduling expensive generation plant dispatch and power contracts based on hourly load forecasts. In addition, wind forecast modeling has made great strides in recent years to prove its operational value, and with continued improvements, trading floors trust the models to deliver elements of reliability. Demand response modeling should be treated in the same light. Taking the following actions will help advance the perception that demand response is reliable:

- Connecting them with their peers (utilities)
  - Many utilities wish to be "fast followers," meaning they seek to avoid the risks from being the first to try anything. A few brave utilities step up, and fast followers seek to learn from their experiences. Thus, it behooves third-party aggregators to connect innovators with fast followers, building a comfort level with not just demand response, but all forms of distributed energy resources.
- Set up milestones: set up to meet loads not expected for two years
  - Developing demand response programs takes time and measurable load reduction should not be expected for at least two years. Slow and steady growth also characterizes the nature of demand response programs. They do not behave like a new combined cycle generator, which takes several years to build, but then begins delivering 400 MWs the day it is commissioned.

Growth for a demand response program is similar to that of an advertising campaign. Waves of sign-ups occur, then sales cycles run their course, each at a different pace for different types of customers. Sales cycles tend to be the longest for the industrial markets, but they deliver fairly large blocks of load reduction. On the other hand, the residential markets typically have shorter sales cycles, but deliver only modest load reductions. Over the course of this growth, impatience on the part of utilities or regulators presents the greatest risk to program longevity; these stakeholders may not believe the program is working or achieving target load reductions fast enough, then decide to go in a different direction or cancel the program.

To assure utilities or regulators of a program's long-term value, program managers must set appropriate, yet flexible milestones that align with a long-term growth strategy versus short-term targets (e.g., delivering 10 MW blocks of load reduction at a given date). For a new program, trends should be viewed as more important than energy-savings block targets. For example, upward trending growth—not a discreet block of demand savings—is set as a performance milestone. Obviously, a point may come where a program does not adequately perform and a change of direction will be required, but, like a fine wine, successful demand response programs mature over time.

Take a Broad View of Program Benefits

Consider these factors in program design:

- System level capacity
- Seasonal/flexible demand response
- Address distribution cap needs

- Reliability
- Customer engagement
- Energy efficiency
- Cross-promote programs
- Monetize in capacity markets
- Drive adoption of new tech (e.g., AMI)

Demand response offers a variety of benefits for the utility, the public, and the environment. Historically demand response was generally considered a seasonal resource, with on- and off-peak pricing programs providing subtle encouragement for utility customers to reduce loads during winter cold or summer heat. More recently, with the advent of new technologies, demand response offers a broader range of benefits. Further, utilities are considering alternatives to traditional transmission and distribution upgrades that generally include some form of demand response. A proper mix of demand response resources targeted on transmission constrained areas or on overloaded distribution facilities may help utilities better manage loads and defer these investments. The challenge emerges in evaluating the pros and cons of demand response investment versus traditional transformer and conductor investments (e.g., non-wires alternatives).

Demand response also plays a role in the move to assist ancillary services. Often, "fast demand response" or "automated demand response" describes technologies that can help balance variable renewable resources by varying the load. Under the traditional grid power system, utilities constantly try to increase or decrease generation resources to balance the variable loads that changing customer demands create for the power system.

Automated demand response can receive regulation signals from a utility, indicating the need for increases in power or decreases in power. For automated demand response, the result is the opposite of generation. The regulation signal of an increase means the demand response system must decrease load, so bulk power systems do not need to supply as much power to the grid. A decrease indicates a need to increase load. For example, if a power system has a significant amount of wind resources, but the wind dies and the regulation signal requires decrease, demand response resources would increase load (e.g., making ice, heating hot water for later use, or utilizing other forms of heat storage).

A better and lower-cost method of balancing loads aids with meeting reliability needs. Large fluctuations in loads tend to cause greater wear and tear on system equipment and increases the likelihood of equipment failures or system problems. Reducing the power system's peaks and valleys results in a more stable and reliable grid.

As demand response is customer focused (rather than utility-equipment focused), it opens a door to a wide variety of combined benefits. For example, engaging more with utility customers means better understanding their needs. Further, demand response naturally fits with energy efficiency programs. When trying to reduce heat loss for a home or business while auditing or encouraging insulation, new windows, or smart thermostats, it makes sense to add demand response components that not only allow energy savings but take into account the timeframe benefits of capacity savings. At the same time, these new services benefit the supplier market by helping create demand for new demand response technologies or improving the capabilities of existing systems.

Request Outcomes, Not Features

- Utilities try to define a solution, but first need to understand the problem
- Allow vendors to meet your objectives the best way they know how, instead of asking vendors to build a custom product
- Utilities should not prescribe the solution

As Comverge asserted, outcomes are important and utilities should focus on the results obtained by vendors, not on dictating how vendors should develop a program. Comverge also asserts there is a greater need for better definitions of program results. However, utilities have large stockpiles of customer data and capabilities to conduct market research with their customers, and many know their customers much better than a third-party vendor just entering the market place. So, they need not grant vendors a free hand at building custom programs. Rather, this should be determined through a joint undertaking, with utilities and vendors drawing from their strengths and perspectives during program design. A utility's customer remains its most important asset, and a third-party vendor may unintentionally jeopardize that relationship through its actions or inactions.

Still, too much prescription by a utility may instill burdensome overhead on a third-party vendor, making the very thin margins for demand response even thinner and rendering the program insufficiently economic or the vendor insufficiently profitable to maintain its financial health and support a prolonged business model. Worse yet, this could nullify a vendor's resource bid.

Generally, utilities should not prescribe the solution. Third-party vendors are hired for their expertise and skill for developing innovative programs that meet a utility's needs and requirements. The vendors then execute the program and generally produce documented results.

Building successful demand response programs with a third-party vendor becomes a balancing act, providing customers with a compelling offer to participate while achieving a utility's objectives for capacity reductions, and developing and maintaining excellent customer relationships while granting a third-party vendor the creativity, freedom, and profitability to build a sustainable product or service. However, utilities should not relinquish the role of M&V to the same vendor who develops the demand response program. This should be done by the utility or an independent third-party to provide proper governance.

As the symposium clearly presented lessons learned from the PNWSGD, leaving communications standards decisions only to vendors resulted in not establishing any standard. The majority of distributed energy resource activities included the vendor's proprietary communications. For example, several battery assets in the PNWSGD became unusable (i.e., stranded assets) when the vendor declared bankruptcy and disabled the web-based communication system. Though the batteries could still function properly, the vendor's proprietary communication systems became inoperable, so the batteries could not be controlled. Also, since it was a proprietary communication system, another vendor could not be contracted to continue storage operations. The result was an expensive, mostly functional asset rendered useless because the vendor did not use a standard communication method.

Consequently, in areas of standards prescription, customer engagement, and M&V, the utility must play an active development role and not let vendors dictate solutions in those areas.

Pay for Performance (P4P), Not Activity

- Comverge is only paid for net MW acquired and maintaining those MW
- If a resource cannot be accessed, vendors should not get paid
- Acquire new customers on vendor's dime, not the utilities'

Though P4P is a worthy goal, making this program development decision involves the appropriate risk allocations. P4P places program delivery risk entirely on third-party vendors. This arrangement offers much appeal for utilities, but it creates two issues.

First, placing all risk on the vendor means they must develop programs that maximize their profitability, possibly by seeking "low hanging fruit" rather than achieving a more impactful demand response program. As P4P forces vendors to provide all upfront capital, it presents challenges in obtaining significant and continuous capital levels from capital markets for the vendor. One need only look at the financial conditions of some third-party demand response vendors to see that this presents serious barriers for smaller and potentially more innovative vendors to enter the market.

Second, utilities find it very difficult not to "meddle" in various program design aspects, especially concerning customer engagement (as described in the previous section) or M&V. A utility's concept of performance measurement may greatly differ from that of a vendor. These program modifications can change a demand response program's risk and cost profile. Consequently, utilities should share some elements of risk. Simply stating contractually that vendors take responsibility for all delivery risk implies vendors receive more autonomy than utilities are often willing to give.

Design with Scale in Mind—Be Realistic

It is dangerous to plan larger programs using with same results/assumptions employed for smaller programs. Simplicity is important. Demand response programs often start two ways:

- A pilot project is proposed internally within the utility, then approved, funded, and executed. These pilots may involve small firms with prior relationships with the utility. If scale is not considered at the outset and

a clear path for is not growth defined, these firms work very hard to deliver excellent programs with shining results. If not rewarded with the project's next phase, which allows the small vendor to expand into a greater market size and grow their business, the vendor may be required to bid on a larger-scale project that, depending on the winning bidder, leads to a vendor that may not have the same sales ability, technology, or will to succeed. The elements of simplicity that may have worked for a small program can become much more difficult for a large program.

- The utility develops an RFP for capacity acquisition, opening this to supply-side and demand-side options. This choice is imperfect because, generally, a supply-side option can utilize a repeatable and scalable method that does not rely upon significant customer interactions. Demand response programs involve customer behaviors and significant customer interactions that have a totally different risk profile. Demand response capacity bidding provides only a small amount of detail in a RFP, upon which the bidders must estimate performance and costs. Without intimate knowledge of the customer mix and customer end uses, a third-party bidder cannot make all correct assumptions for adequately assessing the opportunity, particularly when faced with only a two- or three-week bid deadline.

Some say a utility should not care how capacity is acquired as long as it is acquired successfully. This is much like saying a utility should not care which fuel is used for generation resources as long as it only examines the least-cost fuel. Over the years, this point of view has evolved into examining more than utility costs; it involves incorporating the total resource cost, which includes externalities. Capacity bidding must consider a different set of parameters when evaluating growth strategies that should be determined up front.

THE TRADING FLOOR AND THE IMPORTANCE OF M&V

As an example of grid-scale benefits that directly relate to trading floor activities, many municipal, public utility districts, and cooperative utilities pay substantial capacity charges to the BPA. These charges serve as a strong financial driver for grid-scale demand response.

Shawn Dolan, manager of engineering at Kootenai Electric (a nonprofit electric cooperative serving 25,000 meters in northern Idaho, with a peak load of 111,000 MW) has been involved in demand response issues since 2008. Dolan presented a compelling case for demand response as a means to manage load-shaping the cooperative's load extremes using peak shaving and valley filling. Kootenai became involved with a BPA-funded peaking project from 2008 through 2012, with the cooperative's goal to drive down the BPA's capacity charges for Kootenai's customers.

Measures adopted included water heater and thermostat controls and conservation voltage reductions that managed BPA-controlled events. The utility issued calls for demand response and collected data about the event. Dolan stated that the utility's direct involvement offered a key advantage: a deeper dive into demand response capacity capture, which might not have happened with a third-party provider.

To determine the impacts for thermostat and water heater controls, Kootenai instrumented circuits in each controlled home. For the voltage control system, the utility compared baseline days during the same month (with the same temperatures and weather) against the control day.

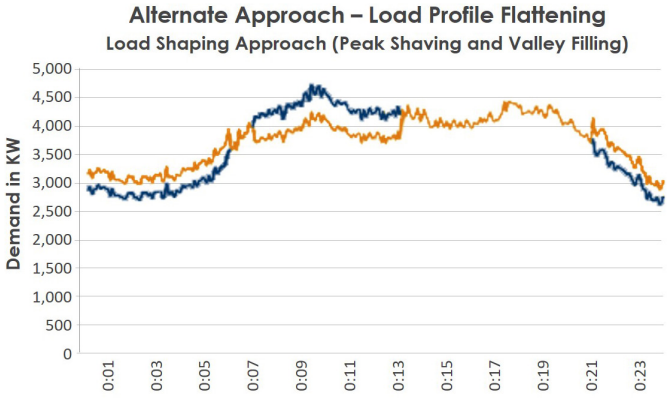
These tactics allowed the utility to establish a solid baseline for each device and to conduct solid testing to make sure systems performed properly. Without proper testing and establishment of a solid baseline comparison (in this case conducted by Cadmus), Dolan believes a utility cannot genuinely determine how much these actions affect load profiles.

Results included a 0.4 per kW reduction in demand from one of the largest resale deployments of Marathon water heaters. Thermostats achieved load reductions of about 3 kW.

After the pilot test, Kootenai examined reductions in the company's BPA wholesale power bills. It found sufficient economic drivers to invest in more demand response for thermostats, but also found that water heaters produced demand response levels too low to justify their costs. The company also realized that considerable utility time was required to maintain the thermostat program. As a substitution, Kootenai chose to invest more in a voltage-control system for demand response load reductions. With demand response-controlled voltage management, the utility could raise valleys and shave peaks, thereby leveling its demand from BPA and

reducing demand charges, with savings passed on to its customers. See Figure 4.

Figure 4. Kootenai Load Shaping



Without establishing an appropriate baseline, with measurements and resulting verifications, Kootenai could not have verified savings results for its customers or make the decisions needed to direct scarce capital to appropriate demand response measures.

Striving for Trading Floor Operations

As discussed previously, David Mills of PSE emphasized that demand response must be dependable and provide a reliable firmness level. Dispatchers must know that, when the demand response switch is closed to provide the grid with resources, this is not a temporary or unreliable solution. Rapid increases in technology and efficiency advances can significantly help mitigate this uncertainty, but so can demonstrations of statistically reliable demand response MW capacity results that can be achieved through continuing demand response program growth. PSE senior market analyst, Elaine Markham, also said in another symposium session that support is not as strong on the trading floor. So, program development staff need to hear trading floor concerns, and trading floor staff must see the program in action, which she believes should be considered an educational effort.

Demand response program results form the basis for building a demand response resource portfolio that can be counted on and packaged for trading floor operations. For example, if a 25 MW demand response program that was clearly defined with a solid price per hour (or sub-hour) operation period, then a transmission tag could be produced that lists the megawatt reduction value with a specific delivery location. Hence, the trading organization could package this within a portfolio of options in its OATI software system. This demand response power block could be scheduled into trading operations for given hours of the day. Once scheduled, demand response events are called by notifying customers (or their devices) of reductions, and their responses would behave just like closing a generator breaker on the system.

Automated demand response can behave this way when connected to a utility's demand response management system or a third-party's demand response network operations center, providing feedback of load reduction values on the balancing authority's system for trading or system dispatch.

The Northwest has an abundance of balancing authorities. A balancing authority is a responsible entity that integrates resource plans ahead of time, maintains a load-interchange-generation balance within a balancing authority area, and supports the Interconnection frequency in real time. Large third-party demand response aggregators are challenged by the sheer number of balancing authorities in the Northwest because it is easier to build demand response programs that aggregate customers across a large geographic area and bid those MWs into a market. Smaller area balancing authorities require that demand response programs are tailored for each balancing authority area and may require a greater customer density than a third-party may typically work with.

In addition to coordinating with Federal Energy Regulatory Commission's trading rules, balancing authorities face rigorous, very structured rules governing how they deal with one other. These rules were not set up and did not contemplate real-time adjustments for specific demand response needs when balancing authority loads drop in one balancing authority zone, but the need for the reduced load falls within another balancing authority. Often, such needs include load movement within the hour of identifying the need. Under current rules, the load can only be moved across if the hosting transmission officer, like BPA, could approve such a product be transferred to markets. So until a system is established for transferring demand response loads between balancing authorities (BAs), and they are packaged properly for trading or allowed in some way to utilize Area Control Error in a unique fashion, such demand response load cannot be moved viably. This forces demand response programs to operate only within the balancing authority where the demand response need exists. This limitation reduces demand response flexibility in areas, like the Northwest, where

numerous balancing authorities operate in a small geographic area.

As with many wholesale utility trades and transactions, after-the-fact verification or clearing must take place to assure the bilateral trading partners that the deal was consummated. To achieve this through demand response, utilities and/or third-party aggregators must complete rigorous M&V in order to demonstrate the performance of the demand response package. It cannot be simply metered at a point of interchange as a generation resource can be.

For the trading floor, current load measurements (minus a solid demand response baseline) are important, as operators need to rely upon a measured resource MW value and demand response resource providers must be paid for verified performance. Solid baselines serve as a foundation for customer payments and trades. They must be sufficiently simple to explain measurement to customers and stakeholders, and they must be sufficiently simple for customers to calculate performance and settlement verifications. Further, they should be determinable in advance of an event, so real-time performance can be managed. Most importantly, utility systems must be able to administrate them. Baselines must be based on sufficient data to calculate them accurately, but should not be crippled with so much data that baselines become either burdensome to calculate or susceptible to errors. The Getting into the Weeds with M&V section provides more information on M&V and baselines.

MARKETING OF PROGRAMS

In a number of ways, marketing plays an important role in demand response's future. A key to engaging customers in demand response programs is marketing the program effectively. This can be a challenge for many reasons.

Leveraging Energy Efficiency Programs

Many utilities already have a base of customers who are interested and engaged in their energy through their involvement in energy efficiency programs. As a result, they prefer to leverage existing, in-house, energy efficiency efforts to build demand response programs. However, the decision to run a demand response program in-house depends on the type of demand response program and the availability of qualified third-party aggregators, which can be preferable in some situations to reduce risk.

Co-Branding of Demand Response Programs

Co-branding can be a powerful tool for engaging customers in demand response programs. Utilities offering a demand response program have many avenues through which to co-brand their product, and several panels in the symposium discussed the pros and cons of leveraging these avenues.

Utilities have the option of running their demand response programs in-house or hiring a third-party aggregator. Either choice has important implications on customer engagement and co-branding of the programs. Three utilities (EWEB, PSE, and Idaho Power) consider in-house demand response programs the preferable option. This largely stems from third-party aggregators making it difficult for utilities to co-brand programs and to maintain close interactions with customers. PSE stresses the importance of branding demand response programs as PSE programs—not programs from third parties; co-branding with a third-party aggregator can be a barrier for many customers who are not familiar with the third-party brand.

PGE implemented its Rush Hour Rewards Program in-house rather than hiring a third-party aggregator. However, the company has leveraged NEST's relationship with PGE's customers to co-brand the demand response program. Josh Keeling of PGE expressed how satisfied the company was with NEST and its ability to promote PGE's Rush Hour Rewards Program and reach a wide range of customers. He also pointed out that customers' experiences and engagement levels do not solely rely on their relationships with their utility providers: "NEST views [these] customers as their customers… [and] protects that experience." At times, program participants may not even know of their utilities' involvement in the program, but they trust certain vendors such as NEST, as they work very closely with program participants and provide them with positive experiences.

Improving Terminology

At a more general level, technology vendors think the term "demand response" could be reworded to provide clarity to customers not familiar with industry language. Oftentimes the term is viewed by customers as something the utilities are demanding to

which customers need to respond, a more abrasive connotation than utilities want to promote. At this point, the audience suggested some possible new terms:

- Rush Hour Rewards
- Flexible Loads
- Demand Response 2.0
- Surge Incentives
- Energy Things

RESIDENTIAL PROGRAMS

Compared to C&I demand response, residential demand response is relatively new. This probably results from multiple reasons, such as the ability to quantify demand response savings from residences and low demand reductions expected in comparison to C&I customers. Residential demand response programs, however, are quickly becoming a staple in many demand reduction portfolios.

Ken Munson of Sunverge discussed that this largely results from recent technological advances, including EVs, Tesla's Powerwall, and NEST smart thermostats. These technologies will significantly affect future load shapes, but can also engage residential customers and provide utilities with information and data in a way not possible previously. As technologies continue to develop and bring value to residential homes, and utilities learn to engage with their residential customers, residential demand response programs across the Pacific Northwest are becoming more and more successful. This section explores these programs' successes and possible improvements.

Motivators to Participate

Given demand response programs' relative youth with residential customers, customer uptake and engagement can be difficult. Understanding customers' motivations to participate in demand response programs remains vital in improving customer engagement and ensuring demand response programs' success. Symposium panelists discussed the following factors that motivate customers to participate in demand response programs:

- **Philanthropic.** Customers who feel some loyalty to their utility participate to help the utility and do not require a great deal of encouragement.
- **Good Citizens.** Customers know of their demand's environmental impacts and want to do their part to improve conditions. To engage these customers, utilities should educate customers about fuel-type usage at peak times.
- **Cost Savings.** Customers want to save money and understand they can do so by participating in demand response programs, a reason particularly applicable for low-income or fixed-income customers.
- **Incentives.** Customers want to take advantage of incentives offered for investing in technology upgrades or changing their demand trends. According to panelists in the residential demand response panel in the program track of the symposium, a significant difference in participation rates does not result from a $50 incentive and a $125 incentive. Panelists urge utilities and vendors to optimize the engagement-to-cost ratio by researching successes at different incentive amounts.
- **Home Market Value.** As technologies develop, customers understand that investing in demand response technology improves home market values. PGE sees this occurring with NEST smart thermostats. It also proves true for EV charging stations: as Tesla and EVs gain traction among residential customers, investing in these charging stations adds value to homes.

These many customer groups can be reached by promoting demand response programs' various aspects and types.

Barriers to Customer Engagement

Despite motivations to participate, customer engagement can be limited by several factors. This especially holds true with residential customers, who, unlike C&I customers, may not always be in tune with their demand needs. A major barrier for the Flathead Electric Cooperative (FEC) and PGE demand response programs arose from deciding how much to educate residential customers on demand response programs:

- How much information was too much?
- What language was most appropriate?
- How can these programs be branded to make customers more comfortable about participating in a potentially confusing, not easily explained program?

- What options should the utility provide to optimize customers' experience and engagement?

This section explores these questions in greater detail.

Improving Education

Overall, among the residential demand response panel, a theme emerged: less is more when it comes to education. Panelists urged utilities and those promoting demand response programs to provide just enough information to customers, but not to employ excessive detail. Josh Keeling from PGE said promotions needed to be "just honest enough." Customers should understand what the utility is doing and trying to provide, but they need not receive too much information that will scare them away and become a barrier to their engagement.

That said, each panelist agreed that the education process should include a more tailored approach, allowing customers to choose their engagement level with the program. Panelists unanimously chose face-to-face education as the optimal forum for educating residential customers about demand response programs. These encounters lead to more tailored experiences for customers and present an opportunity to give customers exactly the information they want. Robin Maslowski from Navigant said, "[Utilities] don't need everyone enrolled in a demand response program. Don't bother customers unless they seem interested…. Follow their lead and give them choices on their levels of engagement."

Language presents another barrier. According to Jeff Gleeson of NEST, customers become concerned when they hear the word "audit" (although a common word in the energy efficiency and demand response communities). Reaching a customer, however, depends on understanding the term in a laymen's context. Teri Rayome-Kelly from FEC spoke about lessons learned through their demand response pilot program and advised avoiding words such as "radio frequency" and "smart grid" because of their intricacies.

Many of these panelists discussed the importance of co-branding and of making customers aware that their utilities support and are involved in demand response programs from vendors. This adds a comfort level to the customer experience, as customers tend to trust their utilities more than vendors. However, co-branding with vendors such as Home Depot, Lowe's, and Best Buy is essential to communicating with customers about demand response programs.

Ease of Participation

Often, the logistical ease of enrolling and participating in a program can present a barrier to customer engagement. If the program inconveniences customers too much (or, for some customers, at all), they become much less likely to engage.

When discussing the demand response future, panelists addressed automation as a method to overcome this barrier. According to Graham Horn from Enbala, automation produces demand response results and inclines customers to participate in demand response programs, because it requires less work for the customers. Less intervention also tends to be a key component with most programs, although Sunverge's Munson said the programs will always require some degree of intervention.

Another barrier may impede customer engagement: utilities often require customers to enter their utility account numbers to enroll in demand response programs. Customers, however, generally do not know their utility account numbers offhand, and this requirement places another layer between interest and enrollment in demand response programs. Hence, removing this requirement would likely increase enrollment in demand response programs.

Providing the Right Options

While customers' seek options and often appreciate a tailored experience, too many options can dissuade customers from participating in demand response programs. Jane Peters from Research into Action provided an anecdote about Japan: "[After the earthquake], they provided nine different time-of-use rates. It was too much; most people signed up for a standard rate because [it was] so confusing." This emerged as a common concern among panelists.

However, offering options probably is necessary to engage the maximum number of customers. Each panelist agreed that an optimal number of options should be presented to potential demand response program participants. For example, as demonstrated in FEC's Smart Grid Program, offering three package options at varying prices and engagement levels led to positive customer experiences and customer engagement. PGE simply allowed participants to select their own NEST thermostat.

Utilities should investigate the level at which they engage their customers once they enroll in a demand

response program. At times, utilities can consider letting their customers opt-in to receiving customized alerts about their demand. Peters, however, urged utilities to consider that this adds another complication level to a program; customers may be less likely to return to the program if they receive too many alerts from their utility company. A representative from Navigant also pointed out that many smart thermostat vendors already have customer alert policies in place, and utilities may not be able to customize how and when they alert customers.

Offering the Right Programs and Technologies

Demand response programs are relatively new, and many programs are still in their pilot phase. This presents difficulties for utilities deciding which program would be best for their service territory. NEST's Gleeson suggested this does not have to be a choice: "Most successful programs ask how many of which [type of program] we should do." He believes a balance can be achieved, which involves considering multiple factors:

- **Cost.** For example, direct install programs are effective but costly.
- **Market Penetration.** Some programs (e.g., Bring Your Own Thermostat [BYOT]) do not reach all customers within a service territory, but they offer several benefits in terms of costs and the utilities' responsibility to the technology.
- **Customer Experience.** Programs that require direct-installation are more invasive and may lead to lower customer satisfaction levels. Customers, however, can become frustrated when technology has not been installed correctly.

The panel discussed two programs in detail: FEC's Smart Grid Demonstration, and PGE's Rush Hour Rewards Program. Both programs succeeded in their own ways and are discussed in greater detail below.

Flathead Electric Cooperative's Smart Grid Demonstration

In 2010, FEC partnered with BPA to participate in the five-year PNWSGD that investigated the cost-effectiveness of smart grid technology. The program offered multiple pieces of technology through three different packages:

- **In-Home Display.** Configured to respond to over-power line communication broadcast from the integrated AMI system for human-in-the-loop demand response.
- **Water Heater Demand Response Unit (DRU).** Traditional demand response technology over-power line allows members to have their hot water heaters operated by the co-op in response to peak demands.
- **Smart Appliances.** Implement the Home Energy Network with Smart Appliance for advanced control with GE Nucleus/Portfolio-Brillion enabled Home Energy Network, and this equipment:
  - Load control-enabled dishwasher
  - Load control-enabled clothes washer
  - Load control-enabled clothes dryer
  - One Zigbee Water Heater Switch
  - One Energy Display

Overall, this program succeeded in terms of customer engagement and demand reduction. The water heater DRU proved to be the most successful program aspect. FEC does not cycle its events; rather, it turns off the water heater for a maximum of three hours at a time. Customers were inconvenienced very little—one of the biggest concerns related to direct-install measures. This partly resulted from the technology's reliability; so far, FEC has recorded few to no failures of water heater DRUs. The water heaters also contributed to the second-largest demand response of the three options, with an average across most events of 0.58 kW per unit in summer and 0.91 kW per unit in winter. The water heater DRUs had an average installation cost of $413, and simple payback was expected within three to five years (though this estimate remains highly dependent on hitting the monthly peaks). So far, around 1,500 water heater units have been installed, with a plan to install 5,000 water heater units over the next few years. Participants receive a $4 participation credit for each month of active participation.

The Smart Appliances option was the leading contributor to overall demand response performance. Across events, this group at times produced up to 2.34 kW per-unit peak reduction. This also, however, was the most expensive option for participating customers, with an $800 buy-in. The appliance suite was valued at over $8,000. Additive home energy network aspects cost $2,500 or more over regular appliances.

FEC considered in-home displays as the program's biggest failure. Despite the lowest cost among the

options, at an average of $125 for implementation (given technology maturation time), this group did not achieve appreciable load response. FEC believes this primarily resulted from event messages not reaching participants.

Rayome-Kelly from FEC discussed an unforeseen issue facing FEC's incentives system; if participants were not at home during a peak event but came home directly afterwards and increased their demand, they received incentives. FEC did not, however, believe any participants learned to take advantage of this loophole. Further refinements of critical peak pricing metrics may close this loophole.

Another finding from the demonstration project was that BPA system needs did not frequently coincide with local utility needs. Utility events needed to be called in addition to BPA events. This was mainly a result of the PNWSGD project design, which called transactive events for testing or simulated results purposes and not as a result of real BPA system issues.

Portland General Electric's Rush Hour Rewards Program

PGE's Rush Hour Rewards Program is a BYOT program that partners with NEST. In several ways, this partnership provides a vital program aspect. BYOT programs offer one advantage: the utility is not responsible for the technology's well-being. NEST is the obligated party, providing the utility with a level of protection. Another advantage arises from access to the technology itself; NEST thermostats automatically adjust cooling and heating temperatures when PGE calls events—an arrangement practical and intriguing for both PGE and its customers. If uncomfortable, customers can still take control of their thermostats.

The program launched in November 2015, with a target of 75 MW in demand response by 2121. Currently, the program has 2,600 participants, more than 400 of those with heating. The program targets demand reduction in heat pumps during the winter and heat pumps and central AC during the summer. The program recruits participants year-round and co-markets with the ETO. The marketing materials show the logos of NEST, PGE, and ETO next to one another.

To evaluate this program's impacts, PGE implemented a randomized control trial design, comparing control and treatment groups. So far, PGE has evaluated preliminary results within planned ranges, and discovered about 0.7 kW in demand reduction on average across all participants and 1.0 kW in demand reduction for those that started (or initially participated) in an event. Sixty-three percent of devices completed the full event of the 87% that began the event.

PGE found high customer satisfaction and engagement levels across treatment and control groups. Josh Keeling even stated that many control group customers expressed frustration that they never experienced an event. Customer satisfaction levels with the NEST thermostat, the incentives, and the program in general were similar between the control and treatment groups.

PGE expressed that they continue to learn a lot as they go through this program. One particular topic of interest was what happens to a smart thermostat when PGE customers move homes. Thus far, PGE has seen it common to find thermostats that move with the home, as these thermostats represent a reasonable monetary investment. It is also common, however, to see smart thermostats advertised as a selling point in homes. This provides an interesting problem when trying to predict program-related demand reduction that PGE hopes to further explore as the program continues.

Another issue with vendor centric programs is the long-term ability to count on the demand reduction if the vendor goes out of business. Programs such as NEST rely on a proprietary communications protocols that will go away if a vendor succumbs to bankruptcy or ceases operations. This can strand these assets and dissolve demand response benefits for the utility. Utilities should explore risk mitigation elements in their contracts with vendors and require open standard communications protocols so this situation can be avoided. See the Interoperability section of this paper for more information.

COMMERCIAL AND INDUSTRIAL PROGRAMS

C&I customers and residential customers differ in multiple ways in their demand response program participation motivations, engagement levels, and the types of programs in which they participate.

Overall, C&I customers need a guarantee from their utility that they can run their businesses, manufacturing, and production processes when necessary. They could lose money without this guarantee, which presents a huge barrier to entering any demand response programs.

Barriers to Participate

According to John Steigers from Energy Northwest, C&I customers express interest in pursuing demand response opportunities. Graham Bailey from the Northwest Pacific Paper Corporation believes there are about $2 million in demand response opportunities for C&I customers. However, participation in demand response programs comes at a risk to these customers.

Safety presents another participation barrier for C&I customers. Many customers are not physically equipped to handle demand response events in a safe yet effective manner. Events can be called with very little notice, but many facilities require time and care to safely shut down their machinery. Rushing this process can be a risk C&I customers are not willing to take, no matter the incentives.

Demand response programs present other risks to C&I customers as well: the foregone revenue resulting from shutting down their business, manufacturing, or production processes often is not worth the incentives available to participants. Participants can also lose customers as a result of an ill-timed event. This, again, is a risk that many C&I customers are not willing to take.

Solutions to Entry Barriers

Despite the risk demand response programs can present to C&I customers, solutions available now and in the future can help engage and acquire C&I customers in demand response programs.

Batteries and Storage

One such solution may be to improve energy storage. Storage would allow C&I customers to participate in demand response events without interrupting their critical loads, which is one of the main barriers to participation for C&I customers. Many C&I customers would likely participate in demand response programs if they could respond to demand response events without disrupting their operations

Bailey of Northwest Pacific Paper Corporation believes battery storage will serve as a game changer, though the cost of investing in battery development currently proves prohibitive for pilot programs. Other storage tools are currently on the market (e.g., storage chests). C&I customers can run their plants, fill up stock chests, and run them when a demand response event is called. Storage chests, however, face many drawbacks. For one, they still require a large monetary investment. They also are susceptible to natural disasters, such as earthquakes—a huge deterrent for California C&I customers. Although batteries and other storage means are currently not available in economically reasonable forms, technology is continuing to improve and prices should reduce. As the price of storage decreases, the value of loads generated will increase, and, when this happens, storage technology can be considered more feasible when rolled out to C&I customers.

Penalties and Incentives

As discussed, participating in demand response events can present higher risks for C&I customers. As such, even if they enroll in demand response programs, no guarantee exists that they will participate in demand response events. Penalizing enrolled C&I customers when they do not participate in demand response events presents one solution to this, and some utilities have seen participation rates improve with such systems in place.

Offering incentives for participating in demand response events provides another obvious solution for utilities' consideration. It will become critical, however, to first determine an optimal incentive amount; C&I customers will only consider incentives after they determine what kind of risk justifies the incentive. The right incentive amount also depends heavily on the year and the industry, but generally it comes down to economics— if an optimal incentive amount exists.

Promoting Other Benefits

Fred Yoo of Pacific Gas and Electric urged utilities and those promoting demand response programs to C&I customers to discuss other, long-term benefits of entering into demand response programs and participating in demand response events. Such benefits can include avoiding sudden blackouts while prolonging the life of their infrastructure. In addition, better load management by C&I customers can prolong the life of both the customer's electric infrastructure and the utility's distribution and substation infrastructure.

Cascade Energy—Insights into Industrial Demand Response

Marcus Wilcox—the CEO of Cascade Energy—provided some insights into industrial demand response programs. Cascade Energy specializes in designing, managing, and supporting almost every industrial program for utilities in the Northwest. Sysco has been Cascade's main client for 11 years. Industrial customers present a distinctive characteristic: as equipment in plants is

expensive to replace, it stays in operation for a long time. When a facility is purchased, equipment is often purchased as well, rather than being switched out for more efficient versions. At the same time, industrial equipment uses much more energy than devices in the residential or commercial sector. Therefore, one industrial customer participating in demand response could have a much greater impact than a large block of residential participants.

That said, industrial customers prove risk averse, secretive, slow, strategic, and understaffed. Stiff competition occurs for departmental budgets, which often pushes energy priorities below safety, compliance, and productivity priorities. When asked to participate in demand response programs, industrial customers express concerns about rescheduling or forgoing their processes and about the tremendous associated risks.

Other than avoiding short notification demand response programs, Wilcox offered several recommendations for facing challenges in the industrial sector. First, utilities must leverage investments already made in energy efficiency for demand response: use controls already set up, and remind customers that demand response requires similar data as energy efficiency. It is also crucial to realize that switching from energy efficiency and demand response capabilities may not produce linear effects; interactive effects between energy efficiency and demand response are site dependent.

For recruitment, prioritize customers who have participated in strategic energy management programs, as they more capably adapt to changes in energy use. This is perhaps the strongest strategy for the industrial sector, echoed by ETO's work. The industry highly values relationships, credibility, and trust. Therefore, utilities must carefully build demand response on top of existing interactions with industrial customers. For example, having a single point of access for energy efficiency and demand response would alleviate customers' uneasiness with a new type of program.

EXPANDING BEYOND THE PILOT

A number of demand response pilot projects have been run in the Northwest in recent years and many are underway. As projects scale up to tackle the Council's goals, the focus will move toward expanding these pilots into full-blown programs that can be rolled out to a larger population of customers in the region.

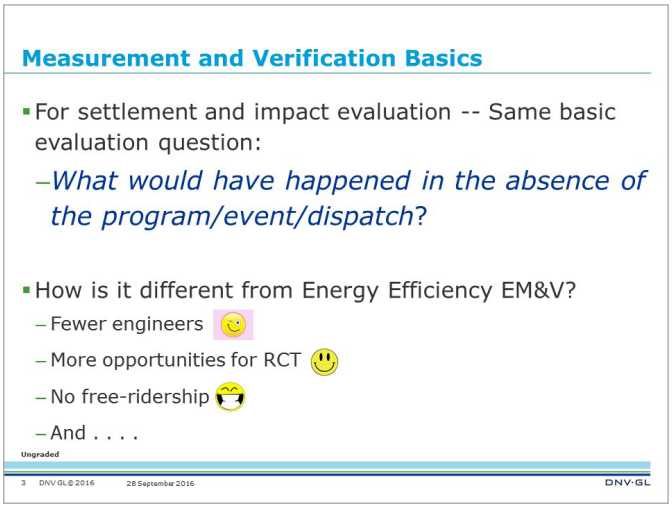
Each panelist agreed that the first question utilities should ask themselves when considering expanding pilot demand response programs is what they want to achieve in the expansion. Investigating lessons learned from pilot programs remains key to entering into a successful, well-maintained demand response program. Comverge suggested targeting customers who can already achieve demand response through technologies in residential homes or C&I facilities. Doing so cuts expansion costs and takes advantage of potential savings already in the service territory. Robin Maslowski from Navigant suggested that, to reach demand response targets, utilities only need to engage a handful of C&I customers.

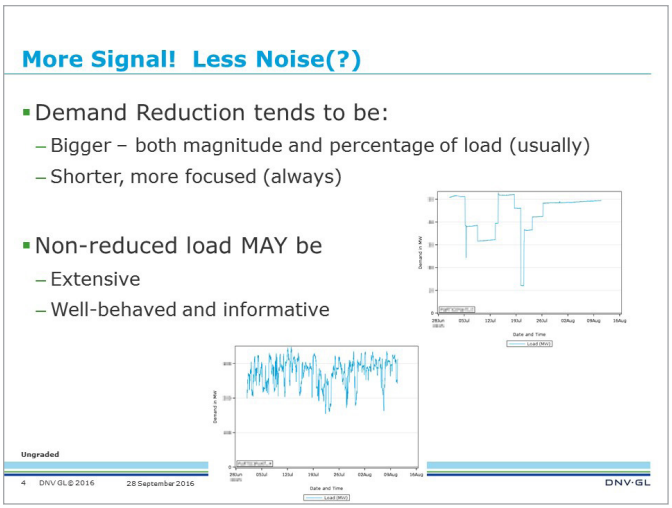
Mature programs also face different challenges than pilots or first-year programs, especially related to customer retention. Not only do utilities need to recruit new participants, they need to maintain currently-enrolled participants. As many participants lose program enrollment when they move homes, Idaho PUC suggested that utilities offer a streamlined process that checks in with customers as they move. Doing so could potentially increase customer retention and recruitment.

GETTING INTO THE WEEDS WITH M&V

Demand response M&V presents an important topic, described in the trading floor section. But just how to accomplish this and if are any standard procedure methods for the process continues to undergo development.

The following two charts from Ken Agmew of DNV GL's presentation clearly sums the benefits of demand response M&V over traditional energy efficiency, making demand response that much more useable and reliable:





Primary demand response benefits are the reliance on real-load data versus the detailed engineering simulations required by energy efficiency facility modeling. Demand response is more data driven. Events happen during dispatch periods, occurring at verifiable time periods, while energy efficiency goes on throughout the year, making it difficult to identify for traditional trading operations.

Randomized controlled trials also can be used, randomly assigning households or businesses into a treatment or control groups that are statistically identical to the treatment group. This eliminates most forms of bias, and allows evaluators to calculate unbiased savings estimates.

Ken Schisler of EnerNOC discussed the need for baselines supported by randomized controlled trials. These baselines come into play when incentivizing demand response customers through a means different than paying for metered load. As with energy efficiency, demand response may be incentivized by everything from loans to cash participation payments to adding frequent flyer miles to a customer's account.

Under ideal conditions, real-time dynamic pricing could eliminate the need for baselines, as incentives would be clear: the price is higher for a particular hour of the day, and load is reduced by customers responding to that price signal. This has been proven effective for demand response in Europe, but, slow in the United States due to conservative regulatory movement and historically inflexible utility billing systems. So, uptake of dynamic pricing flounders and incurs lengthy demand response program development times, and with meager early customer demand response volumes, revamping utility billing infrastructures does not generally warrant the cost.

Dynamic pricing also generally requires painfully high prices to induce proper behaviors, as customers generally do not have time during their busy days to observe prices in effect at a given moment. Demand response programs with proper incentives are simply more popular than dynamic pricing with customers, as they provide a carrot instead of the stick as found with high event-driven prices under systems with dynamic prices.

Many economists consider dynamic prices as truly representing the future of demand response, and these certainly come into play for a future involving transactive energy. However, until utility billing systems can adequately deal with dynamic prices and utility regulation evolves to institute dynamic prices, demand response programs with verified baselines will be required.

Demand response program baselines generally involve clearing or settlements that utilize incentives, as Schisler pointed out in his presentation: "Proving a Negative: The Counterfactual Proposition of What the Customer did not Consume." This has been done for many years with energy efficiency, but it is still being refined for demand response.

Proving a negative requires careful design to avoid "gaming" a system. Demand response gaming can occur when demand response business rules permit a customer or aggregator to artificially inflate performance and cheat the system to gain greater incentives. Demand response can be vulnerable to gaming accusations since performance is based on a counter-factual negative. Many gaming forms have been identified, and best practices exist to avoid them. Typical demand response gaming includes the following:

- Locking in stale baselines
- Overconsuming prior to an event's start
- Inflating peak load contributions

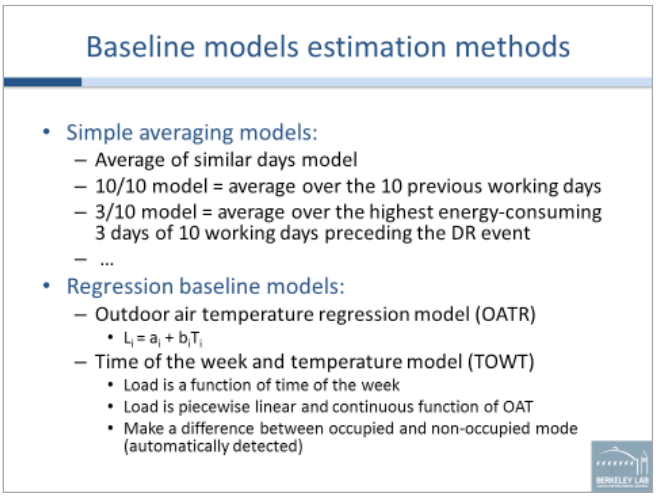
Business rules should be developed and adopted to carefully limit gaming potential. It is difficult, however, to completely design out gaming at the start of a demand response program. Vigilance and enforcement with serious consequences for abuse often works better than trying to stamp out all possible gaming forms in a program's design.

Samir Touzani of Lawrence Berkley National Laboratory described how to build a solid baseline. It begins with good data preparation, which carefully aligns weekdays seasonally and excludes weekends and holidays, which are generally excluded because typical behaviors that lead to system peak do not occur at these times. Loads prove much more random on non-work days as people do not follow a set schedule.

Weather always serves as an important driver of electric loads; a good weather data source is required at the same granularity (30-minute or 15-minute intervals, as needed for the load analysis).

Next, load data must be cleaned. This includes dealing with missing data and determining methods to fill the gaps (e.g., linear interpolation). Unusual events such as power outages or non-routine events also must be screened and excluded from the datasets.

Step 3 involves choosing the right baseline model. Touzani described different model types in a slide from his presentation:



Regression models that compare cleaned loads to outdoor temperatures generally provide a solid basis for establishing a demand response baseline. Baseline modelers must choose models that best fit the data available and fit the demand response program's complexity. Program developers should also keep in mind the relative value cost for achieving a solid baseline compared to the value of the demand response program. It would make little sense to utilize a large portion of a demand response program's budget for developing the perfect analytical baseline when the overall amount of demand response incentives are too small to justify the analysis costs. Stakeholders need flexibility to choose appropriate baselines for demand response program requirements and not overanalyze the process.

DEMAND RESPONSE PRODUCTS, INTEROPERABILITY, AND STANDARDS

The IoT, which represents millions of consumer devices all working together, requires the glue of interoperability standards

DEMAND RESPONSE PRODUCTS

An integral and concrete part of demand response programs are the products and technologies used for demand response communications and control. Some of these products may already be offered under energy efficiency programs, such as building management control systems. The utility industry must work with product manufacturers to ensure demand response communications components are added to existing and new products. Demand response products can display the following characteristics: connectivity, autonomy, granularity, and variable capacity.

Manufacturers such as Whirlpool and GE are embedding wireless connectivity into their products. For example, a clothes dryer can directly communicate with a router and feed information to customer service. As manufacturers are already developing this communication capability, utilities should seize the opportunity to encourage (e.g., through incentives) and require open communication standard channels that allow remote energy management control. Proprietary systems should be discouraged or left to safety or maintenance functions needed only for the manufacturer. For example, Amazon's Echo Dot offers connectivity of devices throughout a home at an affordable price by partnering with manufacturers such as Whirlpool and GE. The Echo Dot introduces

a new lifestyle to residential customers, potentially increasing customer interest in demand response products. Utilities can benefit by examining demand response use for such a communication platform and can organize and encourage Amazon to provide a standard communication path for demand response functions of connected devices. Along with connectivity comes autonomy. For example, Daikin is building its air conditioners to autonomously adjust based on personal comfort and upcoming weather patterns. Daikin could just as easily build in capability to adjust based on variable utility prices.

The new lifestyle concept dovetails with two other characteristics of demand response products: granularity and variable capacity. With the availability of data, people look at common everyday appliances with a more granular perception. They want to alter their environment at a more granular level, feeding into the variable capacity of demand response products. If the utility can talk directly to a clothes dryer, it may also slow the drying process versus shutting it down. The same dryer can dry for a short time with a compressor, or it can dry for a long time at low consumption.

Utilities must work with manufacturers to incorporate demand response capabilities into their products. Manufacturers do not care about the value of demand response; so the utility industry must build a value case for them. Since manufacturers operate at a national or global level, the Northwest must build partnerships with other regions or players to steer the manufacturers.

The state departments of commerce or departments of energy could consider including demand response in federal legislation, requiring demand response components to be added to appliance manufacturing, but this seems highly improbable. On the other hand, utilities should monitor the demand response integration of different types of products done for the manufacturer's reasons. For example, compared to other C&I products, consumer products such as phone app controlled lighting are potentially high-volume markets that could result in significant demand response management ramp up just through normal purchasing behaviors.

INTEROPERABILITY

Once manufacturers agree to build demand response capabilities in different devices, demand response signals must be easily communicated between utilities' system operators and customers. All technology vendors at the symposium agreed that standards were necessary in the demand response industry. Michel Kohanim of Universal Devices stressed that, without standards, automation does not matter because resources cannot communicate with one another, and the system cannot satisfy a client's needs. Graham Horn of Enbala added that, as speed becomes more valuable in demand response, communication standards become even more paramount.

Before delving into the importance of standards, the concept of interoperability must be introduced. Interoperability is the ability of different proprietary systems to communicate with one another. In other words, different systems operate using a shared meaning of content and an agreed specification of behaviors and interfaces. James Mater of Quality Logic deems interoperability as a requisite service quality that embodies reliability, fidelity, and security.

To achieve interoperability without standards, systems must rely on expensive custom integration. Interoperability increases when vendors make an application programming interface more visible and standardized. Then, systems must adopt a common information model (e.g., the same units). A common information model is not the same as a standard—it merely uses the same language. Therefore, achieving interoperability does not necessarily mean complying with standards.

SMART GRID STANDARDS

Different types of standards concern the utility industry (e.g., power standards, safety standards, M&V standards). In demand response, smart grid standards are communication protocols that scale interoperability to the consumer level. Smart grid standards make up an ecosystem that consists of the following types of standards (with examples of some standards for each type):

- Semantic: OpenADR, IEC 61850, DNP3
- Syntax: HTML, XML, SOAP
- Network: FTP, TCP, IP, IPv6
- Transport: Wi-Fi, cellular, mesh

OpenADR serves as a prime example of a quality smart grid standard. As stated on the OpenADR.org website, "Open Automated Demand Response (OpenADR) is an open and standardized way for electricity providers, third-party aggregators and facility operators to communicate demand response signals with each other and with their customers using a common language over any existing IP-based communications network, such as the Internet." OpenADR started in 2002 during the energy crisis in California, attempting to achieve properly functioning demand response in the region. The standard has undergone an iterative process of research and development, pilots and trials, interoperability standards development, and deployment and market facilitation, culminating in an implementation guide released in 2016.

At the symposium, some utilities had questions about differentiating between differing types of standards. For example, OpenADR (a semantics based communication protocol for consumer devices) is confused with IEEE standards (electrical system equipment standards), NERC standards (reliability, safety, and security protocols) and WECC standards (procedures for participating in the western power grid).

WHY DOES DEMAND RESPONSE NEED STANDARDS?

The Oregon PUC offers a few reasons why demand response needs standards such as OpenADR. If smart grids advance from just achieving interoperability to fully complying with standards, they can reach their fullest potential as they allow the broadest possible set of products to work together.

From an open market standpoint, standards enable freedom of choice between different vendors while assuring different vendors products work as expected. Often termed as "interchangeability," this allows new players into the market and increases innovation speeds. Additionally, as customer engagement is extremely important in demand response, having communication standards that enable robust operational controls decreases the likelihood of process disruptions (e.g., for industrial customers).

Simply put, standards save time and money. Cadmus' Mark Osborn shared lessons learned from the PGE Dispatchable Standby Generation Program, which integrated a variety of customer-owned, utility-controlled distributed generators (over 100 MWs) for utility peaking needs. Complying with the IEC 61850-7-420 standard with object oriented programing shortened the integration of a generator to the utility system from three weeks to three days. Sometimes regulators do not realize the magnitude of money wasted in systems integration when standards do not exist. This is because numerous system integrators used for projects are considered a cost of installation, when in reality, standards could have reduced installation times and costs significantly.

Because of a lack of standards' utilized in the PNWSGD, much time and money was spent on custom integrations. The PNWSGD, which created the foundation of a sustainable, regional smart grid that coordinates different assets—including demand response, distributed generation and storage, and distributed automation for 11 utilities across a five-state region—was continually challenged by immature or lacking smart grid communication standards. More importantly, the project accomplished an unprecedented level of interconnection and interoperability among thousands of different makes and models of electronic devices through the hard work and custom integration efforts of dozens of systems integrators. Every five minutes, a value signal (Transactive Incentive Signal) with a 72-hour price forecast was sent to utility devices from Battelle; at the same interval, a load/generation forecast (Transactive Feedback Signal) was returned to Battelle.

LESSONS LEARNED ABOUT SYSTEM INTEGRATION

PNWSGD provided some valuable lessons learned for smart grid deployment, including implementing demand response programs. The project demonstrated that, when utilities have diverse and mostly proprietary systems, each utility faced the very expensive process of custom integration to achieve interoperability. Therefore, adherence to smart grid standards provides a necessary means to avoid custom integration for similar future projects and for broad deployment of demand response to meet the Seventh Power Plan targets.

Although vendors at the symposium acknowledged the importance of standards, some vendors participating in the PNWSGD project would not have used standards if standards were not imposed on them. Therefore, as corroborated by the Oregon PUC, a key lesson learned is that utilities should decide on standards to adopt up-front. Osborn summarized other lessons learned from the

PNWSGD in ensuring interoperability and robust system integration for demand response programs as follows:

- Choose mature standards over underdeveloped ones.
  - Underdeveloped standards can change frequently during program demand response development and may create more problems than they solve.
    - The two most common standards used in PNWSGD (DNP3 and MultiSpeak), followed closely by Modbus, OpenADR, and a couple instances of BacNet.
- Specify standards use in the project RFP and design process.
  - At demo project's start, getting all manufacturers to switch to standards after their bids were accepted proved difficult.
  - Requiring standards in the RFP, contracting, and program design phases facilitates their adoption.
- Choose financially healthy vendors that provide long-term product support.
  - If vendors go bankrupt, utility assets may be stranded only because the communications to the devices no longer works. If standards are used, the utility or another vendor can be operating the bankrupt vendor's devices within a short period of time.
  - Avoid defaulting to currently used vendors, as their solutions may be proprietary or a force fit. Interoperability may be just as easy (or easier) with a new vendor's solution.
- Appoint key human resources in charge of each communication interface between devices to assure interoperability and interchangeability.
- Test, test, test. Devote significant time and effort to lab test all communication systems prior to field deployment.

CONCLUSIONS

The questions for the region: is there sufficient leadership, a compelling enough business case, and a strong enough will to drive demand response development to the point of providing a substantial viable capacity resource?

The Northwest Demand Response Symposium provided an excellent start to answering these questions in the affirmative, but clearly more work remains by all interested stakeholders. The following are the key themes and summary of the symposium.

KEY THEMES

- **Demand response education is greatly needed to provide the visibility of benefits, to gain customer acceptance, and to justify financial investment support.**

Establishing a solid definition of demand response in the Northwest remains a high priority. This paper presented a definition of demand response and put it in the context of other distributed energy resources. However, demand response, like many smart grid technology concepts, has fluctuating definitions depending upon the organization defining it.

For utility program planners, the Council's modeling shows sufficient value to pursue a minimum of 600 MW of demand response to a more typical value of 1,300 MW. However, their modeling only covers demand response's generation and transmission benefits. As utilities evaluate their own positions regarding demand response development, they must consider distribution system benefits in addition to the Council's benefits. Many in the industry believe demand response's true value and compelling business case arises from a detailed analysis of distribution system benefits, such as substation and/or feeder equipment deferrals as well as, strengthening utilities' relationships with their customers.

- **Leadership is needed, and there are drivers and evidence making a case for demand response. Utility program designs should fully exploit the nexus between energy efficiency and demand response.**

Climate change and changes to peak demand serve as the main drivers for demand response, and CAISO's energy imbalance market helps generate the topic's momentum. Regulators at the symposium expressed interest in learning more about demand response and remain open to discussing their roles, whether developing the guidelines for demand response

planning or supporting the mainstreaming of demand response.

Most importantly, regulators and utilities acknowledge that demand response requires a long-term outlook and commitment that may have fuzzy initial benefits. This translates to an immediate need to jumpstart the demand response investigation and development process, while allowing demand response programs to steadily grow incrementally over time.

The utilities that already have some experience with demand response all agree that leveraging the nexus between energy efficiency and demand response is a key element to implementing successful demand response programs. As apparent in the industrial sector, customers who have heard of energy efficiency programs can be more easily introduced to demand response programs. Products and implementation mechanisms designed to incorporate energy efficiency components can be used to incorporate demand response components. Nevertheless, utilities still need to put in efforts to work with manufacturers and regional partners in this regard. Ultimately, the general consensus from utilities is that energy efficiency still comes before demand response; but adding demand response to their portfolios should not conflict with but enhance energy efficiency progress.

- **Successful customer engagement is the foundation of demand response.**

An exemplar of demand response programs was presented to clearly provide a framework for program development best practices. This was followed by the area that clearly needs the most exploration and development so that the trading floor of utilities are fully engaged in developing programs that meet system operational needs. This was reinforced by the need to show demand response as a firm or at least firmer resource to systems operations. M&V techniques as well as performance results will go a long way to structuring demand response programs for trading operations.

Residential program concepts including BYOT were presented along with the specific requirements for successful commercial and industrial demand response programs. It was clear that demand response pilot programs provide a good background and experience, but utilities must work harder to go beyond the pilot program and deploy full roll out programs to all their customers in order to meet Seventh Power Plan objectives. The best practice for full roll out is to build in full roll out objectives into pilot projects and leverage the customer relationships, the industry partners, and the operational experiences developed over all the years of energy efficiency program operations.

Strategies such as co-branding (with technology venders) and stakeholder consultation (even prior to RFPs) may be critical in ensuring successful customer engagement. On the other hand, continuous engagement with customers creates a continuous learning process for utilities to improve their demand response programs.

- **Millions of consumer devices all working together—IoT—requires the glue of interoperability standards.**

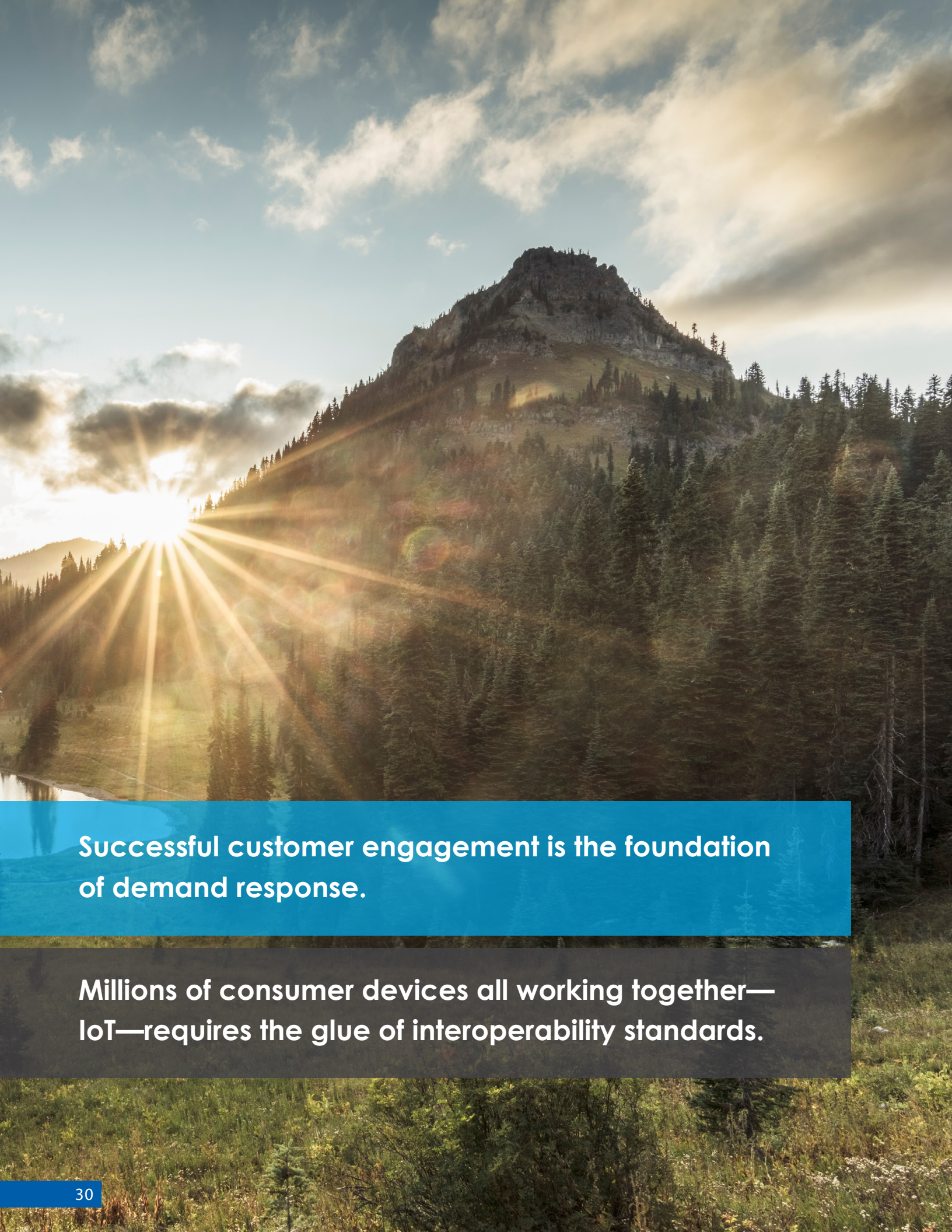
With technological innovations, demand response products can display the following characteristics: connectivity, autonomy, granularity, and variable capacity. Manufacturers of home automation are already adding these characteristics into their products, so utilities must partner with manufacturers to ensure that these characteristics are serving demand response functions as well.

Once demand response components are added to products, demand response signals must be communicated between utilities' system operators and customers. At the very least, utilities need to ensure the interoperability of their systems (i.e., sharing the same language). Adopting communication standards on top of achieving interoperability allows utilities to recuperate the maximum amount of demand response benefits by having the broadest possible set of products working in sync.

Instead of leaving the choice of standards use to demand response vendors, utilities must continually support standards development and take charge in adopting standards so that the success of demand response implementation rests in their own hands. If that is not done, then a real risk to the long-term viability of a demand response program could be stranded assets that result from failed proprietary control communications to the device, not because the device (such as a smart thermostat, water heater, or energy storage system) no longer functions.

Demand response education is greatly needed to provide the visibility of benefits, to gain customer acceptance, and to justify financial investment support.

Leadership is needed, and there are drivers and evidence making a case for demand response. Utility program designs should fully exploit the nexus between energy efficiency and demand response.



Successful customer engagement is the foundation of demand response.

Millions of consumer devices all working together—IoT—requires the glue of interoperability standards.

CADMUS

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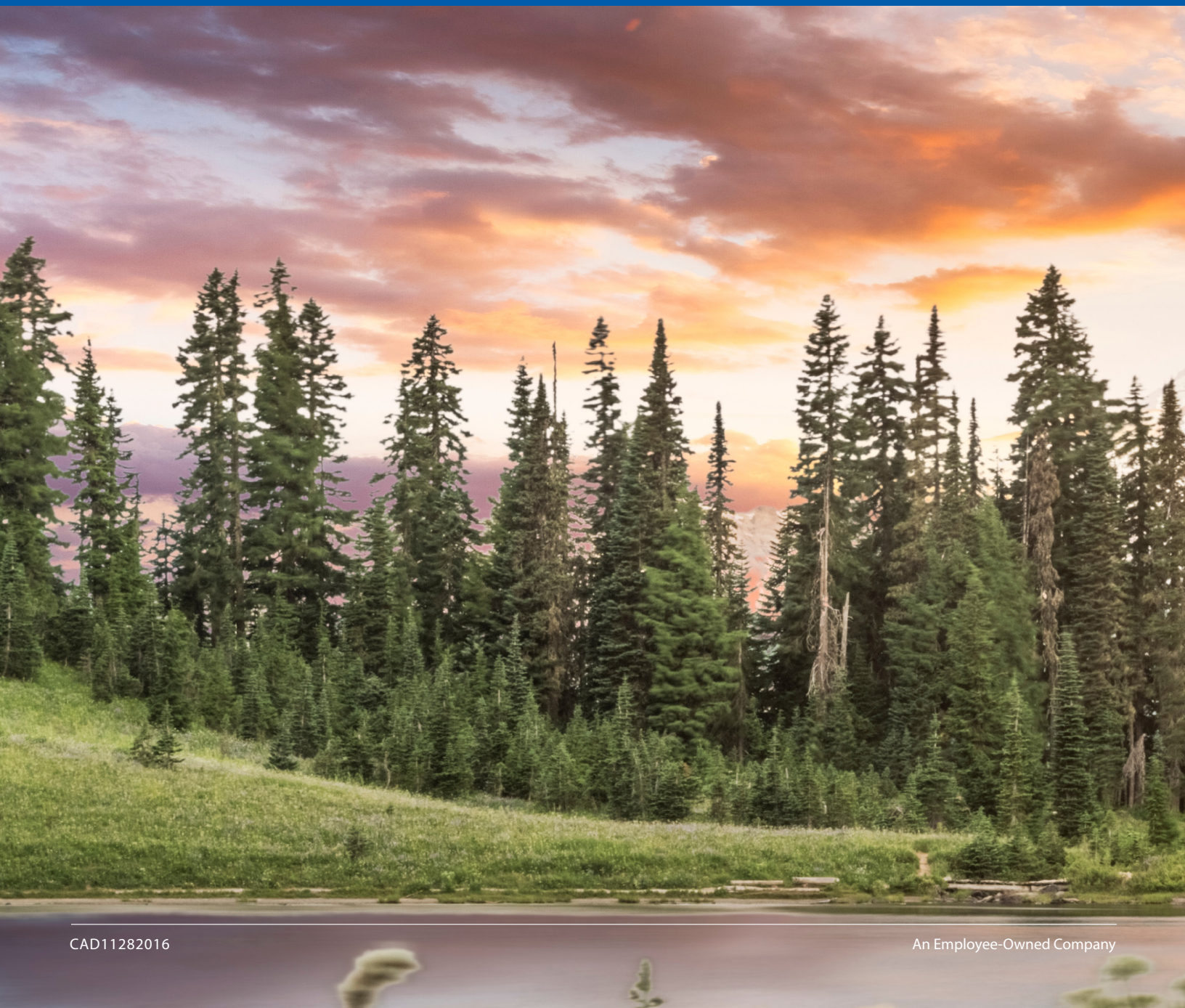

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