ENSURING LOW-COST RELIABILITY

RESOURCE ADEQUACY RECOMMENDATIONS FOR A CLEAN ENERGY GRID

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AUTHOR | ROB GRAMLICH, GRID STRATEGIES LLC

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

Grid Strategies LLC

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I EXECUTIVE SUMMARY

The controversial topic of resource adequacy (RA) is undergoing fundamental reassessment to function properly with the future resource mix. This report integrates legal, technical, economic, and institutional considerations into a set of recommendations. We evaluate some of the main RA approaches and offer ways for each of them to be improved to better function with the future resource mix.

From a legal standpoint, while FERC's authority over resource adequacy in the ISO/RTO setting has been construed expansively, the Commission has declined to mandate capacity markets in circumstances where reliability and economic problems have not been demonstrated. Outside ISOs/RTOs, FERC's authority is much more limited. Where capacity markets exist, if environmental attributes are co-optimized with capacity in a single market, that may confer authority over related environmental issues that could be used by a future set of FERC Commissioners to interfere with state policies as has been done with previous market rules such as the Minimum Offer Price Rule (MOPR).

Technical considerations include: the need to modify both system-wide and resource specific RA metrics, evaluation of RA in all hours not just annual peak, and interactions between resources that in some cases such as solar and storage increase their capacity value when used in the same portfolio.

Economic policy considerations include the "public good" characteristics that underlie the original need for RA requirements, but which may be less prominent with new monitoring and control technologies; the need to precisely define products based on engineering need; and efficiency improvements where there are long-term contracting arrangements for electricity products.

This report is based on interviews with experts across the renewable energy industry as well as a survey of literature and market reports. The work was funded by the American Council on Renewable Energy.

We recommend the following reforms generally in all structures:

1. Provide non-discriminatory capacity value for clean energy and all resources
2. Create buyers with accountability
3. Avoid FERC jurisdiction over environmental attributes
4. Increase regionalization
5. Increase the granularity of resource adequacy and reliability products
6. Shift relative payments from capacity to the energy and ancillary services markets
7. Utilize competitive procurement for new generation
8. Support regional stress testing and evolving resource adequacy assessment methodologies
9. Develop new metrics of system reliability

II INTRODUCTION

The Federal Energy Regulatory Commission (FERC), Regional Transmission Organizations (RTOs), Independent System Operators (ISOs,) state regulators, and utilities outside RTOs are all entering uncharted waters on resource adequacy for the future resource mix. Resource Adequacy, defined by FERC and the North American Electric Reliability Corporation (NERC) as "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses),"[1] has been a controversial topic in restructured electricity markets from the start, and seems to only be getting increasingly controversial. FERC is asking fundamental questions about resource adequacy and capacity markets. Recent involuntary load shedding in California, Texas, and some parts of the Central US raised awareness among the general public and policy makers about both the adequacy and performance of resources. Stakeholders and states in RTO regions and non-RTO regions are evaluating means of ensuring that load can be met in all hours given clean energy targets. A massive amount of generation investment is needed for clean energy objectives,[2] yet many generation investors are questioning how supply investments can be made into markets with low and declining energy prices. At the same time, the main way resource adequacy has been achieved in RTO markets — mandatory capacity markets — has been so controversial that FERC Chairman Rich Glick recently stated, "the future of the RTOs are really at stake, especially in the eastern states."[3] Thus, resource adequacy requires some fundamental re-assessment and many questions must be resolved to achieve clean energy, reliability, and affordability goals.

This paper identifies key issues and directions to achieve resource adequacy in a decarbonized US power system. Legal, institutional, engineering, and economic considerations are integrated into an analysis and set of recommendations. The project included consultations with independent legal and technical experts and their input is provided in two associated memoranda, attached here as appendices. The project also included interviews with clean energy companies and associations and their input is described on an anonymous basis at various points.

The paper evaluates some of the options that have been proposed recently for resource adequacy in a clean energy future. The paper does not discuss the Minimum Offer Price Rule (MOPR) which was expanded in ways that directly harmed clean energy and state energy policy objectives, because that issue is being resolved separately by FERC. We are not listing Commissioner Danly's proposal[4] or LS Power's proposal[5] because they are focused on MOPR-related allegations of price suppression. We assume Expanded MOPR is no longer in place in any option.

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1 Planning Resource Adequacy Assessment Reliability Standard, 76 Fed. Reg. 56,16250 , March 23 2011.

2 By one estimate 70 Gigawatts of new renewables and storage will be needed each year for the next 15 years to reach President Biden's target. Amol Phadke et al., *2035 The Report: Plummeting Solar, Wind, and Battery Costs Can Accelerate Our Clean Electricity Future*, (n.d.).

3 FERC, "Technical Conference Regarding Resource Adequacy in the Evolving Electricity Sector," at 8, Docket No. AD21-10, March 23, 2021.

4 James Danly, "Danly Office White Paper: The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets," May 20, 2021.

5 PJM, "Capacity Market Workshop #4–Next Steps," slide 12, March 26, 2021.

III SUMMARY OF CONSIDERATIONS — LEGAL, ECONOMIC, ENGINEERING, INSTITUTIONAL

Resource adequacy includes legal, economic, engineering, and institutional issues that must be integrated. Some of the key considerations from these areas are summarized below. These findings are based on our interviews with independent legal expert Jon Schneider of Stinson LLP and technical experts Derek Stenclik of Telos Energy and Michael Goggin of Grid Strategies, and the Q&A they provided in associated memoranda.

Summary of legal and jurisdictional considerations

The associated memorandum from Jonathan Schneider of Stinson LLP concludes:

1. State-based regulatory authorities have jurisdiction reserved under the Federal Power Act (FPA) to set the level and composition of generation to serve load. Outside ISO/RTO regions, this authority has been exercised without federal interference. Inside ISO/RTO regions, state-based authority may not be exercised with the aim of affecting FERC-regulated wholesale market prices.
2. In a non-RTO environment, FERC has no obvious basis for exercising authority to impose a resource adequacy requirement, though it may have authority to oversee the administration of a voluntary resource adequacy framework agreed to by market participants.
3. In ISO/RTO organized wholesale markets, precedent holds that FERC has the authority to require Load Serving Entities (LSEs) to pay financial penalties if they do not meet resource adequacy requirements as a condition of participation in wholesale markets.
4. FERC may have the authority to compel participation in capacity markets, though the Commission has held that the exercise of this authority depends on circumstances it has not found evident.
5. FERC's and NERC's authority over electric reliability under FPA section 215 does not support NERC's or FERC's ability to impose a resource adequacy requirement.
6. The environmental attributes of electric generating resources sold on an unbundled basis are outside FERC's jurisdiction. FERC may have ancillary authority over these attributes if they are bundled with electric sales undertaken under FERC's jurisdiction.

These statements are explained in the associated Q&A memorandum with Jonathan Schneider, attached as Appendix A.

Summary of engineering considerations

The associated memorandum in Appendix B from Derek Stenclik and Michael Goggin on engineering and technical considerations concludes:

1. As the resource mix changes and decarbonizes, so do the system needs for reliability. The proliferation of variable renewable energy, energy storage, flexible load, and fossil retirements are altering the way resource adequacy analysis needs to be conducted and the way it is translated to procurement decisions and capacity accreditation.
2. Conventional resource adequacy metrics (LOLE, LOLH, LOLP) only count the number or probability of shortfall events. They provide little or no information on the size, frequency duration, and timing of the shortfalls. With increased variable renewable energy and energy-limited resources, this information is critical to ensure the right resources are selected for the reliability needs.
3. Modeling tools must also adapt. Sequential Monte Carlo analysis — which chronologically evaluates each hour of the year across many years of weather data (wind, solar, load) – is necessary.
4. Peak reliability risk is no longer isolated to peak load hours. In the near-term, risk is shifting to net-load peak but will eventually shift to multi-day periods of low solar and wind output, often occurring in the winter.
5. Capacity accreditation is increasingly complex due to saturation effects (decreasing capacity credit at increasing penetrations) and portfolio effects (changes to individual resource capacity credit due to changes in the underlying resource mix). As a result, ELCC may be sufficient for near-term resource accreditation, but has limitations for long-term planning.
6. If Effective Load Carrying Capability (ELCC) is used as the methodology, it should be applied consistently across resource types. This includes accounting for potential fuel supply disruptions, ambient derates, and increased outage rates during extreme weather.
7. Transmission is an important mitigation for resource adequacy, allowing for geographic diversity in weather, load, and renewable resource availability. Increased transmission should be evaluated as a capacity resource to meet reliability needs.

Summary of economic policy considerations

Resource adequacy is a public policy driven aspect of power systems. There has always been a value and need beyond just what the market would by itself provide. Prior to competitive power markets, vertically integrated utilities would agree through regional reliability councils and coordination agreements to meet common reserve margins. The agreements would attempt to ensure that no other utility was falling short in such a way as to "lean on the system" during peak load times. Leaning on the system became more of a threat with restructuring, and some

early experiences in the late 1990s[6] led the industry to seek more formalized agreements to ensure that power was available when needed.

The economic policy basis for mandatory reserve margins is in the economic theory of public goods, or what is also known as the tragedy of the commons.[7] If a customer can use a good without paying for it, then there is an incentive on the part of all consumers to under-pay and under-procure, and to free ride on what others provide. In the electric power system context, free riding takes the form of utilities leaning on the system and drawing more power than that to which they are entitled.[8] This phenomenon has always existed in electricity because individual end use consumers have not been able to be curtailed. That state of affairs is changing with modern control and metering technology, so economists and engineers have been suggesting there may be ways to "privatize" the public good.[9] But until there are actual physical curtailments of those customers who did not procure enough energy, which is a political issue as much as it is one of engineering or economics, public good characteristics remain, justifying resource adequacy requirements and compensation. Some form of capacity payment has been incorporated into electricity markets in England and Wales Pool, the Single Electricity Market on the island of Ireland, Spain, Argentina, Italy, South Korea, and Chile.[10] Presently every US state and region except Texas/ERCOT has some form of physical resource adequacy requirement.

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6 In the summer of 1999, a Midwestern utility called Cinergy leaned on its ties by consuming more than it was either producing or procuring, causing a system-wide power shortfall that reduced system frequency and putting the whole system at risk of collapsing. See FERC Staff, *Investigation of Bulk Power Markets: Midwest Region*, at 2-35, November 1, 2000.

7 *See*, e.g., David N. Hyman, "The Theory of Public Goods," February 17, 2019.

8 Steven Stoft, *Power System Economics: Designing Markets for Electricity*, Wiley-IEEE Press, June 2002. As described by Ausubel and Cramton, "The need for regulated forward markets in electricity comes largely from market failures on the demand side. Consumer demand response is limited; consumers have limited exposure to spot prices and have no ability to express preferences for reliability. As a result, in most markets, regulators establish the quantity of resources needed." Lawrence M. Ausubel and Peter Cramton, "Using Forward Markets to Improve Electricity Market Design," Utilities Policy, 18, at 196, January 9, 2020.

9 James Bushnell, Michaela Flagg, and Erin Mansur, *Capacity Markets at a Crossroads*, April 2017.

10 Pöyry, *Balancing Resource Options: An Alternative Capacity Mechanism*, November 4, 2011.

To ensure resource adequacy in a market environment, the economic incentives must exist to attract and retain sufficient resources. The common colloquial description in RTO stakeholder processes and some FERC proceedings of the revenue sufficiency issue is called the "missing money" problem whereby energy markets alone do not compensate resources enough to benefit from entering or continuing to operate.

Economic efficiency requires that compensation is tied to the specific product that is needed. In the case of resource adequacy, since it is a policy driven product, the requirements must be carefully defined through engineering analysis, translated into economic products, and assigned and enforced through state or federal authorities. To the extent a product is needed to operate the grid reliably and can be provided by a different set of resources, it should be defined separately from those other products. For example, fast response to cover a few minutes of unpredicted shortfall is distinct from production during a predictable extended period, so those should be separate products. The resources needed to meet summer and winter needs may be very different, and thus those should be distinct products. Thus the findings in the Stenclik-Goggin memorandum should be used to define the physical needs, and the economic products (plural) should follow from those definitions.

Economic efficiency also requires that any and all supply and demand resources capable of providing the service be able to compete for providing the service. Resources that have capacity value should be accurately assigned that value and be able to sell it on a non-discriminatory basis.

The cost of financing new generation is an important economic factor for achieving low costs for consumers, and "just and reasonable" rates as required in the FPA. Consumers ultimately pay the cost of financing. When excessive risks and uncertainties affect generation investment, investors will require higher rates of return from generation developers, who will then need to charge higher prices in their Power Purchase Agreements (PPAs). The ability to hedge through long-term contracts and for generators to pre-sell their products prior to committing large capital outlays can significantly reduce financing costs and benefit customers. Therefore, market structures and designs that facilitate hedging and long-term contracting can benefit customers.

Efficiency also requires performance incentives. With Northeast capacity constructs and reserve margins around the country focused on "capacity," there have been a number of problems over the years with actual performance. The requirements were designed to achieve "adequate resources" to meet peak load, and they were not designed originally with performance in mind[11] or the challenge of meeting the net load conditions of the future portfolio when reliability risks may shift away from peak load hours. While Northeast capacity markets have been evolving towards more performance-based incentives, this incentive is not as strong in capacity markets as it is in energy-only markets.[12]

11 FTI Consulting, *Resource Adequacy Mechanisms in the National Electricity Market*, at 8, July 16, 2020.

12 Performance penalties in capacity markets are based on capacity prices, not spot energy prices. PJM, *PJM Manual 18: PJM Capacity Market*, at 203, May 26, 2021.

Summary of institutional and political considerations

Each region of the US has a different allocation of responsibilities between state and federal authorities. Many states outside RTOs do not want to transfer jurisdiction to FERC for issues like resource adequacy that closely impact their own resource choices. The experience with MOPR in the Northeast capacity markets has discouraged many states from transferring any resource adequacy jurisdiction to FERC.

There are also different jurisdictional and institutional issues for municipally owned and customer-owned utilities other than investor-owned. Many of the utilities in the West are publicly owned and fall under only limited FERC jurisdiction.

In the Northeast RTOs and ISOs covering approximately 20 states from Illinois east to Virginia and North through Maine, resource adequacy is generally regulated through FERC-jurisdictional RTO/ISO tariffs. FERC did not require that; rather, the utilities used their rights to file agreements under Section 205 of the FPA to put resource adequacy agreements into their FERC jurisdictional wholesale ISO/RTO tariffs.

In the Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and California, resource adequacy remains primarily under state jurisdiction and handled through Integrated Resource Planning (IRP), with some limited backstop role for the ISO/RTO.

In the Northwest, Interior West, and Southeast, there is no federal resource adequacy regulation; it remains fully under state jurisdiction.

In most of Texas covered by the Electric Reliability Council of Texas (ERCOT), the power system is regulated by the state and there is no federal regulation of resource adequacy. The state only regulates resource adequacy through ERCOT spot market design and through the structure of Retail Electric Providers, with no physical resource adequacy requirements. However that is one of many issues being reviewed in the aftermath of winter storm Uri in February 2021.

It is unlikely these basic structures will change significantly in the near term. As discussed below, there may be more regionalization in the West and Southeast, which may bring some limited federal responsibilities, but generally resource adequacy improvements must take place within the structure that exists.

IV CRITERIA FOR EVALUATION

There are many different options being developed to adjust resource adequacy procurement and compensation across North America. These various options can be evaluated based on certain public policy objectives:

1. Maintain system reliability. To meet this criterion, load must be met under all reasonably foreseeable circumstances with a socially acceptable probability.
2. Support financing of wind, solar, and storage plants. To meet this criterion, there must be sufficient certainty and transparency to facilitate market entry and a reasonable ability of investors to evaluate market opportunities.
3. Accommodate, and does not hinder, achievement of state and federal clean energy policies. "Expanded MOPR" should not apply, and more subtle forms of interference should not apply either.
4. Minimize cost. Cost should be evaluated as total system cost for the region, since resource adequacy is a regional and system need.
5. Minimize regulatory risk and potential for political and subjective stakeholder influence. To satisfy this criterion, the process should be balanced and transparent, and result in clear rules that are based on engineering and economic fundamentals rather than rely too much on stakeholder voting preferences.
6. Avoid over procurement of non-renewable resources for resource adequacy that may crowd them out of energy markets.
7. Minimize market power. This includes horizontal market power of suppliers and vertical market power of utilities that may favor affiliates.
8. Administrative simplicity to create and run.

These criteria can guide the evaluation of resource adequacy models. We turn now to general resource adequacy structures.

V RESOURCE ADEQUACY STRUCTURES — DESCRIPTION, PROS, CONS, AND WAYS TO IMPROVE

Some general structures of resource adequacy have been the subject of significant discussion in the last few years.[13] Some have advocated for more of a centralized long-term procurement of capacity and environmental attributes while others have advocated for a many buyer/many seller de-centralized model. There is not really a choice between central and de-centralized models since each region is likely to stick with their general structure for the foreseeable future. What is more interesting is to understand the opportunities to improve each model. Here we describe the different models and potential ways to improve them. The next section addresses common themes across all regions and models.

1. Northeast-style mandatory capacity markets

Description:

In PJM Interconnection (PJM), the New York Independent System Operator (NYISO), and ISO-New England, there is a single definition of "capacity" that must be procured through a mandatory auction. All load is covered including munis, coops, competitive retailers without the ability to bypass. The auction functions as a single buyer with competitive procurement. The procurement is one- to three-years ahead of the planning year. Resources selected receive the market-clearing capacity price in exchange for an obligation to offer power available into energy markets. Performance penalties apply to non-performing resources.

Pros:

- Transparent. Prices and rules are consistent and equally known to all.
- Avoids utilities favoring own generation, or favoring types of generation or generation over demand response.
- Has enabled large amounts of competitive investment.
- Generally the model has support from the ISO/RTOs, states, and stakeholders despite many controversies and litigation over the years on various aspects of the design.

Cons:

- Subject to stakeholder subjective views in the design, and stakeholders are generally more invested in conventional resources than clean energy.
- Provided a vehicle for MOPR to be imposed across all three regions, revealing the vulnerability to whims of individual FERC Commissioners.

13 See Paul L. Joskow, "From Hierarchies to Markets and Partially Back Again in Electricity: Responding to Decarbonization and Security of Supply Goals," Journal of Institutional Economics, 1-17, May 10, 2021; Sonia Aggarwal et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, June 2019; and WRI/RFF's series, "Market Design for the Clean Energy Transition: Advancing Long-Term Approaches."

- Has tended to over-procure gas plants.
- Is not valuing resource diversity because each resource's contribution is determined independently of the rest of the portfolio.
- Prices are very sensitive to small changes in load or generation, since all transactions must take place at the single market-clearing price.
- As described in the Schneider legal memorandum, states have been unsuccessful in court in extracting themselves from the regime when they were unhappy with it once it was put in place.

Ways to improve:

The products can be seasonal and more granular. NYISO has a seasonal market and MISO is working on one.[14] The American Wind Energy Association (AWEA), Natural Resources Defense Council (NRDC), and others have advocated for seasonal capacity markets.

Could allow bypass. American Clean Power Association has suggested "capacity as a commodity" approach.[15] In this approach, capacity can be traded bilaterally, bypassing the central auction. A key advantage is that load-serving entities can choose resources based on both their capacity value and clean energy attributes. This way they can co-optimize on their own and purchase both capacity and clean energy from a given clean energy seller rather than having to pay for whatever comes out of the capacity auction and separately for clean energy.

More granular physical requirements. The California Public Utilities Commission (CPUC) has separate local, flexibility, and system resource adequacy requirements.[16] There are proposals to use ELCC differentiated by month and location given its variability.[17] The California Independent System Operator (CAISO) is proposing a resource adequacy requirement based on the net load peak in order to address the situation where evening shortfalls occur.[18] PG&E's proposal is for multiple different time slices.[19] These approaches address the evolving needs of the system. More detail on these options can be found in the Stenclik-Goggin memorandum.

Another possible improvement to centralized capacity markets is from Sue Tierney's "Wholesale Power Market Design in a Future Low-Carbon Electric System: A Proposal for Consideration."[20] In this proposal, states can choose their preferred resource adequacy approach — whether to rely on the RTO or a state program. New definitions of resource adequacy beyond generic capacity would be allowed based on reliability assessments — locational, flexibility, or other. The RTO would perform 10-year planning with inputs from states. Resource Adequacy would be integrated with transmission planning. The Tierney approach recognizes state jurisdiction and enables states to choose environmental and resource adequacy approaches, providing greater flexibility.

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14 *See* MISO, "RAN Reliability Requirements and Sub-annual Construct," updated February 26, 2021.

15 *See* Sari Fink and Mike Borgatti, *Capacity as a Commodity: A Framework for a New Capacity Market Paradigm That Enables Customer Choice*, November 2020.

16 CPUC, "Resource Adequacy," (n.d.).

17 *See* slides 55 and 60 for locational and regional variation of ELCC: CPUC, "Track 3.B.1/Track 4 Workshop," February 25, 2021.

18 *Ibid.*, slide 33.

19 CPUC, "Day 1 of Track 3.B.2 Workshops," slide 42, February 8, 2021.

20 Susan F. Tierney, *Wholesale Power Market Design in a Future Low-Carbon Electric System: A Proposal for Consideration*, November 28, 2020.

Another twist on central markets is Eric Gimon's "Organized Long Term Market."[21] In this proposal there is a long-term central market, but it is voluntary for the load-serving entity. The contracts are tied directly to the spot market, providing stronger performance incentives for the supplier, and a consistent product between the forward procurement and real time operations, unlike capacity and energy markets, which differ from each other.

2. Midwest and California style state-led resource adequacy with RTO backstop

Description:

In MISO, SPP, and CAISO, states have primary responsibility for resource adequacy, while the ISO/RTO provides analysis and performs a backstop function.

Pros:

- Decreases influence of RTO stakeholders and RTOs on capacity market design.
- Decreases reliance on the wide and fat demand curves that tend to be in place in Northeastern capacity constructs which tend to over-procure natural gas plants.
- Allows states interested in clean energy more options. Some Northeastern states have suggested they might be better off with more of a state role, with the ISO/RTO more in a backstop role.[22]
- Provides some regional assurance of resource adequacy.
- Supports reliability through the backstop mechanism to account for resources and address free riders who do not procure sufficient resources.

Cons:

- Could provide utilities more ability to choose power from affiliates over independent power producers, unless this is prevented in state procurement rules.
- Can enable subjective biases of a utility or a state regulator to influence resource choices.
- Once resource adequacy functions have been put into FERC tariffs, it requires FERC action to put them back, as noted in the Schneider legal memorandum.

Ways to improve:

- Fair, non-discriminatory capacity values need to be incorporated into state IRP decisions.
- More use of competitive procurement at the state level. [23]

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21 Eric Gimon, "Let's Get Organized! Long-Term Market Design for a High-Penetration Grid," (n.d.).

22 *See* Comments of NY and MD Commissions at the FERC March 23, 2021 resource adequacy technical conference: "Initial Post-Technical Conference Comments of the New York State Public Service Commission and New York State Energy Research and Development Authority," Docket No. AD21-10, April 16, 2021 and Maryland Public Service Commission Post-Technical Conference Comments, Docket No. AD21-10, April 23, 2021. See also Ann McCabe, David A. Svanda, and Betty Anne Kane, Making Markets Work for PJM States: State Engagement Possibilities with PJM, October 2019.

23 *See* John D. Wilson, Mike O'Boyle, and Ron Lehr, "Monopsony Behavior in the Power Generation Market," The Electricity Journal, 106804, Volume 33, Issue 7, August-September 2020, and John D. Wilson et al., *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, April 2020.

3. RTO spot market with voluntary bilateral markets

Description:

In the market approach, there are many buyers and many sellers, as in normal markets across the economy. LSEs are the wholesale market buyers, contracting with suppliers in a wide variety of ways rather than through a central common single-buyer procurement. Hedging is accomplished through voluntary contracting. Despite the label of "energy-only," market participants rely on negotiated hedge contracts.[24] Hedge contracts can evolve to suit the needs of buyers and sellers. Buyers can choose the contract term, types of products, the price, quantity, location, transmission responsibility, and many other factors. Energy spot prices would reflect Value of Lost Load and operating reserves would be priced according to an Operating Reserves Demand Curve (ORDC). There is no mandatory resource adequacy requirement in this model. An ISO could provide information to the market about expected shortages. Potentially high energy and ancillary service spot prices encourage LSEs to procure the energy they need in advance under stably priced voluntary contracts.

Pros:

- This option is very flexible, allowing for any and all resources to provide their value if they can find a customer.
- Less influenced by subjective stakeholder views and votes about what is valuable or not.
- Accurately compensates flexible resources.
- Puts supply- and demand-side resources on an equal footing.
- Supports long-term contracting more than one- to three-years forward, but only if there are well-equipped buyers.
- Allows buyers' preferences to be reflected in their contracting on the types of generation they may prefer.
- One analysis focused on Australia concluded, "[r]esults suggest that existing energy-only market mechanisms have the potential to operate effectively in a 100 percent renewables scenario, but success will rely upon two critical factors. Firstly, an increase in the Market Price Cap is likely to be required. Secondly, a liquid and well-functioning derivative contracts market will be required to allow generators and retailers to hedge increased market risks successfully."[25]
- Places responsibility on LSEs to make trade-offs between capacity, energy, and environmental values of different resource options. Co-optimization is achieved by each entity.

24 As described by Ausubel and Cramton, "Forward markets, both medium term and long term, complement the spot market for wholesale electricity. The forward markets reduce risk, mitigate market power, and coordinate new investment. In the medium term, a forward energy market lets suppliers and demanders lock in energy prices and quantities for one to three years. In the long term, a forward reliability market assures adequate resources are available when they are needed most. The forward markets reduce risk for both sides of the market, since they reduce the quantity of energy that trades at the more volatile spot price." Lawrence M. Ausubel and Peter Cramton, "Using Forward Markets to Improve Electricity Market Design," Utilities Policy, 18, at 195-200, January 9, 2020.

25 Jenny Riesz, Joel Gilmore, and Iain MacGill, "Assessing the Viability of Energy-Only Markets With 100% Renewables," Economics of Energy & Environmental Policy, Vol. 5, No. 1, at 105-130, March 2016.

Cons:

- Relies on a well-functioning retail market or some form of well-equipped buyers with both the ability (credit-worthiness) and incentive to engage in long-term contracting.
- Thirteen of the fourteen states with retail competition (all of them except Texas) lack meaningful creditworthiness requirements on LSEs.[26] State commissions likely have the power to impose such requirements without legislation, as a condition of obtaining a license to serve retail load, but almost none have taken on this task.[27]
- Relies on utility market power to be mitigated so utilities do not favor affiliates over independent power producers.
- Politically more difficult for regulators to allow volatile spot prices.
- Spot prices are likely both visible and volatile, causing political risk, despite most of the economic value being transacted in long-term contracts.

Ways to improve:

- A physical forward energy contracting requirement could be required to address concerns about resource adequacy. State or federal regulators could require LSEs to procure energy at all times to meet their load responsibilities. LSEs could trade with other LSEs, with suppliers,

26 Frank Lacey and Rob Gramlich, *Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment*, March 2020.
27 *See*, for example, The General Court of the Commonwealth of Massachusetts, Massachusetts General Law, Ch. 164 § 1F.

and with end-users to achieve load-generation balance at all times. A regulator can oversee each entity's procurement plans. Australia uses this approach. The product would be the provision of energy at all times or certain defined times of scarcity rather than simply the "capacity" to provide energy. That change could prevent some of the flaws of capacity markets, which have lacked assurance of fuel supply, advance forward contracting, and performance incentives tied to spot market operation.[28] The requirement would include firm transmission and identified generation sources.[29] Dr. Frank Wolak's Standardized Fixed Price Forward Contract approach is one form of this approach.[30] A related approach is an insurer-of-last-resort approach that adds a requirement for customer-specific insurance to cover needs at times of shortage conditions.[31]

- To avoid excessive charges when there is extended scarcity, a circuit breaker mechanism could be included.

4. State led IRP with no RTO

Description:

This is the traditional vertically integrated utility model where all jurisdiction is at the state level and utility plans are reviewed through periodic IRP proceedings.

Pros:

- Responsibility is clear.
- If the IRP is done well, all options are considered to meet environmental, capacity, and energy needs.

Cons:

- Inefficient by requiring higher reserves than would be needed if performed regionally.
- Utilities often have market power and information advantages.
- Lack of transparency deters entry by new companies and technologies.

Ways to Improve:

- Regional reserve sharing. Reserve sharing is often found to be the most significant source of economic savings from RTOs and regional markets, because expensive generation capacity reserves can be lower if the diversity of all the systems in the region can be integrated into one regional needs assessment.
- Accounting and tracking. In the Northwest, parties are considering a central tracking mechanism to prevent double counting of capacity.[32] Such a system would prevent situations where all are relying on the same resources.

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28 Lawrence M. Ausubel and Peter Cramton, "Using Forward Markets to Improve Electricity Market Design," Utilities Policy, 18, at 199, January 9, 2020.

29 *See*, eg, CPUC, "Track 3.B.1/Track 4 Workshop," slide 16, February 25, 2021.

30 CPUC, "Day 3 of Track 3.B.2 Workshops," slide 8, February 20, 2021.

31 Farhad Billimoria and Rahmatallah Poudineh, *Decarbonized Market Design: An Insurance Overlay on Energy-Only Electricity Markets*, at 10, OIES Paper: EL 30, October 2018.

32 *See* https://elibrary.ferc.gov/eLibrary/filedownload?fileid=020DE85D-66E2-5005-8110-C31FAFC91712: "When it gets hot everywhere at the same time, it becomes a game of musical chairs in which several entities are relying on the same megawatts."

5. Central regional environmental attribute procurement

Description:

This option is being raised in the Northeast as well as in generic conversations about financing clean energy in a decarbonized power system. It involves central procurement of environmental attributes and capacity. The procurement entity could be an RTO but need not be, and might or might not fall under FERC jurisdiction since it is procuring non-jurisdictional environmental attributes. The Brattle Group's Forward Clean Energy Market (FCEM)[33] and Integrated Clean Capacity Market (ICCM)[34] are examples of central regional environmental attribute procurement. The ICCM is the same as FCEM but with co-optimization of capacity and environmental attributes by the same entity. Steve Corneli's PRISM approach is another one, which is a market structure that is built on the co-optimization models that are increasingly being used in the industry.[35]

Pros:

- Facilitates long-term contracts if the central entity has the power to be a counterparty to such transactions or to require load to sign the contracts.
- Provides transparent price signals.
- Reduces utility market power and ability to choose affiliates.
- The advantage of ICCM being considered by some states like New Jersey is that it allows economic trade-offs to be made between environmental attribute value and capacity value. For example, if one resource has high capacity value such as offshore wind but equal environmental attribute value, it might fare better in a co-optimized procurement.

Cons:

- Such clearinghouses are already being provided by private entities like LevelTen's Energy Marketplace[36] and various marketers and traders. Thus, a government-sanctioned clearinghouse may not provide any additional value.
- Requires states to agree with each other on the attributes to be procured. Presently very few state Renewable Portfolio Standards have common resource definitions and the legislation required to change the definitions is extremely difficult to pass.
- Contains any flaws of capacity markets because it is an add-on.
- Environmental attributes are not the expertise of ISOs or RTOs, which may result in interference with state clean energy goals.
- If a new entity other than an ISO/RTO performs the function it would need to be created and state and federal regulators would need to agree on who has jurisdiction over it before its bylaws, governance, funding, and staffing can be determined.

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33 Kathleen Spees, Samuel A. Newell, Walter Graf, and Emily Shorin, *How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals Through a Forward Market for Clean Energy Attributes*, September 2019.

34 The Brattle Group, "New Jersey Board of Public Utilities to Explore Resource Adequacy Alternatives Featuring Integrated Clean Capacity Market Framework by Brattle Consultants," February 3, 2021.

35 Steve Corneli, "A Prism-Based Configuration Market for Rapid, Low Cost and Reliable Electric Sector Decarbonization," December 16, 2020.

36 *See* LevelTen Energy, "The LevelTen Marketplace, (n.d.).

- The proposal was created in the context of MOPR[37] and originally sold as a solution to MOPR because environmental attributes would be traded “in the market.” However, expanded MOPR is being eliminated without requiring market structure or design changes so there is likely no MOPR-related benefit.
- Creates some legal risk that FERC will assert jurisdiction over environmental attributes, especially if the procurement is run by a FERC-jurisdictional entity like and RTO, as described in the Schneider legal memorandum. If FERC asserts jurisdiction over environmental attributes, that increases regulatory risk dramatically because one swing vote at FERC can change the rules, whereas under the state jurisdictional approach, each of the ~30 states with environmental attribute requirements operate independently so risk is diversified.
- All of the downsides of central planning are at play in coordinated central buying—it could be hindered by bureaucracy, influenced by politics, and very sensitive to small modeling assumptions.
- Shifts all risk to load, increasing the risk of stranded costs being incurred. Small errors can have very large consequences as one entity controls all procurement.

37 The same is true of the similar central procurement approach recommended by the Maryland PSC.

VI GENERAL RECOMMENDATIONS

Many of the resource adequacy issues are common across market structures and regions. Here we suggest a set of priorities that apply in all regions and all structures.

A. Provide non-discriminatory capacity value for clean energy and all resources

A theme in our interviews of stakeholders was a view that renewable energy sources and storage are being short-changed in capacity accreditation processes.

Correlated outage risk is now being widely applied to renewable energy sources but not to fossil resources, as described in the Stenclik-Goggin memorandum. And yet there have been many experiences with cold weather, loss of a pipeline, widespread heat, and drought that have affected the performance of fleets of coal, gas, and nuclear energy plants. Current approaches in both IRP and capacity markets tend to assume that outage risks for conventional sources are all independent. ELCC was originally developed for fossil resources and would apply equally well to fossil units.

Portfolio effects should be incorporated. Solar and storage capacity values are higher when the other is present on the system and that should be reflected in the value they are accredited. Wind and hydro similarly have positive interactions.

Northeast RTOs have testified to their concerns about winter peak conditions and yet capacity models are all based on summer peak conditions. If winter conditions pose more resource adequacy risk, then the higher capacity value wind energy provides in winter months should be reflected in their capacity value.

B. Create buyers with accountability

An important part of resource adequacy is putting someone in charge of procuring the needed resources. ISOs and RTOs were not originally designed to procure electricity products other than short-term ancillary services.[38] Traditionally, wholesale buyers have been utility LSEs. With the advent of retail competition, competitive retailers were put in the role of procuring power for the load they serve. However, most of the states with retail choice are in areas with RTOs, and the states have tended to rely on RTO capacity markets and have relieved competitive retailers of the duty to procure long-term power.[39] It is important for resource adequacy purposes to make sure some entity is accountable for procuring the needed resources, whether it is the utility LSEs, government entities, competitive retailers, RTOs, or some other entity.

38 *See* FERC Order 888's ISO Principles and Order 2000 RTO Characteristics and Functions, neither of which have any mention of resource adequacy or auctions for long term products.

39 *See* Frank Lacey and Rob Gramlich, *Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment*, March 2020.

Whoever the buyer is should be encouraged to provide hedging to reduce the ultimate cost to consumers. Generation plant financing costs are lower when there are long-term contracts, allowing the investor to lock in sales prior to committing all of the capital needed.

Long-term contracts are entirely compatible with power markets despite some common misconceptions. Nothing about "markets" requires that they be short-term, or centrally administered. Obviously across the economy in many industries, much of the business takes place through long-term bilateral contracting. This misunderstanding is widespread and pernicious. For example, the Brattle/New Jersey Board of Public Utilities report stated, "[Fixed Resource Requirement] concepts were offered that would transition New Jersey away from a market-oriented approach to meeting supply needs and toward a system of long-term contracts."[40] Regardless of the FRR construct, this view of long-term contracts as somehow not "market oriented" is unfounded.

The ability to rely on ISOs and RTOs to provide or require long-term contracting is unclear. The FPA does not have any language about regulating buyers such that capacity or other obligations or requirements to buy long-term power may be placed on them; it is all about sellers. Recently FERC rejected longer-term (7 year) capacity commitments in New England's capacity market, which has reduced generators' ability to lock in value for their investments, decreasing the certainty provided to entering suppliers.[41]

Locking in capacity values through ISO/RTO tariffs is also in question. This was a priority for clean energy companies and associations in a recent FERC proceeding addressing the PJM market. Those parties wanted today's ELCC to be held to a floor into the future in order to provide more certainty to investors. However, FERC rejected this proposal, saying, "if the floors established by the transition mechanism bind for existing ELCC Resources, PJM would unjustly and unreasonably discount the capacity value of ELCC Resources that enter the market at a later date, despite the fact that these resources are likely to provide similar capacity value to existing ELCC Resources."[42]

It will be a challenge to identify which entities in the marketplace can and will provide the long-term certainty that enables lower cost generation financing. Given states' historic role in generation planning and in regulating retail suppliers, it would be more natural for each state to decide which entity is in charge of procurement and to do this job well, by ensuring there are long-term contracting opportunities.

C. Avoid FERC jurisdiction over environmental attributes

One must look no further than the recent experience with MOPR to see the damage and disruption that can occur with a single swing vote at FERC. If a recent FERC majority can essentially undo state clean energy policies, it takes little imagination to see what could be

40 Abraham Silverman, Kira Lawrence, and Joseph DeLosa, *Alternative Resource Adequacy Structures for New Jersey: Staff Report on the Investigation of Resource Adequacy Alternatives, Docket #EO20030203*, at 27, June 2021.

41 *ISO New England Inc*., 173 FERC ¶ 61,198, Docket No. EL20-54, at P 68, December 2, 2020: "We find that the entry of new resources should be driven, at least in part, by expectations about the prices in future years. The price lock interferes with that dynamic by making a price-locked resource insensitive to the prices in the several FCAs following the entry year."

42 *PJM Interconnection, L.L.C.*, 175 FERC ¶ 61,084, Docket Nos. ER21-278, ER20-584, and ER19-100, April 30, 2021.

done by a future Commission. MOPR votes happened to fall along party lines. While that might be different in the future, the US Senate, which confirms Commissioners, has the narrowest possible majority presently and that can change in any two-year election cycle.

D. Increase regionalization

Great efficiencies, reliability improvements, and clean energy integration possibilities come with regional power systems, compared to balkanized single utility systems. What the Northwest is doing to ensure resource adequacy for the region and what the Western Energy Imbalance Market is doing improves all of these objectives. The Southeast could do the same. Regional resource adequacy enables resource diversity, load diversity, and a larger pool of resources to meet load.

E. Increase the granularity of resource adequacy and reliability products

As described in the Stenclik-Goggin memorandum, raw "capacity" is becoming less meaningful. The reliability needs are different in summer and winter, at different times of day, and over different time scales. Short-term needs tend to require fast response and little advance notice, while longer term needs tend to require low capital cost while allowing for slower response and more notice. There is likely not one "capacity" product but rather more granular products. With more specific products, each resource can provide whichever product it is best suited to provide. The first step is to create seasonal capacity markets, as NYISO has and MISO is working on. This was a focus in PJM before the MOPR issue consumed PJM and its stakeholders. More advanced proposals are being considered in California given their high renewable energy penetration.[43]

F. Shift payments from capacity to the energy and ancillary services markets

The best laid plans will not cover all reliability needs because every situation is somewhat different. To maximize reliability, short-term energy and ancillary services prices must reflect their value at times of scarcity. Scarcity pricing and operating reserves demand curves will provide the right signals to encourage performance, power imports, demand reduction, and other actions needed to keep systems in load-generation balance in any kind of situation. Wind, solar, and battery resources are fast-responding and can benefit from selling power at these times. When systems rely more on accurate spot pricing relative to capacity markets, there is less vulnerability to subjective and political determinations of capacity value and capacity needs.

43 *See*, eg, Southern California Edison Company and California Choice Association, "Track 3 Proposal for the Restructure of the Resource Adequacy Program," before the Public Utilities Commission of the State of California, August 7, 2020.

G. Competitive procurement for new generation

For low-cost decarbonization, it is important to maximize competition in the generation sector. Even in states where utilities serve all load, own and operate transmission and distribution, and own generation, states can decide that all future generation can be competitively procured. There is a set of best practice procurement methods that states can be encouraged to follow.[44]

H. Support regional stress testing and evolving resource adequacy assessment methodologies

The clean energy transition will only sustain if reliability can be preserved. Threats to reliability in recent years are coming from events for which plans were not made—polar vortices, region-wide heat waves, hurricanes, and wildfires. However, these events can be planned for going forward. Each region should conduct “stress testing” to uncover vulnerabilities and identify protections. ISO-New England and PJM performed energy security studies that went beyond normal resource adequacy assessments. The Department of Energy and states could support this work. RTOs and utilities should perform assessments of imaginable, realistic threats. These analyses need to incorporate vulnerabilities in the fuel supply system. Resource adequacy regimes should be tied to the actual threats that may impact a region. Better severe weather forecasts from the National Oceanic and Atmospheric Administration will likely be needed.

I. Develop new metrics of system reliability

As described in the Stenclik-Goggin memorandum, the traditional metrics of reliability do not apply well to the future resource mix. Expected Unserved Energy will likely take on greater prominence.

44 *See* John D. Wilson, Mike O’Boyle, and Ron Lehr, “Monopsony Behavior in the Power Generation Market,” The Electricity Journal, 106804, Volume 33, Issue 7, August-September 2020, and John D. Wilson et al., *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, April 2020

VII CONCLUSION

Resource adequacy is one area that must evolve for the clean energy transition. The changing physical nature of supply and demand requires an evolution of both the system needs determinations and the valuation of each resource type. This evolution must take place within the range of market structures that exist across the country.

Based on the analysis herein and supported by the associated legal and technical memoranda, the following recommendations would support reliability, efficiency, and clean energy integration:

- Provide non-discriminatory capacity value for clean energy and all resources;
- Create buyers with accountability;
- Avoid FERC jurisdiction over environmental attributes;
- Increase regionalization;
- Increase the granularity of resource adequacy and reliability products;
- Shift payments from capacity to the energy and ancillary services markets;
- Competitive procurement for new generation;
- Support regional stress testing and evolving resource adequacy assessment; methodologies; and
- Develop new metrics of system reliability.

APPENDIX A

RESOURCE ADEQUACY FOR A CLEAN ENERGY GRID

LEGAL ANALYSIS

An Interview with Jonathan D. Schneider, Partner, Stinson LLP[45]

This memorandum considers a series of questions related to state and federal jurisdiction over resource adequacy requirements.

STINSON

November 2021

This memorandum considers a series of questions related to state and federal jurisdiction over resource adequacy requirements,[46] including whether the Federal Energy Regulatory Commission (FERC) can mandate participation in capacity markets. The memorandum also considers the extent of jurisdiction under Federal Power Act (FPA) section 215 over electric reliability granted to FERC and the North American Electric Reliability Corporation (NERC). Finally, the memorandum considers whether FERC has authority over the environmental attributes of low-carbon resources unbundled from electric sales, and whether the answer to that may change if the procurement and sale of generating capacity and environmental attributes are co-optimized in a platform overseen by FERC.

The memorandum concludes:

(1) State-based regulatory authorities have jurisdiction reserved under the FPA to set the level and composition of generation to serve load. Outside ISO/RTO regions, this authority has been exercised without federal interference. Inside ISO/RTO regions, state-based authority may not be exercised with the aim of affecting FERC-regulated wholesale market prices.

(2) In a non-RTO environment, FERC has no obvious basis for exercising authority to impose a resource adequacy requirement, though it may have authority to oversee the administration of a voluntary resource adequacy framework agreed to by market participants.

(3) In ISO/RTO organized wholesale markets, precedent holds that FERC has the authority to require LSEs to pay financial penalties if they do not meet resource adequacy requirements as a condition of participation in wholesale markets.

(4) FERC may have the authority to compel participation in capacity markets, though the Commission has held that the exercise of this authority depends on circumstances it has not

45 https://www.stinson.com/people-JonathanSchneider

46 For purposes of this analysis, resource adequacy is taken to refer to a requirement that LSE's demonstrate that they have a specified level of generating capacity available to the market as a condition of their participation.

found evident.

(5) FERC's and NERC's authority over electric reliability under FPA section 215 does not support NERC's or FERC's ability to impose a resource adequacy requirement.

(6) The environmental attributes of electric generating resource sold on an unbundled basis are outside FERC jurisdiction. FERC may have ancillary authority over these attributes if they are bundled with electric sales undertaken under FERC's jurisdiction.

1. *What is the scope of state-based authority over resource adequacy requirements?*

In all markets, whether outside an ISO/RTO setting or within, state-based authorities (including municipal utilities and non-FERC jurisdictional cooperative utilities) have the authority to ensure that sufficient generating capacity is built to meet the needs of retail load, and to stipulate to the nature of that generation. State agencies are generally given authority under state law over measures needed to ensure safe and adequate service. That authority includes oversight of the adequacy of generation to serve load.[47] In a traditional, vertically integrated utility environment, state public service commissions and non-FERC-jurisdictional utilities have relatively unfettered authority in this area.

When acting within the ISO/RTO environment, state-based authority over resource adequacy is constrained in two ways. First, state authorities may not exercise their authority with the aim of affecting FERC-regulated wholesale market prices. According to the Supreme Court in *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2016),[48] this was the objective of a Maryland-supported program assuring participating generators revenue at a guaranteed level, so long as they participated in PJM's FERC-jurisdictional capacity market. The Court expressly withheld judgment with respect to state-based measures "untethered to a generator's wholesale market participation, such as tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector."[49]

Second, while FERC cannot prohibit state and local authorities from directing investments in designated generating resources, its rules governing the eligibility of these resources to participate in mandatory capacity markets, and penalties associated with the failure to do so, trigger concern that states will be required effectively to pay twice for generating capacity, once through the state mandate, and another time though FERC-administered penalties. The court in *N.J. Bd. of Pub. Utils. v. FERC*[50] held this to be permissible, rejecting the argument made by state authorities that this approach interfered with the provision in FPA section 201(b)(1), prohibiting FERC from exercising authority over generating facilities.

2. *What authority does FERC have over resource adequacy outside the ISO/RTO environment?*

FERC has limited authority to direct load serving entities to comply with a resource adequacy

47 *See Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205 (1983) ("[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.").

48 136 S. Ct. 1288 (2016).

49 *Id.* at 1299.

50 *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014) (*NJ Board*).

requirement outside an ISO/RTO region. FERC's authority under FPA sections 205 and 206 to address rules, regulations and practices "affecting" wholesale market prices (discussed more extensively below in the ISO/RTO setting) has relatively little practical impact in the non-ISO/RTO environment, where wholesale market activity and FERC oversight is somewhat limited. Further, FPA section 201(b)(1) provides that FERC does not have jurisdiction "over facilities used for the generation of electric energy."

With that said, where load serving entities and others voluntarily choose to enter into an agreement to bind one another to specified resource adequacy requirements, FERC may have authority over the contractual mechanism, and possibly the relevant administrative entity. FPA section 205 and 206, authorizing the Commission to regulate practices affecting wholesale rates, may carry the Commission as far as oversight of these agreements and activities. This is the working conclusion drawn by participants in the Northwest Power Pool's current effort to establish a voluntary resource adequacy framework among regional load serving entities.[51]

3. *What authority does FERC have over resource adequacy requirements within the ISO/RTO environment?*

FERC's exercise of authority to compel a resource adequacy requirement in an organized market through the imposition of penalties on load serving entities (LSEs) for failure to participate has been upheld in the courts. Precedent also supports the position that FERC may have the authority to direct the creation of a capacity market in the ISO/RTO setting.

FERC's authority to approve financial penalties designed to incentivize the procurement of capacity in order to meet a resource adequacy requirement by LSEs participating in an organized market was upheld in *Ct. Dep't of Public Utility Control v. FERC*.[52] There, the Commission's approval of ISO-NE's Installed Capacity Requirement (IRC) was challenged by the Connecticut DPUC on the ground that it impinged on state authority over generating facilities reserved to the states under section 201(b) of the FPA. The court rejected Petitioners' argument, holding that the FPA's prohibition against FERC regulation of generating facilities "says nothing about its power to review the capacity requirements that an entity like ISO-NE imposes on member LSE's."[53] The court relied on its 1978 decision in Municipalities of Groton v. FERC[54] for the proposition that a capacity deficiency charge aimed at eliciting sufficient generation in the wholesale market involves a "practice affecting rates" under sections 205 and 206 of the FPA.[55] Accordingly, the court held that "[i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying the charge."[56] Though conceding that FERC's statutory authority may be read more narrowly, the court further held it was far too late in the development of related case law to argue otherwise. According to the court:[57]

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51 *See*: https://www.nwpp.org/resources/2021-nwpp-ra-program-detailed-design.
52 *Ct. Dep't of Public Utility Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009) (*"CPUC"*).
53 *Ibid.*, p. 483.
54 *Municipalities of Groton v. FERC*, 587 F.2d 1296 (D.C. Cir. 1978).
55 *Ct. Dep't of Public Utility Control v. FERC*, 569 F.3d 477, p. 484 (D.C. Cir. 2009).
56 *Ibid.*, p. 482.
57 *Ibid.*, p. 483.

> [E]ven if these statutory provisions could be read to prohibit the Commission from requiring LSEs to make adequate capacity purchases, and even if that is what the Commission is doing, this particular camel has long since entered – indeed, ransacked – the tent. Again, three decades ago in Municipalities of Groton, we sustained the Commission's assertion of jurisdiction over 'deficiency charges' NEPOOL imposed on member LSEs that came up short on their capacity requirements.

Addressing what authority is left to the states (and outside FERC control), the court observed that the IRC does not "actually "require' anyone to 'install any new 'capacity at all" and that "[s]tate and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally friendly units, or to take any other action in their role a regulators of generation facilities without direct interference from the Commission."[58]

It is worth emphasizing that the Commission's authority to address practices "affecting rates" under FPA sections 205 and 206 has been construed broadly. In *South Carolina Pub. Serv. Authority v. FERC*,[59] this authority was held sufficient to enable FERC to compel utilities to enter into contracts with transmission developers for the construction of new transmission facilities approved through joint regional planning processes. And in *FERC v. EPSA*,[60] the Supreme Court authority held the Commission's authority sufficient to support a rule compelling ISOs/RTO to modify their tariffs in order to enable demand response providers to bid their service into organized markets, on the ground that the rule is a "practice directly affect[ing] the wholesale rate."[61]

Consistent with the decision in *CPUC*, the Commission has approved penalties for failure to meet capacity requirements in several other ISO/RTO proceedings.[62]

Efforts by ISO/RTO members to exempt themselves from ISO/RTO RA requirements through self-supply or withdrawal of resources and load through such programs as PJM's Fixed Resource Requirement have been restricted or rejected by FERC, motivating certain states to consider withdrawing from the ISO/RTO framework altogether.

4. *Does FERC have the authority to approve and to mandate capacity markets?*

The Commission has long held that it has the authority to approve proposed mandatory capacity markets, and there is support for the position that it has authority to mandate them. The Commission approved ISO-NE's proposed capacity market in *Devon Power, LLC*[63] in connection with ISO-NE's market ("the Commission initiated these Section 206 proceedings... in response to the compensation problems faced by generating resources that are needed for reliability but could not obtain sufficient revenues in the markets to continue operation").

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58 *Ibid.,* p. 481.

59 *South Carolina Pub. Serv. Authority v. FERC*, 762 F.3d 41 (D.C. Cir. 2014),

60 *FERC v. EPSA*, 136 S. Ct. 760 (2016).

61 *Ibid.*, p. 774

62 *See* CAISO, 162 FERC ¶ 61,042, at P 30 (2018); MISO, 162 FERC ¶ 61,176 (2018); MISO, 125 FERC ¶ 61,062, at ¶¶ 126-144 (2008), order on reh'g and compliance, 126 FERC ¶ 61,144 (2009), order on clarification, 135 FERC ¶ 61,081 (2011). SPP, 164 FERC ¶ 61,092 (2018) (approving SPP Tariff revisions to implement a resource adequacy requirement).

63 Devon Power, LLC, 115 FERC ¶ 61,340, pp. 62.

And it did so in PJM's case, also holding that the violation of reliability criteria warranted the finding that the existing rate structure was unjust and unreasonable, and that PJM's proposed "Reliability Pricing Model" was needed.[64]

Judicial support for FERC's exercise of this authority is found in *N.J. Bd. of Pub. Utils. v. FERC*,[65] in which the court rejected challenges to PJM's MOPR, as applied in PJM's mandatory capacity market, in terms that strongly suggesting that FERC has the authority to mandate a capacity market. The court rejected the argument that FERC's elimination of the exemption from application of the MOPR for state-mandated resources violated the FPA section 201(b) prohibition against FERC regulation of generating facilities. Adopting the same approach taken in *CPUC*, the court held that removal of the state-mandate from exemption under the MOPR involved a rule "affecting the rates" for wholesale sales.[66]

Addressing the argument that the decision unlawfully treads on jurisdiction reserved to state authority over generating facilities, the court held that the elimination of the exemption had no effect other than financial on state-based decisions regarding generation. Rejecting the claim that "FERC is preventing New Jersey from using the resources it has chosen to promote," the court held that "New Jersey and Maryland are free to make their own decisions regarding how to satisfy their capacity needs, but they 'will appropriately bear the costs of [those] decision[s],' including possibly having to pay twice for capacity."[67] The court relied heavily on the decision in *CPUC, supra*, for the propositions that rules governing participation in FERC organized markets are within the Commission's "affecting wholesale rates" authority, and that financial penalties assessed to state supported resources do not amount to the regulation of generating facilities.[68]

More recently, in *CSA La Paloma LLC v. CAISO;*[69] *Order Denying Reh'g.*,[70] the Commission rejected La Paloma's request for an order compelling CAISO to implement a capacity market, finding that La Paloma failed to show that CAISO's existing resource adequacy requirement was unjust and unreasonable, though the Commission did not question its authority to issue an order in other circumstances. More specifically, the Commission found that La Paloma failed to demonstrate: (1) that inadequate revenue for competitive generating resources in itself calls for a change to the tariff; (2) that inadequate revenue would result in premature plant retirements and a generation shortfall; and (3) that reliability violations would result from the status quo. The Commission further found no support for La Paloma's argument that the status quo discriminated in favor of renewable resources.[71]

In *La Paloma*, FERC further noted as a general matter that "it has not required a centralized capacity market as part of a just and reasonable market design," citing its earlier decision in

64 PJM Interconnection, LLC, 115 FERC ¶ 61,079 ("PJM RPM Order"), order denying reh'g and approving settlement, 117 FERC ¶ 61,331 (2006) ("PJM RPM Settlement Order"), order on reh'g, 119 FERC ¶ 61,318 (2007).

65 *N.J. Bd. of Pub. Utils. v. FERC, supra.*

66 *Ibid.*, p. 96.

67 *Ibid.*, at 97 (citations omitted). It is worth noting that FERC extended this approach in *Calpine v. PJM Interconnection*, LLC, 169 FERC ¶ 61,239 (2019) to include in the definition of subsidies calling for offsets through the MOPR a variety of state-based programs supporting generation, over the vigorous dissent of now-Chairman Glick, arguing that the order unlawfully intruded in state-based jurisdiction over generating facilities. The order is on appeal, and may yet be revisited at FERC.

68 *Ibid.*, pp. 96-97.

69 *CSA La Paloma LLC v. CAISO*, 165 FERC ¶ 61,148 (2018) (La Paloma).

70 *Order Denying Reh'g.*, 169 FERC ¶ 61,045 (2019).

71 *CSA La Paloma LLC v. CAISO*, 165 FERC ¶ 61,148, pp. 70-77, (2018).

MISO,[72] rejecting a request to impose a mandatory centralized capacity market with a sloped demand curve and MOPR.

Taken together, the courts' decisions in NJ Board and CPUC, and the Commission's decisions in *La Paloma* and *MISO*, strongly suggest that a defense against a proposal for the creation of capacity markets is likeliest to succeed at FERC if grounded in the case-specific circumstances of the proposal, and the proponents' failure to demonstrate that inadequate revenues threaten the vitality of the wholesale market and system reliability. This was the tack successfully taken by CAISO in responding to *La Paloma's* complaint. Critically, CAISO effectively distinguished the Commission's earlier decisions adopting capacity markets in PJM[73] and ISO-NE[74] cases, on the ground that La Paloma failed to demonstrate the reliability or rate problems the Commission reached out to address in those cases.[75] For example, if resource adequacy is addressed sufficiently through other mechanisms such as state policy, then the Commission has little basis to find reliability or rate problems. Of course, those determinations can be subjective and one sitting Commissioner, James Danly, has raised concerns that California's market has reliability and rate problems.[76] Nonetheless, it is worth emphasizing that the La Paloma and MISO decisions suggest that as of this date there is little appetite at FERC to impose new capacity markets on regions that do not have them.

5. Does FPA section 215 (reliability regulation) empower NERC or FERC to implement a resource adequacy requirement?

Probably not. As discussed above, resource adequacy proposals at FERC (including capacity market proposals), and the Commission's decisions approving them, have been consistently supported by reference to the need to support system reliability. But those references have generally been to a broader conception of reliability than contemplated by section 215 of the FPA.

The authority invested in FERC and NERC under FPA section 215 is narrow, as is the definition of reliability concerns addressed by the statute and the facilities (Bulk-Power System) to which the provision applies. First, as to FERC authority, section 215(b) of the statute provides the Commission with jurisdiction over the Electric Reliability Organization (NERC), regional entities and users, owners and operators of the bulk power system only "for purposes of approving reliability standards established under this section and enforcing compliance with this section." The section does not, despite frequent contrary assertions,[77] provide FERC with general authority over grid reliability. The agency has authority under FPA section 215 over the promulgation of reliability standards and their enforcement, and is not given any other plenary authority.

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72 *MISO*, 162 FERC ¶ 61,176 (2018).

73 PJM RPM Settlement Order, *supra.*

74 *Devon Power, supra.*

75 *See* Answer of California Independent System Operator Corporation to Complaint, pp. 34-42, August 24, 2018.

76 "...given the experience in CAISO, it is necessary for us to ask the question as to whether or not in our oversight responsibilities it is necessary to inquire as to the fitness of the tariff they currently have... when utilities have tariffs that are failing to provide through the market mechanisms that they are operating, the benefits and the resource adequacy that we want them to, we have to look into whether or not those tariffs are still J&R." FERC, Open Meeting December 17, 2020, Transcript, pp. 41-42, Commissioner Danly statement in support of a show cause order which was voted down in a 2-1 vote.

77 In its complaint, La Paloma, e.g., asserted that FERC has general authority over the "reliability of the bulk power system."

Second, as to the scope of reliability concerns, section 215 specifies that the ERO's responsibilities are limited to promulgating and enforcing reliability standards aimed at the "reliable operation" of the bulk-power system. The "reliable operation" of the grid is defined in FPA section 215(a)(4) to mean:

> operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

This definition focuses on system instability, a matter not necessarily implicated when considering RA, which assesses the sufficiency of energy to serve load. It is also worth emphasizing that FPA section 215(i)(2) specifies that FPA section 215 "does not authorize the ERO [NERC] or the Commission to order the construction of additional generation…or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."

FPA § 215 does require the ERO [NERC] to "conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America."[78] Under this authority, NERC issues annual assessments[79] of the adequacy of electricity supplies for the upcoming summer and winter peak demand periods, as well as the long-term (10-year) period. Similarly, ReliabilityFirst (a NERC "regional entity") relied on this authority to require "Planning Coordinators" (e.g., PJM) to perform an annual resource adequacy analysis.[80] FERC approved this requirement by ReliabilityFirst in 2011.[81] FERC held that the requirement "does not intrude on the state's decisional authority with respect to building or acquisition of assets or capacity to meet resource adequacy needs." This order was not challenged or reviewed by a court.

6. *Would a FERC-administered capacity market which co-optimizes resource adequacy and environmental attributes subject environmental attributes to FERC jurisdiction?*

Quite possibly. Among the proposals for capacity market reform discussed in this paper are those that call for ISOs/RTOs to assume authority over a market for combined capacity and the participating generators' environmental attributes (tradeable renewable energy certificates, or RECs, or Clean Energy Attribute Credits). This has raised the question whether a "co-optimized" market of this nature may extend FERC authority over the REC market that may not otherwise exist.

FERC has held that RECs are products of state law, and generally outside the Commission's authority. In *American Ref-Fuel Co, et al.*,[82] the Commission granted Petitioners' request for a declaratory order determining that Qualifying Facility (QF) remuneration under PURPA's avoided cost standard does not provide the purchasing utility with a right to the RECs associated with the QF's production of power.[83] The Commission extended this principle

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78 FPA § 215(g).

79 North American Electric Reliability Corporation, "Reliability Assessments," (n.d.).

80 North American Electric Reliability Corporation, Standard BAL-502-RF-03, (n.d.).

81 The current, slightly modified, version of this requirement was approved here: FERC, Letter Regarding Petition of the North American Electric Reliability Corporation and ReliabilityFirst Corporation for Approval of Proposed Regional Reliability Standard BAL-502-RF-03, October 2017.

82 *American Ref-Fuel Co, et al.*, 102 FERC ¶ 61,004 (2003).

83 *Ibid.*, p. 18.

in WSPP, Inc.,[84] holding that “unbundled REC transactions fall outside the Commission’s jurisdiction under sections 201, 205 and 206 of the FPA” on the ground that they are neither the transmission nor sale of energy.[85] Nor, on an unbundled basis, do they “affect” or take place “in connection with” wholesale sales in a manner that would trigger FPA section 205 or 206 authority.[86]

In *WSPP*, the Commission went on, however, to determine that where RECs and energy sales are bundled in the same transaction, its authority over practices “in connection with” wholesale sales is implicated.[87] The Commission applied this principle in *North. Am. Natural Resources, Inc.*,[88] calculating rates and refunds under a PPA that combined RECs and energy sales.

As this applies to a “co-optimized” market in which capacity trade are combined with trading of environmental benefits, this authority may very well pull the market for environmental attributes into FERC’s jurisdiction. That determination will depend on how closely tied these products are (whether the trading of environmental attributes is “in connection with” energy sales), and whether trading the environmental attributes may be said to affect the market for energy sales. In either case, FERC’s authority may be triggered. Factors relevant to that determination may include whether environmental attributes and capacity are combined in a way that makes these values inseparable when bids are evaluated, and whether a non-FERC jurisdictional entity administers the market for environmental attributes.

84 *WSPP, Inc.*, 139 FERC ¶ 61,061 (2012).
85 *Ibid.*, p. 18.
86 *Ibid.*, pp. 23-34.
87 *Ibid.*
88 *North. Am. Natural Resources, Inc.*, 168 FERC ¶ 61,041 (2019).

APPENDIX B

RESOURCE ADEQUACY FOR A CLEAN ENERGY GRID

TECHNICAL ANALYSIS

An Interview with Derek Stenclik, Telos Energy and Michael Goggin, Grid Strategies

This memo answers questions on resource adequacy with high renewable energy penetration.

TELOS ENERGY   Grid Strategies LLC

November 2021

This memo answers questions on resource adequacy for a clean energy future. Our analysis is based on reviewing and participating many region-wide and utility-specific resource adequacy modeling exercises. In summary, we conclude:

8. As the resource mix changes and decarbonizes, so do the system needs for reliability. The proliferation of variable renewable energy, energy storage, flexible load, and fossil retirements are altering the way resource adequacy analysis needs to be conducted and the way it is translated to procurement decisions and capacity accreditation.
9. Conventional resource adequacy metrics (LOLE, LOLH, LOLP) only count the number or probability of shortfall events. They provide little or no information on the size, frequency duration, and timing of the shortfalls. With increased variable renewable energy and energy limited resources, this information is critical to ensure the right resources are selected for the reliability needs.
10. Modeling tools must also adapt. Sequential Monte Carlo analysis – which chronologically evaluates each hour of the year across many years of weather data (wind, solar, load) – is necessary.
11. Peak reliability risk is no longer isolated to peak load hours. In the near-term, risk is shifting to net-load peak but will eventually shift to multi-day periods of low solar and wind output, often occurring in the winter.
12. Capacity accreditation is increasingly complex due to saturation effects (decreasing capacity credit at increasing penetrations) and portfolio effects (changes to individual resource capacity credit due to changes in the underlying resource mix). As a result, ELCC may be sufficient for near-term resource accreditation, but has limitations for long-term planning.

13. If ELCC is used as the methodology, it should be applied consistently across resource types. This includes accounting for potential fuel supply disruptions, ambient derates, and increased outage rates during extreme weather.
14. Transmission is an important mitigation for resource adequacy, allowing for geographic diversity in weather, load, and renewable resource availability. Increased transmission should be evaluated as a capacity resource to meet reliability needs.

Resource Adequacy Need Determination

1. How are resource adequacy needs determined?

Underpinning any capacity accreditation mechanism — whether it be a mandatory capacity market auction in Northeast ISOs or integrated resource planning for vertically integrated utilities — is technical resource adequacy analysis and modeling.

Resource adequacy (RA) analysis utilizes modeling conducted to measure whether the system has enough resources to serve load under a wide range of potential future system conditions. RA analysis considers potential variations in system load, fluctuations in weather and corresponding availability of variable renewable energy (VRE) resources like wind and solar, and planned and unplanned generator outages. By utilizing statistical techniques, the analysis measures the probability, or expectation, that the system has insufficient resources (i.e., capacity) to meet load.

When evaluated across many simulated years of various weather and generator outages, the count of days that experienced some level of capacity shortfall is summarized as the Loss of Load Expectation (LOLE). The LOLE metric is commonly utilized as a resource adequacy criterion (e.g., a 1-day-in-10-years LOLE requirement) in many jurisdictions across North America.[89]

It is important to clarify that resource adequacy analysis simply measures the risk of a power system not meeting load. It can quantify the likelihood of shortfall events and the magnitude of those events, but it does not, by itself, determine the amount or characteristics of required resources. To determine requirements, the resource adequacy analysis – which is measured in a probability of not having enough resources to serve load - must be translated into capacity needs. In many jurisdictions this is done via the planning reserve margin (PRM), which quantifies the amount of surplus capacity (MW) relative to peak load that is required to meet a 1 day in 10 LOLE target, is the metric used to determine total system need. Because different resources have different operating characteristics and availability, estimated contributions to the PRM from each resource need to be determined. We call contributions accreditation metrics, often measured as their “capacity value.”

In many regions, a planned reserve margin around 15 percent has been deemed to be sufficient to achieve the desired probability of meeting load under conditions of long-lasting and sudden generator outages and interannual variation in peak load, given a typical resource mix of coal, gas, nuclear, and hydro. In regulated vertically integrated utility

89 Additional information on resource adequacy metrics is provided in Question 3.

systems, the PRM is used for integrated resource planning and procurement. In deregulated ISOs and RTOs with capacity markets, it determines the amount of capacity required via an administrative demand curve.

Because not all resources have the same expected performance during shortfall events, different resources are accounted for differently. In these cases, a resource is accredited a certain amount of “firm capacity” that counts towards the planning reserve margin. For example, fossil fuel-fired generators may be counted as “unforced capacity” (UCAP) that discounts the firm capacity of the resource by the generator’s forced outage rate (unplanned outages). For variable renewable resources, the generators are often discounted based on their availability during likely shortfall events.[90]

As a result, the resource adequacy analysis, which measures system risk, is translated to system needs via the planning reserve margin (in most jurisdictions), and resource accreditation. The tight coupling of resource adequacy, PRM, and resource accreditation is an important underpinning of most resource adequacy regimes.

However, as the resource mix is changing, so are the system needs and reliability. The proliferation of variable renewable energy, energy storage, flexible load, and fossil retirements are altering the way resource adequacy analysis needs to be conducted and its translation to resource adequacy needs and accreditation.

2. How are system needs shifting, and what does that mean for resource adequacy?

Historically, resource adequacy analysis was relatively straightforward. The traditional resource mix was composed predominantly of large, nuclear, coal, and natural gas generators without significant fuel constraints. As a result, the reliability of the system was largely dependent on the planned maintenance and unplanned forced outages. The resulting system’s reliability risk was almost always concentrated in a few peak load days and hours of the year. Because the resource availability of fossil-fired units were assumed to fluctuate randomly (due to forced outages), the analysis assumed that if there were enough resources to serve peak load conditions, there would also be sufficient resources the rest of the year.

The changing resource mix is changing the way resource adequacy needs to be evaluated. For instance, wind and solar resource availability is not as much a function of maintenance and outages (which is not a concern due to the modular nature of the resources), but rather a function of the underlying weather conditions. In addition, the availability of energy storage resources depends on their ability to charge during low load or high renewable hours and the duration of potential shortfall events. The same can be said for load flexibility and demand response. In a high renewable system, the periods of risk may no longer be the typical peak load conditions but may become more aligned with resource availability and the underlying weather conditions.

Numerous studies show that very high levels of renewable penetration can be achieved reliably and consistent with electricity rates at or close to current levels. When aggregated

90 Additional information on accreditation methods is provided in Question 10.

over large geographic areas, a significant share of wind and solar capacity can be relied on to meet resource adequacy needs. However, the consensus of modeling efforts suggests that relying on wind, solar, and short duration storage to meet 100% of resource adequacy needs is not economic due to their declining capacity value at higher penetrations.

Plots of wind and solar output over time reveal the very large contributions of those resources, and the occasional use of firm backup resources. Across many studies, it tends to be the existing gas fleet that operates at reduced levels but stays available for those rare instances. In the future, "clean firm" sources may be needed to fully decarbonize. The figure below shows wind in green and solar in red, complementing each other, and storage in orange covering ramps and shoulder times. The gray area shows how the existing gas fleet can be used as a dispatchable source of stand-by power to fill remaining gaps. However, the compensation schemes may need to change in order to ensure backup capacity is available when needed.

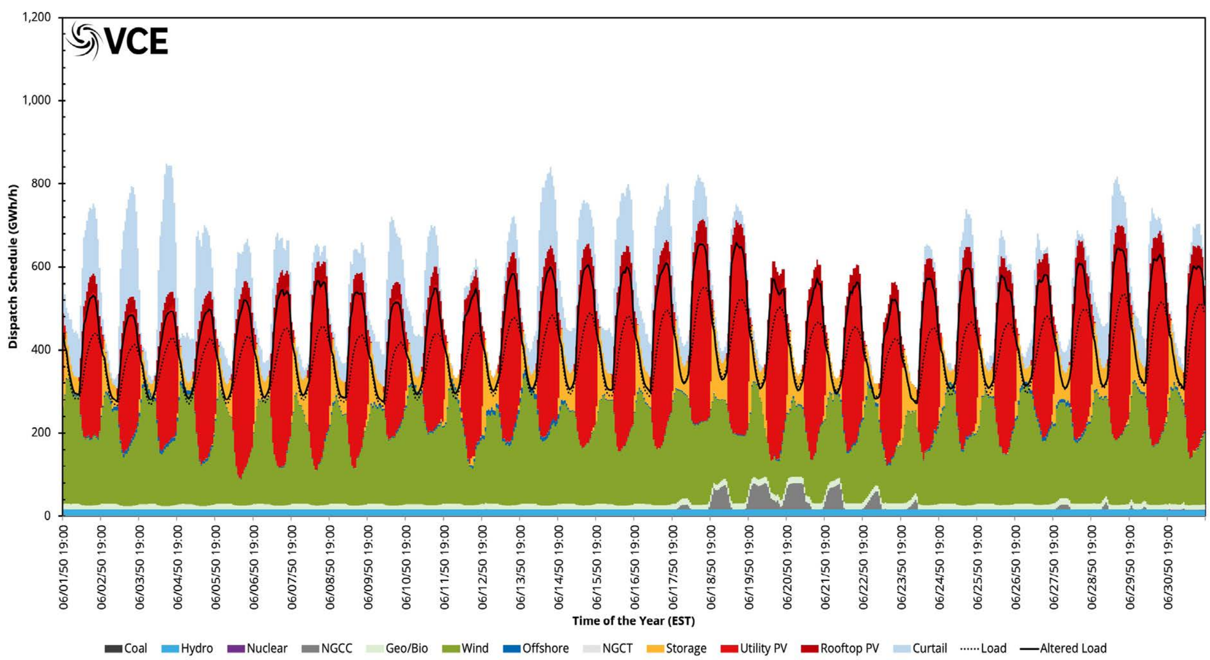

FIGURE 1. *Modeled output by resource for June 2050 in the eastern interconnection. Source: VCE*[91]

The main thrust of resource adequacy is how to ensure enough resources are available at those times when wind, solar, and gas output fall short of meeting demand. A key policy objective for renewable energy interests is to do that in a way that recognizes renewables' contributions and does not discriminate or impose barriers to entry.

The increased role of wind, solar, storage, and load flexibility requires the industry to rethink the way reliability planning and resource adequacy methods are considered and how analysis should be conducted. As the NERC Integrating Variable Generation Task Force concluded, "planning reserve margin, calculated as a percentage of system peak, will

91 Clack et al., Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S, October 2020.

become less meaningful with large penetrations of [variable generation]."[92] This confluence of changes requires new data, methods, and metrics to better characterize evolving risks.

But these shifts are not just due to renewables. The system's resource mix in many regions is also shifting away from a relatively diverse supply of thermal generation (coal, nuclear, natural gas) and becoming more dependent on natural gas. As NERC has stated, "The electric power sector is now tightly coupled with the natural gas delivery system, which delivers fuel on demand, with little or no storage located at the power plant. As a result, correlated outages due to fuel supply failures is now a key reliability risk, especially during the winter months when multiple power plants may experience interrupted fuel supplies simultaneously."[93]

System needs are therefore shifting and becoming more regional. Resource adequacy risk is no longer just about the peak-load hours. In some regions, "peak risk" may no longer be synonymous with peak load and is shifting later in the day, outside of the mid-day solar period and into the evening peak net-load period. In other regions, resource risk is shifting to the winter months due to fuel availability and increasing electrification. Still further, some regions may experience increasing risk in historically low load months, as planned maintenance periods for thermal generation may be challenged if there is an unexpected multi-day lull in wind and solar availability.

These changes in the resource mix are precipitating a need to fundamentally rethink the way we conduct resource adequacy analysis, and the way capacity procurement, accreditation, and markets are designed. For more information on the shifting risk and the traditional resource adequacy analysis problems and their causes, please refer to the recent Energy Systems Integration Group (ESIG) paper on "Redefining Resource Adequacy for Modern Power Systems."[94]

3. **Which resource adequacy metrics are useful for systems with high penetrations of renewable energy and energy storage?**

One way resource adequacy analysis and market design may require adjustment is in the resource adequacy metrics that measure system risk. As discussed previously, a common resource adequacy criterion used throughout most of North America is a "1 day in 10 years" (or 0.1 days/year) LOLE, which counts the average number of days per year when there are insufficient resources to serve load (shortfall event). However, this reliability criterion was developed in the middle of the 20th century, with limited rationale as to how the criterion was selected, and with limited evaluation of the costs and benefits of reliability.

Alternative metrics include loss of load events (LOLEv), which counts the average number of events per year, loss of load hours (LOLH), which counts the average number of hours of shortfall per year, and loss of load probability (LOLP), which translated the metrics into a probability between 0 and 1 of a shortfall event occurring.

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92 North American Electric Reliability Corporation, "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning," March 2011.

93 North American Electric Reliability Corporation, "Integration of Variable Generation Task Force: Summary and Recommendations of 12 Tasks," pp. 21, June 2015.

94 Energy Systems Integration Group, "Redefining Resource Adequacy for Modern Power Systems," August 2021.

But these metrics can be opaque when used in isolation as they only count the number or probability of shortfall events. They provide little or no information on the size, frequency duration, and timing of the shortfalls. In the past, when shortfall events were solved exclusively by adding new fossil generation, this information was less important. Today, when most new capacity additions are wind, solar, storage, or demand response and load flexibility, this information is critical. For example, a shortfall of 1 percent of load for 10 hours is measured the same way as a shortfall of 10 percent of load for 10 hours. These disparate events are not differentiated well by conventional resource adequacy metrics even as they represent dramatically different situations in terms of options for meeting demand in today's power system.

Expected unserved energy (EUE) is another resource adequacy metric commonly calculated in resource adequacy analysis, but rarely used as a reliability criterion. Because EUE measures the amount of unserved energy, as opposed to the count of shortfalls, it may be a better measure of system risk and capture the implications of energy limitations on storage and demand response. Figure 2 shows how resource adequacy metrics can have difficulty characterizing the size, frequency, and duration of disparate events.

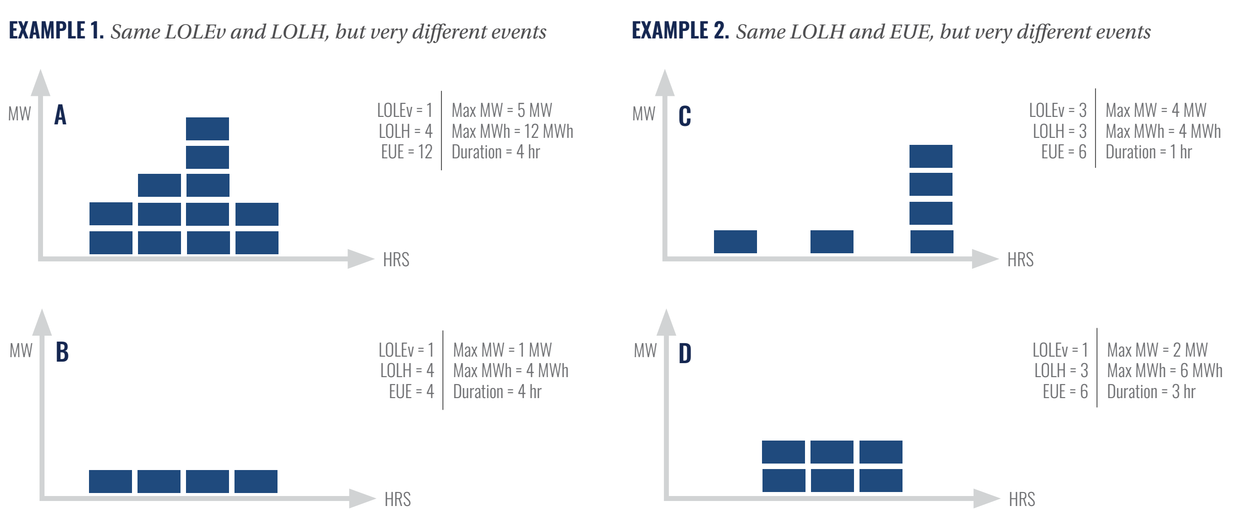

FIGURE 2. *Differentiating resource adequacy metrics by size, frequency, and duration. Source: ESIG*[95]

The planning reserve margin metric also has limitations as system risk shifts outside of peak demand periods. Reliability periods are shifting to periods with lower renewable output and to winter cold snaps as correlated outages on the fossil fleet, along with fuel supply disruptions, limit availability. The increasing need to account for correlated events and chronology makes the PRM – based solely on peak load — obsolete. A consensus is forming that PRM has to be adapted, but the final outcome is still undetermined. If the planning reserve margin is going to be continued, it may need to be adjusted to capture a wider range of system conditions, as described in the three proposals below:

95 ESIG, 2021

- Utilize the peak net-load (net of expected wind and solar generation) rather than gross load as proposed by Southern California Edison,[96]
- Calculated for multiple seasonal and hourly time blocks (see PG&E "slice of day approach"[97]), or
- Calculated across all hours of the year (see HECO's "energy reserve margin proposal"[98])

Finally, one limitation of resource adequacy metrics like LOLE, LOLH, and EUE is they are all expected values. While resource adequacy analysis may evaluate thousands of random samples, the results are averaged and reported as a single value representing all randomized years of simulation. Over-reliance on single point, average metrics can cause planners to miss outlier tail events. Additional insight into the size, frequency, duration, and timing of shortfall events themselves can better ensure that the right "type of resource" is valued accordingly. This will help differentiate the value of short-duration resources (demand response, short duration storage, etc.) versus long-duration resources (long duration storage, thermal generation, clean firm renewables, etc.).

4. **Are current industry models adequate for the task? What types of models need to be developed?**

The current industry models and tools are continuing to evolve to address these challenges. Unfortunately, many of the methods and metrics used by the industry today originated in the mid-1900s and have only been improved incrementally as the resource mix continues to change. Many tools have transitioned from only evaluating peak load days/hours, to ones that evaluate an entire 8,760 hours of operation. This is a critical first step. Where there is still discrepancy between tools is how they address *chronological grid operations and correlated event*s.

Chronological grid operations are increasingly important for grid modeling generally, and resource adequacy analysis specifically. While many tools step through a full 8,760 hourly analysis with varying load and renewable availability, they differ in the ways generation is scheduled. Energy storage and demand response, for example, have energy limitations so they are often referred to as "energy limited resources." The availability of these resources in one hour is highly dependent on system conditions in preceding or following hours and days. In addition, some generating resources — like steam generators — may be highly inflexible, and while it may be technically available, there may be a risk that it cannot start in time. All of these factors require modeling be conducted in sequential Monte Carlo simulations that evaluate the actual commitment, dispatch, and scheduling of grid resources.

96 Southern California Edison Company and California Choice Association, "Track 3 Proposal for the Restructure of the Resource Adequacy Program," before the Public Utilities Commission of the State of California, 8/7/2020.

97 See PG&E Proposal: California Public Utilities Commission, "Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program," 7/16/2021.

98 See HECO Energy Reserve Margin: Hawaiian Electric Company, "Grid Needs Assessment & Solution Evaluation Methodology," June 2020.

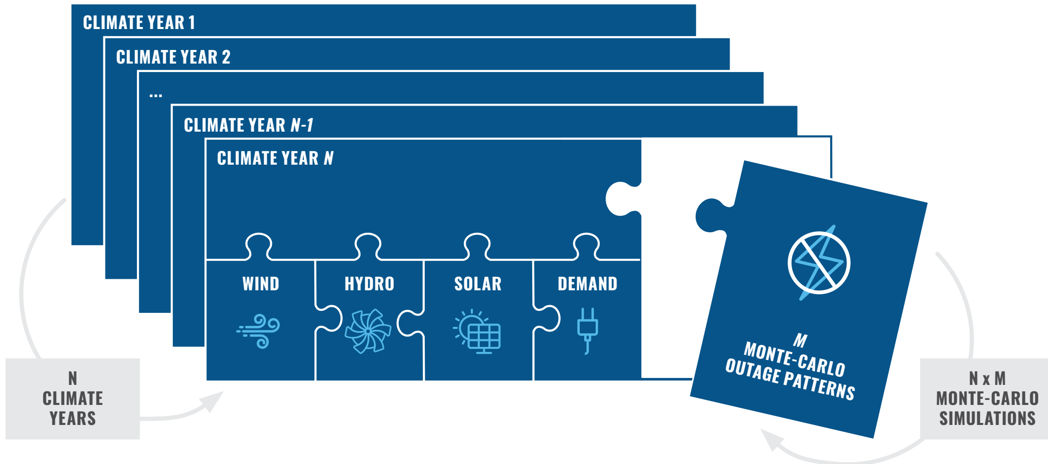

FIGURE 3. *ENTSO-E modeling example of Monte Carlo simulation principles. Source: ENTSO-E*[99]

The second discrepancy is around how modeling tools handle correlated events. In many tools, the availability of thermal generators is determined by the convolution method. This process evaluates each generator's forced outage rate and develops a probability distribution of the system's cumulative capacity on outage. Underpinning this analysis is the assumption that generator outages are purely random and uncorrelated with one another. However, during some events, underlying conditions - like extreme weather and fuel supply constraints - are a driving factor in generator outages. This was the case in the Texas shortfall events of February 2021. NERC and others have demonstrated that in many regions, large, correlated outage events occur far more frequently than would be expected if thermal generator outages were random uncorrelated events.[100]

Thus, it is important that modeling tools be capable of evaluating chronological grid operations and correlated outages. Stakeholders should ensure accurate representation of these drivers, and their impact on different resource types, when they are used for procurement and accreditation decisions.

Often the limitations are not just a factor of the tool being used, but also a function of the planning metrics being reported (previous question) or the data being utilized (following question).

5. **How can weather data be better incorporated into RA modeling and accreditation?**

While the previous question evaluated potential limitations in modeling tools, the related input data and assumptions must also be considered. There is consensus among the system planners that weather data used for resource adequacy analysis is an increasingly important, if not the most important, data need. For example, it is critical that multiple years of correlated wind, solar, and load be considered in the analysis to determine that weather effects are properly evaluated across a wide geographic footprint. It is also important to

99 ENTSO-E, Mid-term Adequacy Forecast 2020: Appendix 2; Methodology, 2020

100 https://www.cmu.edu/ceic/assets/docs/publications/working-papers/ceic-17-02r1-resource-adequacy-risks-to-the-bulk-power-syste.pdf, https://kilthub.cmu.edu/articles/thesis/Correlated_Generator_Failures_and_Power_System_Reliability/8204510

highlight the interdependencies between these resources and the underlying weather. This is commonly implemented by system planners across North America, but often differs in the number of weather years evaluated and the process used to estimate weather data across many generating resources in a region.

It is important that weather data accurately capture the temporal and geographic diversity of weather-dependent resources across the study footprint, and with neighboring jurisdictions. This ensures that the capacity value of variable renewable resources[101] are evaluated with the proper resource diversity. Large national datasets, such as the NREL National Solar Radiation Database (NSRDB)[102] were developed for this purpose, but data availability on load and wind resources is more complex and thus limited. It is also important that historical wind and solar output data not just be linearly scaled up to represent wind and solar output patterns at higher penetrations, as this misses the inherent geographic diversity benefit from adding wind capacity, and to a lesser extent solar capacity, at new sites.[103] In addition, improvements in wind and solar plant performance are increasing output in what had previously been lower output hours, boosting their capacity value.[104]

One way most resource adequacy analysis can be improved is in the use of data for temperature effects on fossil generation, namely gas turbine technology. Gas turbine technology is affected by ambient air temperatures. Extreme heat will derate the systems output coincident with peak load. While resource adequacy analyses in many regions utilize a summer rating for this technology, it may not include the effects of extreme heat. In addition, all generating equipment has a higher likelihood of failure during extreme temperatures, especially extreme cold. This is clearly illustrated in the outage data from the ERCOT 2021 rolling blackout event, which started on Monday February 15th during extreme cold (Figure 4). In many cases this weather data can be better included in the analysis.

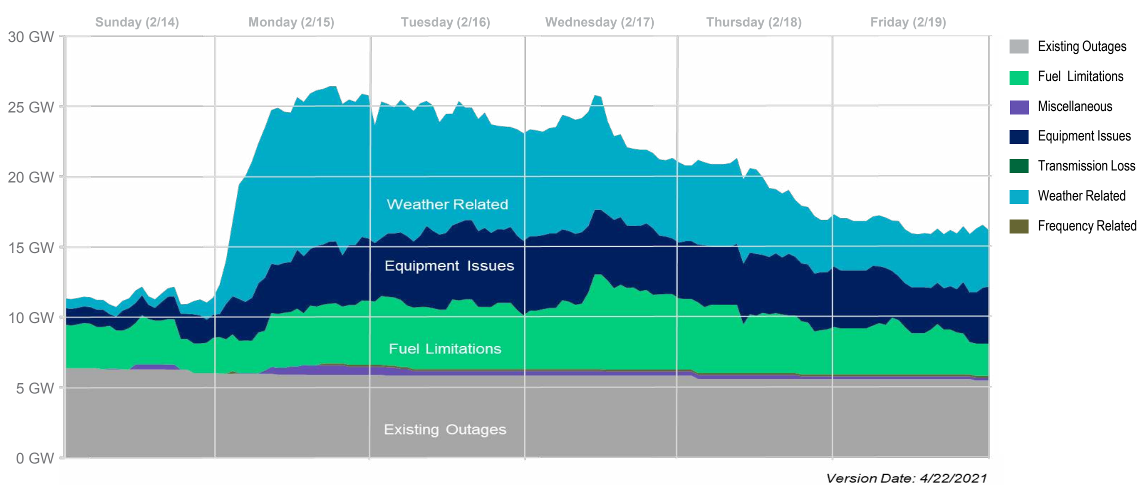

FIGURE 4. *Correlated Outages for Natural Gas Generators by Cause During the ERCOT February 2021 Event. Source: ERCOT*[105]

101 Additional information on accreditation methods is provided in Question 10.

102 National Renewable Energy, "National Solar Radiation Database," https://nsrdb.nrel.gov/

103 https://www.nrel.gov/docs/fy11osti/51860.pdf, at 27-29

104 https://www.sciencedirect.com/science/article/pii/S0140988316300317

105 ERCOT, "Update to April 6, 2021, Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event," 2021.

Resource Accreditation

6. **To facilitate regulation, compliance, and trading, a clear definition of the requirement or "product" is needed. Is there a single definition of "capacity" that works in a high renewable grid? Would there instead be multiple overlapping products reflecting different time periods and reliability needs?**

   In the historical context, "firm capacity" was rather easily defined. The system required a reserve margin of capacity above and beyond peak load, and generation capacity was "stacked up" to reach the reserve margin target. Fossil generation was given near full capacity credit, discounted only by the unit's forced outage rate, if at all. Firm capacity therefore meant a resource's availability during peak (often summer) load conditions. Total nameplate capacity with an adjustment for forced outage rates (assumed to be random) sufficed.

   Today, the notion of "firm capacity" is less clear, as variable renewable resources provide capacity benefits sometimes, but not others. Energy limited resources like battery storage and demand response can provide a high degree of availability during peak load conditions but have a limited response duration. Even natural gas resources, as discussed previously, are not as firm as unforced capacity (nameplate minus a forced outage rate adjustment) would indicate due to correlated outages during extreme temperature and fuel supply outages. Even fleets of nuclear plants have suffered from drought-induced cooling water loss, and fleets of coal plants have simultaneously experienced frozen coal piles or interruptions in coal deliveries.

   This is changing the notion of "firm capacity" as there is no such thing as a perfect resource for resource adequacy. Instead, the definition of capacity is increasingly associated with the ability of a resource to be available during times of system need and scarcity events. A given resource therefore does not have to be firm or dispatchable to have high capacity value. However, it also means the capacity value of a given resource changes with the amount of that resource type, and of other resources, on the system. These include saturation effects due to positive output correlations within individual resource types, and portfolio benefits due to negative correlations among different types of resources. These effects can make resource accreditation - the value at which a given resource is ascribed capacity value — highly dependent on the region, weather conditions, the load profile, and resource mix. Not only does this vary by region, but it also changes over time as the resource mix evolves.

   Saturation effects are common with any resource with correlated output that is only available during certain periods or has energy limitations, as the first "tranche" of the resource added to the system can mitigate certain scarcity events, but subsequent additions are unable to fill in the remainder of events.

   Portfolio effects also challenge attempts to assign individual resources a capacity credit. For example, storage capacity value is altered by the amount of solar on the system, as an increase in solar generation increases the availability of surplus energy to charge to storage, and it shortens evening peak load periods. Similar effects are seen with other types of resource diversity (i.e., complementarity between wind and solar output profiles) or changes with the underlying load profile over time.

Generation planning tools used by utilities and grid operators do not typically account for complementary portfolio effects among wind, solar, and storage, as these interactions introduce multivariate complexity into the tools' calculations. As a result, the widely used utility capacity expansion optimization models understate the capacity value contributions from adding portfolios of wind, solar, and storage resources. This both biases the model's optimization against selecting wind, solar, and storage resources, and also causes the model to overbuild capacity and overshoot reliability targets.[106] Portfolio effects can be captured by iteratively assessing dozens of potential portfolios of resources in a probabilistic resource adequacy modeling tool, but that is much more time-intensive than running a capacity expansion model once and letting it search for optimal resource mixes.

For a simple analogy, the traditional resource adequacy construct stacked a set of uniform "blocks" of capacity until the reserve margin was met. On the other hand, the changing resource mix resembles trying to stack a set of blocks that are all different shapes and sizes, which also change shape over time. This makes the capacity accreditation process difficult and the ability to treat capacity as a commodity increasingly challenging.

One way to overcome the disparate resource capabilities is to segment the capacity needs by time of day, by season, or both. Instead of using a single annual planning reserve margin, the resource adequacy analysis and procurement process could break down the year into distinct blocks (see PG&E "slice of day" approach[107]) and ensure there are enough resources available to cover each block, somewhat independently of one another.

The key takeaway from these trends is that there is no one type of "perfect capacity." System planners should recognize that all resources have both benefits and limitations and defining "firm capacity" is difficult due to the portfolio and saturation effects of various resources.

7. **Should resource adequacy constructs differentiate between resource flexibility and include other types of grid services?**

Another way to potentially define capacity needs is related to resource flexibility. For example, if a resource is not variable due to the weather, nor energy limited, it still may not be available during system needs and scarcity events because it cannot be started in time, or it was not anticipated to be a scarce supply period. This can be true for older steam oil or steam coal units, which may be uneconomic to run on a regular basis but remain in the market (or in a vertically integrated utility portfolio) because of the capacity credit and resource adequacy needs.

Historically, this inflexible capacity receives full capacity accreditation, but there is growing concern that the capacity may not be available when called upon – either due to start time limitations or the possibility of a failed start. Some ISOs, like PJM and ISONE, have introduced a pay for performance penalty that would penalize these resources for not showing up during a resource adequacy event. Others are potentially considering minimum start time requirements. Part of the growing demands to evaluate all generation, not just

106 For a discussion of how not accounting for portfolio effects causes a widely-used capacity expansion model to overstate reliability targets, see footnote 28 on page 81 in PNM's recent IRP: https://www.pnmforwardtogether.com/assets/uploads/PNM-2020-IRP-FULL-PLAN-NEW-COVER.pdf
107 PG&E, 2021.

variable renewables and energy limited resources, through an ELCC construct is to ensure that start times and/or failed starts are accounted for in resource accreditation.

California is one region considering flexibility in their resource adequacy requirements. The state's resource adequacy construct distinguishes between three types of resource adequacy; 1) System RA, 2) Local RA (based on localized needs), and 3) Flexible RA. The latter sets a requirement to cover the largest three-hour ramp for each month and sets an obligation for load serving entities that have a portfolio of resources that can meet a Flexible RA requirement. Similar argument could be made for resource adequacy covering other grid services, like ramping reserves, regulation reserves, spinning reserves, etc.

However, for the purposes of this report, short-term flexibility products — while essential for operational reliability — are considered a separate product than capacity for resource adequacy. This short-term flexibility is distinct from multi-day capacity needs for multiple reasons. For one, it is of lower concern in the future given the likely supply of fast-responding storage and demand response, as well as the physical abilities of wind and solar to ramp down, and reserve headroom to ramp up when there is wind or solar energy available.

Second, there is a continuum of grid services ranging from sub-seconds (inertia and fast frequency response), to seconds (regulation), to minutes (spinning reserve), to hours and days. Figure 5 below illustrates these time frames. Short-term market design needs to attract sufficient fast-responding resources to keep supply and demand in balance in these intra-second/hour/day time frames and that is a short-term market design question, separate issue than the longer-term periods of day/multi-day periods with insufficient energy supply.

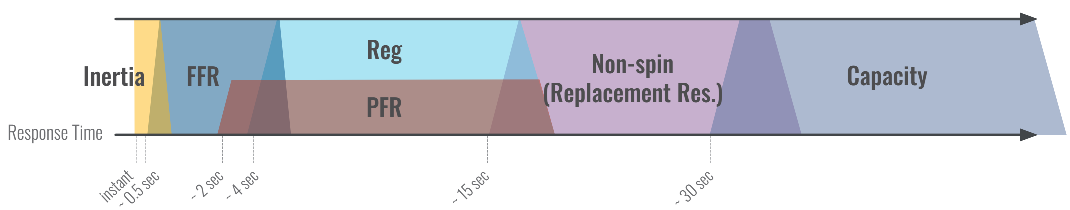

FIGURE 5. *Representative layering of short-term grid services. Source: Telos Energy*

In addition, the short-term flexibility needs are often an order of magnitude smaller than capacity and energy needs, with ancillary service markets in most regions only identifying a need for a few thousand Megawatts (MWs) of various reserves in each market.

At the same time, flexibility is also a system requirement, and grid operators and planners need to ensure it is in sufficient supply. California has a separate flexibility resource adequacy requirement from its "system resource adequacy" requirement.

From a resource adequacy perspective, the supply risk is less concerned with short-term intra-day flexibility needs and focused instead on risks associated with extreme peak loads, unexpected generator outages, and multi-low wind and solar resource days.

8. **Which resources can meet load when wind and solar output is low on a day-to-day, seasonal, or annual basis?**

The previous question identified saturation effects that occur with increasing levels of variable renewable energy integration. While wind and solar resources can be effective at reducing system risk during some time periods, they are not always available. As a result, at high renewable penetrations resource adequacy risk shifts to periods without high wind and solar resource availability, such as summer late evening hours or winter early mornings and evenings with light wind conditions. While battery energy storage may be effective at shifting available capacity from one time of day to another to mitigate some risk, it too experiences saturation effects at high penetration due to energy limitations and duration.

Eventually — at high penetration of variable renewables, energy storage, and fossil retirements — the resource adequacy risk will be concentrated into periods of multi-day low wind and solar events, or seasons with lower resource availability. Battery energy storage, in its current two-to-eight-hour duration form, has limited ability to solve these resource adequacy challenges. While multi-day periods of sustained low wind and solar resources may not be common, they do occur and need to be planned for in resource adequacy and portfolio analysis.

When focusing on extended multi-day periods with little renewable energy output, the options to preserve reliability widen from the traditional set. While traditional system planning relied on conventional combustion turbine capacity to meet peak reliability requirements, other options are likely available.

The first way to mitigate multi-day and seasonal periods of low wind and solar production is to increase the geographic footprint of the planning area. By expanding the size of the system, via transmission and through inter-regional coordination and planning, geographic diversity increases, and the threat of sustained multi-day low wind and solar production is mitigated.

Storage sources that are long-duration and slow-moving might come into play. Costs can be reduced significantly for storage sources that do not need to charge and discharge quickly or be used very often. Long duration storage could include new chemistries for batteries, pumped storage hydro, traditional reservoir hydro, compressed air energy storage, gravity-based systems, and many other emerging technologies. For example, Form Energy provides one type of resource (iron air storage) that is low cost (for long duration storage) and slower moving, yet available when needed.[108] Canadian hydro plants across the West, Central, and Eastern provinces provide months' worth of storage that could fill in gaps in US supply, if connected through more transmission.

Mothballing old gas plants with low forced outage rates but inefficient heat rates is another low-cost option. Even environmental groups have supported this option in some Integrated Resource Planning cases. These resources can be mothballed at essentially no cost and then restarted in six to eight weeks if load growth occurs, or unexpected long-duration outages occur on other plants. The system's net emissions impact is trivial for a plant that may only be called upon to run during critical emergencies.

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108 Utility Dive, "Form Energy's $20/kWh, 100-hour iron-air battery could be a substantial breakthrough," 7/26/2021.

Any resource adequacy solution in a highly decarbonized grid will likely also include an increased role for load flexibility. While much of the demand response used today is focused on short-term voluntary load curtailments (i.e., air conditioning or water heating), load flexibility options will likely broaden due to increased communications and interactive end use loads as well as shifts towards more real-time or time-of-use pricing.

Finally, the highly decarbonized grid also has a role for clean resources that are not variable, otherwise referred to as "clean firm" resources. These options include reservoir hydro (which is still subject to some long-term weather conditions), geothermal, biomass, waste-to-energy, nuclear, fossil with CCS, and generators running on fuels containing hydrogen produced through renewable electrolysis. A large part of the justification for these options is rooted in resource adequacy.

9. **To what extent do the physical resource needs vary by region and change over time?**

   Developing a national construct for resource adequacy is challenging because the underlying reliability risks and resource mixes for each region drive different physical resource mixes. A large part of this is due to the different load profile for each region. For example, California and the Southwest have extreme summer peak load conditions, but relatively modest winter loads. Many power systems in the Northwest currently experience winter peaks, the Southeast is largely a dual-peaking region (with similar summer and winter peak loads), and the Northeast is a summer-peaking region that may switch to winter-peaking over time with increased electrification.

   The regional variation is also a function of the underlying resource mix. Some regions with increased solar integration may have physical resource adequacy needs in the evening hours, where other regions with larger amounts of wind generation likely have a different resource adequacy need.

   While each region is unique, there is consensus that physical resource needs also change over time. Part of this is due to changes in the load pattern, either due to climate change (i.e., increasing frequency of summer peak loads in the Pacific Northwest), or structural changes in the load factor (i.e., increasing residential demand relative to industrial). With changes taking place both on the supply and demand side of the resource adequacy equation, the physical resource needs for capacity ultimately change over time as well.

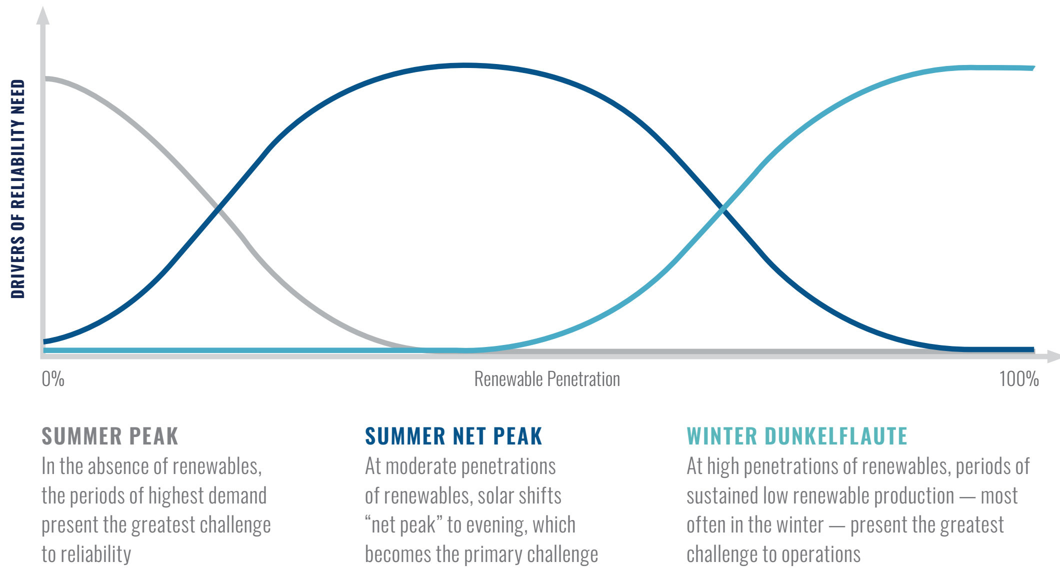

FIGURE 6. *Evolving grid challenges at increasing renewable penetrations. Source: E3*[109]

However, a resource doe s not have to be available every hour of the year to be effective for resource adequacy and capacity needs. However, the necessary timing and duration of availability is constantly changing. This makes capacity accreditation difficult and requires regular updates. This also challenges the ability to "lock-in" a resources' capacity value over a long period necessary for financing.

Because of the regional variation in the load profile, resource mix, and climate trends over time, any resource adequacy construct will likely need to have different physical needs. When combined with differences in regulatory structures and markets, a single resource adequacy construct is difficult. However, a broad regional framework does increase both resource and load diversity, allowing for lower cost solutions for resource adequacy needs, provided that adequate transmission can ensure the transfer of available resources from one region to another.[110]

10. What are the best ways to determine the capacity contributions of various resources? How should Effective Load Carrying Capability (ELCC) be determined, and should it apply to all resources?

Because the physical needs of the system are changing, so are the methods to accredit variable renewables and energy storage. Traditionally, fossil units are counted as "firm capacity," at the level of their nameplate capacity (sometimes seasonally adjusted) discounted slightly to unforced capacity (UCAP) based on their forced outage rates. Variable renewables and energy storage were accredited with rough rules of thumb for capacity value, discounting their nameplate capacity based on their availability during peak load.

109 Olson, A., Ming, Z., Carron, B., "ELCC Concepts and Considerations for Implementation," Prepared for August 30th, 2021 NYISO Installed Capacity Working Group, 2021, Energy and Environmental Economics.

110 Additional information on transmission and regional coordination is provided in Question 12.

There are different methods to technically measure capacity accreditation, including average capacity factor during peak load hours, and more sophisticated ELCC calculations. Over the past several years, ELCC has become the most accepted way to measure variable renewable and storage capacity credit as it is based on detailed resource adequacy simulations.

However, ELCC also has limitations as the resource mix changes. First, it is often not applied to all resource technology types, but rather only to variable renewables, energy storage, and demand response resources. This is biased, as there is no such thing as perfect capacity. Fossil generation has risks associated with fuel supply constraints, degraded performance during extreme heat, increased failure during extreme cold, and potential for large, discrete forced outages. These limitations should be reflected in the resource adequacy analysis and ELCC should be applied to all resources, not just variable renewable energy and energy limited resources. As the NERC Integration of Variable Generation Task Force (IVGTF) stated, "The fundamental calculations of loss of load probability, LOLE, and ELCC are not new, nor are they unique to variable generation. The reliability-based approach to calculating resource adequacy is a robust method that allows for the explicit estimate of the shortfall of generation to cover load. The traditional use of LOLE is to determine the required installed capacity, based on expected capacity during peak periods, and ELCC measures an individual generator's contribution to overall resource adequacy."[111]

ELCC for a given resource is highly dependent on the underlying resource mix, load profile, and other system characteristics that are constantly changing. For example, the capacity accreditation of storage and demand response technology depends on the amount of solar on the system. This is because high solar penetration reduces midday and afternoon loads and narrows the peak load risk to be better handled by limited duration storage and demand response. The same is true for balanced solar and wind resource mixes, as the resources are complementary. In addition, as the load profile changes due to energy efficiency, electrification, and rate structures — the peak risk periods will also change and may be suited to the underlying variable renewable resources. It also raises the question of who should be assigned credit for the diversity benefits. A system with increasing solar will increase the incremental ELCC of storage, but the same could be said about solar in a system with increasing storage.

These interdependencies — referred to as portfolio effects — make long-term ELCC attribution difficult. While ELCC may be a valuable metric for near-term compensation structures — like forthcoming capacity market auctions – it is problematic for long-term planning. Some resources such as wind, solar, and short-duration batteries are complementary such that more of one increases the capacity contribution of the other, while putting more of the same resource at the same location reduces ELCC (Figure 7). On the other hand, resources with similar output profiles reduce the other's capacity value. For example, in PJM, whether storage is dispatched before or after demand response leads to a 47 percent ELCC[112] with one method and 97 percent with another.[113] These interactions make assigning clear credit to any one resource difficult.

111 North American Electric Reliability Corporation, "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning," p. 9, March 2011.

112 Rocha-Garrido, "Public 1st Draft ELCC Results and the Process to Provide Preliminary ELCC Results," July 10, 2020.

113 Astrapé Consulting, "Dispatch Effects on Storage ELCC in PJM," July 16, 2020.

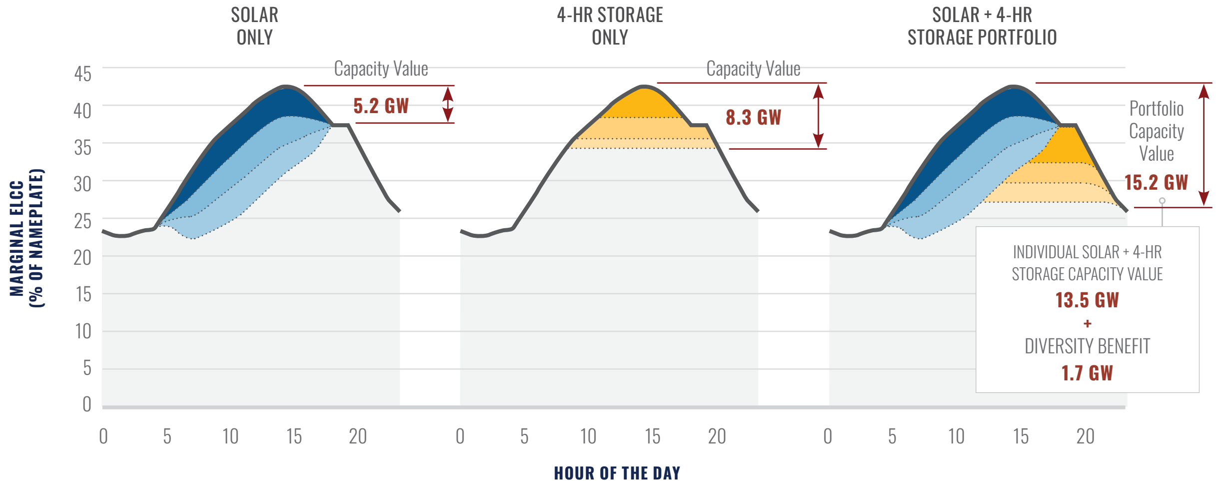

FIGURE 7. *ELCC of Solar, Storage, and Portfolio Effects. Source: E3*[114]

11. Are renewables getting fair treatment for capacity value?

The capacity accreditation process (and ELCC methodologies specifically) is one of the most contentious issues in resource adequacy constructs, whether in a deregulated capacity market or in vertically integrated IRP processes. Regardless of the process, capacity accreditation often relies on system modeling and assumptions.

It should be noted that increasing renewable energy is not leading to an increase in resource adequacy risk — but rather the subsequent retirement of fossil generation and increased reliance on variable renewables and energy limited resources for capacity needs. Without fossil retirements, the addition of variable renewables does not lead to increased reliability risk. Said another way, adding renewable energy never decreases the resource adequacy of a power system. Therefore, resource adequacy discussions should not be an impediment to adding variable renewables to the system, but rather a discussion on when to retire traditional fossil capacity and what to replace it with.

Disputes on equitable treatment are often on when the saturation point occurs for each resource type — which can be highly dependent on modeling assumptions. These assumptions include the following:

- **Weather profiles used:** a generator's ELCC is highly dependent on the assumed weather profile, which may vary considerably from year-to-year, and its correlation with the underlying load profile and other variable renewable plants in the region. To address this concern, many modelers use many decades of synthetic renewable output and load patterns that retain the correlations among those profiles.
- **Plant configuration:** each variable renewable plant or storage system is unique, but its attributes may not be reflected in ELCC calculations. This may include the inverter loading ratio (where higher ratios increase plant availability during low solar conditions), solar panel direction, turbine hub height and rotor diameter, storage duration, etc.

114 Schlag, N., Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang, "Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy," 2020, Energy and Environmental Economics.

- **Hybrid resources:** an increasing trend in hybrid resources (solar+storage, wind+solar, etc., with varying types of connection to the grid) is also making the accreditation process more complex for plant owners.
- **Storage utilization and forecasting:** whether the storage resources are used strictly for reliability, or other use cases (operating reserves, energy arbitrage, etc.) will influence the capacity accreditation. The order in which these resources are scheduled relative to other energy limited resources also impacts their valuation.

Perhaps the most notable issue regarding equitable treatment of renewables is the lack of an ELCC or accreditation process for incumbent fossil generation. Currently most regions either ascribe full capacity credit for fossil generation (assuming the installed capacity for planning reserve margin purposes), or discount the resources slightly based on their unforced capacity (UCAP) associated with the generator's historical forced outage rate. This, however, does not include the effects of correlated events that may occur across the fossil fleet due to the following:

- **Fuel supply disruptions,** specifically on the natural gas system,
- **Increased probability of forced outages** during extreme weather events,
- **Higher than average ambient derates** during extreme heat,
- **Flexibility constraints** that may make the generator unavailable when needed.

While the industry has taken great effort to quantify and measure the capacity accreditation of variable renewable and energy limited resources because they are new entrants, there has been less attention given to measuring capacity contribution of fossil generation which is likely overstated. As a result, any process that is used to accredit variable renewables and energy limited resources should also apply to fossil-fueled resources.

Transmission & Regional Coordination

12. How should neighboring balancing areas and jurisdictions be considered in resource adequacy assessments?

According to the ESIG Redefining Resource Adequacy Task Force, the incorporation of transmission and regional coordination is one of the six principles that needs to be considered in evolving resource adequacy analysis and modeling:

Resource adequacy modeling can be complex and is often computationally challenging; a large power system must typically be simulated across hundreds or thousands of Monte Carlo samples. To make this problem tractable, simplifications are required. Often that means only limited representation of neighboring power systems and the transmission network in general.

However, resource sharing can be a significant, low-cost alternative to procuring new resources. Imports from neighboring regions are likely to become more valuable for resource adequacy due to the increased diversity of chronological wind, solar, and load patterns over a much larger area. A typical wind plant output tends to have little correlation with other wind plants a few hundred miles away. Solar output varies with cloud cover and time zones. Load diversity is greater across large areas. While extreme weather can happen anywhere, it does not happen everywhere at once.[115]

As a result, it is critical to not evaluate a region's resource adequacy needs in isolation, but to ensure transmission is both modeled as a supply option, and to consider the likelihood of available imports from neighboring systems.

The same is true for resource adequacy markets. Expanding the load and renewable resource diversity across regions can reduce the need for capacity significantly. This was one of the primary drivers for the creation of early ISO markets. It is also evident across the Western Interconnection, which (outside of California) is currently composed of many vertically integrated utilities, each of which does resource adequacy planning individually. This leads to a potential overbuild of capacity across the region, which is discussed in the following question.

13. **Should each region be required to meet its own load locally? Do imports need to be contracted?**

While the benefits of transmission and regional coordination on resource adequacy are clear, the mechanics are not. Ultimately the regulatory structure in each region determines who is responsible for resource adequacy, which in turn sets requirements one needs to be self-reliant. Regulators and planners in most regions believe a system should be self-reliant and able to serve load without requiring imports from neighbors during critical time periods. This approach is not unreasonable; ultimately the utility or system operator is responsible for reliably meeting its customer's needs, regardless of what happens in neighboring regions. Oftentimes, regulators require that imports that count towards resource adequacy requirements be contracted.

An example of this accounting across jurisdictions is evident in a recent proposal for the Northwest Power Pool,[116] is seeking to bring a regional framework to resource adequacy planning across much of the Western Interconnection. It would establish a voluntary program where each load serving entity could join a bilateral construct where participants would be able to enter into capacity agreements with one another. This process would largely normalize the accounting principles — ensuring resources are not double counting, develop a consistent framework for resource adequacy targets and ELCC calculations, and establish a transparent contracting process. A similar development in the Southeast, and coordination across ISOs, could yield significant resource adequacy savings, without new capacity additions.

14. **How should transmission deliverability factor into resource adequacy assessments for wind and solar resources? Do interconnection study deliverability modeling and assumptions need to evolve with the growth of wind, solar, and storage?**

The interaction between transmission deliverability and resource adequacy is complex. For conventional generators whose output during peak periods is typically binary (either the resource is producing at full capacity, or the generator is on outage and producing 0%), it makes sense to require full deliverability. That ensures that if one generator experiences a forced outage, the others are fully deliverable to pick up the slack and meet peak demand.

However, wind and solar plant output profiles are not binary, and the output during peak net load is typically less than 100% of nameplate capacity, so 100% transmission deliverability

115 ESIG, 2021.

116 Northwest Power Pool, "Resource Adequacy Program - Detailed Design," July 2021.

should not be required for the resource to provide its full capacity value. Most wind projects pay for sufficient grid upgrades to ensure they can deliver the vast majority of their annual energy, with some acceptable level of curtailment that mostly occurs during low load periods in the spring and fall. Because wind output tends to be below average during peak demand periods, and because wind projects tend to be located in remote parts of the grid where there are few conventional generators delivering their maximum output into the local transmission zone during those peak periods, in most cases there will be adequate transmission to deliver their output during those peak periods. This is confirmed by data showing very low levels of wind curtailment during peak months.[117]

Similarly for solar, most peak net load periods occur in the late afternoon or evening when solar resources are well below their maximum output, particularly once solar penetrations are high enough to push peak net load later in the day. As a result, whatever level of transmission deliverability is built to ensure a solar plant's energy is not heavily curtailed at noon should be more than adequate to ensure deliverability of the plant's output during peak net load periods.

In addition, there is significant geographic diversity in renewable output profiles within a given generation pocket, particularly for wind resources. As a result, plants that are producing less than others will help to ensure that transmission constraints are not exceeded.

However, at higher renewable and storage penetrations, it will become increasingly important to model transmission deliverability to understand the complex time and spatial interactions of renewable output and flows on the transmission system. As computer processing power increases, moving away from interconnection studies based on snapshots of peak, off-peak, and shoulder periods to a sequential hourly approach that models renewable output patterns and the duration limits of storage. In the interim, grid operators should continue to update their interconnection study assumptions to account for how increased renewable penetrations are shifting the time periods of greatest transmission congestion and peak net load. For example, this can better capture the fact that storage resources located in solar-heavy areas can be deliverable at peak net load without causing a major need for grid upgrades because solar output has dropped off by the evening, while storage can also reduce congestion that limits the deliverability of solar resources midday by charging during that period.

New assumptions are also needed for modeling storage and hybrid resources in interconnection studies. Because battery storage can be flexibly dispatched to charge or discharge based on locational marginal prices, storage should tend to reduce and not exacerbate transmission congestion.

Grid operators should also focus interconnection studies and required grid upgrades on addressing reliability concerns, like determining what grid upgrades are needed to ensure the deliverability of resources at peak net load, and leave economic decisions about upgrades that ensure the deliverability of energy during other time periods up to the interconnecting generator.

117 https://www.pjm.com/-/media/committees-groups/subcommittees/irs/2020/20200302/20200302-item-08-wind-power-curtailment-graph.ashx