Electricity Markets Under Deep Decarbonization: Summary of Workshop Conversations

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Disclaimer

The meeting organizers and note-takers made every effort to accurately convey the conversations that took place among the participants. Any incorrect or misheard statements are the responsibility of the organizing team.

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Contents

Abbreviations

CAISO	California Independent System Operator
ELCC	Effective load-carrying capability
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
IRA	Inflation Reduction Act
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
LMP	Locational marginal price
LSE	Load-serving entity
MISO	Midcontinent Independent System Operator
REC	Renewable energy credit
RPS	Renewable portfolio standard
RTO	Regional transmission organization
SPP	Southwest Power Pool

Electricity Markets Under Deep Decarbonization

Introduction

The energy system is going through a remarkable transition. To meet climate and carbon reduction goals, numerous local and federal government policies, corporate goals, and consumer preferences are leading toward a lower-carbon future. A key part of that low-carbon future is a low-carbon electricity supply fleet and the electrification of other sectors such as buildings and transportation. This can create challenges, as the way in which the electric power system is planned for and operated can be significantly different from what it is today. In 2019, the Energy Systems Integration Group facilitated a workshop to review several workstreams representing the challenges associated with meeting a 100% renewable energy power system and the research needs to mitigate the challenges.[1]

In many parts of the world, wholesale electricity markets are an enabling feature of the electric power system. While operating and planning strategies, new software tools, reliability standards, and grid codes can support the reliability of the system into this transition, electricity markets can often enable strategies to do so in economically efficient ways, while incentivizing cost-reducing and innovation strategies. Electricity markets are designed differently in different parts of the world, but often use uniform prices based on the marginal cost to provide in a particular location and time, markets for bulk system grid services, and some mechanism to promote resource adequacy. The designs differ and grow in complexity from there. Retail markets also exist in some parts of the country where retailers can provide different options to consumers.

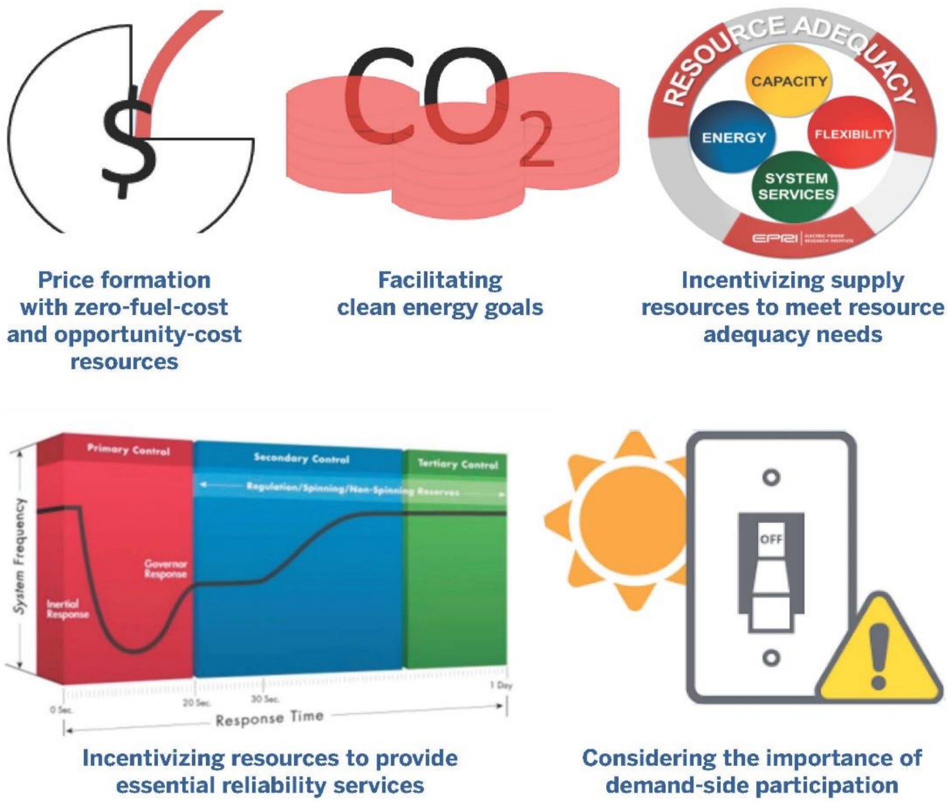
The wholesale electricity markets were designed after a supply fleet that was mostly traditional thermal resources that represented base load, mid-merit daily cycling resources, and peaker resources. Practitioners and researchers have been asking the question of how well the primary design of these markets will work if:

- The supply is predominantly from resources without fuel costs.
- Demand is more responsive to prices.
- Our ability to maintain an adequate supply comes to have a different meaning than it does today.
- We have a different set of reliability services—or different needs for them—that may require innovative ways to enable them through market solutions.
- We determine that market forces are necessary to accomplish the most efficient way to meet clean energy targets.

[1] https://www.esig.energy/esig-releases-toward-100-renewable-energy-pathways-key-research-needs-report/.

On February 28 and March 1, 2023, experts were convened in Washington, DC, by the Energy Systems Integration Group, Electric Power Research Institute, Argonne National Laboratory, National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, Johns Hopkins University, and the Department of Energy for a workshop on electricity markets under deep decarbonization. This workshop brought together a set of experts to listen and debate the existing market designs and their effectiveness, solutions that have been explored and their effectiveness, and the possible actions necessary to bridge any remaining gaps. The discussions are the first of what will be many, exploring paths that will allow the markets to continue to play a role in promoting reliability and efficiency as the energy transition proceeds (Figure 1).

FIGURE 1
Areas in Which Markets Can Play a Role in Promoting Reliability and Efficiency in Decarbonized Electricity Systems



Source: Electric Power Research Institute.

Participants in the workshop included people representing many different organizations involved in the design of electricity markets and impacted by those designs: wholesale market operators, wholesale market regulators, transmission-owning utilities, independent power producers, financial traders, financial investors, market monitors, consumers, technology providers, environmental organizations, and researchers. The discussions were robust and yielded many more questions than specific actions. These discussions will help two organizations prioritize their efforts:

- The Energy Systems Integration Group will create a task force to explore electricity market design under 100% clean energy systems
- A research consortium supported by the U.S. Department of Energy will be conducting research using advanced tools and methods to explore the topics discussed in this workshop and provide quantitative results to support the industry with informed decisionmaking

Important Considerations and Disclaimer

The details of these discussions are given below. The workshop used the Chatham House Rule, and as such the names of the individuals and organizations are not provided. The authors and notetakers have done their best to capture the conversation as it happened (with no recording) and may not have captured the discussion with perfect accuracy. All participants voluntarily chose three of the nine sessions to participate in. Repeat sessions on a given topic did not include any of the same participants. The dialogue was completely open without any additional rules other than to discuss challenges, opportunities, and potential actions related to the topic for each session. Statements made during the discussion have not been checked for accuracy. The organizations that facilitated this workshop, including the Energy Systems Integration Group, the Electric Power Research Institute, and the U.S. Department of Energy and its national laboratories, do not necessarily support or reject any policy opinions or other suggested actions made during the meeting.

Can Markets Be Designed to Enable Emissions Targets and Clean Energy Goals?

Session 1, Emissions Targets and Clean Energy Goals

Summary

This session focused on the opportunities, capabilities, and responsibilities of different organizations in the context of reaching clean energy goals, in particular, clean electricity. Competitive procurement or investment auctions run by states or large corporations were identified as key markets that are often overlooked when discussing markets, because they are not organized by independent system operators and regional transmission organizations (ISOs/RTOs). Evaluating different approaches to these competitive procurements was identified as a potential research opportunity. Consumers expressed wanting parallel play for capacity procurement, that is, to use both direct agreements and ISO/RTO markets. Concerns were raised about a disconnect or "wedge" between clean energy goals established via public policy, the role of the ISO/RTO, and efficient ways of achieving the desired outcomes.

Key questions included:

- Could ISOs/RTOs offer better instruments to allow policies to more precisely target the "right" goal versus using an imprecise proxy (e.g., a renewable portfolio standard (RPS) when the goal is decarbonization)?
- Should ISOs/RTOs be responsible for gatekeeping or guarding against cost-ineffective policies? If not, should there be any other oversight or is it clear that elected policymakers are those responsible?
- Should ISOs/RTOs provide transparency or "truth-telling" service to policymakers and the public about the costs and options of different clean energy goals?

Participants discussed how wholesale markets have helped enable clean energy goals, citing that the rate of reaching RPS goals is higher in states covered by an ISO or RTO and giving the example of wind developers viewing the Southwest Power Pool (SPP) as a favorable location because of the RTO-facilitated access to transmission.

Discussion topics:

- How should markets rules and practices consider clean energy policies?

- How should spot and bilateral work together to enable the achievement of clean energy goals?
- What is the best role for organized markets to enable clean energy goals?
- Should markets account for the Inflation Reduction Act (IRA) and other policies?
- How do spot markets fit with 24x7 clean energy purchasing?
- What is the relevance of carbon pricing compared to other state or federal decarbonization policies?
- Can issues such as leakage (consumers spending money outside the local market) be overcome if different states and countries or economies choose different carbon values? How can organized markets address leakage?
- Should we have market products other than renewable energy credits (RECs), for example, clean capacity credits and marginal emissions abatement credits?
- Should we consider central clean energy/capacity procurement?
- Will ancillary services become more important in a decarbonized grid?
- Should ancillary services be reformed to be more value-based rather than opportunity cost–based?

Conversation

Participant 1: What is the path—investment auctions or competitive procurement? What is often missing in discussions is that states are adopting plans and then holding competitive procurements (e.g., California and in New England). Virginia has a year-by-year RPS for 30 years with carve outs for technologies. This is a major part of "markets," but how does this mesh with RTOs? Google procured hundreds of megawatts for data centers in Virginia; efforts like this are driving changes in the generation mix in many areas.

Participant 2: Looking at rates via power purchase agreements for clean energy, no wholesale value streams are identified. There is no requirement to participate in wholesale markets; states are clear on what they want, and they are not getting it from markets. They don't want power purchase agreements on books. Are markets only for operation, or do they also drive procurement?

Participant 3: There was a study by the Brattle Group on the rate of clean energy investment, which found that it far exceeded RPS targets. The beauty and danger of central planning is they almost always get it wrong; they're often not aggressive enough. This is occurring exclusively in ISO markets. We need to look at role of state policies—do they surrender resource adequacy decisions to ISOs when they join? So far, the market has been a much more powerful driver of clean energy investment than state policies because of direct access buyers have to sellers.

Participant 4: In 2021 there were 65 GW of clean energy procurement nationally, accounting for 41% of all renewable capacity in the last decade.

Participant 5: A 500 MW deal was almost lost due to legislation being considered, showing how the underlying regulatory structure is important consideration for state policies. Can customers directly access the market? In RTO markets we see biggest benefits.

Participant 6: Do you want to directly procure clean energy from the RTO? PJM has done a good job supporting buyers with clean energy goals in capacity markets, but it is difficult to see a world where we rely entirely on RTOs for clean energy anytime soon. We need the ability to contract on our own, need granular hourly tracking of where energy is coming from. PJM is working on this, which builds confidence in ISOs.

Participant 7: Customers are looking for voluntary options for clean energy targets. There may be intermediate solutions, but these are not efficient long term. There is a limited menu of options for expressing clean energy needs. Is there a role for RTOs or others to expand the menu of options for voluntary buyers? Is there a role for centralized procurement?

Participant 5: When you start expanding menu of options, does this start to get away from the core of what an RTO is supposed to do? Goals are reliable service, just and reasonable—does this create Federal Energy Regulatory Commission (FERC) issues? We want to be careful to avoid overly strict or rigid capacity markets through narrow production definitions and provisions like the Minimum Offer Price Rule (MOPR) that deem certain resources to be necessary. We also don't want the only option to be taking whatever a central capacity market spits out; we want to maintain other options.

Participant 8: ISO markets are a great facilitator. Certain buyers might find it preferable to buy hourly clean energy that matches their real-time consumption. In this case, RECs will need an hourly tag. The non-FERC part of PJM is working on this, which would not be a centralized market.

Participant 6: This could also be taken on by a private entity, theoretically. It doesn't have to be part of the guts of the FERC market. A "parallel market."

Participant 9: From a user perspective, the visibility of bilateral arrangements to the ISO becomes important for transmission planning. The goal of policies and markets should be to accelerate procurement.

Participant 2: There has to be parallel play; states will always drive what they want and getting in the way will lead to litigation. Markets are great operationally, but states hear things are important and want to prescribe resources. For example, some jurisdictions are aggressive on decarbonization and happy to pay for offshore wind, but terrified by electrification, as they don't think markets will be able to handle it. There has to be a point where states are reigned in from choosing very out-of-market resources.

Participant 6: But who has the power to reign in state choices?

Participant 2: We will rely on the ISOs to be responsible and provide signals on how much things will cost. Utilities may not be able to do that.

Participant 10: ISOs/RTOs can't get involved in this; though; it is state and local policy. That would come across as price suppression. There are lots of products that don't get us what we need, and carbon pricing will probably never happen. In addition, lots of wind and solar development has been economic, particularly with federal credits.

Participant 7: ISOs/RTOs are not policymaking entities, of course, but they could play bigger role in informing good policy. They could demonstrate the benefit of central procurement for clean energy, and make this easier to understand and more transparent.

Participant 6: What do industrial customers see as rational clean energy design? Industrial customers doing bilateral power purchase agreements to get what they want (mostly in the Electric Reliability Council of Texas (ERCOT)). They are mostly concerned with low costs right now. In general, industrial customers are in favor of organized markets, but companies are going to go where they can get the best deals.

Participant 3: ISOs can indirectly address part of the concern around heading down a path toward an unreliable resource mix through the capacity accreditation process. Reliability becomes an ISO concern; therefore, they aren't powerless to address it.

Participant 11: SPP has a ton of wind. When production tax credits came out, the ISO model became a good place to site developer-led resources. In SPP, the future is now. Reliability issues from large wind are happening, especially when gas infrastructure is stressed. This is interesting because it is not state policy–driven development, but more from the federal production tax credit. There is virtually no retail choice within SPP; utility customers are all vertically regulated. How do we get out in front of the states and policymakers? Something is missing. How do we get that into policy if we want to enjoy the same reliability? We are seeing new challenges in Colorado, for example, where investment is more policy driven. Operators need choices if they are going to make optimal decisions.

Participant 12: In European markets the debate is around going to locational marginal prices (LMPs) and what that actually gets you. This has solidified some of the benefits of U.S. markets. Transparency in markets is big enabler of clean energy. For example, it is difficult to put together power purchase agreements and other contracts without price visibility. Also, in the UK, National Grid is doing a lot of re-dispatching.

Participant 6: In summary, I'm hearing that LMP markets are still very necessary. Does anyone disagree?

Participant 11: Generally I agree, but there can be complaints during long periods of zero to low prices. Is this really what we are heading toward?

Participant 3: If there are gigawatts of $1/MWh energy, can't we just get this low cost to consumers?

Participant 11: One key is interregional transmission planning, but who is going to pay?

Participant 3: Relieving congestion would reduce pockets of negative prices, so, yes, it comes back to transmission.

Participant 13: There was a collaboration between the World Resources Institute and the National Science Foundation in 2020 on organized long-term clean markets. The conclusion was that they are developing and are not ready for prime time. The general assumption is that markets make better decisions than central planning. This may be true in general, but it does not always apply in electricity markets where reliability is a public good. Markets will only make the right decisions if the prices are right, and it is really hard to provide the right price signals. Prices are always getting capped, trimmed, adjusted, because we live in the real world with regulators. Organized long-term markets are not just a single flavor, need to look out further than one to three years, be technology-neutral, and incorporate social goals. Can we do it all with wind, solar, and batteries? Likely no, we'll need some clean firm resources. In which ISO do these technologies have a chance of being built? What are the barriers for these technologies?

Participant 12: The focus should not be on just one technology. There are subsidy mechanisms, like the IRA, that offset initial costs, but what happens when incentives are gone? Paying for capacity in some form will incentivize clean firm resources, but who are the buyers? Right now, they are largely government, but this needs to expand.

Participant 6: Should ISOs be buying? Is this their role, or market participants'?

Participant 12: Coming back to centralized long-term clean energy markets, New England actually has four clean market products.

Participant 7: To get the prices right you need the right products. Interest in a clean capacity product is growing for voluntary participation. It is important to support state and customer preferences, but you don't want to deviate too far from least-cost decarbonization pathways. Is the clean capacity product the best approach to achieve decarbonization? Again, what is the role of the RTO?

Participant 14: Specifically, are ISOs responsible for being proactive in achieving decarbonization goals? Or are they supposed to be reactive to system changes initiated elsewhere?

Participant 7: We operate markets in the context of the policy world, and it is not an ISO role to proactively pursue policy objectives. But they can anticipate poor policies and provide better options.

Participant 2: There is a need for a truth-telling role, and ISOs are well suited. How much will different options cost? ISOs can help to communicate cost premiums to policymakers.

Participant 3: One challenge is that it is hard to estimate future costs. For example, what investor-owned utility is going to invest in large nuclear after Vogtle? [A nuclear power plant in Georgia where additional expansion of the facility has incurred high cost overruns and build delays.] There is still plenty of space for states to dictate the resources they want. We also tend to overstate the value of clean baseload. Central planning versus markets is all a question of striking the right balance. Markets have central planning elements baked into in their design: capacity markets, operating reserve demand curves, and RPSs are all central planning. Making portfolio-wide commitments for 15 to 20 years out based on what we know today is not a good idea.

Participant 15: It seems like much discussion has been around top-down approaches to achieving goals, but what about bottom-up approaches? Let the market operator do what it does best, and rely on the rest of the economy to drive decisions. Is there a way to get at these goals even though it's not an explicit goal of the ISO?

Participant 6: There is a big question here around roles and responsibilities.

Participant 13: ISOs are already making some implicitly policy decisions; this is dangerous because they are not really accountable. We need to be careful about laying more policy on ISOs. We don't want market designs to put up hurdles. For example, most countries are saying nuclear is part of the future. Let's not make bad policies that prohibit this.

Participant 6: Do we have any consensus and next steps?

Participant 14: If current markets aren't going to get us to 100% cost-effectively, whose problem is that? ISOs or policymakers? What does cost-effectively even mean if we are coming up short of goals? Which take precedence, the goal or the cost?

Participant 2: What does governance look like for clean procurement under different market structures?

Participant 16: We need to avoid paying for empty gestures.

Participant 9: The reality is that renewable energy uptake is not where it needs to be for 2035 in many regions. The IRA may help but doesn't solve transmission problems. This could be a role for ISOs—less focus on subsidizing generation and more on enabling.

Session 2, Emissions Targets and Clean Energy Goals

Summary

Discussion topics:

- Is this a market design question or a policy/regulatory question?
- States' clean energy policies versus Federal Power Act (FPA)/FERC non-discrimination rules in ISOs/RTOs
- What does it mean to "enable" clean energy? Is this a role of markets?
- Carbon markets and electricity markets
- Markets and sector coupling
- Capacity markets
- Interactions with the IRA
- The role of ISOs/RTOs: prescriptive versus facilitating or accommodating?

This session focused on discussing clean energy goals and potential ways to reach them. According to the participants, it is unclear whether clean energy goals should be met via electricity markets or through policy and regulation. There was a general understanding that markets would be a better option; however, it is not straightforward to determine an adequate market design to achieve the objective. For instance, it was mentioned that energy and ancillary service markets will be still necessary but not sufficient to signal clean energy investments. A potential alternative discussed by participants could be the creation of national RECs that can be traded in electricity markets. Transparency in terms of prices and trades would be a key aspect for RECs to work, which is not the case for currently traded RECs. Other participants mentioned that RECs may be a first step toward achieving clean energy goals, but further steps will be needed. Some participants also questioned the effectiveness of capacity markets in bringing the needed resources. Overall, the participants agreed that fundamental actions are needed to push the necessary clean energy investments in a cost-effective manner.

Conversation

Participant 1: There were 65 GW of customer-driven clean energy in the U.S. in 2021, which accounts for 41% of all wind solar and storage. What is enabling this? Eighty percent of it was in ISO territories, and the rest was driven by green tariffs.[2] Eighty-three percent of corporate deals are in ISOs, and 33% are in ERCOT alone. It is hard to isolate individual factors driving clean energy, but policy and customers are key drivers.

Participant 2: Energy and Environmental Economics (E3) has a white paper on scalable markets for the energy transition.[3] Is clean energy adoption meant to be a function of electricity markets? Fundamentally, it is driven by massive climate change externalities and not a function of electricity markets. The preferred approach to clean energy adoption is to price the externality and let this drive decisions, but the problem is implementation in practice. Pricing across only part of the system leads to perverse results and leakage. It may be worse than doing nothing. What if we put out something simple like a national REC? This doesn't mean people have to buy it, but it leaves electricity markets alone. Perhaps a trading platform where everyone can trade RECs. It can still create leakage issues: customers moving to a market where suppliers do not have an obligation for RECs. For example, the carbon market in Europe is serious, creating an incentive for loads to move to areas without requirements. RECs would need to be certified and tracked and only used once. In this case, would we need a single national registry? It would be inefficient to have it state by state.

Participant 3: We should also be thinking about organized long-term markets. We need to be digging into whether or not these are sufficient. Energy and ancillary service markets are necessary but may not be sufficient. It's not just about getting ISO prices right.

Participant 4: This sounds like the parallel play concept from an earlier session: compete to participate in the market rather than relying on the market alone. We need both the markets and some form of national carbon policy or pricing.

Participant 5: So, what is the role of ISOs in this case?

Participant 6: ISOs have a large role. They don't need to procure everything, but they have a lot of information that others don't have. They need to facilitate the process. States could collectively engage in resource adequacy; they need to petition FERC for this engagement.

Participant 7: But lots of control is at the state level. How do you get states to work together?

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[2] Utility green tariffs are designed as optional programs offered by utilities in regulated electricity markets and approved by state public utility commissions to enable larger commercial and industrial customers to purchase bundled renewable electricity from a specific project through a special utility tariff rate.

[3] Energy and Environmental Economics (E3), "Scalable Markets for the Energy Transition: A Blueprint for Wholesale Electricity Market Reform" (San Francisco, CA (2021), https://www.ethree.com/wp-content/uploads/2021/05/E3-Scalable-Clean-Energy-Market-Design-2021.05.25.pdf.

Participant 8: On the state regulatory side, states want to be engaged. Regional planning has to happen, but this requires regulators to come together, and right now states are going in very different directions.

Participant 9: In load-serving entities (LSEs) with an RPS and RECs, when there is oversupply and you get curtailed, you lose RECs. Energy that served your load is inferred at average carbon intensity even though you had the capacity for more clean energy. Do we need a mechanism to address this?

Participant 1: Organized markets are a key transparency tool. ISOs are almost the only entities from which you can get this marginal emissions factor. This information should be reported on an Energy Information Administration dashboard.

Participant 2: Back to the role of ISOs, their job is to run an electricity market to procure what they need to be reliable. Part of this is eliminating existing biases against clean energy. Otherwise, their role in clean energy transition doesn't look that different. One key exception is transmission planning. They have to adapt to state policies. They could operate a forward clean energy market, as this fits their capabilities.

Participant 9: One key piece to FERC Order 2000 has been overlooked here. The primary function of an ISO is not to run a market; they can contract a third party to do that. The primary role of ISOs is to operate the transmission system. But they do need an LMP to manage transmission, so running the market is an important role.

Participant 4: How do we deal with fragmentation across states?

Participant 2: It's cheaper to build wind in the Midcontinent Independent System Operator (MISO) region than New England. So, establish a national Energy Transition Credit and build there first. We don't need federal regulation to see this happen; it can be voluntary.

Participant 1: How is this different than today when buyers can go and get a Texas REC?

Participant 2: We're talking about a national open trading platform where anyone can trade RECs.

Participant 4: Doesn't this still create leakage issues? Buyers only have obligations where they are located. Looking at Europe, the carbon market is now getting serious with prices over $80/ton. This creates an incentive for industrial load to move to regions without requirements.

Participant 2: That's already an issue today, and a national credit market would help to alleviate the problems somewhat. There is a difference between a partial credit and partial carbon market. You can be certain that a REC is displacing carbon somewhere (assuming certification and one-time-use only for the credits).

Participant 1: Again, this is sort of what buyers are already doing, but there are inefficiencies due to multiple tracking systems. So this could streamline that, but doesn't seem like a fundamental change.

Participant 2: That's true, but it should help with liquidity.

Participant 6: The challenge is that other longer-term solutions are so much more complicated.

Participant 1: Another challenge is efforts to stamp RECs with a marginal emissions factor. This would enable identifying higher value but needs state participation. PJM is publishing marginal factors.

Participant 10: We found that you don't need a carbon price and a REC—they are redundant. Thinking about the investor perspective, how much value and confidence can they get out of these mechanisms? How do you actually price the value of the clean energy attribute? Today's REC market is bilateral and not transparent (prices are brokered), so there is lack of certainty in what future prices will be.

Participant 2: One can post to a futures board so investors see what prices are coming. We see this as a big benefit of common definitions and database with liquidity.

Participant 1: You can clarify and strengthen market signal, with parallel markets where the ISO's job is to facilitate.

Participant 7: Who is buying RECs? Large commercial and industrial customers. They are changing their own definitions. This makes the whole market concept somewhat contrived.

Participant 9: If you have a tradable product and everyone agrees on the definition, market interactions will take care of themselves. Carbon content doesn't have to be integrated into market dispatch if you have emissions credit. Emissions credits are not tied to physical delivery, so there is a benefit to not integrating this in dispatch. Deliverability is a bigger challenge for futures generally, but one can get around this with RECs if it's within the same RTO.

Participant 6: Tradeable non-physical RECs are different than what we need on the system. Eventually we need physical resources on the system. ISOs try to make this happen with price signals or a capacity market with marginal effective load-carrying capability (ELCC).

Participant 1: I see RECs as an early way to get things started.

Participant 6: What we have today is muddling through to the future we are envisioning. Are capacity markets alone going to bring on the kind of resources we need? States have to recognize that they need to make up costs of resources that will decline in value over time.

Participant 9: Let's talk about marginal ELCC. Values can decline over time as new resources come online. You can't vintage them and lock in capacity values.

Participant 6: This creates uncertainty in long-term value and energy prices.

Participant 9: It's a different world under the IRA for pricing energy and capacity components separately. And load is a wildcard.

Participant 6: Everyone needs to recognize the need for planning. ISOs have an important role to play because of their planning capabilities. They can inform resource selection, but they're not selecting. They can have a role in helping states. I don't think we can rely on LMP alone as investment signal. I haven't seen a good study that shows what happens when every resource in the system has a production tax credit under the IRA.

Participant 4: This highlights that you need to be careful about central planning. State policies are a form of planning and are making the problem worse. Each marginal solar and wind project does have less value for resource adequacy, that's just the reality. Are there other things the market can do, such as better signals for flexible demand and storage?

Participant 6: I still don't think spot price signals alone are going to get us the "correct" resource mix. Markets cannot signal for all the capabilities we need; wind and solar can provide certain services but will need more than a price signal to get those. How far out do we give signals?

Participant 2: Issues will resolve naturally. For example, as Texas solar loses marginal value, investments will go elsewhere. Eventually we'll need energy at night and geothermal will come along, etc. The main difference between RECs and a carbon price is a lack of incentive for shifting from coal to gas. Otherwise, they have largely similar impacts.

Participant 10: This brings up the question of where do markets end and where do we just need to mandate certain capabilities or attributes? For example, ISOs aren't requiring grid-forming inverters and manufacturers aren't making them because they don't have the specs. It's a cyclical problem. Someone needs to move first.

Participant 11: One idea is to allow grid-forming inverter resources to skip the queue. Frequency has a role to play.

Participant 2: There is an important distinction between clean energy and clean capacity. In actuality there's no such thing as clean capacity.

Participant 4: The ELCC discussion highlights that there is no single concept of capacity either.

Participant 11: Lack of demand participation is still huge problem, and states have not done their part to enable it.

Participant 8: See the recent white paper by Travis Kavulla, "Why Is the Smart Grid So Dumb?: Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector."[4]

Participant 1: Public utility commissions are trying to protect consumers, and with demand participation, costs increase for customers that don't monitor prices.

Participant 8: Will these be opt-in or opt-out programs? That is a big distinction.

[4] T. Kavulla, "Why Is the Smart Grid So Dumb?: Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector" (a white paper from the Retail Pricing Task Force, Reston, VA: Energy Systems Integration Group (2023), https://www.esig.energy/aligning-retail-pricing-with-grid-needs.

Price Formation Under Zero-Fuel-Cost and Opportunity-Cost Resources

Session 1, Price Formation

Summary

Discussion topics:

- The definition of LMPs and extended LMPs
- With a lack of fuel costs, how does the definition of marginal cost pricing change?
- What will prices look like in the future, on average? How will price volatility change?
- Are opportunity costs associated with storage properly accounted for? If not, how should they be changed?
- How important will administrative shortage pricing be in future systems? What values will it reflect, and how will it be administered?
- Will market power be a different problem than it is today? How will market power mitigation change with differing costs?

Storage technologies are likely to play a major role in price formation in the near future, and the way their opportunity costs are considered or neglected by system operators might open the possibility for storage owners to exercise market power. This session devoted a significant amount of time to opportunity cost, the role of demand-side resources, and the role of ISOs in price formation. The group universally agreed on the need for nodal LMPs and the importance of demand-side resources interacting with the market, but no concrete ideas were established for how to achieve this. The group had competing views on the role of devices versus operators for setting opportunity cost, as well as on the role of spot prices for long-term investments.

Key challenges include the need to better understand how an opportunity cost should be calculated and how to better model it, the need to engage the demand side in a truly price-responsive manner, the lack of clear connections between the spot market and investments/long-term contracts (i.e., what is the role of an ISO if spot prices are not driving investments?). These challenges pointed to a number of research needs, including determining the appropriate market sequence and structure (look-ahead horizon length, number of market settlements, role of the day-ahead market, the timing of forward markets, etc.) to support efficient price formation and investment without violating market power mitigation, and then incorporating those price formation capabilities in simulation tools. The group also highlighted the need for educational materials on how prices are formed with opportunity costs.

Conversation

Participant 1: On September 6, 2022, there was a near-miss event in California. The "Flex Alert" level 2 was announced for 4:00 to 9:00 pm. All batteries were discharging around 12:00 to 2:00 pm in the afternoon because price was at cap, so they fully discharged before the critical interval (and all batteries are 4-hour because of resource adequacy requirements). Then, a level 3 emergency alert was issued later in the day. This demonstrated that pricing problems can become reliability problems. On the next day, the same thing started happening, but it was manually stopped.

Participant 2: What happened in the day-ahead market that caused breakdown?

Participant 1: The day-ahead market did see that an issue would happen in evening, but California has a special mechanism allowed by FERC, a “minimum state of charge” requirement, so a battery owner can save state of charge for later in the day, but it has to be made whole. The issue is with the real-time market not seeing far enough out.

Participant 3: Cost recovery will move away from the marginal energy market to a capacity procurement mechanism.

Participant 4: These batteries were procured by the state on behalf of the consumer. So, now there is concern over the benefit they provide, but they’re already paid for by the state so the state can do what it wants (it can “order” them to do whatever it wants).

Participant 5: If you want optimal use of resources, you would do it in a centralized manner to support reliability, but this is in tension with the profit-maximizing arbitrage objective of the devices.

Participant 4: In California, investor-owned utilities own all pumped hydro. (California restructured and left nukes and pumped hydro in the hands of investor-owned utilities.)

Participant 6: Whoever financed the resource needs to submit the opportunity cost based on the expected cycling. It is similar to the Independent System Operator of New England (ISO-NE) setting an opportunity cost of hydro (a dynamic number based on expected usage) that is applied at end of the horizon.

Participant 7: What about reliability linkage (capacity remuneration mechanisms, etc.)?

Participant 4: The issue is how to negotiate contracts.

Participant 5: The overarching issue seems to be opportunity cost. What is it? How to implement it efficiently?

Participant 1: There is a stakeholder education component for explaining how opportunity cost works.

Participant 5: If we have a grid with wind, solar, and batteries, would the real-time energy price always be zero?

Participant 6: If there are lots of zero prices, then we will see lots of H_2 and bitcoin miners as well as electric vehicle charging, etc. We cannot anticipate a lot of zero prices without anticipating users.

Participant 5: What is the signal for those times?

Participant 6: The market will schedule if you have enough flexibility.

Participant 2: If wholesale prices go to zero, then we may not see the large growth in load that we expect, because end users see different prices (i.e., retail rates) unless they have access to wholesale prices. New York has hydro and wind, and when the wind blows, the prices in northern New York go negative. When these negative prices happen, we are not seeing growth in load in those areas.

Participant 7: Opportunity cost is a key concept that will determine prices. Norway, which has lots of hydro, has been running on opportunity cost. There is a challenge in differentiating 4-hour battery versus long-duration energy storage. Historically, opportunity cost is linked to natural gas prices, and if that goes away then it is unclear how calculate it.

Participant 1: One option is with demand response and administrative pricing.

Participant 5: The consumer protections will not allow the end user to pay the actual cost of electricity based on administrative pricing.

Participant 6: No one knows what their value of electricity is.

Participant 2: At the prices that a residential customer sees, there’s no incentive to turn off power. So, we cannot expect demand response when we don’t turn up prices high enough.

Participant 8: We have to pull in the demand side.

Participant 9: Will we have a transmission system that can support extra load?

Participant 6: It is hard to justify transmission if we will curtail wind on regular basis.

Participant 4: When the wholesale spot market breaks down, then it reverts to bilateral contracts. This is what happened in California. The current California market is a power pool, and prices aren’t worth anything because so much is contracted. If providers are short on revenue in California, they go to the California Public Utilities Commission behind closed doors to renegotiate contracts. The power still flows, but there is no transparency. A resource planning–driven process is not really a market. It is just a power pool where extra energy is dumped. So, this can be a backup of sorts.

Participant 2: Here is the New York perspective on a decarbonization vision. The state has rejected repowering of existing resources and new resources with emissions. There is active contracting for all other resources with retail net metering (homeowners have net metering based on retail rates, although that is in flux). They still have LMPs, but the investment time scale has challenges similar to California today.

Participant 2: What is an opportunity cost if one has a sufficient optimization horizon?

Participant 1: All optimization has a finite horizon, so there is always a residual value.

Participant 7: The longer the horizon, the less this value is. Norway, for example, optimizes across multiple years.

Participant 2: For 4-hour battery, what horizon do we need to get to have a meaningful opportunity cost?

Participant 7: A few days for a 4-hour battery.

Participant 2: Is there an interplay between the day-ahead and real-time horizon?

Participant 1: Is a two-settlement market setting enough? Do we need another settlement period?

Participant 9: Can we trade balance of day, month?

Participant 4: California effectively uses out-of-market externalities (retreat to bilateral contract).

Participant 5: We draw a very narrow circle around what we mean by 100%.

Participant 2: Value of LMP provides a factual basis for starting discussion (e.g., the value of lots of things is based on LMP forecasts) and is a critical input to the decisionmaking process even if it doesn't solely guide investment decisions.

Participant 7: As we scale up renewables, how do we support flexibility? We need to maintain granular signals (a role for LMPs).

Participant 6: Quantity risk is taken care of by the ISO; supply locks in quantity, demand locks in price.

Session 2, Price Formation

Summary

Discussion topics:

- Structures to price attributes needed for clean energy transition
- Incentives for storage
- State polices
- Incorporation of the demand side in LMP markets
- FERC price formation efforts

In this session, the participants discussed the impacts of the current ongoing decarbonization process on price formation and also the potential effects that we might observe in the future. The first main concern raised was the increased volatility in market prices that will arise as a result of the current integration of intermittent resources. Associated with this concern, there is also the lack of adequate mechanisms to price reserves to cope with forecast uncertainty. The group agreed that markets currently do not have appropriate structures to price attributes necessary for the energy transition. Long-term contracts were mentioned as a potential solution to hedge against price volatility. In addition, some participants suggested that demand-side participation, including at least the more flexible customers, should be properly incorporated in LMPs.

According to participants, storage systems may have a predominant role in price formation of future wholesale markets. It will then be important for ISOs/RTOs to define the participation of storage systems in markets such that:

- Their ability to exercise market power is curtailed
- Their compensation does not raise discriminatory concerns (e.g., storage being compensated to keep a certain level of state of charge while a conventional generator is not compensated to keep some unused capacity)
- Their discharging actions take place when the resource actually needed (avoid premature discharging)

Opportunity costs of storage systems will have to be closely monitored.

Participants also discussed the need for interconnection reform, better incentives for storage development, better reserve/ramping products, improved coordination between gas and electricity systems, a way to better price resources that may be needed but not profitable, and a potential need for multi-settlements markets.

Conversation

Participant 1: Markets are supposed to provide appropriate signals to motivate the integration of wind and flexibility resources. A study from ISO-NE showed how market designs impact the LMPs of systems with high levels of renewable participation.[5]

Participant 2: It seems that the assumption is that there is limited demand-shifting here.

Participant 1: One key challenge is pricing reserves to cope with forecast uncertainty. Uncertainty is going to grow, and there is no good mechanism today to provide incentive compatible solutions. The result is lots of uplift or out-of-market payments.

Participant 3: Losses are not appropriately considered in market designs.

Participant 1: According to a recent study, net load uncertainty grows considerably when we go from a 1-hour-ahead forecast to a 4-hour-ahead forecast.

[5] T. Schatzki, C. Llop, P. Ross, J. Shen, D. Stuart, T. Farrell, C. McManamy, L. Daniels, and S. Ma, *Pathways Study: Evaluation of Pathways to a Future Grid* (Analysis Group (2022), https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf.

Participant 4: Currently, there is no market structure to price resources needed for the future energy transition. There is no incentive for storage. States' politics are a difficult issue. The demand side is not properly incorporated in LMPs. States should provide the correct incentives, and perhaps this process should be guided by FERC. Besides that, we need FERC decisions focused on pricing attributes, interconnection reform, state incentives for long-duration energy storage, and gas-electric coordination. We also need to revisit ancillary service products, operating reserve demand curves, and ramping, and to shift revenues from capacity to energy markets.

Participant 5: Price is based on value via supply and demand bids. Policymakers with risk concerns need hedging to lock prices. Every RTO sees an increase in volatility coming. They're at different moments. Some regions may need resources for 3-hour ahead services whereas others may need something for second-to-second balancing. There is no obvious nationwide product that everyone needs; therefore, this isn't a FERC rulemaking role. Everyone agrees that the fundamentals of LMPs still apply.

Participant 4: Politics have a large influence on the issues. States, for example, had reactions against actions from PJM. High prices still get politically heated; states come down hard on market operators.

Participants 5 and 6: Yes, but we get past it. There is going to be heat, but that's just the nature of things.

Participant 7: Perhaps, but this could still impact future market designs.

Participant 3: It is more a political business than an engineering one.

Participant 6: We could easily argue that $2,000/MWh is too low for scarcity. Even at $9,000 the price for scarcity is less than the price incurred in the capacity market. This turns into price discrimination between resources that have to survive in an energy-only market and those in a capacity market. One option is to bring the capacity markets down to $2,000. If policymakers want to protect consumers with price caps, they could create a shadow market that determines that "true" price and make it available to flexible customers on a voluntary basis. It is insane that demand cannot respond to variations in prices that can be huge. Politicians don't need to get very involved if you have some sort of shadow market where demand can respond to prices and therefore provide flexibility. Flexible customers would pay less than under a fixed price, but no protections would be built in. The idea that there will be a TWh of negative price energy out there is crazy; consumers will jump all over it and erase these low prices. We don't need every customer exposed to "real" market price signals.

Participant 3: The retail market should solve this problem without the need for a shadow market for flexible customers. Retail utilities could make these prices available. Regional resource adequacy should not be a regional responsibility; rather, it should be taken care of by LSEs by following standards that could be determined by the region.

Participant 5: What is the opportunity cost for storage? How does the market monitor address market power mitigation for storage? What is its marginal cost?

Participant 1: There is no imperative to make storage provide flexibility. We need a way to curtail storage's ability to exercise market power. Market power mitigation can work well without stringent thresholds—just come up with a reasonable benchmark.

Participant 8: Market monitors could check what the storage devices do with their end-of-horizon inventories and how they measure the future cost of these inventories. If the day-ahead market is working correctly, it will optimize storage profit based on expectation of end-of-horizon inventory and project future opportunity costs. I don't think you need an offer curve. You only need to specify end-of-horizon opportunity cost. If optimization is working well, you should let the ISO schedule you.

Participant 3: It seems wrong to develop a separate storage product. What we need is active offer management by participants. Storage can be a three-party transaction. Keep interval in the tank for a retail customer, market operators optimize the remaining volume and give you a credit, withhold on the piece committed to third party. It will be a long time before this becomes an issue.

Participant 1: In real time, there is always a possibility that unforeseen events may happen.

Participant 5: Is it a computational challenge to decide how to dispatch storage devices?

Participant 9: Should we allow bid/offers to charge/discharge?

Participant 8: The idea can be to allow the ISOs to optimize storage behaviors. The offer curve of storage would say how the market optimizes its dispatch. The only opportunity cost needed is the one associated with the end of the horizon, which can be the end of the financial horizon. Storage owners would just need to specify their round-trip losses and end of horizon and let ISOs schedule them. Since the real-time market only clears one interval at a time, more computation is needed. A truncated real-time horizon might lead to mistakes. There is a real-time option value from price volatility that is hard to detect from a marker monitor standpoint. It is all about expectations, and their guess is as good as anyone's.

Participant 1: In real time, unforeseen things may happen. So day-ahead schedules can be very different from the real-time ones.

Participant 8: And in real time you would bid up or down compared to the day-ahead according to circumstances.

Participant 1: For any markets, certain situations may make real-time prices spike.

Participant 8: In real time, you need to quantify your expectations.

Participant 9: You want a day-ahead schedule that keeps some state of charge to take advantage of the real-time option value because prices fluctuate.

Participant 6: When will storage not be a price-taker?

Participant 5: When scarcity prices show up. Also, if there is premature discharging, storage can affect prices. California got through a fall event without too much trouble. Price caps can mess things up with discharging before prices hit the cap, and then batteries aren't available when needed most. Resources will take the $2,000 and run rather than waiting to hit a $2,500 cap.

Participant 1: In California, is there any out-of-market rule for storage resources?

Participant 9: Operators require states of charge of certain storage resources to be at certain levels. This requirement also raises the question of whether storage should be paid for its state of charge in addition to being compensated for energy like typical generators. This extra payment is considered a discriminatory issue and people don't want it. Essentially a gas generator, for example, also usually has a part of its capacity that is not dispatched, but does not receive compensation for it.

Participant 4: Penalty factors for constraints violation can change market clearing prices.

Participant 5: There should be some limits on scarcity prices, but the solution to avoid being vulnerable against these prices is hedging. The solution to political concerns around scarcity pricing is to make sure everyday consumers have someone hedging on their behalf. Regulated systems have better hedging.

Participant 10: Different prices place stress on transmission constraints. When things get into scarcity pricing, it becomes hard to manage.

Participant 8: All transmission lines come with three ratings. As long as you don't violate all of these ratings, ISOs should be fine.

Participant 10: But also, dynamic line ratings may raise concerns because ratings may change from day ahead to real time.

Participant 11: Massive amounts of renewable deployment could happen because of the IRA. Some technologies like hydrogen, small modular nuclear reactors, carbon capture and storage, etc. will be expensive and won't be able to compete in ISOs. So they will get built in regulated markets. Are those the preferred structures for these types of resources? How can we get them to participate in ISOs? It may be hard to get to clean energy goals with wind, solar, and storage in markets; prices in ISOs will be too low for them to compete.

Participant 6: But this is present in regulated regions, too. No investor-owned utilities are building nuclear. What if we start defining resource adequacy as what is needed to survive seven days of low wind and solar and put this responsibility on LSEs' resource adequacy obligations? This helps resources that don't compete in day-to-day energy markets. ELCC was never designed to provide capacity accreditation for existing resources; the average value of wind in Texas is different than the marginal value of wind.

Participant 1: Resource adequacy and accreditation are designed to do what you're talking about.

Participant 5: What about more granular long-term capacity products to capture seasonal variations and capabilities?

Participant 3: There's an argument to be made for standardized ELCC methodologies, Bonneville Power Administration gives 8% for wind, and in Colorado it's 15% to 30%. ELCC does not measure instantaneous capacity. Wind in MISO is accredited on an ELCC basis.

Participant 5: ELCC can be another session. If we assume we have only renewables and storage, can they work in an RTO market? In California, they gave the adequacy responsibility to the state and to the LSEs, and they realized balancing energy was needed and they invested in storage. Accountability worked in this case. California never wanted resource adequacy to be FERC jurisdictional; it kept it in state and gave it to LSEs.

Participant 11: Most of the proposed solutions help mostly in the short run. Is there a better way? What do we need to be working on next to get us better solutions?

Participant 1: We need some intraday sort of market that compensates resources for providing availability. Ultimately, we'll probably need a sort of multi-settlement market.

Participant 6: In Europe, they have a multi-settlement market. Is that something that MISO is looking at?

Participant 10: MISO allows offers to be updated. However, settlements need data to be collected in a more granular way with lots of meters that are not currently available.

Participant 8: Regarding negative prices, which may increase in frequency and magnitude, demand-side innovation can be a solution. For example, when prices go negative, people can make hydrogen via electrolysis. When prices go positive, the hydrogen can then be converted into power. This exchange can give the consumers the possibility to choose whether they want to consume when negative prices show up and turn those prices positive. If you give more customers an opportunity to participate in wholesale markets, these problems will start to resolve. The future is going to look a lot different.

Participant 1: According to this conversation, some of the points to highlight are: (i) volatility risk can be dealt with through long-term contracts; (ii) discussion is needed for storage optimization and storage cost, especially because storage will have an important influence on prices in the future; (iii) do we need innovative ways to value technologies that will be needed but not necessarily profitable depending on the market design? and (iv) are multi-settlement markets needed?

Session 3, Price Formation

Summary

Discussion topics:

- Is the combination of LMPs and co-optimized ancillary services still an efficient solution in the future?
- How should criticism of the LMPs-plus-ancillary-services model be addressed?

Due to the increasing integration of low-marginal-cost resources, LMPs might not provide sufficient signals for important actions, such as investment in new resources to keep power systems adequate to supply their energy demands. The first half of the session was spent discussing whether the current market framework of LMPs co-optimized with ancillary services will continue to be effective in the future or whether a completely new approach without marginal cost pricing is needed. The group came to a consensus on the former position due to LMPs' ability to describe grid and market conditions. There was general agreement among participants that LMP does have the right operational considerations and incentives for peaking and inframarginal resources now and in the future. There was less agreement on modifications to make it work under a highly volatile, potentially binary pricing situation of the future.

The group moved on to discuss ancillary service products and pricing needed to support this model going forward. The second half of the session focused on criticisms and misconceptions of LMPs and how they are used, and how the participants would communicate their position from the first half.

Conversation

Participant 1: Will LMPs combined with co-optimized ancillary services still work in the future? Option A is "no, a new system is needed, and LMPs and marginal cost pricing will not work." Option B is "uniform marginal cost LMPs will continue to work." In the case of option B, changes are still necessary to support LMPs of the future: new ancillary service products as well as changes to scarcity pricing and operating reserve demand curves.

Participant 2: Why does there exist an option A?

Participant 3: People might think about option A because, in today's world (following the invasion of Ukraine and high fuel prices in 2022), a single clearing price overpays zero-fuel-cost resources.

Participant 1: Also, in tomorrow's world, there will be lots of zero or low prices that won't pay enough to support investment in resources.

Participant 4: I've heard interest in fossil resources plus carbon capture and storage from people concerned about LMP without capacity. There is a concern about locational dependence in Europe, which currently uses uniform marginal cost pricing but does not use granular locational pricing. In the EU and the UK, offshore wind can't change its location.

Participant 1: There is much more concern over market design of the capacity markets in the U.S. than energy markets.

Participant 5: I don't think there is a dispute about starting understanding/description of grid/market condition.

Participant 6: Under uncertainty, system operators end up choosing to defer costly commitment decisions until closer (we don't have stochastic dynamic unit commitment now) and/or committing out-of-market for 99th percentile chance. This tanks value for those others. You don't incentivize these flexible resources. I would like to see a way to bring these operator actions into market. There is an unmet need for operators. The academic work on stochastic optimization is a little far from reality. Shorter-term approximations of this might look something like flexibility/ramping/energy option at various horizons (24 hours, 8 hours, etc.). These would be like new ancillary service products.

Participant 7: There is a price adjustment part (reliability unit commitment), but it isn't perfect.

Participant 2: Everyone does reliability unit commitment, but it doesn't match economic theory.

Participant 1: How do we send different signals for different needs (fast ramp, reliability, low-carbon, etc.)?

Participant 8: Different products and locational nature offers these signals.

Participant 3: Energy LMP is never this—always MW=MW=MW. Is our future in 20 years different enough to call energy market LMP into question?

Participant 9: There will be 1 billion prices per year when separating out by node, five-minute intervals, ancillary products, in the U.S. Lots of data on when and where energy is needed.

Participant 1: Is energy a commodity? The energy market is not differential. ELCC is what differentiates resource type for reliability purposes.

Participant 10: Yes, according to recent studies about the efficiency of LMPs.

Participant 11: LMPs may not be zero because batteries have degradation costs, and hydrogen and others have marginal costs. Also, there are opportunity costs and variable costs. Probabilistic thinking can affect offers.

Participant 1: We may not need new ancillary service products, but we may need to rethink pricing. For example, is an opportunity-based compensation scheme for ancillary services the right thing?

Participant 5: Yes, opportunity costs exist (e.g., staff to turn on), so they are fair to include. If you offer something like $5, we don't evaluate further for market power.

Participant 6: Regarding the inclusion of nonconvex costs in price formation, today these are mostly not included in LMPs for 5-min because they're not avoidable at that stage. Is there a role for inclusion of nonconvex costs in longer-time horizon? "Fast-start pricing for all." Blocky demand response is an example.

Participant 9: SPP includes start-up cost in bids.

Participant 9: There are different costs that aren't per MWh (depth of discharge, etc.). How do you reflect these costs in bids? Should one look at including starting costs?

Participant 8: Fast start is like bending the space-time continuum.

Participant 12: We may need to rethink how ancillary services are priced—value-based pricing instead of purely opportunity costs. If energy prices are zero, then the ancillary service price, if based purely on opportunity cost, is also zero.

Participant 8: Paying resources based on value? How would this work?

Participant 9: Extended operating reserve demand curves can provide a lot of value by giving prices on a long spectrum (not just when the service is short). But those are currently set administratively, which is not ideal if a large portion of prices and revenues are impacted by this. How does demand set those?

Participant 1: Are out-of-market actions an impediment to price formation? They depress energy prices because the action is not priced. Out-of-market actions in the reliability unit commitment process are different from random operator actions. They are based on automated processes. Stochastic modeling can help act like an operator when determining best decisions to reduce risk.

Participant 8: LMP is the best signal to allow demand participation. What is second best if we don't use LMP?

Participant 5: Is there a difference? Load can provide 10-min reserve if you have, for example, a couple of large industrial customers and bitcoin mining. ERCOT has significant load involvement in the ancillary service market. ERCOT Contingency Reserve Service is about to be implemented and will allow greater load participation.

Participant 13: The issue in Europe to move to nodal pricing is more of an implementation challenge. If you already have LMP, that's great.

Participant 10: Extending LMPs to the distribution level—is there a reason conceptually not to do this?

Participant 8: Only because the RTO doesn't manage LMPs and wouldn't use them. There could also be computational, data, and equity issues.

Participant 1: How to respond to critiques of an LMPs-plus-ancillary-services model? Not all anti-RTO camps are anti-LMP.

Participant 9: Write better studies or more easily defendable metrics? Europe has more real issues in how prices are impacting consumers, and this has migrated to the U.S. The discussion of what prices will be under lots of zero-marginal-cost resources is valid, because we don't know what the prices will look like. Whether prices are bang-bang or moderate is to be determined. Both have reasonable people who think this will happen. Many studies show benefits of RTOs and many show costs—how to reconcile these? The conflation of wholesale and retail is part of it. How do we better quantify the effects of RTO efficiency given all of the different flavors that exist (not all RTOs have retail choice, many RTO states are vertically integrated)?

Participant 7: We can't ignore critiques because if the "wrong side" has the better narrative, it will succeed.

Participant 4: In the conversation in the UK about going to LMPs, there are arguments about efficiency, but the opposition says we already know what the constraints are and where the prices will be high/low. For example, some may say that a true coherent debate may conclude with consensus that LMP is right, but may not be politically desirable. There are misconceptions that U.S. consumers pay LMPs.

Participant 3: How big of a risk is this really? Even if people in public discourse say whatever, unless it is enough for New Jersey to up and leave PJM, it isn't much of a threat. I don't see this raised at FERC, state commissions, etc.

Participant 15: This is an issue in the West in creating and expanding markets.

Participant 16: Almost every resource out there is under some contract or another, so the LMP isn't really about how resources are paid or project revenue. It is the right choice for optimal dispatch. Developer has a long-term power purchase agreement with off-taker. The market prices are part of the perceived benefit (fully bundled) to buyer. Market prices have a bigger effect on merchant tail, but they are somewhat put off for now, and I think costs may shift to RECs or other products. Somehow, we continue to make these deals and find buyers, but it requires a lot of creativity when it is mostly capital costs.

Participant 17: The power purchase agreement price will exceed LMP, so people are buying for other reasons.

Participant 3: LMP is 90-70% of revenue for my organization.

Participant 18: LMP branding is very transparent, and without it we would be like the gas market.

Participant 4: When markets were new, LMPs led to lots of operational efficiency gains (e.g., reduced nuclear outages), and we could see improvements of cost to serve. Eventually that translated to retail rates.

Participant 6: I still see promise as investment signals. I agree that demand side is part of this. What is the role of price caps?

Participant 8: They are intended to be a signal for routine use decisions. They don't have to be for value of lost load.

Participant 10: Argument for messaging about LMPs: LMPs aren't stand-alone. Also uplift.

Participant 12: I saw public power members embrace benefits of economic dispatch related to study of coal plants self-scheduling.

Incentivizing Supply Resources and Meeting Resource Adequacy Targets

Session 1, Resource Adequacy

Summary

Discussion topics:

- The role of ELCC in resource adequacy studies
- Which entities should be responsible for ensuring resource adequacy?
- Should LSEs be responsible for resource adequacy with ISO/RTO guidance and under the approval of states?
- Is there a need to consider operational flexibility in resource adequacy studies?
- Can resource adequacy or capacity markets solve the flexibility issue?

Traditional resource adequacy methods are becoming outdated with the continued integration of intermittent generation in power systems. In this session, participants discussed the elements that need to be incorporated in resource adequacy analyses to reflect the current and future needs of decarbonized systems. ELCC was the first mechanism mentioned to level the playing field to assess the value of different technologies. However, participants also discussed how resource adequacy exercises need to be more forward-looking—more proactive than just creating market products to solve today's challenges—and need to consider more detailed aspects such as different time frames and geographical conditions, since each region has different needs. States' politics were mentioned as a major factor influencing the quality of resource adequacy analyses, as states can establish objectives that may not fully consider operational issues and may take reliability for granted. In addition, participants discussed how both centralized procurement and organized capacity markets face challenges in valuing future reliability contributions of new resources, and it is not clear who should pay for the resources' reliability contributions. Some participants think that LSEs should responsible for resource adequacy while following regional guidelines.

California was mentioned as the only state keeping capacity aside, and other states are phasing out most non-renewable generators. In the case of California, the power system is managed by a single state, and, after the rolling blackouts of August 2020, it incorporated ELCC within resource adequacy markets, which made the state decide to postpone the retirement of gas units.

Some participants raised the point that flexibility should be better incorporated within resource adequacy methods. It is not clear how much flexibility will be needed and where it can be bought. Resource adequacy exercises may need to include more detailed operational characteristics to quantify how much flexibility will be needed and which resources can provide it. One participant made the interesting point that resource adequacy and capacity markets are usually misunderstood as being the same process. According to them, resource adequacy is actually related to what we need to have in the future. Once we realize what attributes we need for the future, we can incentivize some of these attributes to be made available via capacity markets, but other attributes may need other types of incentives so that resources can build with these in mind.

The overall conclusions of the session were that: (i) LSEs should be responsible for resource adequacy, with ISO/RTO guidance and under the approval of states; (ii) flexibility is important, but there was no consensus on whether resource adequacy or capacity markets can solve the flexibility issue; (ii) fuel constraints need to be considered, and all resources should get similar treatment for resource adequacy and capacity markets (e.g., thermal ELCC); (iii) a capacity market is one year but investments are for 15 years or more; (iv) ELCC, and in particular marginal ELCC, is an improvement and is a helpful alternative to other historical methods, but will always be wrong; (v) we need to define which resources are needed and determine how to incentivize the attributes that they need to have. Flexibility is key for future high-renewables systems.

Conversation

Participant 1: In the past, resource adequacy took into consideration a pool of firm generation, and it was a matter of summing up their capacities to understand whether we had sufficient resources. Now, with emerging technologies such as renewables and storage, we need better mechanisms like ELCC; we can no longer assume independence. ELCC is a convex function of the resources portfolio. ELCC is supposed to create a level playing field to evaluate the value of different technologies. The ELCC accounts for forced outages, energy availability, fuel availability, etc. Many of the issues we are seeing can be addressed by efficient allocation and accreditation. No resource is perfect and that has to be taken into account. Marginal ELCC can account for providing incentive toward what the system needs. Average ELCC may be an amalgamation of different things together. There is no foundation for the reliability criterion of 1 day in 10 years. We also aren’t sure how to value lost load.

Participant 2: Each market has its own regional issues. Today, resource adequacy is a reactionary exercise rather than a forward-looking approach. There is a need for more robust reliability assessment metrics and considerations via the use of scenarios that comprise different time frames and geographical circumstances. Everyone agrees that policies defined by states are a major factor in how renewables will be integrated.

Participant 3: Why do we need to wait for a loss-of-load event to occur before thinking about this? Can we ask ISOs directly which resources are needed?

Participant 2: We’re being reactionary. More interaction between states and ISOs is needed. Can we get states to understand the impact of their policies on the availability of resources? We need to bridge the gaps between states and ISO goals.

Participant 4: Are states considering reliability when legislating?

Participants 1 and 2: Likely not. States may be making their decisions based on an incomplete picture.

Participant 5: The IRA may be the new deciding factor, locking economics in. How much do the policies of states matter when economies have shifted? Reliability issues are what we need to figure out. We know how to get to the 90% renewable target but not beyond that.

Participant 6: Everything [needed for decarbonization] will be built, but is it what you want? Will it cover reliability?

Participant 7: States may think they can import energy whenever they need to cover reliability (perhaps with the exception of California). How to enforce states to take responsibility for resource adequacy? There is an accountability issue. And a free rider issue in multi-state regions, as each state may think the other is solving the reliability problem.

Participant 1: ELCC will give an idea of how resource adequacy could be achieved based on the preferences of the states.

Participant 8: LSEs should take the responsibility of resource adequacy. There have to be accreditation standards such as ELCC.

Participant 7: I think states should take the responsibility.

Participant 9: Do we really know how to reach an 90% renewable target?

Participant 5: I also think LSEs should take the responsibility for resource adequacy. It is more efficient if the LSE has the obligation, regardless of the mechanism.

Participant 10: That may not be realistic given accreditation practices. This is the part that may need standardization and need to be operated by the system operator. Thermal resources will need marginal accreditation as well.

Participant 4: Can marginal ELCC properly function as a signal of how different technologies will be helpful?

Participant 11: Why is only California keeping gas capacity, while other states are phasing it out?

Participant 1: In California, it is easier to coordinate because it's a single state. Also, it is historically an importer and there were the rolling blackouts in August 2020. So, they decided to look at improving resource adequacy metrics with ELCC and figured out that they cannot retire gas units in the near future. In California, there is a summertime electricity problem and a wintertime gas problem. Reliability must-run contracts are hard to do for anything but transmission security in most regions.

Participant 8: Regional imbalance markets are not incentivizing investment.

Participant 12: Is there a need for flexibility consideration within resource adequacy studies? Where do we have to buy that? How to incentivize procurement for flexibility within resource adequacy? More operating characteristics are needed to ensure that resources considered in resource adequacy studies are actually flexible in real time. A step in this direction is the California Independent System Operator (CAISO) Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO) procedure that incentivizes three hours of ramps from a planning perspective.

Participant 1: Inverter-based resources are in fact very flexible and can move very quickly between zero and their variable upper limit.

Participant 13: Energy and ancillary services may be the best way of incentivizing certain attributes.

Participant 14: The industry tends to couple resource adequacy and capacity markets into one identical process. Resource adequacy is the process of determining what we need to have built in the future. The "what" is anything—MW, MW/min, transmission MW, pipeline capacity, frequency response, emission reduction, you name it. Once we realize what we need for the future, we can then start to think about ways to incentivize building these things. Some of these attributes can be incentivized through capacity markets. Others may be incentivized through other things such as energy markets, ancillary service markets, grid codes, or decisions to change any of these things.

Participant 1: When do we need to buy each service? When do we need to buy flexibility or anything else?

Participant 8: As an LSE, I would want to be able to procure my own resources rather than following central procurement.

Participant 1: Curtailing solar in the afternoon and making the ramp less steep would avoid much of the need for flexibility in California.

Participant 3: Collective mechanisms would be better than just relying on LSEs to take care of resource adequacy.

Participant 7: I would suggest keeping flexibility out of capacity markets.

Participant 14: Five years ago, we were asking about energy adequacy within capacity markets. Energy adequacy was not in capacity markets and generally not considered in resource adequacy. Now we are all frantically suggesting that it be included. Compare that with our discussion here today, where we are asking about operational characteristics within resource adequacy because that will impact the actual flexibility of the system. Are we sure we want to ignore the inclusion of something important in resource adequacy studies again?

Participant 10: I think the spot market is where the flexibility issue should be addressed. However, flexibility to adjust beyond an hour is not incentivized well in current energy and ancillary service markets.

Participant 12: SPP has proposed a 1-hour uncertainty product. Is that enough?

Participant 1: What incentives are needed to support economical operation of flexibility? You can always curtail renewables and get flexibility.

Participant 9: Resource planning is always present in all time frames, we need mechanisms to procure resources in all time frames, and we need correct incentives in all time frames to make sure that resources are available when needed. It is a matter of determining in which time frames we have problems and dealing with them.

Participant 7: Intertemporal problems are difficult to solve. Participants and the ISO see it coming, but how do they represent it?

Participant 15: Most investors are more interested in day-ahead and real-time prices, and I do not see incentives in those prices to invest, which may hurt reliability. In PJM, it used to be 90/10 (energy versus capacity market revenues), but now is more like 70/30. Capacity markets distort energy markets. How do we explain negative pricing to investors?

Participant 7: Do system operators trust market designs? An easy way to cope with risk is to operate with an over-committed system.

Participant 16: How would a multi-state compliance program work, for example, in the West?

Participant 1: I think a WRAP [Western Resource Adequacy Program] combined resource adequacy would be an improvement over what we have today, with so many different planning authorities.

Participant 9: ELCC may not be sufficient because we also need to simulate the operation of the system. ELCC is good for capacity needs, but simulation is needed to evaluate reliability.

Participant 6: I think that correlation between resources could be included within ELCC.

Participant 9: ELCC is good to some degree, but it does not incorporate more technical concerns such as congestion issues. Interactions between technologies are also not well represented. ELCC results are very much dependent on the current portfolio of technologies. They are always wrong (though better than other approaches) and are a moving target. The more forward they are, the less accurate they are as well.

Participant 2: To what extent will the demand side participate in supporting resource adequacy? How will the need for flexibility impact resource adequacy designs? What side of the equation should that fit?

Participant 8: LSEs just care about customers and not about regional issues or needs.

Session 2, Resource Adequacy

Summary

Discussion topics:

- Capacity markets
- Accreditation

- Flexible demand response
- Policy goals
- Revenue sufficiency
- What events to plan for?
- Centralized planning versus more distributed decisions/investment
- Where are we today, where do we want to go, how do we get there?

This session covered a range of topics related to the fundamental tenets of reliability, including what is capacity, what is reliability, how much reliability/capacity do we need, who decides, who is responsible for meeting reliability criteria, how do we measure it, can ancillary services replace the role of capacity, and how do we value reliability on both the demand and supply sides? The overarching resource adequacy challenge is marrying increasingly variable demand with increasingly variable supply, with increasing dimensions of their joint variability. As a result, the group agreed that demand will need to be shiftable. The reliability expectations and price willingness of those customers is what ultimately defines the value of reliability; however, we do not know how to quantify it (i.e., determine the value of lost load).

The group agreed that ancillary services cannot replace capacity, although views varied on what the role of capacity as a product is and should be. The group also discussed the need to expand historical metrics beyond aggregate, average values in order to understand the distribution of outcomes. The group debated the trade-offs between capacity accreditation and capacity performance/penalty approaches. Accreditation was seen as better for planning, while performance incentives need to be set to the "sweet spot"—high enough to motivate the targeted outcomes without causing bankruptcy. These discussion points highlighted the research needs for more granular resource adequacy metrics, better understanding of value of lost load, and better understanding of how to set and balance the trade-off between capacity accreditation and performance incentives.

Conversation

Participant 1: Capacity as a product does not make sense, but I'm not sure whether ancillary services can fill the need we actually have.

Participant 2: Revenue from energy and ancillary services is necessary but not sufficient. Capacity as a product is trying to fill ancillary service needs.

Participant 3: What does a year-ahead ancillary service auction look like?

Participant 4: Capacity is just a longer-term version of reserves. Do people think that is tractable? Or is there a demarcation where capacity is fundamentally different?

Participants 1 and 5: A capacity market is more about having energy than capacity, not really a reserve. We need to focus on getting energy prices right.

Participant 6: We still need a measure for describing deficiency/need.

Participant 7: How do you define capacity? Capacity for energy, flexibility, etc.

Participant 4: Generation, storage, and demand response are all eligible for the capacity market in PJM. Transmission can contribute through capacity value.

Participant 8: PJM includes transmission in planning.

Participant 2: Are capacity and reserves the same thing but on a different time scale? No, because capacity payments are for underpaid capacity, but operative reserves are payment for misplaced payments and to prioritize the service when needed (some as artifacts of historical hourly settlements, e.g., 10- and 30-min products), but this assumes we can avoid a collapse.

Participant 6: The collapse is a key piece because we can't avoid it.

Participant 5: Uncertainty also contributes.

Participant 9: The question of what reserve products can do is long-standing. ISO-NE has a forward reserve product. Reserves are 1-3% of total revenues, and the cap is 30%, so if the cap is removed, then there is the need to replace with something else. In California, system planning includes a long-term view of accreditation, results in long-term contracts. Reserve is more of an accounting on a short-term horizon; so in California, the capacity requirement is more of a check while system need is being addressed by integrated resource planning.

Participant 4: What does responsive demand look like in the future? Does PJM have a lot of emergency demand response that participates in a capacity market?

Participant 10: A paper by O'Neill, Lew, and Ela from the Energy Systems Integration Group's Retail Pricing Task Force talks about bid-in demand as a way we can get more participation by demand in wholesale markets.[6] There is a lot to be gained if demand can be exposed to time-varying price structures that reflect grid needs. We need to stack all of the value streams so that isn't just energy; bidding in demand to the market (just like supply) is a critical step to supporting resource adequacy (true price-responsive demand would eliminate the need for resource adequacy).

Participant 9: Demand in PJM is a supply-side resource so it's paid to curtail. That is fundamentally different than bidding in as a demand-side resource. It's not enough to have a bid in the market; it must also meet other qualifications to be eligible for capacity. If you're a flexible load, it's not transparent what your obligation will be if you participate/bid. This is not trivial.

Participant 8: Load has to be able to respond for long duration (sometimes multiple days). It needs to be a different attitude than what has been the case (optional, voluntary, only cut rarely).

Participant 11: Long-duration curtailing of industrial customers is a bit of a concern. They can tolerate a few hours, but not a week.

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[6] R. O'Neill, D. Lew, and E. Ela, "Treating Demand Equivalent to Supply in Wholesale Markets: An Opportunity for Customer, Market, and Social Benefits" a White Paper from the Retail Pricing Task Force (Reston, VA: Energy Systems Integration Group (2023), https://www.esig.energy/aligning-retail-pricing-with-grid-needs.

Participant 12: The buy-in point for demand is high. It would have to be a huge incentive to curtail a data center, for example. Demand is more likely to engage on the operational front—shifting load across space rather than curtailing. For example, a company could shift data center load from one region of the country to another region where it has another data center. This spatial shifting could be sustained for multiple days. This is more appealing than shifting temporally.

Participant 6: The challenge now is pairing variable demand with variable supply, not just finding one hour in year that is most concerning and sizing to it.

Participant 7: What about the future with massive electrification and with demand bidding into markets?

Participant 4: Who should bear the risks, and how can those risks be managed? What are the governance issues associated with who picks the resource adequacy target? How should we think about different types of risks in the future?

Participant 2: We may need a non-market way to identify contingencies.

Participant 12: Who has authority?

Participant 4: Maybe accreditation could be used to enforce handling contingencies/risks (versus a non-market way). Accreditation has to consider the types of events you are preparing for.

Participant 8: Accreditation is ELCC.

Participant 6: That definition assumes you are procuring in advance.

Participant 6: What do we do with reliability metrics, not looking at distribution of outcomes. How can we use models to help us understand potential outcomes of different events that can challenge the reliability of the system?

Participant 5: Climate change is a key data input.

Participant 11: How much reliability are we willing to pay for?

Participant 9: We need to do a lot of analysis, understand what the state of the art is and push it forward. We have intellectual firepower in industry but we don't use it. The California Public Utilities Commission lagged for a few years in calculating the capacity value of photovoltaics and ended up over-calculating it. There is hardly any validation done of any analysis. CAISO does 2,000 runs every year to assess resource adequacy, which is buried in a report somewhere. It is a hard-to-understand report with very little ongoing incorporation of different methods and how results fit together.

Participant 16: From the modeling side, a big limitation is data. We need data inputs that are more granular and forward-looking so that we can capture a broader distribution of system states in our resource adequacy modeling. The lines between planning and operation time scales are becoming more blurred; some of the traditional assumptions we have included in our resource adequacy modeling may need to be revisited. A good example is how assumptions for when storage is charged and discharged can impact the available state of charge during times of system stress. Those are largely operational factors, but when we have uncertainty in our operations, then those operational assumptions can impact the resource adequacy results. We also may need to consider more sophisticated analysis approaches that allow us to explore paths of least regret and not just quantify risk. There are some new applications in the “decisionmaking under deep uncertainty” space looking at this type of approach.

Participant 10: We need lots of work to understand value of lost load. What is the value? When does it happen? All of these details feed into resource adequacy.

Participant 5: Equity is a key factor.

Participant 6: There are different types of reliability. Fast internet or slow internet—pay for the service you want, but don’t go without internet. Value of lost load is higher than it used to be.

Participant 13: People don’t want 1 day in 10 years, but desire more reliable. Establishing reliability criteria is very political.

Participant 2: Can do either price signals or resource accreditation. Accreditation is hard, but even if you can get it right, it’s unlikely that you could get it through the stakeholder process. We tend to overestimate the credit. If there is no full-strength penalty behind it, then it tends to not work. It’s better to have incentives that are as strong as possible. For now, we need accreditation because price signals are so weak.

Participant 14: Accreditation lends itself better to planning, while prices are better for operations. Prices can back up the accreditation process. We won’t know if penalties aren’t high enough until a reliability-related event occurs and we can see if it worked.

Participant 6: When does a penalty go from incenting a desired response to being punitive? We have to find the sweet spot.

Participant 4: How to design performance incentives? Which hours? How high? Prices/penalties could be quite high. A generator could make a case around going bankrupt, but make it up in one year during an event.

Participant 9: When PJM started storage capacity accreditation, it started with a 16-hour requirement and people went crazy, so they then did performance-based (expose to penalty) but couldn’t finance projects that way, then 10-hour, then ELCC to 6-hour today. They followed the entire arc of accreditation versus penalty and relative risk.

Participant 15: Where do we put our bandwidth in wrestling with all of these problems? Let’s stop focusing on analysis and just get stuff built. We need a reliable system. Put a ton of zero-carbon resources, use H_2 as intermediate. Worry less about finding super granular answer.

Participant 6: The preference would be to let customers choose their own level.

Participant 8: There needs to be a minimum level of resource adequacy that is advocated by some group.

Participant 11: We need real-time pricing.

Participant 6: The bitcoin guys are a model for how to be flexible load (but not bringing actual value to society…).

Participant 15: Did anyone think about who should handle/manage responsive load?

Participant 6: We need aggregators.

Incentivizing Resources to Provide Essential Reliability Services of the Future

Session 1, Essential Reliability Services

Summary

Discussion topics:

- What are the essential reliability services today, and how will they differ in the future?
- What resources are going to be providing these services in the future? Are they sufficient?
- What incentives will be there for those resources to invest and operate to provide those services?
- Need to plan for future reliability services now. Not usually something that is done beyond resource adequacy (which typically ignores operational services).
- Have a useful reference for best practices for when a service can be interconnection requirement, cost-of-service recovery, or competitive auction with marginal cost pricing.
- How do you know when you need a new market product for a grid service?
- Can we incent longer-duration resources through market mechanisms? Should incentives target reliability services and provision of energy separately?
- What barriers exist to expanding/incenting non-traditional resource participation in reliability services?

This session focused on the essential reliability services for today and those needed in the future. Participants discussed how different regions may have different needs and how the main driver for new reliability considerations is the change in the resource mix, which includes massive integration of renewables. The participants noted that renewables can potentially contribute to mitigating reliability issues that they may bring. This contribution needs to be well defined before conventional resources are phased out in an orderly manner. It was unclear for the participants what the future resource mix should be. It was also not clear how investments in these resources should be incentivized and which new products the electricity markets may need in order to ensure reliability in the future. Flexibility products that allow some sort of demand response or participation and adequate use of storage might be important to achieve a desired level of reliability, but it is not straightforward to determine when and which new products would be most useful. All in all, there was general agreement that further discussion is needed to identify reliability needs and ways to supply these needs as well as to determine best practices to ensure that appropriate reliability services will be available for future decarbonized power systems.

Conversation

Participant 1: What will the system look like under deep decarbonization? What new or changed needs will need to be addressed? Perhaps deep electrification, and a need for high reliability. Does everyone need the same type of reliability?

Participant 2: The level of reliability depends on the region's resource mix. Assessing resource adequacy will require different approaches based on the region, given different attributes of resources. Needs are still going to be relatively the same, but the resource mix is changing.

Participant 3: Black start and inertia may be a question depending on the resulting resource mix. However, most other services can be provided by emerging resources including renewables and storage. Renewables may be creating new services or increasing the need for some services. They can also contribute to addressing the needs they cause if managed well—though this may currently be an inefficient way to manage those needs due to economics of renewable energy; however, it may be more economical in the future.

Participant 4: If resources are contributing to reliability needs, it is because of contractual obligations and not necessarily due to their physical characteristics.

Participant 5: What is the role of slow-start resources in the future? What does the future fleet look like? Should there be market products or requirements for interconnection?

Participant 6: The problem changes over time. Different resources provide different services but require something else; for example, renewables might require ramping flexibility to be provided from other resources. How do we manage a decline in critical assets, or how do we ensure they are kept for critical periods? We have to plan for different versions of the future, which makes it hard to plan. There is a need to study different futures and scenarios. What are the needs and what is the best way of getting there?

Participant 7: Standards or ancillary services products/markets.

Participant 8: It ought to be an interconnection requirement and need not be an energy requirement. More frequent planning exercises are needed. Long-term planning considers resource adequacy and transmission security.

Participant 9: Will there be a need to send a signal to incent services as well?

Participant 10: Service changes: the services are very much linked. Primary frequency response is used prior to regulation and spinning reserve, followed by replacement reserve. The addition of one service may mean less need for another. For example, more fast frequency response means less need for primary frequency response. This may also mean less need for regulation.

Participant 11: Mid-term transition is the issue. What about the next 3, 5, or 10 years? Premature retirement of resources that still need to be there for reliability? What characteristics are needed from these resources? How can we ensure services coming from conventional resources that are retiring? There is a need for coordination for an orderly exit. This will be particularly important with delays in interconnection. Most essential reliability service is being able to provide energy when needed.

Participant 12: We have a good idea of the services and quantity needs of those services today, and the markets align with those needs. But what about the needs of 10 years from now? If the markets are incentivizing for what we need now, how will investors know what services and attributes are needed tomorrow? Who raises the flag? Studies that show future ancillary service needs without any forward compensation? We are not sure what the resource mix will be in the future, so how do we know what ancillary service needs there will be? Can we include studies of multiple futures?

Participant 13: Greater penetration of variable renewable resources can cause a greater need for services, and variable renewable resources can also provide services. Do we know whether services are still going to be important? Will incentives/prices for services be negligible? How should we incentivize the provision of these resources? Challenges are introduced by inverter-based resources, but they can also help solve challenges.

Participant 14: Do the traditional market design structures send signals for long-duration storage, or is there an opportunity to incent those resources?

Participant 15: What services are provided by long-duration storage? Resource adequacy? Can they be a substitute for thermal resource? How to plan for multi-day needs?

Participant 16: May not even need storage as such. It can be done with just variable renewable resources with appropriate headroom.

Participant 17: How many different products do we need? ISO, stakeholders, FERC, market monitors propose these products given that they see issues in the near term. Products and participation models never sunset. They may instead need to be part of the planning process. Developments are not pursued based on theory but based on prioritization. Do we need conversations about the need for product supported by data for measurement of what the need is? Forward-looking studies. Persistent out-of-market actions. Instead of introducing a new product, perhaps we have a new intra-day market structure?

Participant 18: Forward market for grid services? Or simply non-binding forward prices for grid services that show the need for prospective entrants. Signal? We need to understand if there is a greater need or value for the future or not a need for today. Meeting some needs may not always require a market for services. It is worth mentioning that administration, software, and stakeholder debate time are in the millions of dollars. So, a new product that can save $2 million a year may not justify those costs.

Participant 19: What is more important? To suppress price spikes through new products? To have price spikes and have storage provide the needed response? To do whatever it takes to reduce cost to serving load?

Participant 20: We need flexibility services to incent demand flexibility and need to have ways to compensate demand. A structure is needed to capture demand flexibility that is absent today.

Participant 21: Having separate upward services and downward services of the same type can provide benefits. Storage charging wants to provide upward service and the opposite when discharging. The usefulness of separating upward and downward services depends on how often a resource is called upon. Regulation is called regularly, and a regular call may distort the offers provided for bi-directional service.

Participant 22: Two perceived barriers are duration requirements and metering and sub-metering requirements.

Participant 23: What is the transition going to require? How do you incent conventional resources to provide services during the transition, and how do you plan for a 20-year future? It's important to be systematic and define needs, to ask what resources can do today and what are they not doing that they could be doing? What is essentially needed for each of these services?

Participant 24: Are future reliability service needs studied by RTOs and shared openly with stakeholders? How comprehensive are these studies? Dispatchability will have a market in the future. Is dispatchability an essential reliability service?

Participant 25: How do you know you need a new service?

Participant 24: Persistent out-of-market actions can help determine when a new service is needed. Prices are not sufficient given the types of resources coming onto the system. Zero price on a product does not mean that it did not provide value.

How Will the Demand Side Participate in the Future Markets?

Session 1, Demand Side

Summary

Discussion topics:

- Will demand-side participation be necessary for future decarbonized power systems?
- How can customers be incentivized to follow demand response signals?
- Should the demand side be more connected to the wholesale market and actually be exposed to market clearing prices to be more responsive?
- Can demand response be a firm service?
- Are there market failures that prevent the correct evaluation of the value of demand response?

In this session, participants discussed the present and future potential of demand-side participation in power systems. In general, the participants agreed that a future decarbonized power system will most likely have some sort of demand-side participation to support a cost-effective full decarbonization of energy matrices. However, there was also general agreement that demand-side participation will not solve all the issues associated with having fully renewable systems. Looking at the present, the participants mentioned several challenges for a more immediate increase of demand-side participation. These challenges include competition with storage, which can provide similar capabilities to the system; lack of trust of the actual responsiveness of residential customers to demand response signals; large industrial customers having a certain level of comfort in being traditional inflexible loads; insufficient compensation for customers to participate; and ISOs'/RTOs' lack of visibility of distribution systems.

While there is no clear solution to these challenges as of now, these are some of the points that the industry will have to figure out to make demand-side participation prevalent and useful in electricity markets.

Conversation

Participant 1: In the future, say 2050, with all demand supplied by renewables, can the system work without any sort of demand-side participation? I really don't think so.

Several participants: Demand-side participation will not be enough.

Participant 1: The demand side will not solve everything. My point is that demand-side participation will be an essential and necessary enabler of systems totally supplied by renewables.

Participant 2: There are two stages in the energy transition. The first stage is to incentivize electrification. The second stage is to incentivize flexibility.

Participant 3: There is no real expectation currently of the expansion of demand response. Current studies are dealing with reliability without considering extreme events.

Participant 4: It is possible to make the transition to a renewable system without demand response, but it will be very expensive. Ironically, demand-side participation is not currently incorporated into planning, but everyone says it will happen.

Participant 3: The value of demand response will decrease as you have more flexible resources like storage. To explore the value of demand-side participation, there is a window of years before other flexible solutions on the supply side show up.

Participant 1: Are we just going to curtail the excess renewable generation instead of leveraging demand-side participation, which could be done via electrolysis, for example? Heating, hydrogen, electric vehicles will all be on the demand side.

Participant 5: I think demand response will be happening on a daily basis in 2050, and this could be through power to X, where X can be hydrogen.

Participant 4: Do you see retail demand response shaping wholesale markets?

Participant 6: If there is a massive increase in peak demand, there should be an incentive for people to look at their thermostats and be responsive.

Participant 7: If you have a smart thermostat system and a third party paying you a flat rate to manage it, will people actually be responsive. Can demand response be accurately accounted for as a firm response?

Participant 2: ISOs have no visibility of the distribution systems.

Participant 2: There is a latent appetite for consumers to participate in demand response. If there is predictability of when demand response is most needed, customers will be more inclined to participate.

Participant 7: The chances of customers making optimal decisions are minimal. But there are companies working on ways to manage these decisions.

Participant 4: People don’t want to rely on resources that may not show up when needed.

Participant 8: In my opinion, demand response should have all the rights and privileges that generators currently have. Generators say what they can do and ISOs optimize them. If you are providing demand-side services and not participating in the market, you are actually just green washing.

Participant 9: Would this proposition (demand-side having rights and privileges of generators) be an extension of the current unit commitment problem?

Participant 8: Yes, and we saw evidence that it can work in the recent studies.

Participant 1: Twenty years into the future (when we have growth in heat pumps, electric vehicles, digital meters, real-time pricing), it will not be possible to manage everything without aggregators, which will be the retail competitors of the future. Aggregators will be highly needed. Aggregators collect data, talk to people, collect 1,000 customers, buy power in the wholesale market. Aggregators will manage decisions for customers and give them flat rates.

Participant 5: What are the main barriers for large customers to act as providers of demand-side services?

Participant 4: The market does not pay for our demand-side programs. There is also some technology learning to do on the distribution systems to understand how to best measure and control resources (distributed energy resources management systems (DERMS), etc.). Is there a value for demand response? Why is it not working in markets?

Participant 10: There are considerations regarding the ability of large consumers to be flexible. It is possible to shift load across data centers, and use data centers in different regions to provide demand response. However, there is no commercial appetite to do more. There is a certain level of comfort in being a traditional inflexible load. Also, the speed of services that rely on data centers is a key part of customer satisfaction, and shifting load across data centers can decrease this speed. Without adequate compensation for this loss of efficiency, it does not make sense to provide demand-side participation.

Participant 11: Wholesale energy markets work well, but the demand side is disconnected. Demand-side participation should not be about being paid to curtail; rather, it should be about paying for what the customers use.

Participant 12: Maybe there is not sufficient variability to motivate demand response. In California, where there is more variability, storage is being deployed. Maybe other resources are eating demand response’s lunch now in wholesale markets.

Participant 9: If volatility is not allowed to rise in wholesale markets, how can the value of demand response be evaluated?

Participant 5: When PJM created a pricing model for demand response, people celebrated the availability for this service, but, at the end of the day, market monitors said demand response was a disappointment. In California, the same thing happened because demand response was scheduled a lot but did not show up when needed.

Participant 4: There has been a change in the market to enforce supervisory control, so demand response should be firmer.

Participant 7: In evaluating demand response, how much of the customer reaction can be taken into consideration when accrediting demand response?

Participant 13: In Texas, there is a set of loads contracted for emergency service that would not be served in the first step of an emergency—they will curtail these guys before an emergency happens, when it is anticipated. Industrial and municipal loads are very good at changing their consumption according to prices, so it can be done.

Participant 4: There is a value stream.

Participant 8: Bidding demand does all of that but better. However, the case of residential customers is difficult. If you are freezing in the winter, would you be a responsive load? If you put customers in the market, you may get higher prices in the energy market, but you may get lower prices in the capacity market. Scarcity prices should be driven by the demand side instead of relying on operating reserve demand curves. However, there is a big reluctance and ignorance about demand and bidding. During recent events, there were complaints about $1,400 prices to be dealt with by the players of the electricity market while charging very low prices from end-customers. So, there was no incentive for end-customers to behave in a way that would lower the $1,400 price.

Participant 13: In Winter Storm Uri in February 2021 in Texas, could we have flipped feeders in and out and rotated outages instead of continuously curtailing the same feeders? I think something like that should have been done.

Participant 4: In general, not even time-of-use rates have large adoption.

Participant 11: Major demand-side enablers such as aggregators should be included within the discussion.

Participant 13: Who owns the customer data?

Participant 4: The privacy laws depend on the states. So, third parties have different barriers to access the data of the customers.

Participant 1: If you have smart meters, you should be able to decide who can see your data.

Participant 10: RTOs’ visibility of demand is important.

Electricity Markets Under Deep Decarbonization: Summary of Workshop Conversations

This workshop summary is available at https://www.esig.energy/market-evolution-for-100-percent-clean-electricity/.

To learn more about work being done in this area, please send an email to info@esig.energy.