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R STREET POLICY STUDY NO. 97
May 2017

EMBRACING BASELOAD POWER RETIREMENTS

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INTRODUCTION

A wave of coal and potential nuclear retirements has prompted extensive political controversy over the future of "baseload" power plants and the effects such retirements could have on the reliability and affordability of the bulk electric-transmission system. Some contend that, as some baseload natural-gas plants also are unprofitable, "all traditional baseload generation sources are at risk."[1]

At the same time, market forces have driven a massive amount of new gas capacity, while public policy continues to provide the largest tail wind to the expansion of renewables. Renewables and natural gas now meet half of domestic electricity demand, compared to 38 percent in 2011.[2]

The causes and consequences of baseload retirements have significant policy implications. In April, the U.S. Energy Department announced an abbreviated review of baseload retirements, with particular attention focused on the role played by policies that promote renewable energy.[3] The overwhelming evidence from independent studies, monitors of wholesale electricity markets and other industry experts reveals that market fundamentals are the largest driver of coal, nuclear and gas retirements, but regulations and preferential policies also play significant roles. The most important question is whether monopoly-utility planning and competitive electricity markets have facilitated efficient and reliable investment decisions (e.g., proper incentives to build, upgrade or retire power plants) amid dynamic economic conditions.

BASELOAD IN CONTEXT

Policymakers often use the term "baseload" as synonymous with "dispatchable" (i.e., able to adjust generation output on-demand) or "dependable" year-round generation capability. This refers to the *capability* of a power plant, whereas the industry definition refers to actual *operation*. Specifically, those in the industry define "baseload" as "the minimum amount of electric power delivered or required over a given period of time at a steady rate."[4] Baseload power plants therefore provide power consistently (i.e., with little or no dispatch change needed) to meet the minimum level of demand, while "intermediate" or "load-following" plants adjust their output to match regular fluctuations in demand above this minimum level (or, increasingly, shifts in other

1. Raymond L. Gifford and Matthew S. Larson, "State Actions in Organized Markets," Wilkinson Barker Knauer LLP, February 2017. http://e67ti2w9ws71al8xmnhsozd3.wpengine.netdna-cdn.com/wp-content/uploads/sites/64/2017/02/Wilkinson-BarkerKnauer0217.pdf

2. Bloomberg Finance LP and the Business Council for Sustainable Energy, "2017 Sustainable Energy in America," Jan. 26, 2017. http://www.bcse.org/sustainableenergyfactbook/

3. Gavin Bade, "Updated: Perry orders DOE review of clean energy impacts on baseload generation," UtilityDive, April 17, 2017. http://www.utilitydive.com/news/updated-perry-orders-doe-review-of-clean-energy-impacts-on-baseload-genera/440578/

4. U.S. Energy Information Administration, "Glossary," accessed May 20, 2017. https://www.eia.gov/tools/glossary/index.php?id=B

supply). Peaking plants provide power during irregularly high demand periods and/or when other supply is unusually low. All of these standard resource classifications are dispatchable and dependable. Such characteristics are not unique to baseload resources.

To minimize the costs of operating the transmission system, grid operators dispatch generators in ascending order of cost, a process also known as "merit-order dispatch." This results in the dispatch of the least-cost resources to meet baseload demand, followed by higher-cost generators for load-following and peaking needs. Dispatch must account for the physical limitations of power plants. Coal and nuclear plants typically have less operational flexibility (e.g., they cannot turn on or off, or dispatch up or down rapidly) when compared to natural gas, storage and hydropower plants.

Grid operators can dispatch nonbaseload resources to meet baseload demand. Variable and use-limited resources (in other words, those that can't operate at consistent output) may cover baseload demand if other sources of load-following supply "fill in the gaps." This reduces the potential to operate plants at a steady rate (i.e., baseload operations). Some resources may use generation limits of short duration (e.g., sub-hourly fluctuations of wind and solar or multi-hour limits of storage); medium duration (e.g., several days of on-site fuel inventory or environmental restrictions on oil generators); or long duration (e.g., seasonal limitations on hydropower).

Transmission system reliability ultimately relies on having a portfolio of resources with the *cumulative* ability to provide all electric services (e.g., bulk energy, frequency response) dependably. No one resource is perfectly dependable. Instead, all resources fall on a reliability spectrum. Even baseload power plants experience outages, often resulting from mechanical malfunctions. Electricity-system planners—whether they are monopoly utilities or administrators of competitive capacity markets—use outage rates to determine the dependability of individual resources in meeting peak summer demand, or peak capacity. The one exception is the Electric Reliability Council of Texas (ERCOT), which relies on price signals alone to entice sufficient resource investment to meet reliability needs (in other words, whether to build or maintain resources and minimize outages in order to increase revenues).

Competitive markets and quality utility-planning processes do not *explicitly* procure baseload resources, but rather define and procure reliability attributes and parameters needed for a dependable resource portfolio. This *incidentally* results in the procurement of baseload-capable and nonbaseload-capable resources. A resource portfolio with year-round dependable resources makes system planning easier, but does not necessarily result in a more reliable or lower-cost portfolio. For example, if summer-only demand response (e.g., cycling air conditioners) is less expensive than building additional year-round peaking power plants to meet peak summer demand, then a portfolio with fewer year-round resources is more economic. The ability of variable and use-limited resources to meet system reliability needs is more difficult to incorporate in planning processes, but as many such resources become more economical, these processes must evolve proactively to meet their least-cost objective function.

CAUSES OF BASELOAD RETIREMENTS

Shifts in market fundamentals and some public policies have increased financial pressures on coal, nuclear and low-efficiency natural-gas plants. Market fundamentals—namely declines in demand and costs for natural-gas generation—are the principle causes of coal and nuclear retirements. In particular, highly efficient natural-gas plants utilizing historically inexpensive gas are the driving force of baseload retirements. Since these new gas generators have complete baseload functionality, new baseload-capable plants have primarily replaced baseload-capable retirements.

Coal and nuclear generation historically provided baseload power, given their comparatively low operating costs, while gas plants met load-following and peaking needs. This decade, advances in natural-gas plant efficiency and the trajectory of gas prices plummeting below $4/MMBtu created operating cost parity (or outright advantage) for many gas plants relative to coal plants (i.e., some gas plants moved even with or ahead of coal plants on the supply curve).[5] This has pushed efficient natural-gas plants into a baseload role,[6] while relegating many former baseload coal plants into less frequent operation (i.e., used more as a load-following than baseload resource). From 2005 to 2015, utilization of efficient gas plants[7] rose from 30 percent (common for load-following) to 50-80 percent (closer to baseload range).[8] In 2015, the utilization rate of efficient gas plants exceeded that of coal plants for the first time nationally.[9] The economic advantages of new efficient gas plants even markedly exceed those of other gas plants, leading to new gas plants replacing older ones (this is especially evident in Texas).

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5. This only refers to operating costs. The gas price parity point for total average costs, which includes capital costs, is substantially higher. In other words, it is generally less expensive to build and operate a gas plant than a coal or nuclear plant because the capital cost advantage outweighs higher operating costs above $4/MMBtu.

6. E.g., see U.S. Energy Information Administration, "Average utilization of the nation's natural-gas combined-cycle power-plant fleet is rising," *Today in Energy*, June 9, 2011. https://www.eia.gov/todayinenergy/detail.php?id=1730

7. This refers to the capacity factor of natural-gas combined-cycle plants.

8. U.S. Energy Information Administration, "Average utilization for natural gas combined-cycle plants exceeded coal plants in 2015," *Today in Energy*, April 4, 2016. https://www.eia.gov/todayinenergy/detail.php?id=25652

9. Ibid.

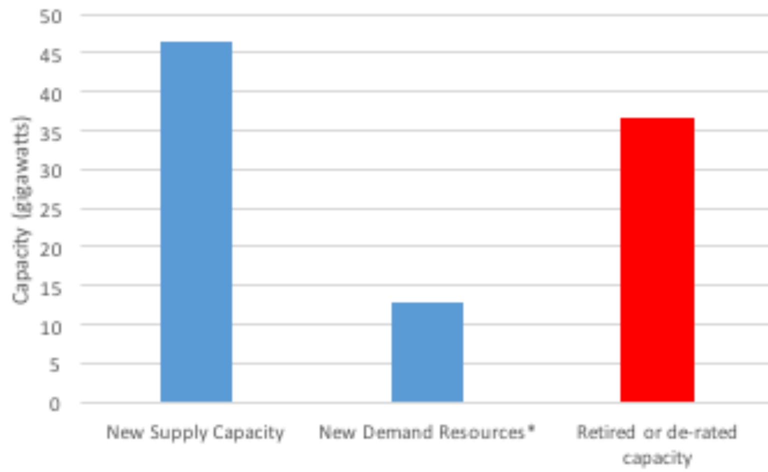
Some policy and regulatory pressures have been peripheral contributors to coal and nuclear retirements. The costliest regulatory burdens, namely the Mercury and Air Toxics Standard for coal and increased nuclear safety-compliance costs after the 2011 Fukushima Daiichi accident, are now behind us. In limited cases, some policies have deliberately discriminated against coal and nuclear facilities, such as statewide coal phase-out policies. In the future, policies that affect renewables deployment and energy efficiency are likely to create the greatest policy pressures on coal, nuclear and gas plants. Demand-side management programs already have contributed to most regions of the country having experienced flat or declining demand for at least the past decade.[10]

A sharp uptick in variable energy resources (VERs), namely wind and solar, has reduced the value and occurrence of baseload operations and increased the need for load-following capability.[11] Grid operators dispatch wind and solar first because they have the lowest operating costs. However, the weather-dependent nature of the resources creates a need for other resources to adjust their dispatch more frequently and extensively to balance system supply and demand. The result is a mix of VERs and load-following plants that displaces baseload operations.

VER deployment primarily has resulted from state renewable portfolio standards (RPSs). Federal tax credits for wind and solar have "lubricated the markets" more than driven increased investment.[12] Heavy cost declines have contributed to wind and solar achieving cost parity with efficient gas generators in some states,[13] which has helped spur a major increase in corporate customers procuring renewable energy over the past several years. These procurements are typically energy-only, however, as the contribution of VERs to meet "capacity" or dependable resource needs is limited.

The PJM Interconnection LLC, the largest domestic grid operator and competitive market administrator, has experienced extensive loss of baseload resources, providing a valuable case study. Low gas prices and environmental regulations drove 18,500 MW of coal retirements in the early to mid-2010s. The PJM capacity market "passed this stress test with surprising robustness and no evident threat to reliability."[14] Declining demand has also placed pressure on coal and nuclear resources (forecast demand shapes the amount of capacity the market procures). Most recently, forecast peak demand decreased by more than 3,200 MW in PJM's 2017 capacity auction (planning year 2020/2021) from the prior year.[15]

FIGURE I: PJM CUMULATIVE CAPACITY CHANGES 2007/2008 TO 2019/2020 DELIVERY YEARS



SOURCE: R Street analysis of PJM data[16]
NOTE: Includes demand response and energy efficiency programs.

Since its inception, PJM's capacity market has attracted 47 gigawatts (GW) of new generation and 13 GW of new demand resources, while retiring or derating 37 GW of capacity, for a net change of 23 GW of additional capacity. Nearly two-thirds of generation capacity additions came from efficient natural-gas plants (baseload and load-following capable), followed by peaking gas plants (15 percent) and coal and oil steam plants (11 percent). Wind and solar have only accounted for 4 percent combined.[17]

The limitations of wind and solar to contribute dependably to meet peak summer capacity needs results in heavy derating of the proportion of its maximum output eligible to serve as a capacity market resource. Conventional power plants often receive capacity credit for about 90 percent of their maximum output potential, which accounts for unplanned outages, whereas PJM gives 13 percent capacity credit for

10. Advanced Energy Economy Institute, "Changing the power grid for the better," May 2017. http://info.aee.net/hubfs/PDF/Changing-the-power-grid-for-the-better.pdf?t=1494983400395

11. Renewables have the lowest operating costs and, when available, they displace the need for other generation, primarily gas and coal (occasionally nuclear).

12. Todd Bessemer and Francis X. Shields, "Resource Investment in the Golden Age of Energy Finance: Financial Investment Drivers and Deterrents in the Competitive Electricity Markets of the U.S. and Canada," ISO/RTO Council, May 2015. http://www.isorto.org/Documents/Report/201505_IRCResourceInvestmentReport.pdf

13. Stephen Munro, "Energy reset?," Bloomberg New Energy Finance, April 6, 2017. http://www.ncac-usaee.org/pdfs/2017_04Munro.pdf

14. Johannes P. Pfeifenberger, Samuel A. Newell, Kathleen Spees and Roger Lueken, "Response to U.S. Senators' Capacity Market Questions," The Brattle Group, May 5, 2016. http://www.brattle.com/system/news/pdfs/000/001/055/original/Brattle_Open_Letter_to_GAO_-_Response_to_U.S._Senators'_Capacity_Market_Questions.pdf?1462477158

15. PJM Interconnection LLC, "2020/2021RPM Base Residual Auction Planning Period Parameters," January 2017. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-rpm-bra-planning-parameters-report.ashx

16. PJM Interconnection LLC, "2019/2020 RPM Base Residual Auction Results," May 24, 2016. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx

17. Ibid.

wind and 38 percent for solar.[18] PJM's 2016 capacity auction (PY 2019/2020) only cleared 969 MW of wind, or roughly the size of one nuclear reactor or large coal plant.[19] Solar cleared roughly one-third this amount during the same auction. As a result, new gas generation and declines in demand have created the overwhelming capacity market pressure on existing resources (baseload and otherwise) to retire, while pressure from wind and solar is modest. The effects of wind and solar on baseload are likely more pronounced in the energy markets (day-ahead and real-time operating markets), where inflexible generators like coal and nuclear may operate at periodic losses when wind and solar output is high. This general trend exists in all competitive markets (Texas and Northeast), albeit capital stock turnover has been less in other footprints that did not historically rely on coal to the same degree as PJM had.

It isn't necessary to procure capacity directly to obtain sufficient dependable resources; the alternative is to rely exclusively on real-time price signals. This requires robust "scarcity pricing" (in other words, strong price signals in the real-time market when there is a systemwide shortage of power reserves), which is the approach taken by ERCOT. ERCOT has experienced rapid growth in wind. This has reduced market prices mostly during off-peak hours, but only modestly during peak periods.[20] The shift has resulted in lower revenues for inflexible plants—especially coal—that operate continuously (i.e., in a baseload role) without dampening the scarcity signal greatly. This creates a market signal for flexible generation that accommodates wind fluctuations and remains dependable during peak demand.

CONSEQUENCES

Concerns over baseload retirements typically boil down to questions over the reliability and economics of an evolving fuel and technology mix. The strong shift to gas generation in competitive markets (and to a lesser extent, by monopoly utilities) primarily reflects a sudden shift in market fundamentals. As a result, considerable downward pressure has been placed on customer rates. Massive and abrupt coal retirements in PJM already demonstrate that such a transition can occur affordably and reliably.

Some critics contend that natural-gas plants do not offer the same dependable baseload qualities as coal or nuclear. At face value, a power plant that stores fuel on-site may seem inherently more reliable than one that relies on just-in-time fuel delivery, but plants with fuel stored off-site may perform as well or better than those with on-site fuel inventories. For example, despite having weeks of fuel on-site, sometimes coal plants cannot access their fuel for various reasons, including breakdowns in conveyor belts or frozen stockpiles. A holistic examination of plant performance requires tallying all of the causes of unplanned outages.

Efficient gas plants typically have fewer unplanned outages than coal and oil plants (nuclear usually performs best, but the differences are marginal).[21] Coal and oil generators were the primary drivers this decade in declining generator dependability in ISO New England (ISO-NE).[22] Gas interruptions only accounted for 24 percent of unplanned generator outages in PJM during the 2014 "Polar Vortex" (mechanical failures from cold weather caused most),[23] which critics often overstate as evidence of overreliance on "undependable" natural gas. Mounting generator performance concerns led PJM and ISO-NE to enact capacity market reforms to provide greater penalties for nonperformance. This has improved reliability-enhancing behavior, such as "firming" fuel-delivery arrangements and spurring power-plant weatherization and maintenance improvements. If anything, because the delivery period of these capacity markets span one year, the markets overinvest in nonsummer resources (i.e., procure year-round resources based on summer peak demand despite lower demand outside summer, which gives the advantage to baseload-capable resources).

Perhaps the greatest lessons from the Polar Vortex and other extreme weather events are the limitations of conventional market design and monopoly-utility planning to account for common mode failure. Standard industry practice assumes generator outages are independent, unrelated events. However, a single factor may cause outages at multiple power plants. Extreme weather may present the most prevalent example, where harsh conditions cause mechanical malfunctions at multiple power plants. Some elements of the transmission system represent potential common mode failure as well.

Common mode failure also applies to fuel disruptions at power plants. For example, snowpack levels have an effect on hydropower availability for multiple dams. Reliance on a few congested railway lines for coal deliveries caused some coal plants in the Midwest and Great Plains to operate on a

18. Ibid.

19. Ibid.

20. Potomac Economics Ltd., "2015 State of the Market Report for the ERCOT wholesale electricity markets," Independent Market Monitor for the ERCOT Wholesale Market, June 2016. http://www.puc.texas.gov/industry/electric/reports/ERCOT_annual_reports/2015annualreport.pdf

21. See forced outage rates for natural gas combined cycle compared to other generation types. A recent statistics summary for ISO-NE is available at: ISO-NE Public, "ISO New England EFORd Class Averages from NERC Brochure," Dec. 13, 2006. https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf.

22. Robert Ethier, "Meeting Natural Gas-Electric Interdependency Challenges through Market Enhancements," U.S. Department of Energy's Electricity Advisory Committee, Sept. 25, 2014. https://energy.gov/sites/prod/files/2014/10/f18/08a-REthier.pdf

23. Mike Kormos, "Polar Vortex 2014," FERC Technical Conference, April 1, 2014. https://www.ferc.gov/CalendarFiles/20140401084146-Kormos,%20PJM%20Slides.pdf

restricted basis in 2013 and 2014.[24] Similarly, when multiple power plants rely on a single natural-gas storage facility (for example, the Aliso Canyon outside Los Angeles) or pipeline for fuel, a single infrastructure disruption may create outages at multiple power plants if no alternative fuel supply line exists (i.e., lack of fungible fuel). While the conditions that create fuel-related common mode failure are very situation-specific, increased penetration of natural-gas generation may potentially introduce localized reliability risks.[25] This is a distinct issue from the amount of baseload functionality on a system, but turnover in the baseload fleet could exacerbate some forms of common mode failure.

POLICY IMPLICATIONS

Critics have levied that wholesale electricity markets undervalue baseload power, yet no credible empirical evidence finds a systemic underpayment for attributes associated with baseload, in particular.[26] The notion that the current financial struggles of coal and nuclear signify market design problems fails to note that these generation types were highly profitable "cash cows" when natural-gas prices were high last decade. Legitimate market design flaws exist with the pricing of fast-start resources (typically peaking plants) and demand response resources. However, there are no evident price-formation problems for baseload or intermediate (load-following) resources.[27] Pricing other resources more efficiently should increase real-time revenues for baseload plants. Improved scarcity pricing, even in areas with capacity markets, would result in a more accurate reflection of reliability services that would reward those resources that perform well, baseload and nonbaseload alike.

The independent market monitors of the wholesale markets question why baseload is such a policy concern. They uniformly believe the biggest risks to market performance are political interventions, especially those that aim to preserve uneconomical baseload plants.[28] The monitors for the markets covering New England and New York, which have enacted or proposed nuclear subsidies, noted that interventions for these large capacity resources create larger market distortions than those for renewables (considering how much renewables are derated in capacity markets).[29] The PJM monitor began its latest annual report by noting that the PJM markets have successfully brought the benefits of competition to customers, but that subsidies threaten the viability of those competitive markets.[30] The monitors emphasize that markets have performed relatively well, but a variety of market design improvements would further enhance performance, none of which specifically target baseload plants.

Accelerated turnover in the generation fleet can expose flaws in market design and monopoly-utility resource planning. Markets, which only minimize going-forward costs (as opposed to sunk-cost accumulation incentives for monopolies), are especially prone to rapid turnover when market fundamentals shift abruptly. While this creates greater economic value, it places particular onus on proactive market-design enhancements to ensure dependable performance of the generating fleet. Regulators and policymakers should prioritize holistic analyses of common mode failures and methods to capture these in market design and utility planning. These processes have traditionally focused on meeting peak summer needs at least-cost; however, this paradigm must shift toward achieving year-round resource adequacy as the fuel mix evolves (i.e., achieving sufficient generator performance commensurate with seasonal demand profiles).

As VER penetration grows, capacity accreditation becomes more important and challenging in utility planning and market design. The variability in available output at one wind or solar facility relates to that of an in-kind facility in the same meteorological footprint. The contribution of VERs to meet peak needs also declines as the amount of in-kind VERs on a system increases. This raises considerable capacity-planning methodology challenges.

Numerous studies have evaluated the cost of integrating VERs. There has been less work to evaluate the operational effects of resource integration.[31] Various forms of operating flexibility (e.g., rate and range of dispatch) associated with load-following operations will be at a premium, and monopoly-utility and market-procurement mechanisms need to value these reliability attributes explicitly if VERs are to be integrated reliably and affordably. This will efficiently signal the shift to load-following operations for much of the former baseload generation fleet.

24. Staff Overview, "Coal Delivery Issues for Electric Generation," Federal Energy Regulatory Commission, Dec. 18, 2014. https://www.ferc.gov/media/headlines/2014/2014-4/A-3-presentation-staff.pdf

25. North American Electric Reliability Corp., "Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation," May 24, 2016. http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf

26. The one possible exception is the Midcontinent Independent System Operator. However, nearly all of its resource requirements are procured through monopoly-utility processes.

27. See comments of Potomac Economics Ltd., before the Federal Energy Regulatory Commission on "Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators" in docket No. AD14-14-000.

28. Based on personal conversations with the external market monitors of ISO-NE, NYISO, ERCOT and PJM.

29. David B. Patton, "Comments of David B. Patton, PhD regarding state policies affecting Eastern RTOs," Federal Energy Regulatory Commission, April 24, 2017. https://www.ferc.gov/CalendarFiles/20170426150115-Patton,%20Potomac%20Economics.pdf

30. Monitoring Analytics LLC, "State of the Market Report for PJM, Vol. 2: Detailed Analysis," March 9, 2017. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec1.pdf

31. Astrape Consulting, "The Economic Ramifications of Resource Adequacy White Paper," Eastern Interconnection States' Planning Council, January 2013. http://pubs.naruc.org/pub/536DBE4A-2354-D714-5153-70FEAB9E1A87

CONCLUSION

Though the energy industry uses a different definition of "baseload" than the one commonly promulgated by those in policy conversations, policymakers' inclination to be concerned about dispatchable and dependable power is on-point. Public policy should strive to obtain reliability at the least cost. "Baseload" is not a reliability attribute; it merely refers to a type of power plant dispatched at a steady rate.

The rate of retirements of baseload generators has raised many important policy questions. However, concern over baseload retirements often masks an underlying preference for certain fuel types, namely coal and nuclear. Criticism of baseload retirements often ignores that nonbaseload resources can meet baseload demand reliably; that the maximum potential and actual role of baseload generation has decreased (e.g., coal units operating in load-following roles); and that new dependable resources have replaced retiring generators to meet reliability needs. Policymakers and regulators should be concerned with whether the economic paradigms driving power-plant investments are achieving system reliability at the least cost, not whether they reward a subset of politically preferred resources.

When examining power-plant investment processes, the policy imperative is to achieve the lowest-cost portfolio of power plants that *collectively* perform dependably (i.e., sufficient to meet reliability needs). This does not necessarily mean a portfolio with more *individual* year-round dependable resources will perform more reliably or at lower cost than, say, one with more seasonally variable resources (e.g., higher usage of demand response in summer and hydro in winter). Historically, conventional baseload resources were integral to achieving portfolio reliability at least-cost, but some of these resources no longer provide the most economical means to meet reliability needs.

The evolving generation mix has exposed shortcomings in conventional monopoly-utility resource planning and competitive market design. In particular, some forms of common mode failure have become more prevalent and increased levels of VERs create additional reliability service needs and methodological challenges in capacity markets. Some states have encouraged improvements in utility planning, while the Federal Energy Regulatory Commission, Texas regulators and industry stakeholders all have pursued refinements in market design.

Much work remains to be done, as regulators and policymakers should ensure the full inclusion of all reliability attributes. But this needs to happen regardless of whether it happens to favor or disfavor conventional baseload plants.

ABOUT THE AUTHORS

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