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The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study

Elliott J. Nethercutt and Chris Devon

A growing number of states have instituted renewable portfolio standards (RPS) through policies and corresponding commission orders to reduce carbon emissions in the electricity sector. No state has transformed its grid with more ambitious policies than California, which introduced its RPS in 2002, initially requiring 20 percent of retail electricity sales to be served by renewable resources within 15 years.[1] This program has been adjusted multiple times, most recently by Senate Bill 100 (SB100) in 2018, which increased the requirement for carbon-free generation from electric retail sales to 60 percent by 2030 and 100 percent by 2045. The California Public Utilities Commission (CPUC) is charged with implementing this RPS program and administering compliance over the state's investor-owned utilities (IOUs), Energy Service Providers (ESPs), and community choice aggregators (CCAs).[2] The CPUC is also responsible for ensuring that jurisdictional load-serving entities (LSEs) procure enough capacity to meet the commission's resource adequacy program requirements.[3] These two objectives collided on August 14 and 15, 2020, when the California Independent System Operator (CAISO) called on utilities to initiate controlled rotating electricity outages on two occasions to maintain adequate reserves in the midst of a regional heat wave. These two load-shedding events affected 491,600 and 321,000 customers, respectively.[4] California's electric system was ultimately unable to maintain reliable operations for the first time in almost two decades.

Significant loss-of-load events on the bulk power system often result from a combination of factors. After months of collaborative investigation, the CPUC, the CAISO, and the California Energy Commission (CEC) released a final root cause analysis (referred as "root cause analysis" throughout this paper) that identifies several operational factors that contributed to the events, including: actual loads exceeding forecasts; significant variability in wind and solar output; reduced imports from neighboring states (due to transmission constraints, market rules, and high demand throughout the Western Interconnection); and significant unit derates and forced outages. According to the root cause analysis, two of

1 California is one of several states with aggressive clean energy targets, requiring 100 percent carbon-free electricity by 2045. According to the NCLS, 14 states have RPS goals of 50 percent or greater by 2045. The types of resources that qualify for California's RPS have evolved. For additional information, see Section 399.12 of Senate Bill 1078 and the CPUC's RPS Program and Legislative History.

2 The California Energy Commission (CEC) is responsible for the certification of generation facilities as eligible renewable energy resources and adopting regulations for the enforcement of RPS procurement requirements of publicly owned utilities.

3 A 1-in-2 forecast assumes there is a 50 percent probability that the forecasted peak will be less than actual peak load and a 50 percent probability that the forecasted peak will be greater than actual peak load. The demand forecasts are adopted by the CEC as part of its Integrated Energy Policy Report (IEPR) process. The 15 percent planning reserve margin (PRM) includes 6 percent to meet the Western Electricity Coordinating Council (WECC)-required grid operating contingency reserves, plus a 9 percent planning contingency to account for plant outages and higher-than-average peak demand, CAISO/CPUC/CEC Final Root Cause Analysis, p. 11.

The 50/50 load forecast assumes a normal distribution. For example, if the forecasted load for a system is 25,000 MW, there is a 50 percent chance actual load will be higher, and a 50 percent chance load will be lower.

4 Total customer outages amounted to 491,600 on August 14 and 321,000 on August 15, CAISO/CPUC/CEC Final Root Cause Analysis, p. 35.

the three primary causal factors were related to resource planning targets that "have not kept pace" with the changing resource mix, leading to insufficient resources available to meet demand during the early evening hours.[5] The August events highlight the need for continued improvement to resource adequacy constructs, along with developing and implementing enhanced metrics to accurately assess an electric system that continues to be transformed by ambitious state decarbonization policies.

In this *NRRI Insights* paper, we examine how the evolution of California's RPS program has led to increasing system variability with higher potential for reliability events—particularly during extreme weather conditions. We further explain how the rapid retirement of baseload and dispatchable generation has outpaced replacement capacity with adequate characteristics needed to maintain system reliability. We discuss the CPUC's recent finding that future procurement decisions must balance RPS requirements with resource adequacy needs. We then explore how the continued development of advanced reliability metrics can help bridge the gap between decarbonization policy goals and resource adequacy needs. Throughout this paper, we review the ongoing CPUC and CAISO actions in response to the ongoing supply shortages and offer some additional proposals aimed at improving the state's near- and long-term reliability outlook.

California's Decarbonization Policies and System Reliability

The California legislature established the first RPS program in 2002, with subsequent decisions and process modifications introduced by the CPUC.[6] Additional legislation with more stringent requirements and associated compliance timelines were signed into law in 2003, 2005, 2015, and 2018.[7] Load-serving entities repeatedly demonstrated that they could interconnect large amounts of utility-scale wind and solar, while large amounts of rooftop photovoltaic were also installed behind the meter. During this period of relatively rapid system transformation, the CAISO continued to operate the system without any major events, reinforcing the idea that policy-makers could introduce more ambitious RPS requirements without compromising grid reliability.[8] The CAISO has facilitated the interconnection of large amounts of utility-scale wind and solar by providing open and non-discriminatory access to the wholesale transmission grid and supporting comprehensive infrastructure planning through dozens of stakeholder initiatives. These initiatives led to the deployment of over 13 gigawatts (GW) of utility-scale solar and 7 GW of wind on the CAISO system in under 18 years.[9] As a result, the CAISO system is currently able to serve over 80 percent of demand with renewables during certain periods, double the amount reported in 2015, and more than any other system in the country (**Figure 1**).[10]

The Decline of Baseload and Dispatchable Resources in California

California's rapid and ongoing growth of intermittent resources like wind and solar has flourished, while baseload and dispatchable resources have

5 CAISO/CPUC/CEC Final Root Cause Analysis, p. 1.

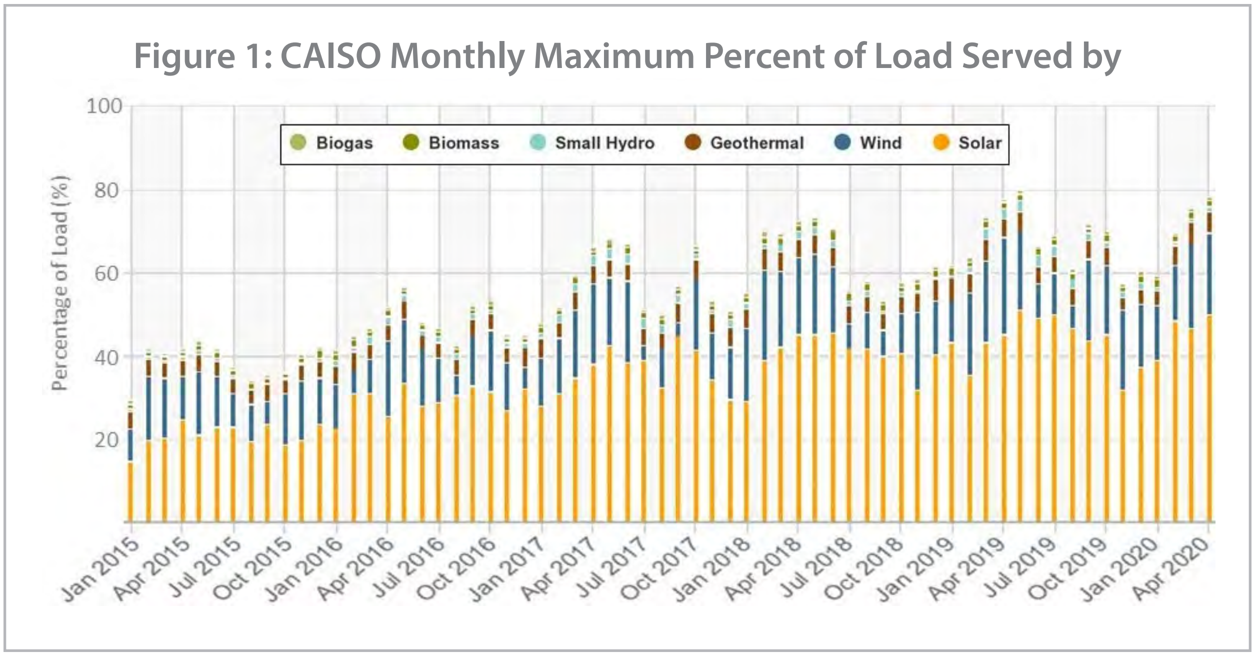
6 See the CPUC RPS website for a complete list of the state's RPS program.

7 The 2003 Energy Action Plan I accelerated the 20 percent deadline from 2017 to 2010 (Senate Bill 107 (2006) codified the accelerated deadline into law). The 2005 Energy Action Plan II examined a further goal of 33 percent by 2020. Senate Bill 350 (2015) required all in-state utilities to source half of their electricity sales from renewable sources by 2030.

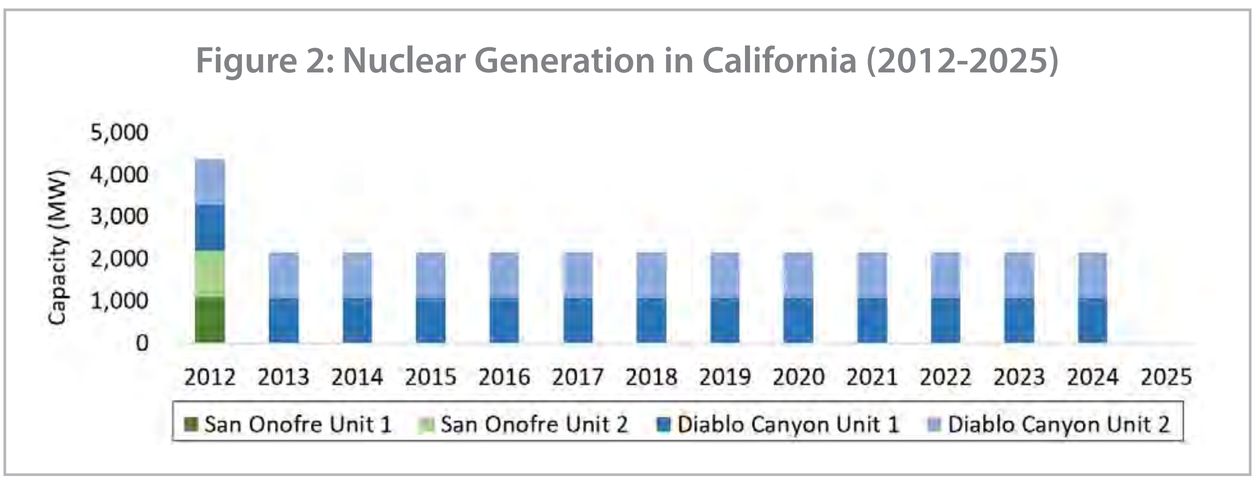
8 California's electric system had not experienced wide-spread rotating outages since 2001, when the CAISO declared a Stage 3 emergency leading to the controllable firm load-shedding during the California Energy Crisis. The 2011 Southwest Blackout was not a controlled load shedding event, rather it was determined that the system was not operating at an N-1 state.

9 California Energy Commission's Electric Generation Capacity and Energy data indicates 11.2 GW of solar additions and 4.4 GW of wind additions between 2001 and 2019. In July 2020, the CAISO footprint has 13,383 MW of utility-sale solar and 6,977 MW of wind.

10 The CAISO system served a record 81.88 percent of system demand with renewable generation on May 2, 2020 at 1:40 p.m. The CAISO chart does not show May 2 record of renewables serving demand. Chart modified and resized by authors.



declined.[11] In 2012, the San Onofre Nuclear Generating Station (SONGS) plant was taken offline and permanently decommissioned one year later. SONGS had provided 2.2 GW of zero-emission baseload generation in close proximity to the densely populated Southern California load pockets. Four years later, plans were announced to close the state's remaining nuclear plant, Diablo Canyon, by 2025. Its two reactors total 2,160 MW and serve three million customers. Nuclear plants maintained an average 2019 capacity factor of 93 percent, compared to approximately 24 percent for solar. Thus, it would require at least 6 GW of nameplate solar capacity to fill the void created by the retirement of the Diablo Canyon plant.[12]



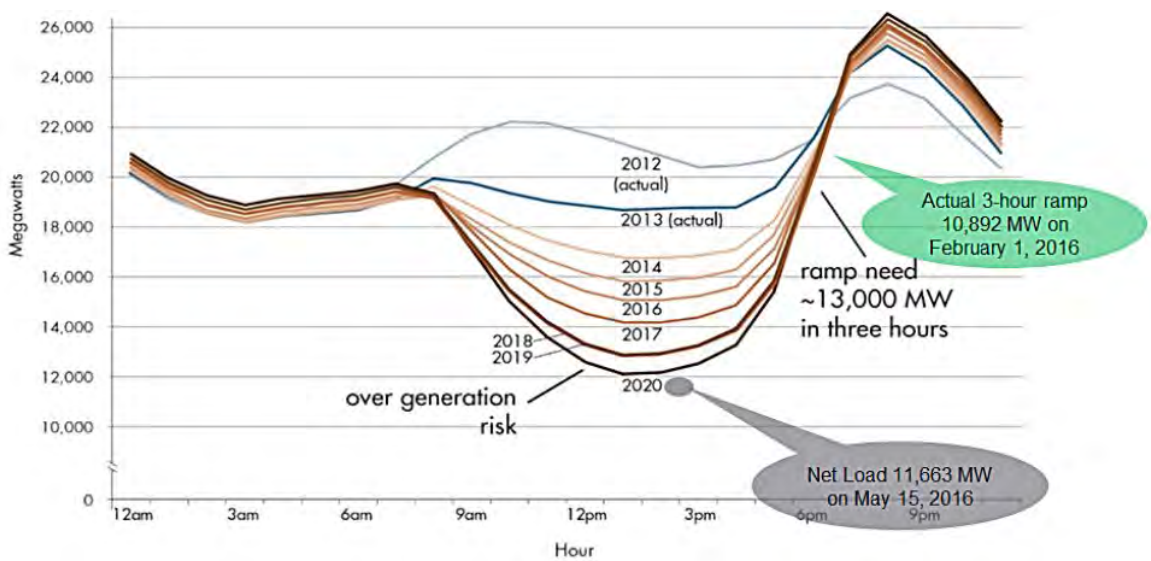
11 Baseload generation includes power plants with high capacity factors that are able to be operated at sustained output levels with limited cycling or ramping. Examples includes most nuclear, coal, and natural gas steam generators, none of which qualify toward achieving the state's RPS. California has essentially retired all coal-fired capacity.

12 EIA 2019 Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels; EFI: Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, p. 40.

In addition to the ongoing loss of baseload generators, dispatchable resources that are highly responsive to intermittent resources are also in decline. Ramping concerns initially emerged as a growing challenge for the CAISO more than a decade ago. Today, the majority of the state's solar resources are not dispatchable by the CAISO, but are located behind-the-meter on customer rooftops.[13] Solar output from these distributed resources (in aggregate) offsets what would otherwise be higher system loads. However, output rapidly declines after the sun sets, creating a steep ramp in demand that must be served by other resources on the CAISO system. During the same period, residential electricity demand also increases, as customers return home from work and use more appliances during the late-afternoon and early-evening (especially air conditioning). This load pattern, often referred to as the duck curve (and more recently referred to as "net-load ramps"), is exacerbated by the long, narrow, north-south geographic orientation of the state (**Figure 3**).[14, 15]

The ongoing challenges associated with meeting increasingly steep net load ramps were identified in the joint report as a contributing factor to the August 2020 events.[16] Concerns about insufficient ramping capability on the system were initially recognized by the CAISO Board of Governors in 2011 and resulted in their approval of a flexible ramping constraint interim compensation methodology. The resulting market policy established a flexible ramping product to address ". . . increasing levels of

Figure 3: The Duck Curve Highlights the Need for Responsive Resources to Address Growing Ramping Needs



13 According to the CAISO's January 2021 Key Statistics, there are 12,697 MW of utility-scale solar (includes load-serving entities participating in California's market). SEIA's Q3-2020 fact sheet indicates that a total of 29,218 MW of total installed solar.

14 If solar resources were instead spread across an east-to-west orientation, the decline in solar output would occur over a longer period as the sun sets. This would allow operators more time to identify and "ramp-up" other dispatchable resources. A ramp refers to the generator responding to the change in load or to changes in output from other generators on the system. Daily net load ramps are especially prevalent during the spring and fall and are the result of growing amounts of distributed solar resources (primarily rooftop photovoltaic) that have caused overall system demand to decline during the middle of the day (the belly of the duck, when solar output is highest). Demand then rapidly increases in the late afternoon and early evening, when solar performance declines as the sun sets, causing net load to increase rapidly.

15 The duck curve demonstrates that the net load variability required fast-acting resources to "ramp-up" as much as 10,892 MW in 3 hours during the late-afternoon on February 1, 2016. CAISO Fast Facts: What the duck curve tells us about managing a green grid (2016).

16 CAISO/CPUC/CEC Final Root Cause Analysis. Executive Summary ES.2, pp. 3-5.

variable energy resources and behind the meter generation…" which contributes to the operational challenges associated with ramping capability.[17] The flexible ramping product promotes securing enough ramping capability in the 5-minute and 15-minute market to address the variability of wind and solar resources.[18] Unlike baseload generation, which provides relatively constant output, generation capable of ramping allows the CAISO to dispatch these plants to change output based on the changing needs of the system. These impacts are on the demand-side (due to the variability of distributed rooftop solar PV), as well as the supply side (due to changes in output from utility-scale wind and solar). Accordingly, the CAISO needs additional flexible resources capable of responding to increasingly variable system conditions. Flexible resources include the ability to perform the following functions:[19]

- Sustain upward or downward ramps
- Change ramp directions quickly (react quickly and meet expected operating levels)
- Respond to operator dispatch to maintain output for a defined period of time
- Store and modify time of energy use
- Start-up from a zero or low-electricity operating level with short notice (i.e., rapid start-up)
- Start and stop multiple times per day
- Provide accurate operating capability projections (i.e., the metered output from a unit matches the information provided to the system operator)

However, resources on the CAISO system with many of these characteristics have been taken out of service at a rapid pace. Approximately 9 GW of natural gas fired generation was removed from service within five years, including many combustion or combined-cycle plants that can respond rapidly to net load ramps.

Table 1: Capability of Different Power Generating Technologies to Provide Flexibility

Plant Type	Start-up Time	Max Change in 30 Seconds (%)	Max Ramp Rate (%/min)
Simple Cycle CT	10 - 20 min	20 - 30	20
Combined Cycle CT	30 - 60 min	10 - 20	5 - 10
Coal Plant	1 - 10 hr.	5 - 10	1 - 5
Nuclear Plant	2 hr. - 2 d	< 5	1 - 5

The ramp rates for most simple-cycle and combined-cycle gas turbine models are shown in **Table 1** and compared with other generating technologies.[20]

Meanwhile, the CAISO previous projections that the 3-hour ramp would grow to 13,000 MW by 2020, actually occurred on January 1, 2019, with an actual 3-hour ramp rate of 15,639 MW.[21] Despite these alarming trends, an additional 1.9 GW of dispatchable capacity was taken offline between June 2019 and June 2020.[22]

Replacement Capacity Must Address the System's Changing Reliability Needs

Generation retirements to meet RPS requirements or

17 CASO Revised Draft Final Proposal - Flexible Ramping Product, p. 3.

18 The Flexible Ramping Product requirements for the 15-minute market is usually higher than the requirement for the real-time dispatch, since there is uncertainty observed between the two market intervals, CAISO Energy Markets Price Performance, p. 72.

19 CAISO Fast Facts: What the duck curve tells us about managing a green grid, 2016, p. 2.

20 Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices (2020). (p.10).

21 Actual ramps have been as high as 14,360 MW during a 3-hour period, CAISO projecting 3-hour ramping needs to surpass 20,000 MW by 2022, p. 20. The net load is defined as system load minus renewable generation, including distributed generation (primarily rooftop photovoltaic), solar thermal, and wind power in California. The net load ramp also refers to the evening period of greatest ramping needs driven by the quickly diminishing solar output. Projections and actual data provided by the CAISO's Flexible Capacity Needs and Availability for 2020, p. 22.

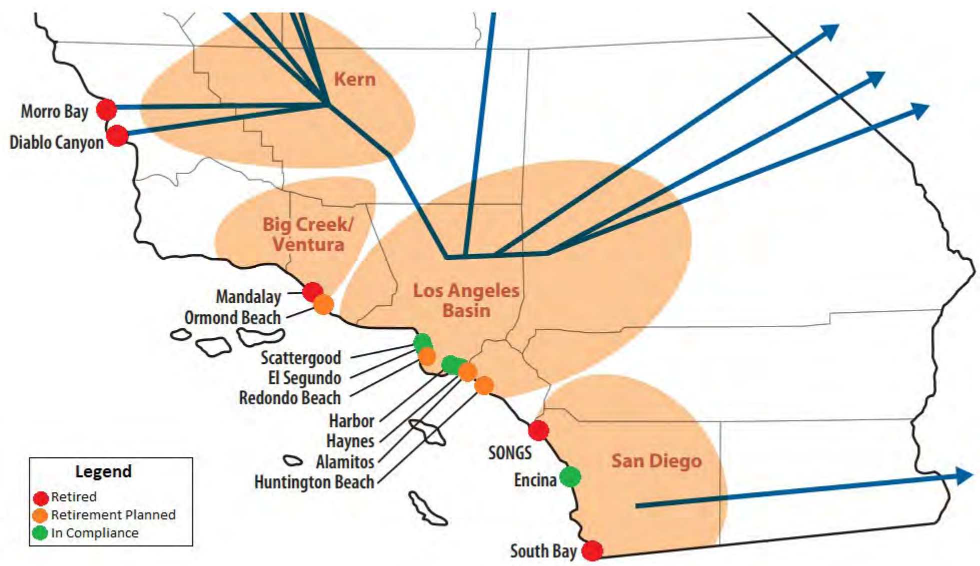
22 A total of 1,926 MW of dispatchable generation was taken out of service from June 1, 2019 to June 1, 2020, CAISO 2020 Summer Loads and Resources Assessment, p. 27.

comply with the California State Water Board's ongoing regulations that phase-out once-through-cooling (OTC), have occurred without securing enough adequate replacement capacity needed to address the operational challenges associated with increased system variability.[23] Former FERC Commissioner Cheryl LaFluer recognized this problem: "In the past three years, California has closed 5,000 MW of gas generation in anticipation of building 3,000 MW of battery storage that is still on the drawing board. In a heat wave, when every resource is needed, this gap in resources came home to roost."[24]

Former Energy Secretary Ernest Moniz also observed that "there is a shortage of [generating] capacity" and warned California policymakers that a combination of solar power and battery storage would not be able to fill the state's projected demand for electricity during the coming decade.

The ongoing retirements of nuclear capacity will significantly reduce the baseload capacity in Southern California. Concurrently, the most concentrated phase-out of gas-fired generation is occurring in the Los Angeles region.[25] To maintain system reliability, replacement capacity must be capable of providing essential reliability services to aid operators in managing growing net-load ramps caused by intermittent wind and solar. Transmission additions or reinforcements can further support the deliverability of resources across the system.[26] Of the 19 identified OTC plants (totaling 20,600 MW), more than half (10,400 MW) have been taken out of service since 2010. As shown in Figure 4, seven of the remaining plants are located near load

Figure 4: Southern California Generation Impacted by the Once-Through Cooling Phase-out Policy



23 Once-through cooling (OTC) technology causes adverse environmental impact by pulling large numbers of fish and shellfish or their eggs into a power plant's cooling system. Organisms may be killed or injured by heat, physical stress, or by chemicals used to clean the cooling system. Larger organisms may be killed or injured when they are trapped against screens at the front of an intake structure.

24 LaFleur, Cheryl A., What's Ailing California's Electric System?, Columbia University Earth Institute, September 2, 2020, https://blogs.ei.columbia.edu/2020/09/02/whats-ailing-californias-electric-system/.

25 The Los Angeles Department of Water and Power (LADWP) plans to retire three natural gas-fired power plants (1,211 MW) by 2025. EFI California Energy Study Outlines Ambitious Agenda to Maintain Global Leadership, p. 39.

26 "Deliverability" refers to a generator's ability to deliver its energy to load during different system conditions, including expected congestion caused by other generators' output, https://www.caiso.com/Documents/Jan2-2020-TariffAmendment-ImplementDeliverabilityAssessmentMethodologyEnhancements-ER20-732.pdf.

centers (Los Angeles and San Diego) providing reactive power, voltage support, inertia, and other essential reliability services to those areas. We expand on the importance of maintaining essential reliability services in the next section.

After the August events, then-President and CEO of CAISO, Steve Berberich highlighted the CAISO's requests to address projected capacity shortfalls needed to maintain established levels of resource adequacy.[27] The joint root cause analysis further recognized the need to ". . . address electric sector reliability and resiliency considering evolving policy goals of the state."[28] One proposed approach involves more cautious planning approaches for capacity retirements. In recognition of the recent capacity shortages highlighted by the August events, regulators at California's State Water Board extended OTC compliance deadlines and corresponding scheduled retirements of four power plants.[29] The continued availability of this generation will help maintain system reliability through 2023, as appropriate replacement capacity is identified and brought online.

The CPUC has also taken steps to address the concern regarding ongoing capacity shortages, indicating that "at least 3,300 MW of incremental system resource adequacy capacity and renewable integration resources would be needed by summer 2021."[30] The CPUC has contracted for 2,906 MW of Net Qualifying Capacity, scheduled to be online by August 1 of 2021, consisting primarily of intermittent resources and new storage technologies (**Table 2**).[31] Wind and solar resources have lower capacity factors and provide less consistent output compared to fully

Table 2: New Resources Expected – Sum of Net Qualifying Capacity (MW) by Load Serving Entity (LSE) and Technology Type

Sum of Net Qualifying Capacity (NQC), September NQC Megawatts (MW)					
	Online by 8/1/2021	Online by 8/1/2022	Online by 8/1/2023	Online post 8/1/2023	Grand Total
Contracted NQC MW	**2,388**	**840**	**481**	**267**	**3,977**
Investor-Owned Utility (IOUs)	*1,769*	*548*	*33*	*10*	**2,360**
Energy Storage	1,221	548	25	10	**1,804**
Solar plus Storage	494				**494**
Solar	38		8		**47**
Wind	16				**16**
Community Choice Aggregators (CCAs)	*584*	*274*	*427*	*257*	***1,543***
Solar plus Storage	152	81	269	257	**759**
Energy Storage	240	113	80		**433**
Solar	85	58	78		**221**
Wind	96	9			**105**
Geothermal		14			**14**
Small Hydro	12				**12**
Electric Service Providers (ESPs)	*35*	*18*	*21*		***74***
Solar	35	3	6		**43**
Solar plus Storage			15		**15**
Wind		15			**15**
Confidential or Uncontracted NQC MW	**518**	**156**	**693**		**1,368**
Grand Total NQC MW	**2,906**	**996**	**1,175**	**267**	**5,345**

27 August 17 briefing: "We told the CPUC 4,700 MW was needed through 2022 and that the gap started in 2020…Despite all that, only 3,300 MW was authorized for procurement, but that's not starting [until] 2021." Additionally, Berberich emphasized "…the situation we are in could have been avoided…For many years we have pointed out to the procurement authorizing authorities that there was inadequate power available."

28 CAISO/CPUC/CEC Final Root Cause Analysis. (p.75).

29 The State Water Resources Control Board amendment extends OTC compliance or phase-out dates at four fossil fuel power plants as follows: Compliance dates for Alamitos Units 3, 4, and 5 (1,165 MW), Huntington Beach Unit 2 (225 MW), and Ormond Beach Units 1 and 2 (1,516 MW) extended until December 31, 2023; the compliance date for Redondo Beach Units 5, 6, and 8 (850 MW) extended until December 31, 2021.

30 CPUC Rulemaking 20-11-003: Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. (p.10)

31 CPUC Status of New Resources Expected, as of December 2020 (See slide 7).

dispatchable resources, especially during peak demand periods, as demonstrated during the August events.[32] Battery storage technology accounts for a small portion of the resource mix, with the CAISO currently operating 216 MW of installed capacity.

Battery Storage as Replacement Capacity Faces Remaining Operational and Market Hurdles

Relying primarily on battery storage additions to address near-term supply shortages poses reliability risks for several reasons. First, while the CAISO has demonstrated the ability to incorporate new technologies, operators still have limited experience with dispatching batteries on the system. Operators must contend with a learning curve associated with the deployment of a novel technology to develop an understanding of the behavioral characteristics and potential challenges associated with large-scale battery storage. Second, the CAISO has identified that the performance and effectiveness of battery storage systems are highly dependent on their location. Battery systems located near load centers can face challenges in accessing available transmission to ensure they are able to be charged and available when called upon.[33] Alternatively, batteries located long distances from load centers may face transmission congestion when attempting to inject power where needed. Related market performance issues are also still in development. A CAISO stakeholder initiative is underway to determine appropriate locational price signals to promote battery charging and availability windows that align with system needs.

Finally, it is important to recognize that even the most advanced batteries can provide continuous, stable energy output for limited durations (approximately four hours).[34] Extreme heat waves can last for days. CAISO's Steve Berberich has suggested that as much as 15,000 MW of fast-acting batteries (of different duration levels and various technologies) would be needed for California to achieve 100 percent renewables by 2045. Ongoing measures by the CAISO and the CPUC to monitor the impact of additional battery storage will help ensure that this technology can be reliably added to California's system to help offset the loss of dispatchable generation.

Reliance on Imports from Neighboring States

The transformation of California's system towards 100 percent carbon-free resources has also increased dependence on imported power from neighboring states. On average, the state relies on imported power to serve approximately a quarter of its annual electricity demand. However, maximum net imports during high-load conditions actually declined from 11,147 MW in 2017 to 8,792 MW in 2019, despite the ongoing expansion of the Western Energy Imbalance Market (EIM).[35] This trend indicates that the availability of imports needed for high load periods could be at risk during a time when CAISO may be most dependent on them.[36]

While the EIM has helped to promote coordinated resource sharing by allowing participants to access CAISO's real-time market, notable benefits won't be recognized until participants can also bid in the

32 According to the CAISO/CPUC/CEC Final Root Cause Analysis, "…with today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability…" (p.4). Resource performance will be further discussed in the next section.

33 Transmission congestion can occur in load centers that make it difficult for batteries to charge during certain periods, since lines are already loaded to serve demand. Congestion can also make it difficult for batteries to inject power in some areas of the system.

34 Whereas existing storage technology can provide longer durations, the four-hour output requirement is a function of the RA rules. Specifically, the rules only require that a storage facility produce at least four hours of output to be classified as RA.

35 The EIM participants across the Western Interconnection can bid into the CAISO's real-time market to buy and sell power close to the time electricity is consumed. It offers system operators real-time visibility across neighboring grids. The ability to share a larger pool of resources can support resource adequacy needs by increasing balancing capabilities and reducing costs. "High-load conditions" are described by the CAISO as load that is "equal to or greater than 43,000 MW," CAISO/CPUC/CEC Final Root Cause Analysis, p. 4.

36 CAISO/CPUC/CEC Final Root Cause Analysis, p. 4.

day-ahead market. This would allow entities throughout the west to efficiently plan and commit resources based on price signals. The day-ahead commitment will also help the CAISO identify transfer capability, system congestion, and potential resource shortages with more time to secure additional generation. This ongoing stakeholder initiative to unlock such benefits has been under discussion for several years due to unresolved concerns of some EIM members.

Despite the potential progress toward an extended day-ahead market or a Western RTO, the limitations of the existing transmission infrastructure are also a concern. During the August events, transmission paths across both the California-Oregon Intertie and Nevada-Oregon Border were heavily congested, as "…transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint."[37]

Importing additional power into California will likely require transmission upgrades or additions, assuming that neighboring states are willing to offer these imports in the future. Entities across the west could begin to withhold exporting power to meet decarbonization policies in their own state. For example, Washington State's RPS of 100 percent renewables by 2045 may limit hydro exports to California. Similarly, plant retirements in Arizona, Nevada, and New Mexico may further diminish the CAISO's current access to out of state resources.

The importance of reliance on imports from neighboring states necessitates continued collaboration to better understand how individual state policy goals will impact transfer capability. In the northeast, the Integrated Clean Capacity Market (ICCM) puts individual state energy policies at the center of a revised resource adequacy market, while modernizing existing resource adequacy constructs throughout the PJM Interconnection. Specifically, the ICCM promotes a flexible market framework to accommodate states at varying levels of progress toward a decarbonized electric system so that the energy goals of some states can be supported without imposing any costs on other states with differing policy priorities.

In the near-term, the CAISO may also consider modifying the assumptions for projected imports in their seasonal assessments, which currently assume the inclusion of non-RA imports, despite the risk that this energy may not be available during extreme weather events throughout the region. Future projections of import availability could also include scenarios that examine increased limitations due to potential transmission constraints and/or EIM market rules that impose transfer limits (e.g., flexible ramping sufficiency test).[38]

Limitations of Demand Response

The preliminary root cause analysis partially addresses the issue of procuring additional resources through a recommendation that the CPUC and CEC collaborate "to expedite the regulatory and procurement processes to develop additional resources that can be online by 2021. This will most likely focus on resources such as demand response and flexibility. . . "[39] In November 2020, the CPUC opened a proceeding to address reliability needs for the 2021 summer. Three of the four CPUC proposals supported demand-side solutions.[40]

Demand response and other demand-side management programs have traditionally been used to reduce peak capacity investment needs by reducing electricity consumption during emergency events. However, demand response programs vary significantly in how they are controlled and dispatched by the system operator. Demand response performance is also a concern, as well as limitations on the number of times a program participant can be called upon to respond per season or year. In evaluating

37 Ibid, p. 48.

38 CAISO/CPUC/CEC Final Root Cause Analysis. "On August 14 and 15, the CAISO failed for less than two hours on each day and a cap was imposed on the transfer limit into the CAISO." See B.3.4 Energy Imbalance Market, pp. 130-131.

39 CAISO/CPUC/CEC Preliminary Root Cause Analysis, Preliminary Recommendations ES.5, p. 15.

40 CPUC Press Release, "CPUC Acts to Establish Policies and Procedures for Ensuring Grid Reliability during Extreme Weather Events," p. 1.

these proposals, it will be important to recognize the flexibility limitations associated with demand response, particularly in the inland portion of the state, where there is less tolerance for cutting air conditioning or temporarily suspending the operation of agricultural pumping stations during the summer months.[41] For this reason, demand response programs need to complement, not substitute for "iron in the ground" capacity.

Supplemental Reliability Procedures

Despite the ongoing system retirements described above, the system operator holds two important backstops to address unresolved resource adequacy deficiencies and/or meet specified reliability needs. The first backstop, the capacity procurement mechanism (CPM), provides an economic incentive to keep generators online. The CAISO tariff provides two compensation options. The CPM resource can either receive compensation based on its capacity bid price up to the CPM soft offer cap (set at $6.31/kw-month),[42] or the CPM resource can offer capacity at a cost above the soft offer cap. Offering capacity above the cap requires the provider to file a justification for the higher price with the FERC. Both options allow the CPM resource to retain all future revenues earned in the CAISO markets.[43] The CPM provides a useful tool for incenting retiring resources to remain online, although the CAISO may need to revisit the soft offer cap in 2021.[44] Future revisions to the program will likely be informed by the August events, including the impacts of 1,900 MW of dispatchable generation taken out of service between October 2019 and January 2020.[45]

The second reliability backstop allows the CAISO to designate certain power plants as Reliability Must-Run (RMR).[46] This delays any scheduled retirements or recalls mothballed units when needed to meet the established reliability criteria. Prior to the summer of 2020, the CAISO designated three natural gas units (totaling approximately 125 MW) to remain available for the 2020 summer.[47] Even with the extended availability of these RMR units, system operators did not have enough controllable resources to serve load during the August supply shortages.

While these backstop mechanisms are effective, regulators might also wish to examine policies that further promote the mothballing of certain plants. Similar to the RMR approach, this would involve collaborating with the CAISO to identify units that would remain idle, but not decommissioned, to support compliance with environmental requirements, but available to address future capacity shortages and local resources adequacy concerns. Similar approaches have been introduced in Texas, where NRG Energy restarted a 385 MW natural gas-fired combined-cycle plant that had been mothballed since 2016, for the 2020 summer season, partly to address tight supply conditions in ERCOT. Germany, a country with decarbonization goals similar to California's, used a similar approach to return approximately 1.4 gigawatts of mothballed

41 The CPUC, CEC, and the CAISO assign derates to DR programs based upon the results of DR load impact studies and program dispatch requirements (e.g., price, demand, location, duration).

42 This cap is based on the fixed operations and maintenance costs, ad valorem taxes, and insurance costs of a reference unit, plus a 20 percent adder to that total cost. See FERC's May 29, 2020, Order Accepting CAISO Tariff Revisions.

43 A 2019 stakeholder initiative to increase the soft offer cap was rejected in mid-2020 when it was determined that the current soft offer cap was still relevant to the existing grid composition.

44 A higher offer cap may further incent additional generation, or incent existing generators to remain operational, instead of retiring.

45 Including: Alamitos units 1, 2, 6, 7 (844 MW); Redondo unit 7 (493 MW); Inland Empire Energy Center Unit 1 (340 MW); and Huntington Beach Unit 1 (225 MW).

46 Local Reliability Criteria are unique to the transmission systems of each of the Participating Transmission Owners. Local Reliability Criteria and related Local Capacity Requirements reflect CAISO, NERC, and Western Electricity Coordinating Council (WECC) Planning Standards, as well as WECC Operating Criteria (OC) Path Ratings and System Operating Limits (SOL).

47 These units included Greenleaf Unit 2 (47 MW), the E.F. Oxnard plant (48 MW), and Channel Islands Power plant (27 MW).

gas plants to service in 2020.[48] Introducing market mechanisms to keep certain capacity idle but operable could help California meet carbon emission reduction goals, while still maintaining enough standby capacity for periods when system reliability is threatened. Examples of this process include ERCOT's Operating Reserve Demand Curve, PJM's capacity markets, ISO-New England's competitive forward capacity auctions (used competitive forward capacity auctions, and other market structures for securing system supply to meet projected resource adequacy needs.

The next section examines ongoing efforts by the CPUC and the CAISO to enhance their infrastructure planning approaches. We also explore potential opportunities for regulators and operators to more accurately capture the changing reliability characteristics (and potential risks) associated with an increasingly variable system.

Addressing Resource Adequacy Needs through Enhanced Planning Metrics

The final root cause analysis recognized that "changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability [and] . . . additional work is needed to ensure that sufficient resources are available to serve load during the net peak period and other potential periods of system strain."[49]

In order to understand the additional work that is underway, it is important to identify the multiple participants that share responsibility for infrastructure planning in California. These entities and planning processes have remained largely intact since the late-1990s, with key responsibilities summarized in **Table 3.**[50]

California's infrastructure planning processes necessitate close collaboration with – and input from – both the CAISO and CEC. System-wide and local reliability requirements, as well as flexibility needs, are ultimately developed within the CPUC's resource adequacy (RA) program.[51] Established after the 2000-2001 California Energy Crisis, this program creates requirements for jurisdictional LSEs to maintain resource availability through contractual obligations. The planning reserve margin (PRM) is a critical element of the RA program and is used to

Table 3: Primary Entities Involved in California's Resource Planning Processes

CPUC	Jurisdictional LSEs	CAISO	CEC
Manages the state's Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP). This process is designed to ensure that the electric sector meets its GHG reduction targets while maintaining reliability (with a resource adequacy program) at the lowest possible cost. This process involves modeling the system topology and market dispatch results to determine the appropriate resource portfolio needed to meet policy goals.	Must submit individual IRPs (based on the parameters in the IRP-LTPP) for CPUC review and approval.	Develops an annual Transmission Planning Process used to identify needed transmission upgrades and inform the CPUC's IRP-LTPP process.	Develops long-term energy demand forecasts as part of their Integrated Energy Policy Report (IEPR). The CEC's IEPR demand forecasts are inputs into the CPUC's long-term resource planning process and the short-term annual resource adequacy process, used to establish RA procurement obligations for LSEs.

48 Germany met over 40 percent of the country's power consumption with renewables in 2019, exceeding the 2020 target of 35 percent one year ahead of time. The government is now taking aim at 65 percent by 2030, as stated in its Climate Action Programme 2030.

49 CAISO/CPUC/CEC Final Root Cause Analysis, p. 5.

50 A detailed process is available within the CPUC's Long-Term Procurement Plan History and Related Process Documentation. (See Process Diagram (v3.8). While the terminology has changed since the release of the v3.8, the CPUC has not released an updated diagram.

51 CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP).

establish monthly requirements to ensure LSEs procure sufficient resources for the CAISO to reliably operate the system. The PRM targets also inform the commission's procurement decisions.

Limitations of Existing Resource Adequacy Metrics

As discussed earlier, jurisdictional LSEs must procure enough capacity to serve the peak demand forecast, plus a 15 percent PRM.[52] To demonstrate this concept, we examine California's planning reserve margin leading up to the August 2020 events.[53] From a seasonal planning perspective, the CAISO system appeared to have had adequate planning reserves going into the summer of 2020. The CAISOs projected 46,903 MW of capacity to be available in August, with a 1-in-2 net peak load forecast of 40,370 MW. Using NERC's reserve margin method would have indicated that this was a healthy reserve margin of 17.1 percent, excluding the projected 1,339 MW of demand response capability:[54]

$$\textit{CAISO Reserve Margin} = \frac{\text{Peak Resources–Forecasted Load}}{\text{Forecasted Load}} = \frac{46{,}903–40{,}037}{40{,}037} = 17.1\%$$

The reserve margin metric provides a snapshot of system adequacy and reliability at the highest forecasted demand. It is based on the important assumption that system reliability will be maintained throughout all other hours of the analysis period (planning horizon). Based on traditional planning criteria, a 17.1 percent margin (well-above the 15 percent PRM target) indicated that the system had adequate planning reserves for the 2020 summer season. However, the current PRM target of 15 percent was established in 2004, based on "analysis of then-current market data and forecasts of how the market was expected to evolve due to anticipated increases in renewables, energy efficiency, demand response, and other factors."[55] A significant finding of the final root cause analysis of the August events was that "resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging."[56]

California's PRM targets are based on Loss of Load Expectation (LOLE) modeling, designed to measure the reliability of an electric system, based on assumptions that incorporate a variety of conditions.[57] The PRM targets are ultimately dependent on the level of system reliability that the CPUC determines to be acceptable for the state. Currently, PRM targets are developed based on an annual LOLE target ranging from 0.095 to 0.105. This roughly translates to 1 loss of load event over a 10-year period. The CAISO's current LOLE assumptions combine multiple loss-of-load events occurring within one day into a single event (for purposes of counting events toward a reliability targets).[58] Accordingly, the analysis fails to capture a series of smaller events that could, in aggregate, impact system reliability.

Annual LOLE Target ≈ .01 → **PRM Target = 15%**

The LOLE analysis and the more commonly referenced reserve margin have both been heavily relied-upon by the industry for decades. Although useful and informative, these metrics must be examined in the proper

52 Like RA, IRP modeling is also based on the CEC's adopted 1-in-2 demand forecast plus a 15 percent PRM.

53 This example is a simplistic example examining the entire CAISO system. PRM requirements apply to individual of LSEs.

54 NERC (the North American Electric Reliability Corporation) defines the reserve margin as "…the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage" (p.35). Available demand response capability: CAISO 2020 Load and Resources Report, p. 5.

55 CPUC Rulemaking 19-11-009. Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations, pp. 18-19.

56 CAISO/CPUC/CEC Final Root Cause Analysis, pp. 1, 4, 38.

57 CPUC 2020 ELCC Methodology Working Group – Review of ELCC Study improvements, September 2019.

58 CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, p. 11.

context. Baseball enthusiasts don't rely on a single statistic to evaluate a player. They examine the player's on-base percentage (OPS), runs batted in (RBI), home runs (HR), stolen bases (SB), and dozens of other measures of performance in various aspects of the game. Measuring resource adequacy and system reliability should be no different – especially considering the significant changes on California's system during the past decade.

Increasingly, the LOLE and deterministic reserve margin approaches do not fully capture the level of resource adequacy for systems with large amounts of intermittent wind and solar. This is because the LOLE methodology was initially developed to measure the resource adequacy of systems with mostly controllable resources (e.g., large hydro, fossil-fired, and steam-powered generators) serving relatively predictable load patterns. Because these resources were controllable by system operators, planners made procurement decisions based largely on serving changing demand projections. Today, system operators also have reduced control over the supply side due to growing levels of utility-scale wind and solar that is variable in nature (i.e., operators cannot increase wind speed). On the demand side, load projections have also grown in complexity with the rapid deployment of distributed solar PV, which causes net-load to fluctuate based on cloud cover and other factors that are outside the system operator's control.

The CPUC took action to address these concerns prior to the 2020 summer supply shortages. Their June 2020 order initiated a review of the PRM target range, authorizing the commission's Energy Division to facilitate a working group to develop a set of assumptions for use in an LOLE study.[59] After the August events, the commission also opened an Emergency Reliability rulemaking to prioritize resource adequacy and resource procurement for the 2021 summer season. Several entities involved in California's resource planning efforts responded, including CAISO:

> The CAISO greatly appreciates the Commission's efforts to increase resource adequacy procurement to address summer 2021 reliability. Importantly, this incremental procurement should be tied to an increase in the planning reserve margin (PRM) to 20 percent for two critical reasons. First, increasing the PRM will ensure new resources do not substitute for existing capacity, thus leading to little or no net increase in the resource adequacy resource fleet. Second, increasing the PRM will allow the CAISO to use its capacity procurement mechanism (CPM) to backstop to the higher PRM.[60]

The CAISO subsequently revised its recommendation to 17.5 percent.

Increasing the PRM will improve short-term resource adequacy by requiring jurisdictional LSEs to secure additional reserve capacity.[61] The CPUC will ultimately need to examine the cost implications associated with a higher PRM requirement. The commission might also consider developing a PRM range with localized requirements to address areas facing insufficient resources or transmission constraints. Local reserve requirements designed to co-optimize the energy dispatch and reserve schedules could promote local market prices that reflect constraints based on reserve availability in a sub-area.[62]

The Case for Hourly Modeling

Because LOLE and reserve margin analyses are becoming a smaller part of the resource adequacy puzzle, the CPUC recognized that "a LOLE value of 0.1, which is a direct translation of the decades old industry "one day in ten years" standard, may warrant

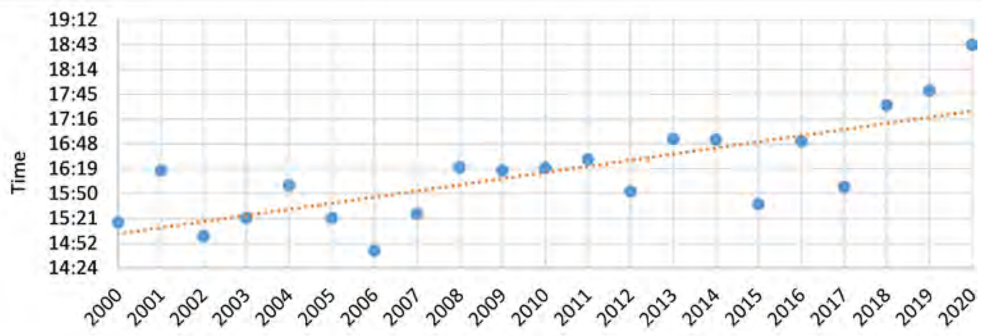
59 CPUC Decision 20-06-031. Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations, pp. 4, 21, 89.

60 CAISO Responses to Ruling Proposals and Questions. Response to question 5, p. 3.

61 Any change in the PRM would not apply to non-firm (independent power producers) capacity, as the CPUC will likely require all qualifying resources to provide qualifying RA.

62 William Hogan has suggested this approach for ERCOT, Harvard Electricity Policy Group: Priorities for the Evolution of an Energy-Only Electricity Market, 2017.

Figure 5: The Summer Peak Is Occurring Later in the Day



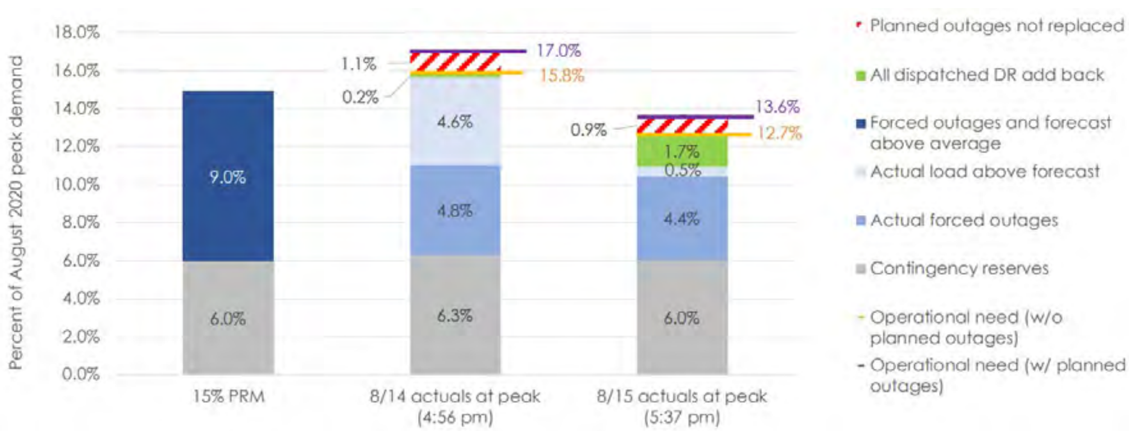
reconsideration in light of the sophisticated hourly models and advanced computing available now. . ."[63] Hourly modeling is necessary to address the changing load patterns, which have pushed seasonal system peaks further into the evening (**Figure 5**).[64]

Figure 6 demonstrates that the CAISO system was able to reliably serve load during the both peaks on August 14 and 15 and "although a PRM comparison is informative, the rotating outages both occurred after the peak hour..."[65] Hourly modeling can provide important insights for planners, allowing them to identify and prepare for potential reliability risks that occur outside of the peak period.

Resource Adequacy Accountability

The final root cause analysis recommended increasing RA requirements for LSEs to address extreme weather events.[66] However, as the number of CCAs and smaller electric service providers (ESPs) continues to increase, it's important to ensure these entities are providing sufficient levels of RA capacity. CCAs and ESPs currently provide 26 percent of the load formerly served by the state's three largest investor-owned

Figure 6: August 2020 PRM and Actual Operational Need during Peak



63 CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, p. 11.

64 Figure created by NRRI staff using the following CAISO data: CAISO historic peak loads; CAISO Key Statistics – August 2020.

65 CAISO/CPUC/CEC Final Root Cause Analysis, p. 43.

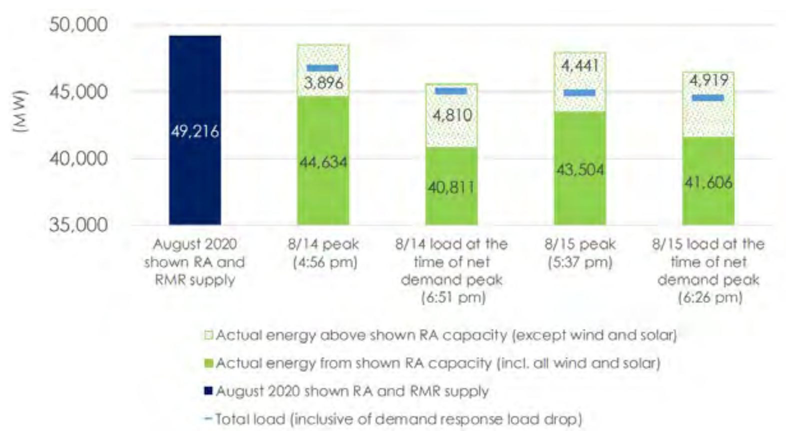
66 Ibid, pp. 91-92.

utilities (IOUs).[67] The CPUC has warned that this trend contributes to a state-wide planning process that is less consolidated and "creates a more complex paradigm for assessing both system reliability and whether California is on-track to achieve its climate goal. While CCAs and ESPs are subject to the same annual RPS Procurement Plan (RPS Plans) requirements as required by the IOUs, recent RPS Plans show that many CCAs and ESPs continue to provide minimal information in their RPS Plans… inadequate procurement planning may cause LSEs to not meet the state's requirements, resulting in negative implications for reliability of the power system."[68] As CCAs continue to expand their generation portfolios and customer base, these entities must be increasingly involved in planning activities and held accountable for meeting system reliability requirements.[69] The CPUC plans to address challenges during the coming years within their IRP-LTPP program by possibly introducing enforcement penalties for CCAs and ESPs that fail to provide them with adequate planning data.[70]

Developing More Robust Resource Adequacy Metrics

Recognizing these shortfalls, system planners across the country have made significant progress in improving resource adequacy metrics, moving away from deterministic approaches and toward a greater focus on stochastic and probabilistic methods. One of the recommendations of the final root cause analysis called on the CAISO to coordinate with the CPUC and other stakeholders to "refine the counting rules as they apply to hydro resources, demand response resources, renewable, use limited resources, and imports."[71] The analysis further indicated that the actual output of RA and reliability-must-run (RMR) capacity did not reflect their projected availability (**Figure 7**).[72,73]

Figure 7: August 2020 Shown RA and RMR Capacity vs. August 14 and 15 Actual Energy Production



The CPUC and CAISO will benefit by further examining these discrepancies and updating the underlying assumptions used in future RA and RMM projections. In terms of actual performance by resource type, the final root cause analysis further reported that the natural gas generation fleet collectively experienced between 1,704 MW to 2,371 MW of forced outages, more than any other resource.[74] These outages translate to between 4-6 percent of the natural gas generation fleet that was not already scheduled to be

67 CCAs allow for communities to join together to choose their electric provider and sources of electricity.

68 *CPUC 2019 RPS Annual Report to the Legislature,* p. 54.

69 According to the CPUC, "load allocated to CCAs in the year ahead process went from two percent of the peak in 2016 to 25 percent of the peak in 2019. Energy Division anticipates 'this trend towards disaggregation of load to continue…'" CPUC Rulemaking 17-09-020, p. 21.

70 Additional information on the CPUC gap analysis that addresses CCA RA shortfalls is available here: California Customer Choice Project - Choice Action Plan and Gap Analysis.

71 CAISO/CPUC/CEC Final Root Cause Analysis, p.72.

72 Ibid, p. 110.

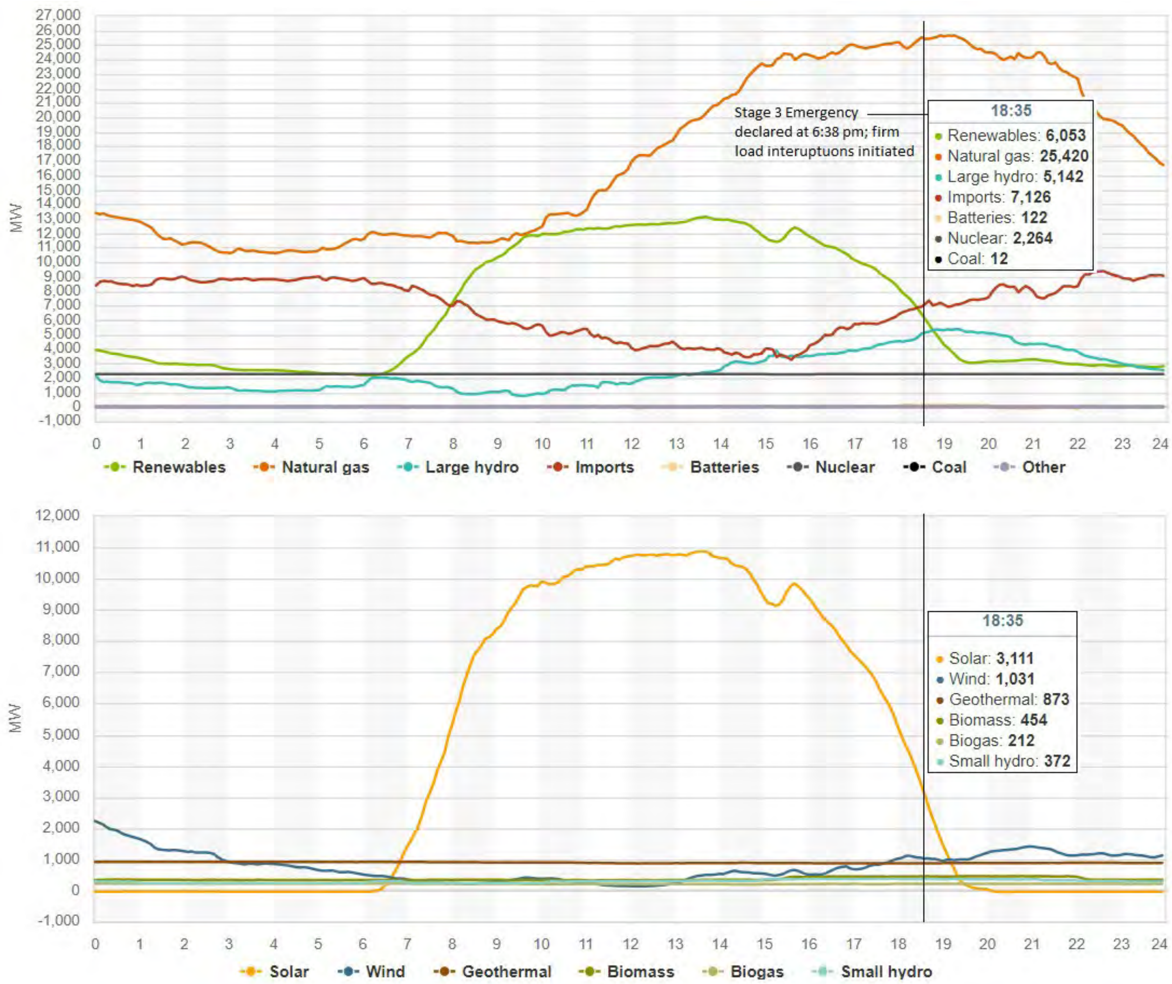
73 Assumes all wind and solar counts as RA supply; CAISO/CPUC/CEC Final Root Cause Analysis, p. 110.

74 CAISO/CPUC/CEC Final Root Cause Analysis, p.87. (Includes derates to individual units, as well as unit outages.)

out of service. The natural gas generation fleet served over half of the state's load when the Stage 3 Emergency was declared at 18:38 on August 14.[75] During the same period, actual output from 24,016 MW of installed renewable resources served 6,053 MW (14.3 percent) of load.[76] Renewable output (particularly solar) actually decreased by 1,064 MW during the next 15-minutes as net load continued to increase, finally peaking at 18:51. In contrast, output from dispatchable resources, including natural gas and in-state large hydro, increased by 321 MW during the same 15-minute period, serving 73.1 percent of net load during the peak. Although renewable resources performed as expected, their overall contribution during the peak period further highlights the performance attributes of each resource—especially during extreme weather events (**Figure 8**).

The CAISO has already begun using more sophisticated approaches for assessing resource adequacy with increased renewables, including the Unloaded

Figure 8: August 14, 2020 Total Supply Performance at 18:35 (Beginning of Stage 3 Emergency)



75 Assumes the California Energy Commissions 2019 Installed In-State Electric Generation Capacity (latest available), with a natural gas generation fleet totaling 40,382 MW. Natural gas performance at 18:50-18:55pm (5-minute market) was providing 25,539 to serve the net demand peak (42,237) at 18:51 p.m. on August 14. See the CAISO supply trend data for August 14, 2020. Demand data: CAISO/CPUC/CEC Final Root Cause Analysis, pp. 44-45.

76 CAISO Key Statistics – July 2020. See Installed renewable resources (as of 8/01/2020), p. 3.

Capacity Margin (UCM). This metric measures the amount of surplus resources or capacity that can respond within 20 minutes or less during the forecasted demand during a specified interval.[77] Similar to a reserve margin, the UCM metric is expressed as a percentage, but it is more comprehensive, because it captures multiple hours (beyond the peak period). The CAISO's 2020 Load and Resources Assessment demonstrated that the median UCM for all 2,928 summer hours (modeled within each of the 2,000 summer scenarios), was 41.3 percent.[78] Levels of UCM above the operating reserve requirement for any given hour (typically around 6 percent) indicate the amount of capacity projected to be available to address system contingencies (beyond the NERC operating reserve requirement). The Minimum Unloaded Capacity Margin (MUCM), the lowest UCM from each of the 2,000 scenarios modeled, is used to establish the probability of various events occurring. Continuing to enhance stochastic production simulation tools will enhance the CAISO's ability to assess the widest array of load, wind, and solar outages, as well as understand historic performance profiles. This tool can also provide planners with a distribution of potential outcomes and probabilities. The ongoing Resource Adequacy Enhancements initiative will depend on input from the CPUC and other stakeholders to determine the appropriate reliability criteria, as well as the quantity and attributes needed to address existing resource portfolio deficiencies.

NERC, the FERC-designated electric reliability organization (ERO) in the United States, has codified multiple reliability attributes provided by different resources. These essential reliability services (ERS) include frequency and voltage support, as well as ramping and balancing capability. The ERS capabilities and operating behaviors of conventional generators are well-documented, compared to those of relatively new wind and solar technologies. NERC states that "changes in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability, thereby raising issues that need to be further examined."[79] Measuring a system's level of ERS offers a more comprehensive approach to resource adequacy by examining other important reliability attributes. NERC indicates that overall system reliability can be maintained…

> as the resource mix evolves, provided that sufficient amounts of essential reliability services are available.[80] [NERC further emphasizes that]. . . merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to provide sufficient amounts of these [essential reliability] services and maintain system balance.[81]

Although wind and solar resources can provide certain types of ERS (e.g., synthetic inertia), there must also be adequate levels of frequency response, ramping capability, inertia, and reactive support for voltage control. Operators rely on these essential reliability services to operate the system under a variety of conditions, including extreme weather events that can cause generator outages and increase variability in wind and solar output.

Conclusion

The contributing factors leading to the August 2020 reliability events in California have been examined, and the lessons-learned from the events can be applied to other states that are introducing policies

77 CAISO, 2020 Load and Resources Assessment, p. 6.

78 Taking into account the unloaded capacity margin for all of 2,928 summer hours (June 1 through September 30) within each of the 2,000 summer scenarios. According to the 2020 Load and Resources Assessment: "The unloaded capacity refers to any portion of online generation capacity that is not serving load and offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. The unloaded capacity includes operating reserves the system procures. The Unloaded Capacity Margin (UCM) is the excess of the available resources, within 20 minutes or less, over the projected load expressed as a percentage on an hourly basis."

79 NERC Sufficiency Guidelines White Paper, December 2016, p. iv.

80 Ibid, p. vii.

81 Ibid, p. iv.

aimed at rapidly decarbonizing the grid, often leading to the addition of intermittent and behind-the-meter resources. These include:

- Systems with increasing amounts of intermittent resources (e.g., wind and solar) will require additional modeling and stochastic metrics that can provide a more complete measure of resource adequacy and help identify associated reliability risks.
- The continued development of advanced reliability metrics, including those that examine risks beyond the peak hour, can inform policy and regulatory decisions to promote the reliable transformation to a cleaner system.
- Existing planning processes and reliability constructs need to better identify the system impacts of retiring resources, examining the status of essential reliability services on the system, including ramping capability, frequency response, and inertia.
- Future projections of RA availability and ELCC values should be reviewed and modified to incorporate resource performance during the August events.[82]
- Regionalization can help promote reliability by efficiently pooling resources; however, increased coordination will be needed to recognize the impacts of transmission constraints and individual state policy goals.

These approaches can inform policy makers and state regulators charged with balancing the responsibilities of managing RPS compliance and resource adequacy requirements.

82 "Based on further analysis by the DMM, the actual production of all resources shown as RA or obligated under an RMR contract was sufficient during the peak but insufficient during the net demand peak period to meet all load, losses and spinning and non-spinning reserve obligations on August 14 and 15," CAISO/CPUC/CEC Final Root Cause Analysis, pp. 109-110.

About the Authors

Elliott J. Nethercutt is a Principal Researcher at NRRI. He has worked on market design enhancements at the California Independent System Operator (CAISO), developed reliability assessments at the North American Electric Reliability Corporation (NERC), and supported transmission siting efforts and smart grid funding programs at the U.S. Department of Energy. Elliott earned a bachelor's degree in economics from the University of Colorado and a master's degree in applied economics from the Johns Hopkins University.

Chris Devon is a Director of Market Intelligence at Customized Energy Solutions. He provides regulatory and market design policy coverage on the California Independent System Operator (CAISO) and wholesale electric markets in the West. He has also worked on resource adequacy and emerging technology policy enhancements at the California Independent System Operator (CAISO). Prior to his work in California, he advised the Michigan Public Service Commission (MPSC) on energy market design and resource adequacy policy matters. Chris earned a bachelor's degree in economics from Michigan State University.

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The National Regulatory Research Institute (NRRI) was established in 1976 as the research arm of the National Association of Regulatory Utility Commissioners (NARUC). NRRI provides research, training, and technical support to State Public Utility Commissions. NRRI and NARUC are co-located in Washington, DC.

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MARCH 2021

Regulatory Questions Engendered by the Texas Energy Crisis of 2021

Dr. Carl Pechman and Elliott J. Nethercutt

1. Introduction

The February extreme cold weather event in Texas resulted in significant electric outages across the Electric Reliability Council of Texas (ERCOT) system. The disruptions contributed to the loss of human life, with significant economic harms in the aftermath. Understanding the regulatory dynamics, markets, and economics that resulted in widespread power outages across the state will be instrumental for determining whether the price of power that resulted from the crisis warrants modification. Further, understanding the causes of the problem will facilitate redesigning market rules, regulations, and other protocols. It is important to note that the market design in Texas has evolved over many years and that the solutions to the issues raised by the crisis will require the cooperation of many stakeholders.

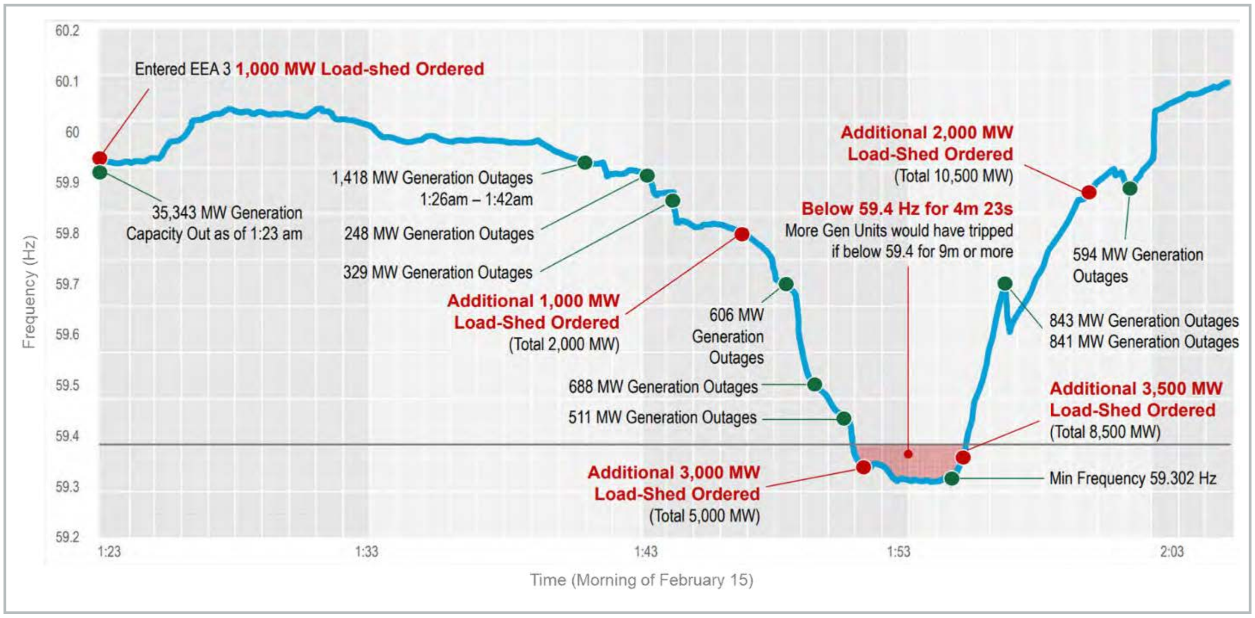
The purpose of this paper is to pose regulatory questions that will facilitate the understanding of the underlying regulatory actions and market behaviors that affected the likelihood of this catastrophic event. Although a thorough investigation and root cause analysis will be required to formulate complete answers, NRRI offers these perspectives and discussion about the role of the current regulatory regime and market design to further promote resource adequacy, resilience, and operating security for a system that has experienced an increasing number of extreme weather events during the past two decades. In presenting these questions, we explain the underlying rationale behind them. The questions elucidate a number of themes: 1) inherent market design flaws, 2) insufficient regulatory oversight, 3) market manipulation, and 4) the distinction between reliability and resilience in designing and managing the electric market.

2. Why Did ERCOT Nearly Black Out?

The cold snap began on February 12, 2021 and resources across the system started to fail over the following days, while loads remained high. At 7:06 p.m. (CST) on the 14th, ERCOT hit a winter peak of 69,222 MW. The system operated without incident through the record winter peak. By early on the 15th, system conditions deteriorated rapidly as an additional 20 GW of generation tripped offline (in addition to the 25 GW that were already out). ERCOT declared an Energy Emergency Alert (EEA-3)[1] at approximately 1:20 a.m. Subsequently, the system operator began efforts to maintain system stability through a series of load sheds. Despite coming within minutes of a cascading blackout, the system operator demonstrated what will likely be studied as a textbook example of managing a power system through severe operating conditions. **Figure 1** demonstrates these developments through a detailed timeline, showing how frequency dropped as prolonged extreme weather and sustained high demand resulted in increased generator outage rates. When frequency drops below established operating limits, generators have protection systems that automatically disconnect the unit from the grid to avoid equipment damage. It is important to recognize that demand-side actions (load curtailments that began at 1:45 a.m.) ultimately allowed the system to recover from dangerously low frequency and avoid an ERCOT-wide blackout.

1 An Energy Emergency Alert-3 (EEA-3) is declared when operating reserves cannot be maintained. See, *ERCOT's use of Energy Emergency Alerts*, http://www.ercot.com/content/wcm/lists/164134/EEA_OnePager_FINAL.PDF

Figure 1: System Frequency during the Initial Minutes of the February Load-Shedding Events[2]



3. Do Generators in ERCOT Have an Obligation to Perform?

No, generators in ERCOT do not have an obligation to perform. The ERCOT market is based on a Hayekian philosophy — that price provides all of the information necessary to ensure efficient availability, dispatch, maintenance, and investment in generation and generator performance.[3] This is an incentive-based system in which the prospect of profits for the sake of power results in optimal system generation investments. Accordingly, generators are only paid for the energy services they provide, incented by price signals, without an obligation to perform. This approach differs from some other organized electric markets,[4] which maintain reliability in part by having financial penalties for failure to serve when needed.

A linchpin of this incentive to perform in ERCOT is setting prices that capture the value of reliability to customers during periods of shortage. "The key connection is with the value of lost load (VoLL) and the probability that the load will be curtailed. Whenever there is involuntary load shed and the system has just the minimum amount of contingency operating reserves, then any incremental reserves would correspondingly reduce the load curtailment. Hence, the price of operating reserves should be set at the value of lost load."[5] For this mechanism to work, there must be "enough room to allow some generators to exercise a little market power and bid high enough to reflect the scarcity rent."[6] This is a delicate dance, balancing the behavior of generators and customer protection.

The Public Utility Commission of Texas's (Texas PUC) administratively approved system-wide price cap for ERCOT (based on an estimate of the VoLL) has tripled

2 ERCOT Presentation – Review of February 2021 Extreme Cold Weather Event. Slide 12, (Axis titles added by NRRI staff, (February 24, 2021), http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf

3 "Fundamentally, in a system in which the knowledge of the relevant facts is dispersed among many people, prices can act to coordinate the separate actions of different people in the same way as subjective values help the individual to coordinate the parts of his plan." See Hayek, F., 'The Use of Knowledge in Society," *American Economic Review* (1945): 519-530.

4 Organized energy market operators administer the transmission system independently of, and foster competition for electricity generation among, wholesale market participants, https://www.ferc.gov/industries-data/market-assessments/electric-power-markets

5 Hogan, W., *Electricity Scarcity Pricing Through Operating Reserves: An ERCOT Window of Opportunity* (November 1, 2012): 6, https://scholar.harvard.edu/whogan/files/hogan_ordc_110112r.pdf

6 Hogan, W, Texas Nodal Modal Market Design: Observations and Comments. Presented at ERCOT Energized Conference, Austin, TX (May 2, 2008), https://www.hks.harvard.edu/publications/texas-nodal-market-design-observation-and-comments

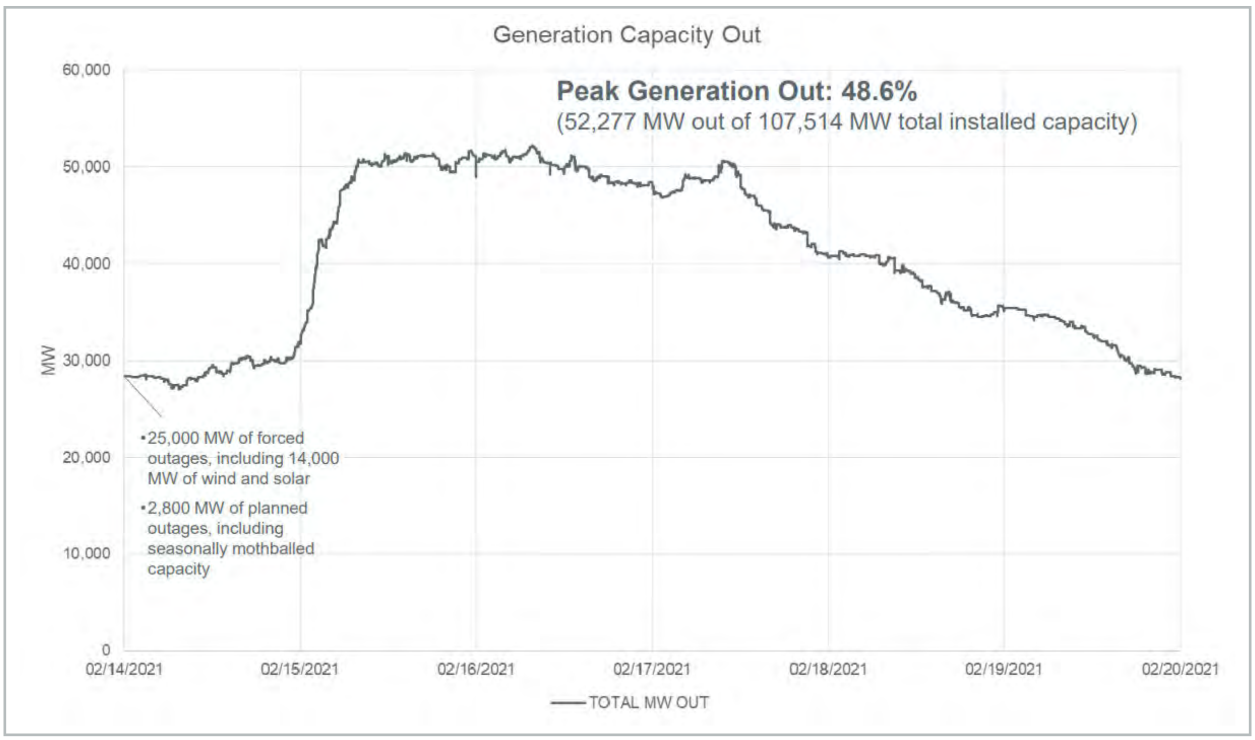
to $9,000/MWh between 2012 and 2015[7] and is incorporated into the automated market management software. This price cap is the highest in the nation. An empirical question is whether the increase in the market price cap has resulted in an improvement in generation performance, or investment in plant winterization.

4. How Did ERCOT and the Texas PUC Respond to System-wide Generator Performance Failure?

During the early stages of the event, generation of all types failed at an unprecedented rate, as demonstrated in **Figure 2**. Prior to shedding load, energy prices had reached or exceeded ERCOT's system-wide offer cap of $9,000/MWh, while prices are typically closer to $22/MWh.[8] As a result of the treatment of load curtailments by the ERCOT market algorithms, prices became very volatile, falling from scarcity pricing to as low as $1,200/MWh. As a result, natural gas-fired plants that were still online (26 GW failed during the event) were at risk of selling electricity at a loss, assuming that they could secure fuel. The result was an incentive that the market was not designed to properly address, highlighting the need to reevaluate scarcity pricing and the important interplay between the natural gas delivery interruptions and impacts to energy prices.[9]

ERCOT alerted the Texas PUC to this apparent anomaly, as the price of natural gas was increasing by

Figure 2: ERCOT Generator Failure during the Freeze[9]



7 The Texas PUC approved raising the energy price cap (high system wide offer cap) from $3,000/MWh to $4,500/MWh in August 2012 and subsequently approved gradually increasing the cap to $5,000 MWh in 2013, $7,000 MWh in 2014, and $9,000 MWh in 2015, http://www.beg.utexas.edu/files/cee/legacy/Gulen%26Soni_Impacts_of_Raising_Price_Caps_ERCOT.pdf. The Texas PUC determined the value of lost load as $9,000; see London Economics International LLC, "Estimating the Value of Lost Load Briefing"(June 17, 2013), http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf This offer cap was subsequently reviewed within a 2014 Brattle report, "Estimating the Economically Optimal Reserve Margin in ERCOT." http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf

8 Gold, R., "Texas Power Market Is Short $2.1 Billion in Payments After Freeze," *Wall Street Journal*, February 26, 2021. https://www.wsj.com/articles/texas-power-market-is-short-2-1-billion-in-payments-after-freeze-11614386958

9 ERCOT Presentation – Review of February 2021 Extreme Cold Weather Event. Slide 13 (February 24, 2021), http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf

as much as 10,000 percent.[10] In response to the events of February 15, the Commission held an emergency six-minute meeting and issued an order granting ERCOT the authority to modify market outcomes that were "inconsistent with the fundamental [market] design."[11] The commission justified its decision by stating that "the market price for the energy needed to serve that load should also be at its highest."[12] This action could be seen as an effort to increase market confidence. However, the Commission's order resulted in higher energy prices during a time when customer demand was especially inelastic. The intention of ERCOT and the Texas PUC to incent generators to operate during the crisis was laudable. However, the extent to which these efforts were successful can be evaluated empirically by examining whether the availability of generating units on the system increased. If generators did not respond to the higher prices, then the increased revenues associated with these higher prices are a wealth transfer. The question is whether or not the scarcity pricing regime designed to support resource adequacy is an effective market mechanism for incenting performance during the cold snap. Other market design questions include whether additional market mechanisms, more than prevailing and prospective energy prices, are required to ensure that generators are available to maintain resilience, and what those mechanisms might be. A prudent regulatory decision would have required the Commission to weigh all these factors during that meeting.

ERCOT's request and the Commission's response are highly unusual and raise issues about whether market design processes were prepared for the potential outcomes resulting from prolonged system stress.

Although this freeze was especially extreme, it was not unprecedented — with a more severe storm of longer duration occurring in 1989,[13] and another severe and costly freeze in 2011. Other markets typically do not require real-time market changes to be authorized by regulators during a crisis, relying instead on market protocols that allow the system operator to take "out-of-market" actions to prioritize the stability of the system over potential price signals.[14]

The Commission's emergency order that enabled generators to bid $9,000/MWh on its own motion, demonstrates that maintaining scarcity prices was its highest priority. It is important to know why the market software produced the prices that it did after entering into EEA-3. Did the software perform as specified? And was the intent of ERCOT's market design to allow market prices to remain at the $9,000/MWh for as long as supply shortages persist, without regard for generator performance or the magnitude of profits earned? If so, where, when, and how was that considered? It is clear that this foreseeable event was not contemplated in the market design, raising the issue of whether the Commission's order was supported by adequate evidence for these circumstances. It is in the customer's interest for the Commission to reevaluate its order based on complete information about whether the market design actually supported its decision and to determine if the price increases allowed by the order should be readjusted. **Figure 3** demonstrates how the Commission's emergency order to address the dramatic price reduction after the load-shed events resulted in energy prices remaining near (and in some cases above[15]) the system-wide offer cap during most of the event.[16]

10 Paradis, C., "Texas Natural Gas Prices Attract Federal Investigation After 10,000% Spike," *International Business Times,* February 23, 2021, https://www.ibtimes.com/texas-natural-gas-prices-attract-federal-investigation-after-10000-spike-3150792

11 Gold, R., and Blunt, K., "Amid Blackouts, Texas Scrapped Its Power Market and Raised Prices. It Didn't Work." *The Wall Street Journal*, February 25, 2021, https://www.wsj.com/articles/texas-power-regulators-decision-to-raise-prices-in-freeze-generates-criticism-11614268158, Texas PUC Project No. 51617, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

12 Texas PUC Project No. 51617, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

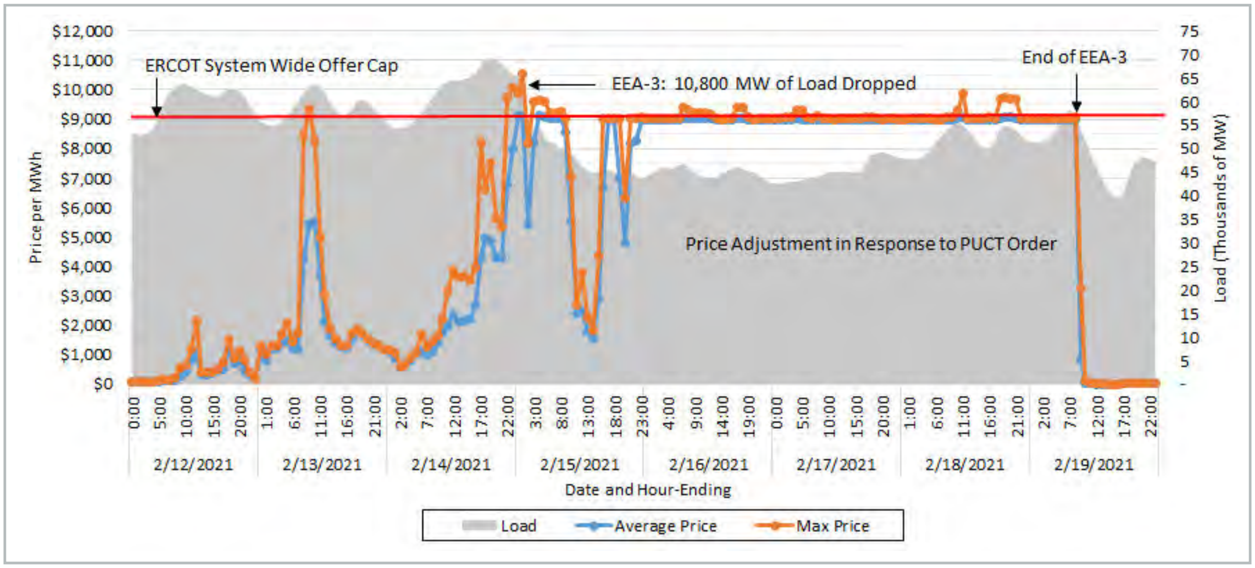
13 NERC whitepaper, *ERCOT Emergency Operations*, December 21-23, 1989, http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/ERCOT%20Emergency%20Operation%201989.pdf

14 For example, the CAISO can perform out-of-market dispatch. These actions are recorded in the market as manual dispatches. See Market Disruption – EIM (January 6, 2021): 12, https://www.caiso.com/Documents/2720.pdf

15 While offers are limited by the energy price cap of $9,000/MWh, the market software can drive prices higher due to congestion and other system constraints. "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints," http://www.ercot.com/services/comm/mkt_notices/archives/4645

16 Texas PUC Project No. 51617, Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

Figure 3: Electricity Prices (8 ERCOT Load Zones) and Load during the Cold Weather Event[17]



5. Why is it Important to Investigate Whether Market Power was Exercised during the Freeze?

The Texas wholesale electric market, unlike markets regulated by the Federal Energy Regulatory Commission (FERC), does not require prices to be just and reasonable, thereby limiting the regulatory tools for adjusting prices. Prices in ERCOT are presumed to produce optimal results. The focus of the market design has been to provide generators with adequate revenues, resulting in reduced attention to ratepayer protections. The protection afforded to ratepayers for wholesale market transactions in Texas lies within the Commission's authority to address market power.[18] These remedies include both penalties and the ability to force disgorgement of excess revenues.

The potential exercise of market power goes beyond generator bidding behavior to market fundamentals. There are at least two ways in which the Texas market prices can be manipulated to earn extraordinary profits: passive withholding and gas price manipulation. The FERC has already announced its intent to examine "wholesale natural gas and electricity market activity during last week's extreme cold weather to determine if any market participants engaged in market manipulation or other violations."[19]

a. Did passive withholding exacerbate the crisis?

Withholding production is a recognized form of market power abuse in the electric industry. *Passive withholding* is defined here as the practice of selectively configuring part of a generation portfolio explicitly to exploit market design or system vulnerabilities.

Active withholding occurrs when a company that owns two or more generators in a particular market withholds the supply of one of those generators to increase the overall market price to compensate for the lost revenues of the withheld unit at normal prices. One way to withhold generation is to take a generator offline during needle peaks to perform discretionary inspections, such as deciding to shut down a generator during a time of a critical system conditions to have divers search a unit's cooling

17 Chart developed by NRRI staff using ERCOT's Historical RTM and Settlement Point Prices (SPPs) data for each ERCOT Load Zone). Maximum and average prices are for all intervals and all load zones for each hour, starting at 00:00, February 10, 2021, through 24:00, February 19, 2021. Load zones include: AEN; CPS; HOUSTON; LCRA; NORTH; RAYBN; SOUTH; WEST. http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13061&reportTitle=Historical%20RTM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey). (Load zone map available here: http://www.ercot.com/news/mediakit/maps

18 According to Chapter 39, Section 39.157 of the Texas Utilities Code: "On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power…," http://statutes.capitol.texas.gov/StatutesByDate.aspx?code=UT&level=SE&value=39.157&date=3/18/2015

19 FERC News Release: FERC to Examine Potential Wrongdoing in Markets During Recent Cold Snap (February 22, 2021), http://www.ferc.gov/news-events/news/ferc-examine-potential-wrongdoing-markets-during-recent-cold-snap

water intakes for zebra mussels. This is a reasonable thing to do under normal circumstances, but is an exercise of market power when the system is experiencing such a high level of stress.

Passive withholding recognizes that during system emergencies, energy prices will be higher, potentially approaching the offer cap.[20] As a consequence, generator owners may have an incentive to make weatherization enhancements to only a portion of their fleet, enabling those units to operate through extreme temperatures and access higher revenues that would more than compensate for generation units that are forced out of service. Sophisticated generation and trading companies have game theorists who evaluate alternative ways in which their firms can gain profits. In retrospect, a firm that selectively winterized its generators would have made significant profits. The question is whether generators employed a practice of strategically preparing only a portion of its generating fleet for extreme cold weather events, because it would elevate prices and produce added profits.

In the event that a hypothetical entity owning multiple power plants had strategically winterized only a portion of their generation portfolio, thereby contributing to a system-wide shortage, there would be a potential for significant profits to the generators that remained online. Whether or not passive withholding has occurred can be determined by examining the underlying analysis of winterization investments by plant owners, fuel procurement practices, and effected availability for providers with larger generator portfolios.

It will be especially important for regulators to understand the specific actions generator owners and other entities previously undertook to invest in plant winterization or not, especially following the February 2011 cold weather events that resulted in a controlled load shed of 4,000 MW, affecting some 3.2 million customers. According to the joint North American Electric Reliability Corporation (NERC) and FERC report issued after that event, "Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm. Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed."[21] Plant winterization is not mandatory in Texas.[22] In response to the state's energy crisis, the Texas Legislature and NERC are exploring potential mandatory weatherization standards.[23] Although there is an increasing recognition of the need to regulate winterization practices (including ensuring natural gas supply), the state also needs to investigate the underlying investment behavior of ERCOT's generators to determine whether passive withholding occurred.

b. Did natural gas price manipulation drive the peaker net margin?

The February 15 Texas PUC order demonstrates a clear nexus between natural gas prices and allowable prices in the ERCOT market. High natural gas prices provided the Commission with the regulatory rationale for suspending the low system-wide offer cap (LCAP). The impact of this suspension is demonstrated by **Figure 4**, which tracks ERCOT's estimates of the peaker net margin (PNM). ERCOT established the PNM metric[24] to track the net revenue that a hypothetical natural gas generator would earn in a single year, given the relationship between real-time

20 "Maintaining a price cap equal to the value of lost load (VoLL) during outages and prices reflective of marginal system costs in other types of scarcity events will provide efficient signals necessary for market-based responses from generators and demand response." – "Estimating the Economically Optimal Reserve Margin in ERCOT," prepared by Brattle for the Texas PUC, p. xi, http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf

21 FERC/NERC Staff, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,* (August 2011): 10, https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf

22 Travis, A., "Winter preparedness not mandatory at Texas power plants and generators, despite 2011 report" (February 17, 2021), https://www.kxan.com/investigations/winter-preparedness-not-mandatory-at-texas-power-plants-and-generators-despite-2011-report/

23 NERC Standard Project 2019-06 Cold Weather, https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx, Reuters, "Texas Governor Asks Legislature to Mandate Winterization of Generator," https://www.usnews.com/news/top-news/articles/2021-02-18/texas-governor-asks-legislature-to-mandate-winterization-of-generators

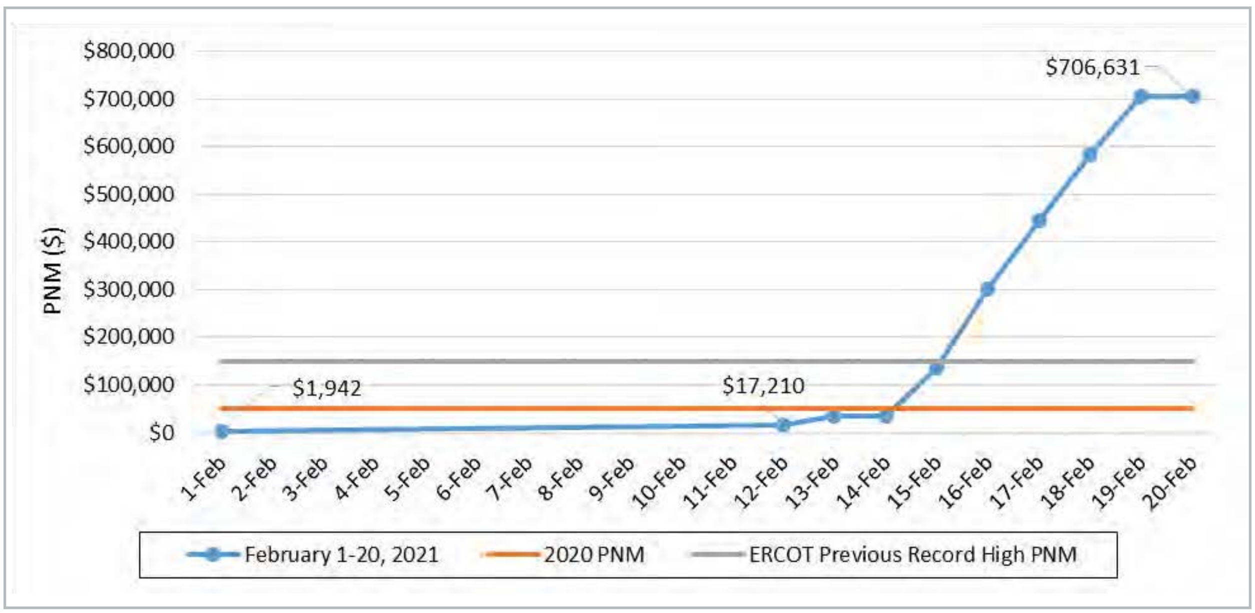
24 See Texas Commission rule 16 TAC § 25.505(g)(6), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

power prices and natural gas spot market prices. As a consequence, it is important to understand the price formulation that led to a 10,000 percent increase in natural gas prices to determine whether or not market power was exercised.

During the February events, ERCOT informed the Commission that generator revenues were approaching the PNM threshold ($315,000/MW-year)[25] or three times the annual cost of a new gas-fired generator. According to the rule, once the PNM threshold is achieved, the system-wide offer cap is set at the LCAP, which is "the greater of either (i) $2,000 per MWh and $2,000 per MW per hour; or (ii) 50 times the natural gas price index value determined by ERCOT (expressed in dollars per MWh and dollars per MW per hour)."[26] The price of natural gas during the event increased significantly, with the Houston Ship Channel spot prices approaching $400/MMBtu. This was a tremendous increase compared to the period both before the freeze and in prior years, when gas prices ranged between $2-3/MMBtu.[27] In response to this price increase, the Commission removed the LCAP of $2,000/MWh "to ensure appropriate energy prices to both consumers and generators"[28] and instead continued to enforce the high system-wide offer cap (HCAP) of $9,000/MWh. As shown in **Figure 4**, the PNM levels during the February event dwarfed prior records, demonstrating a generator's ability to garner extraordinary profits.[29]

The Commission's suspension of the LCAP resulted in some plant owners being exposed to extraordinarily high natural gas prices throughout the supply shortages, as frozen wellheads, pumps, and pipes reduced supply. ERCOT is the only market in the

Figure 4: Peaker Net Margin (PNM) February 1-20, 2021



25 Watson, M. "Texas regulators keep prices near $9,000/MWh cap during rotating outages," *S&P Global*, February 16, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/021621-texas-regulators-keep-prices-near-9000mwh-cap-during-rotating-outages

26 See Texas Commission rule 16 TAC § 25.505(g)(6), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

27 Matthews, C., Eaton, C., "U.S. Natural Gas Shortage Hampers Blackout Recovery," https://www.wsj.com/articles/u-s-natural-gas-shortage-hampers-blackout-recovery-11613671759

28 Texas PUC Project No. 51617, Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

29 Watson, M., "Texas regulators keep prices near $9,000/MWh cap during rotating outages," *S&P Global*, February 16, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/021621-texas-regulators-keep-prices-near-9000mwh-cap-during-rotating-outages

United States whose market rules (the LCAP) tie energy prices directly to a natural gas price index.[30] Without the HCAP, gas prices would have driven energy prices to as high as $17,957/MWh.[31] Whether or not these natural gas prices may have been inflated due to an exercise of market power also warrants investigation by FERC and the appropriate Texas authorities. Whether sustained scarcity pricing was effective in bringing generators back online will be another important question to resolve in the aftermath of these events; for this reason, the Commission may decide either on its own or by direction from the legislature to also examine other market-design enhancements.

6. Was Enabling a Price of $9,000/MWh an Exercise of Structural Market Power?

It is necessary to evaluate whether there were forms of market power that have been experienced here that have not generally been contemplated in the literature. At issue is whether the market structure institutionalized the exercise of market power. The Texas PUC had an especially Hayekian marketcentric response to the emergency. As prices dropped with the curtailment of load, the Commission determined that "(e)nergy prices should reflect scarcity of the supply."[32] There is a more critical question as to whether the Commission order, which indicated prices should reflect scarcity conditions, led to unanticipated price regime both in terms of length and magnitude. The duration during which the price remained at the system-wide cap is unprecedented, with ERCOT reaching these high prices only on one other occasion due to scarcity.[33]

There is a real question of whether the implementation of the revised market rules that enabled market prices to remain at the offer cap for days is a form of market power invoked by the Commission and implemented by ERCOT. There is a presumption by the Commission that enabling such market prices was consistent with the design of the market. However, if this was not contemplated in the market design, then the Commission's actions were taken simply to raise market prices. Without sufficient information to create expectations about the response, this action needs to be investigated to determine whether or not it inappropriately led to the exercise of market power for which profits should be disgorged.

After the Commission issued its order, the PNM increased to over $700,000/MW-year in a matter of days. Given that 356 generating units[34] were impacted during the event as a result of frozen equipment, lack of fuel supply, and several other factors, it is an empirical question as to whether high energy prices resulted in a significant supply response. At issue is whether or not the Commission had a reasonable expectation that generators would actually respond. Indeed, it is important to determine whether this action inappropriately effectuated the enormous wealth transfer that will result in continued economic disruption, customer hardship, bankruptcy, and business failure in the midst of a pandemic.

The *Wall Street Journal* has reported the architect of the ERCOT[35] system has said that "this week's blackouts weren't indicative of a major design flaw, but rather inevitable imperfections stemming from extraordinary weather challenges."[36] This is where the Hayekian view of markets failed the people of

30 See Texas Commission rule 16 TAC § 25.505(g)(6), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

31 Watson, M. "Texas regulators keep prices near $9,000/MWh cap during rotating outages," *S&P Global*, February 16, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/021621-texas-regulators-keep-prices-near-9000mwh-cap-during-rotating-outages

32 Texas PUC Project No. 51617, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

33 A second instance occurred in January 2018; due to a software error and prices were corrected. Texas Coalition for Affordable Power, ERCOT Experiences Record Consumption, Real-Time Prices Reach $9,000 Cap. August 14, 2019, https://tcaptx.com/industry-news/ercot-real-time-prices-hit-record-9000-mark

34 ERCOT Presentation – Review of February 2021 Extreme Cold Weather Event. Slide 19, February 24, 2021, http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf

35 See: Hogan, W, "On an "Energy Only" Market Design for Resource Adequacy," - Hogan_Energy_Only_092305.doc (harvard.edu)

36 Blunt, K., Gold, R. – quoting William Hogan "The Texas Freeze: Why the Power Grid Failed," *Wall Street Journal*, February 19, 2021, https://www.wsj.com/articles/texas-freeze-power-grid-failure-electricity-market-incentives-11613777856

Texas. The wealth transfer associated with the market design is not an inevitable imperfection; it is the consequence of a market that was not designed to adequately respond to extreme weather events, which likely will be more common and potentially more widespread. If the Commission determines it was in error and that error resulted in institutionalizing the exercise of market power, it has the responsibility to evaluate the appropriate pricing during the freeze and to correct market prices based upon its powers to mitigate market power.

7. Did ERCOT's Independent Market Monitor Overlook the Potential Impact of Extreme Cold Weather Events?

ERCOT's independent market monitor, Potomac Economics, Inc., has published dozens of monthly, quarterly, and annual reports that examine the energy market structure and various market design attributes. None of these reports has examined the market impacts that might result from significant loss of generation due to extreme winter weather events. The impact of freezes on generation was a known risk that not only resulted in significant economic and customer harm during the freeze of 2011, but also caused over a thousand MW of capacity to trip due to freezing weather events in 2014, 2016, 2017, and 2018.[37] This raises the question of whether market oversight was sufficient to protect customers and other market participants. To answer this question, it is important to understand why the independent market monitor did not evaluate the potential impact of extreme cold weather events on generator profitability and the customer impact.

8. What Other Regulatory, Market Design, and Policy Issues Will Help Prevent a Future Reoccurrence?

a. Is a capacity market needed?

Analysis of different market structures that can support investment in both decarbonization and resilience is warranted. As described in the recent NRRI paper, *Wither the FERC: Overcoming the Existential Threat to Its 'Magic Pricing Formula' through Prudent Regulation,*[38] ERCOT's Operating Reserve Demand Curve (ORDC) is a capacity market. What distinguishes ERCOT's capacity market from those of the ISO-NE, NYISO, and PJM is that they are based on an installed reserve margin construct, whereas ERCOT's capacity market is based on an operating reserve construct. Both can be considered forms of capacity markets. They seek to achieve the same result, an efficient and effective power market, but use very different mechanism to achieve that outcome. As described in the NRRI paper, traditional approaches to capacity market design are under stress, given the increase in customer demand response and zero-marginal cost renewable generation. As a consequence, adopting a capacity market based on an installed reserve construct in Texas at this point would be to substitute one set of market design issues for another. What is clear is that ERCOT needs to examine new market mechanisms, specifically those structures that focus not only on remunerating generator performance, but also on protecting customers.

b. How did a sizable load forecasting error contribute to the event?

ERCOT's under-forecast of load contributed to its challenges by having to address higher than expected demand with generation and infrastructure that were unprepared to handle the extreme cold weather. The ERCOT normal load forecast for the winter peak was 57,699 MW, whereas the actual peak was nearly 70,000 MW.[39] This record exceeded ERCOT's extreme winter forecast of 67,208 MW, as well as the prior winter peak record of 65,915 MW set in January of 2018. Seasonal weather outlook, population growth, and economic projections are the primary drivers of most load forecasts. However, extreme weather events are becoming more frequent and have greater impacts, causing higher demand and reduced generator availability, which calls for improved modeling. Without a forward capacity

37 Allgower, A., Presentation at ERCOT Generator Winter Weatherization Workshop, September 5, 2019, http://www.ercot.com/calendar/2019/9/5/186081

38 Pechman, C., *Whither the FERC? Overcoming the Existential Threat to Its Magic Pricing Formula through Prudent Regulation* (Washington: National Regulatory Research Institute: 2021), https://www.naruc.org/nrri/nrri-library/research-papers/whither/

39 ERCOT, "Seasonal assessments show sufficient generation for winter and spring," Press Release, November 5, 2020, http://www.ercot.com/news/releases/show/216844

market, load forecasting becomes an even more important driver for investment in new capacity. Potential investors depend heavily on these public projections to understand ERCOT's expectation of resource needs and make decisions about building generation. If the winter load forecast had been more accurate, it is likely that it could have driven additional investment in more capacity. An important issue for regulators is whether ERCOT's load forecasting methods are adequate.[40]

c. Is it time for Texas to begin a comprehensive energy planning process?

The recent Texas energy crisis has highlighted the relationship of two critically important energy systems, electricity and gas, to the health and welfare of the people of Texas. Planning is not explicitly performed in Texas, because the state has taken the Hayekian approach—relying on the market to send sufficient price signals for the system to optimally plan. The approach of relying on the market has clearly failed the people of Texas not factoring in the importance of resilience, which is not just a cold weather issue but is important with respect to other extreme weather events, including hurricanes and heat. A comprehensive plan would provide feedback to electricity market design. Among other things, it would evaluate, the vulnerabilities of the system, the role of decarbonization, and the relationship between natural gas, and electricity. It would also evaluate the interplay of the energy system with other life and economy sustaining systems, such as water and health.

d. Is Texas unique in needing to re-evaluate the structure of its market?

There are a number of drivers that will have an impact on the structure of all markets. These include the need to incorporate resilience into market design, the impact of renewables on the market supply curve, and the additional investments needed to decarbonize, presumably while increasing electrification. The challenge in market design is to balance the needs of investors, who provide resources to serve load, with cost and the customer's desire for reliable and cost-effective cost power. There is a growing conversation, such as the one sponsored by the World Resources Institute and Resources for the Future, about the wide variety of ways to design markets.[41] The process of revising the ERCOT market would be enhanced by the participation of the Texas PUC staff and commissioners.

e. How is designing a market for reliability different than designing for resilience?

The nature (scale and scope) of the risk that you are designing the system to withstand is different for reliability than it is for resilience. ERCOT is a market for reliability in the traditional engineering/economics sense. It pays for reliability through scarcity pricing, and that price reflects a valuation of an outage of relative short term in a limited geographic footprint. The outage costs studies used to elicit VoLL evaluate outages for relatively short durations (usually of only a few hours) occurring frequently and without consideration of whether the outage is local or covers a wide-area. One design objective of the ERCOT market is to provide resource adequacy, based upon an expected load forecast and the probability of individual uncorrelated generator outages. The resilience risk is different. It is a systematic risk, also called a common-mode failure, in which large groups of generators are impacted at the same time, resulting in a simultaneous outages, as experienced during the Texas freeze.

f. Is increased integration with the Eastern Interconnection warranted?

Detailed power system planning studies are necessary to identify the benefits of increased reliability through a higher degree of interconnection of ERCOT to the U.S. grid. There likely wouldn't have been enough transfer capacity to make up for the 48.6 percent of ERCOT's generation that failed

40 EPRI outlines the shortcomings or current capacity planning protocols in meeting widespread and persistent outages. EPRI. *Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy*, January 28, 2021 https://www.epri.com/research/products/000000003002019300
Maitra, A. and B. Neenan, *Measuring the Value of Electric System Resiliency: A Review of Outage Cost Surveys and Natural Disaster Impact Study Methods* (Palo Alto, CA: Electric Power Research Institute, 2017). https://www.epri.com/research/products/000000003002009670

41 World Resource Institute, "Market Design for the Clean Energy Transition: Advancing Long-Term Approaches." December 16, 2020, to December 17, 2020, https://www.wri.org/events/2020/12/market-design-clean-energy-transition-advancing-long-term

recently. During the February freeze, the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO), the two neighboring regional transmission organizations, also had operating issues, which necessitated power outages across portions of their systems to maintain system frequency. Importantly, however, increasing ERCOT interconnections would generally increase the available resource pool, which could provide significant reliability and resilience benefits.

9. How Will the Financial Consequences of This Event Be Resolved?

The physical crisis has subsided, thanks to the tireless efforts of many workers involved in system restoration. Most people have returned to their normal lives, but many will bear the long-term economic harm and emotional scars from the impact of this event for the foreseeable future. The staggering financial impacts on the utility sector will reverberate for months or years. Forty-two thousand customers had index rate plans that will bill them based on the market price, which remained at or near $9,000/MWh for several days. One Texas cooperative has already filed for bankruptcy after receiving a $1.8 billion bill for less than a week of power.[42] Some competitive retail suppliers that were not fully hedged and made fixed-price retail sales will have significant revenue shortfalls. So far, ERCOT has reported $2.1 billion in outstanding payments (approximately 17 percent of the amount owed for electric production during the freeze).[43] Additional bankruptcies will likely surface in the coming weeks. Ultimately, the consequences will be felt by customers, competitive retail providers, utilities and — possibly ERCOT itself. Bankruptcy is not a court of equity, and the resolution of these bankruptcies will create significant financial disruption. The Texas PUC will need to determine its role in this process, and how it can work to promote a just and reasonable outcome. To do so, it would be useful to account for the financial flows that occurred as a consequence of the crisis, including where the money came from and where it went, as well as identifying outstanding financial liabilities.

10. Conclusion

The Texas PUC and other relevant agencies, ERCOT, its stakeholders, the Texas legislature, and those harmed by this event need to understand details of how this catastrophic failure occurred. The lessons from this catastrophe must form the basis for future investments, policies, regulations, and market rules designed to ensure that this will never happen again. We hope that these questions and context provided by NRRI will help facilitate that process.

42 Reuters, "Texas power cooperative files for bankruptcy, citing $1.8 billion grid debt," March 1, 2021, https://www.reuters.com/article/us-bankruptcy-brazoselectric-texas-outag-idUSKCN2AT1FE

43 Gold, Russell, "Texas Power Market Is Short $2.1 Billion in Payments After Freeze," *Wall Street Journal*, February 26, 2021, http://www.wsj.com/articles/texas-power-market-is-short-2-1-billion-in-payments-after-freeze-11614386958

About the Authors

Dr. Carl Pechman
Dr. Carl Pechman, Director of the National Regulatory Research Institute, is an electricity economist with expertise in market design and the theory and practice of regulation. His experience includes work as a staff member at the New York Public Service Commission and the Federal Energy Regulatory Commission.

Elliott J. Nethercutt
Elliott Nethercutt is a Principal Researcher at the National Regulatory Research Institute (NRRI) where he specializes in state and federal electricity policy issues. Previously, he advanced market design enhancements at the California Independent System Operator (CAISO), developed reliability assessments at the North American Electric Reliability Corporation (NERC), and supported transmission siting efforts and smart grid funding programs at the U.S. Department of Energy (DOE).

About NRRI

The National Regulatory Research Institute (NRRI) was established in 1976 as the research arm of the National Association of Regulatory Utility Commissioners (NARUC). NRRI provides research, training, and technical support to State Public Utility Commissions. NRRI and NARUC are co-located in Washington, DC.

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* * *

MISO's Renewable Integration Impact Assessment (RIIA)

EXECUTIVE SUMMARY – FEBRUARY 2021

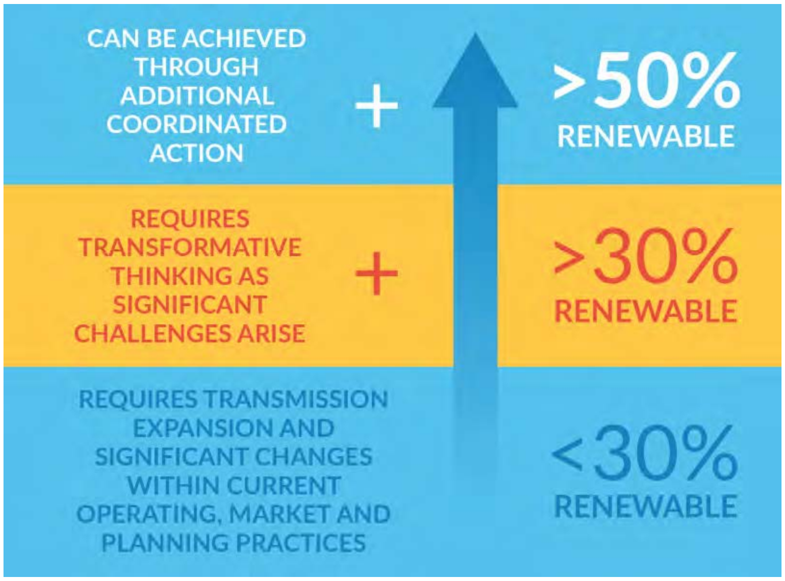
MISO

misoenergy.org

Executive Summary

A Technically Rigorous Exploration

MISO's Renewable Integration Impact Assessment (RIIA) demonstrates that as renewable energy penetration increases, so does the variety and magnitude of the bulk electric system need and risks. Managing the system under such conditions, particularly beyond the 30% system-wide renewable level is not insurmountable and will require transformational change in planning, markets, and operations. Through coordinated action with MISO stakeholders, RIIA concludes that renewable penetration beyond 50% can be achieved.



While grid operators have managed uncertainty for decades, MISO is preparing for an unprecedented pace of change. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the Reliability Imperative, which is broken into four categories Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements. RIIA is a key part of understanding the risks ahead.

RIIA is a technically rigorous systematic analysis that evaluates increasing amounts of wind and solar resources on the Eastern Interconnection bulk electric systems, with a focus on the MISO footprint. RIIA examines renewable penetration levels in 10% increments up to 50% to better understand the complexities of integration at each level. This assessment provides examples of integration issues and examines potential mitigation solutions.

RIIA is policy and pace agnostic: generation changes in the analysis are assumed to occur regardless of external drivers and timelines. As a technical impact assessment, RIIA does not directly recommend any changes to the existing electrical power system or construction of any new resources. That said, this body of work demonstrates that as renewable penetration increases, so does the variety and magnitude of system risk requiring transformational thinking and problem-solving.

"MISO, our members, and the entire industry are poised on the precipice of great change as we are being asked to rapidly integrate far more renewable resources. Given our regional Reliability Imperative, MISO must act quickly, deliberately, and collaboratively to ensure that the planning, markets, operations, and systems keep pace with these changes. We can achieve this great change if we work together."

— Clair Moeller, MISO President

New and Changing Risks Emerge, Requiring Support

As new risks emerge, adaptation within the existing planning, market, and operations constructs will suffice only to a point. As renewable generators are added, and conventional generators retire, RIIA identifies both new and changing risks and system needs:

New Stability Risk

The grid's ability to maintain stable operation is adversely impacted, primarily when renewable resources are clustered in one region of the transmission system. As inverter-based resources displace conventional generators, the grid loses the stability contributions of physically spinning conventional units. A combination of multiple technologies — such as high-voltage direct current (HVDC) lines, synchronous condensers, motor-generator sets and emerging technology such as grid-forming inverters — are needed to provide support, along with operational and market changes to identify and react to this risk as it occurs.

Shifting Periods of Grid Stress

The periods of highest stress on the transmission system shift from peak power demand to times when renewables supply most of the energy and long-distance power transfers increase. As power flows across longer distances, local planning and operational issues become regional challenges. As renewable resources supply most of the energy, the system becomes more dependent on the stability attributes of the remaining conventional generators, increasing the system risk associated with unexpected outages of those generators. As the direction and magnitude of power flows change rapidly due to the output of renewable resources that vary with weather conditions, increased flexibility, and innovation in planning and infrastructure is needed to adapt to new and shifting periods of stress.

Shifting Periods of Energy Shortage Risk

The risk of not having enough generation to meet demand shifts from the historic times of peak power demand to other periods, specifically hot summer evenings and cold winter mornings, when low availability of wind and solar resources is coincident with high power demand. These shifts are regional in nature. The colder and windier northern states exhibit different patterns than the hotter and sunnier southern states. To address this changing risk, the system needs to ensure (1) sufficient visibility of locational risk and (2) that other energy-supplying resources are available during these new times of need, with adequate transmission to deliver across regions.

Shifting Flexibility Risk

The ability of resources to provide system flexibility will be challenged. Current flexibility is needed primarily around the morning load ramp as energy demand increases and again during the evening load ramp as demand decreases. This risk shifts as variable renewables are added. As solar resources meet a larger share of the mid-day generation needs, non-solar resources are needed to ramp down in the morning and ramp up again in the evening to balance the solar pattern. Similarly, non-wind resources will ramp up and down to balance wind patterns, which change daily. To address this shifting risk, overall flexibility need increases and shifts to align with the periods in which it is required.

Insufficient Transmission Capacity

The current transmission infrastructure becomes unable to deliver energy to load. This is especially true if renewables are concentrated in one part of the footprint while serving load in another. Without added transmission, power flow across the footprint is hindered. The variable supply of renewables would, therefore, become much more challenging to manage, resulting in increased curtailment and markedly different operation of the remaining generators. Given how much time is typically needed to build transmission, proactive planning is necessary.

Integration Complexity Increases Sharply after 30% Renewable Penetration

In the general sense, system integration complexity is the effort needed to plan for, support, and operate new resources as they connect to the grid. In the RIIA analysis, complexity is measured quantitatively to understand its relative magnitude when comparing across various drivers.

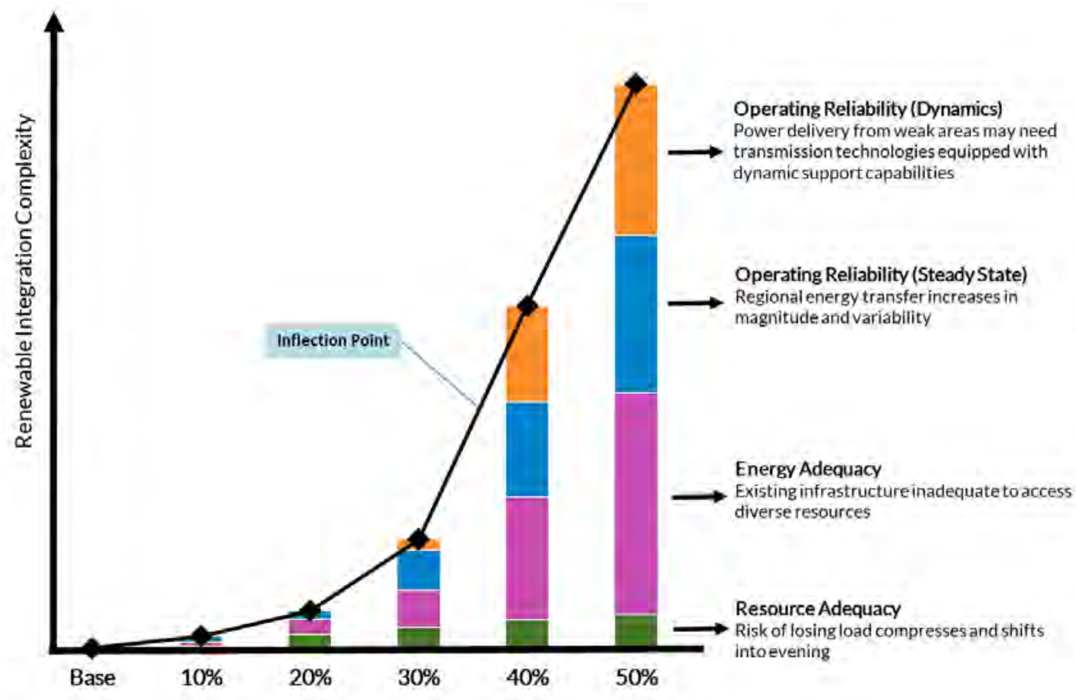


Figure 1: Increasing renewable penetration will significantly impact grid performance with complexity increasing sharply after 30% renewable penetration levels

> **"RIIA is the most comprehensive engineering study of the power system renewable transformation."**
> **— Aaron Bloom, Chair, System Planning Working Group, Energy System Integration Group**

RIIA found when the percentage of system-wide annual load served by renewable resources is less than 30%, the integration of wind and solar will require transmission expansion as well as significant changes to current operating, market, and planning practices — all of which appear manageable within MISO's existing framework. Beyond 30%, transformative thinking and coordinated action between MISO and its members are required to prepare for the significant challenges that arise (Figure 1). It is important to note that renewable growth does not happen uniformly across the MISO footprint, or the broader interconnected system. Growth occurs fastest in areas with high quality wind and solar resources, available transmission capacity, and favorable regulatory environments. For example, when MISO reaches 30% renewable energy penetration, some Local Resource Zones are likely to be approaching 100% renewable energy penetration. Locations which experience the fastest renewable growth experience challenges first, but beyond 30% renewable penetration the system as a whole facing new and shifting risks rather than simply local issues.

Today, MISO's renewable fleet accounts for 13% of MISO's system-wide energy, and MISO operates 26 GW of wind and 1 GW of solar. Nearly 80% of MISO's renewable resources are in the northwest region of MISO, concentrating the current integration challenges to one area.

Looking ahead, as the significant pipeline of generators with executed Interconnection Agreements reach commercial operation (6 GW of new wind, 10 GW of new solar), renewables are expected to account for approximately 20% of the system-wide annual energy mix. Beyond that, MISO Futures demonstrate the 30% milestone could occur as soon as 2026.

Three Key Focus Areas, RIIA Insights and Next Steps

RIIA illustrates areas of system weakness, recognizes when those weaknesses could become problematic and identifies potential means to address them. This work has informed initiatives already underway at MISO and will serve as a key input to initiatives in the future. The assessment aims to support a broader, more informed conversation about renewable integration impacts on the reliability of the electric system within the MISO stakeholder community and the greater industry. The analysis suggests three key focus areas for MISO and stakeholders (Figure 2) and informs the sequencing of actions required to manage various renewable penetration levels.

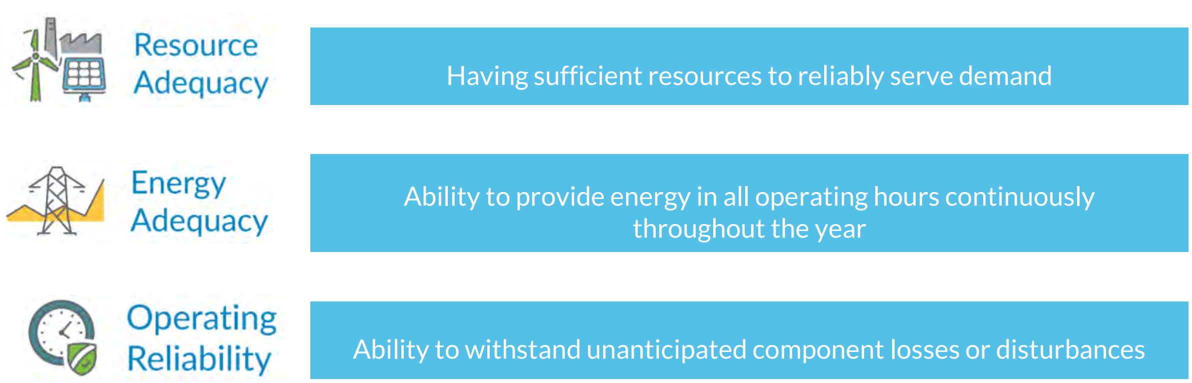
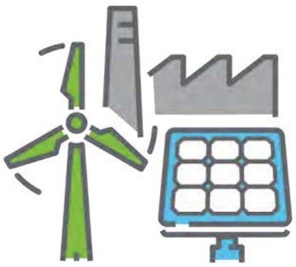


Figure 2: RIIA's three focus areas: Resource Adequacy, Energy Adequacy and Operating Reliability

Note: Where appropriate, the insights below are tied to the Reliability Imperative efforts in the categories of Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements.

Resource Adequacy



Resource Adequacy is the ability of available power resources to reliably serve electricity demand when needed across a range of reasonably foreseeable conditions. Resource Adequacy complexity is defined as the effort needed to maintain capacity necessary to maintain a "one day in 10 years" loss of load expectation target.

RESOURCE ADEQUACY INSIGHTS

INSIGHT: Risk of losing load compresses into a small number of hours and shifts into the evening. The risk of not serving load shifts later into the evening and is observed for shorter durations with higher magnitude. Sensitivity analyses show risk shifting to winter and later in the evening, depending on technology and geographic mix.

NEXT STEP

- Ensure resource availability outside of traditional risk periods, both during evening hours and winter periods (Market Redefinition).

INSIGHT: Resource changes will significantly impact grid performance, with complexity increasing sharply after 30% renewable penetration levels.

NEXT STEP

- Develop and implement market solutions to identify issues prior to the system reaching 30% wind and solar penetration (Market Redefinition).

INSIGHT: Diversity of technologies and geography improves the ability of renewables to serve load. Yearly weather variations drive Resource Adequacy outcomes.

NEXT STEP

- Develop ways to increase the fidelity of renewable energy forecasts by using improved weather data.

RESEARCH STEP

- Explore ways to incentivize new resource additions to enhance technological and geographical diversity to serve MISO reliability.

Energy Adequacy

Energy Adequacy looks at the ability to operate the system continuously and deliver sufficient energy every hour of the year. Energy Adequacy complexity is defined as the effort to develop the transmission needed to maintain and deliver renewable energy during every hour of the year. The generation fleet's ability to respond to the load is limited by existing generation and transmission constraints, and new transmission costs act as a proxy to measure the additional flexibility needed to access diverse resources.

ENERGY ADEQUACY INSIGHTS

INSIGHT: With renewable penetration levels above 40 percent, there is both a greater magnitude and increased variation of ramping needed. Increasing variability due to renewable generation will require generators to perform differently than they are today.

RESEARCH STEPS

- Explore the landscape of system flexibility solutions (e.g., renewables as a solution to variability need and nuclear plant ramping).
- Explore changing risks such as the ability of the natural gas system to deliver fuel to enable gas generator flexibility, and fewer units providing needed system flexibility (due to retirements).
- Explore flexibility incentives (Market Redefinition).

INSIGHT: Existing infrastructure becomes inadequate to fully access the diverse resources across the MISO footprint. Grid technology needs to evolve as renewable penetration increases, leading to an increased need for integrated system planning.

NEXT STEP

- Educate stakeholders about complexities and opportunities of emerging technologies (LRTP).

RESEARCH STEPS

- Explore co-optimization between economic and reliability transmission needs, along with resource deployment (software, process, and data development needed).
- Explore additional opportunities to align and co-plan for system needs across the various MISO planning functions.
- Explore the gaps, opportunities, costs, and benefits of new grid technology (such as FACTS, VSC HVDC lines, grid-forming inverters) and its ability to solve emerging grid needs.

INSIGHT: Storage paired with renewables and transmission help optimize the delivery of energy.

RESEARCH STEPS

- Explore concept to understand benefits better
- Explore process changes to align benefits with outcomes

Operating Reliability

Operating Reliability studies the system's ability to withstand sudden disturbances to system stability or unanticipated loss of system components. This focus area is subdivided into "steady state" and "dynamic stability" analysis and considerations.

Steady State

Steady-state analysis examines whether the transmission system exceeds the thermal ratings of lines, transformers, and other devices following deviations from normal operating parameters occurring without warning. Complexity in steady-state analysis is defined as the effort to create the transmission needed to ensure acceptable system performance after outages.

OPERATING RELIABILITY — STEADY-STATE INSIGHTS

INSIGHT: Resource location and system conditions cause transmission risk shifting to spring and fall and increasing in frequency. Additionally, sensitivity analysis shows risk shifting to summer shoulder load periods during high solar output.

NEXT STEPS

- Align planning dispatch assumptions with shifting system conditions and risk (LRTP).
- Develop tools and processes to capture changing risks as they appear for transmission planning (LRTP).

RESEARCH STEP

- Evaluate opportunities to align and co-simulate power-flow and production cost models.

INSIGHT: Regional energy transfer increases in magnitude and becomes more variable, leading to a need for increased extra-high voltage transfer capabilities. Transmission bottlenecks shift to higher voltage lines due to increased regional energy transfers.

NEXT STEPS

- Proactively align to future needs, develop long-range, cost-effective, and least-regret transmission plans, and move construction forward (LRTP).

Dynamic Stability

Voltage stability, frequency stability, rotor angle stability, and non-oscillatory behavior of electrical quantities are considered dynamic stability issues. Dynamic stability includes maintaining operating equilibrium of three distinct elements after a disturbance in the electric grid: (a) voltage stability; (b) adequate frequency response; and (c) rotor angle stability. Complexity in the Operating Reliability — Dynamics analysis is defined as the effort to install transmission equipment and control system tuning required to ensure stable operation.

RIIA identifies potential issues with all three dynamic stability elements along with converter-driven stability, which is an additional category associated with inverter-based equipment. Concerning voltage and converter-driven stability, the assessment demonstrates that as inverter-based resources increase in penetration, there is a corresponding decrease in the online thermal generation, which intensifies reliability issues. This is significant because commercially available inverter-based resources, such as renewables, need strong voltage connections to operate reliably and efficiently. This study identifies several approaches to address the issues, such as tuning inverter controls, re-dispatching generation, adding synchronous condensers, and using advanced technologies (FACTS, VSC HVDC). Frequency-related risks can be resolved by adding storage or maintaining online headroom from resources, including wind and solar.

OPERATING RELIABILITY — DYNAMIC STABILITY INSIGHTS

INSIGHT: Power delivery from "weak-grid" areas may need transmission technologies equipped with dynamic support capabilities.

RESEARCH STEPS

- Explore and decide ways to address "weak-grid" issues (such as improved inverter technology, new technology pilots, operational visibility, proactive and integrated transmission planning).
- Update inverter control tuning approaches as penetration of inverter technologies increases.

INSIGHT: Small signal stability issues increase in severity after 30% renewable penetration, thereby requiring power system stabilizers. Frequency response is stable up to 60% instantaneous renewable penetration but may require additional planned headroom beyond 60%.

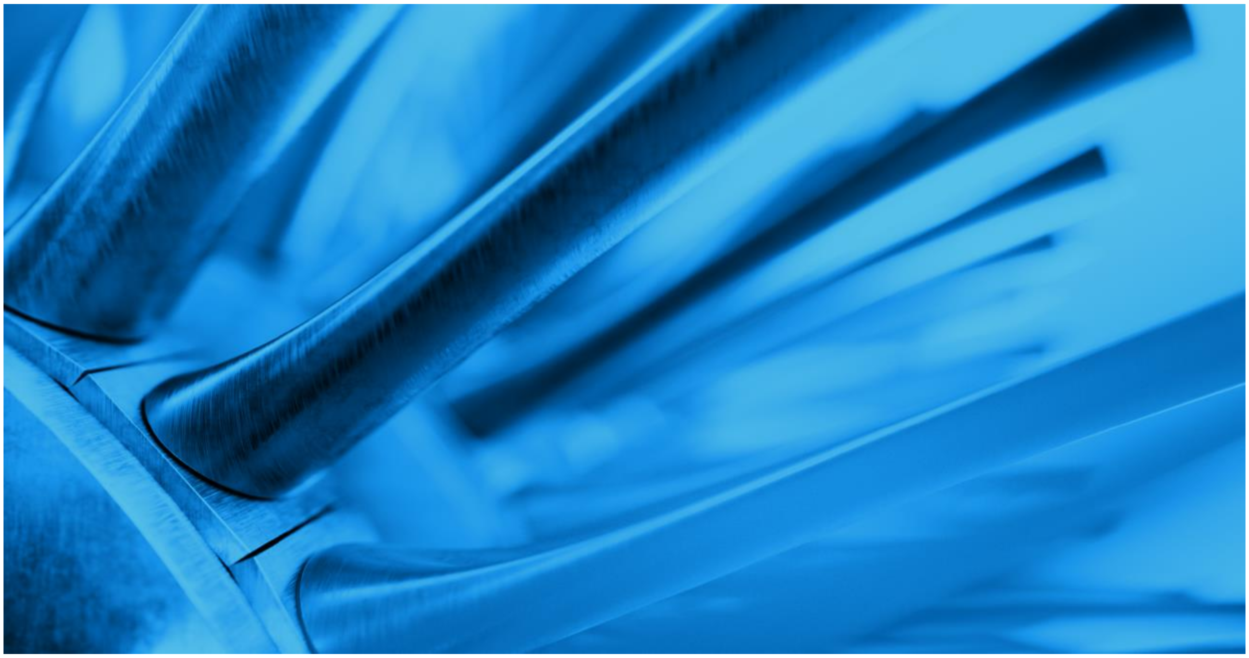
RESEARCH STEPS

- Explore new methods to stabilize the grid, such as battery storage.
- Explore operations tools to monitor and commit power system stabilizers when needed.

INSIGHT: On average Critical Clearing Time (CCT) improves as large generating units are replaced, but new local issues emerge.

RESEARCH STEP

- Explore process to plan for new protection techniques or new transmission devices.



Additional Work Is Needed

RIIA is the culmination of four years of stakeholder collaboration and intense exploration into the impacts of increasing renewable integration in the MISO region. While the analysis is highly comprehensive, it is not finished. Additional work is needed to transform the way MISO and the power system are planned and operated to continue to maximize reliability and value creation across the region in a high renewable system. RIIA has shown that while there are challenges, the MISO region can achieve renewable penetration of at least 50% with transformational change and coordinated action amongst all participants.

"We believe it will take transformational change, including redefined markets and planning processes, to enable efficient and reliable operations in the future. Coordinated action amongst all stakeholders will be necessary to facilitate participants' decarbonizations goals and plans for higher levels of renewable generation."

— Richard Doying, MISO EVP Market & Grid Strategies

ENERGY RESOURCES PLANNING TASK FORCE

TESTIMONY QUESTIONS

Please send your responses to ERPTaskForce@adeq.state.ar.us on or before April 30, 2021.

ATTORNEY GENERAL OFFICE

1. **To help the Task Force understand the various ongoing efforts currently under review by other agencies, could the Attorney General briefly summarize the type of issues your Office will be working on with respect to the power shortage events that occurred during the February winter weather event.**

   Response: Arkansas Attorney General Leslie Rutledge is conducting simultaneous investigations of the actions of public utilities and of potential violations of Arkansas's price-gouging laws relating to the February Winter Weather Event. Her investigations are not limited to power shortages. As or perhaps more importantly, the Attorney General is investigating energy pricing during the Event, the potential financial impact on Arkansans, and whether the financial impact can be mitigated.

   <u>Investigation of Public Utilities</u>

   On February 25, 2021, Attorney General Rutledge sent a letter to Arkansas Public Service Commission Chairman Ted Thomas asking that the Commission "open an investigation of the cost of energy – power and natural gas – incurred by Arkansas's electric and natural gas utilities during the recent severe weather event." A copy of the letter is attached. On March 4, 2021, the Commission opened the investigation sought by the Attorney General. See attached Order No. 1 in APSC Docket No. 21-036-U. The Attorney General is an active participant in that docket, and she has issued a number of discovery requests to regulated utilities.

   First, the Attorney General will be investigating the specific actions taken by Commission-jurisdictional natural gas and electric utilities during the February Winter Weather Event. The Attorney General is reviewing both action during the Event itself, but also the actions taken in the short and long-term leading up to the Event.

   Additionally, the Attorney General will be analyzing the February Winter Weather Event to determine what lessons can be learned and what actions to recommend to the Commission for future resource planning.

   The Attorney General anticipates that the aforementioned investigations and need for potential adjustments may take place across several Commission Dockets which are directing dealing with the February Winter Weather Event, or utility matters that may be impacted by same.

Price-Gouging Investigation

In addition, as indicated in her February 25 letter, Attorney General Rutledge "has opened an investigation of potential price gouging by parties that are not subject to the Commission's jurisdiction." To that end, the Attorney General's Office (AGO) will focus initially on price increases for natural gas. The AGO has met or is scheduled to meet with all natural gas utilities and electric utilities that use natural gas to generate electricity. This includes both public utilities regulated by the Commission and municipal utilities. Civil Investigative Demands (CIDs) have been issued to these utilities seeking information about their natural gas suppliers and pipeline service providers. See attached CID example. CIDs have also been issued to several large volume industrial and commercial natural gas users that purchase natural gas supplies from third parties, not from public or municipal utilities. The information that is being gathered will help the AGO determine which natural gas suppliers should be investigated for potential price-gouging.

Review of sales of electricity in power markets for potential price-gouging will begin in May. That sales of power occur in markets facilitated by Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP).

2. **Are there any recommendations or areas of further investigation that the Attorney General would like to bring to the attention of the Task Force with regard to addressing energy supplies during future events?**

   Response: The Attorney General believes that her office and the Commission have adequate authority and enforcement tools to investigate and hold accountable any party that acted imprudently or in violation of Arkansas's public utility laws and consumer protection laws. The Attorney General also believes that recently enacted Act 641 will provide another source of funds that can be used by public utilities to arrange long-term financing of storm-related costs at low interest rates and to recover those costs from ratepayers in a reasonable time period.

   In the AGO's meetings with municipal utilities, the need for similar funding mechanisms became apparent. While not every municipal utility may require financial assistance from the State when severe winter weather produces incredibly high costs, having access to grants, loans or other types of funding would be very beneficial for those utilities who do not have the financial means to meet their obligations to natural gas suppliers and also provide police and fire protection and other essential services.

   The Attorney General would point out certain issues relevant to the February Winter Weather Event are likely within the exclusive jurisdiction of the federal government, and more specifically the Federal Energy Regulatory Commission (FERC). FERC has exclusive jurisdiction over interstate commerce involving the transmission grid, including rates and tariffs for the two Regional Transmission Organizations (RTOs) – MISO and SPP – that currently operate in Arkansas. FERC also regulates interstate gas pipeline transportation. Many municipal electric systems, and wholesale customers (both natural gas and electric), may need to address their cost issues directly with FERC.

   There may also be issues pertaining to gas production, markets, and actions taken during the

February Winter Weather Event that are within the jurisdiction of the Federal Trade Commission (FTC) and/or the United States Department of Justice.

The Attorney General believes that cooperative regulation and enforcement jurisdiction exists into many of these issues, and will attempt to remain apprised of actions at FERC, FTC, and other courts of law, including the potential for direct action by the Attorney General of Arkansas into any such proceedings.

The Attorney General will also seek out cooperative opportunities with the Offices of Attorney General in other states affected by the February Winter Weather Event, to the extent that multi-state litigation might align to the benefit of Arkansas.

The Attorney General would like to make clear to the Task Force that resolution of all investigations and potential litigation involving issues relevant to the February Winter Weather Event may take months to fully conclude.

February 25, 2021

Hon. Ted Thomas, Chairman
Arkansas Public Service Commission
P.O. Box 400
Little Rock, Arkansas 72201

Re: Request for Investigation of the Cost of Energy Incurred by Arkansas Utilities During the Recent Severe Weather Event

Dear Chairman Thomas:

Recent winter storms exposed great disparities between consumer demand for energy and the ability of Arkansas's utilities to meet that demand in severe weather. Arkansans experienced service outages, and many businesses were forced to close. In the coming weeks, we will know more about the impact of energy shortages on customer bills. We anticipate that customer bills may skyrocket because of the high prices paid by utilities to third parties for energy needs that were either unanticipated or needed to replace resources that failed to materialize. Before these costs appear on customer bills, I respectfully request that the Arkansas Public Service Commission open an investigation of the cost of energy – power and natural gas – incurred by Arkansas's electric and natural gas utilities during the recent severe weather event.

Specifically, the Commission should investigate:

- The impact on rates and whether higher costs should be passed on to ratepayers;
- The cause of outages and significant operational problems experienced by Arkansas public utilities;
- Whether Arkansas public utilities were sufficiently prepared to respond to the severe weather;
- How the actual weather compared to the weather used to model peak day needs;

- The accuracy of peak day forecasting;
- The actions taken to meet peak day capacity and supply needs;
- What emergency plans were in place to secure natural gas and any other necessary fuel to meet unanticipated needs;
- Performance of suppliers under contract to affected Arkansas public utilities; and
- Actions taken by electric utilities in response to MISO and SPP alerts.

Apart from its proposal that the Commission investigate these matters, the Attorney General has opened an investigation of potential price gouging by parties that are not subject to the Commission's jurisdiction.

Sincerely,

Leslie Rutledge
Arkansas Attorney General

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN INVESTIGATION INTO THE OPERATIONS, PROCEDURES, AND PERFORMANCES OF THE REGULATED UTILITIES DURING THE WINTER WEATHER EVENT IN FEBRUARY 2021	)))))	DOCKET NO. 21-036-U ORDER NO. 1

ORDER

On February 11, 2021, through February 20, 2021, Arkansas experienced extreme weather events resulting in sub-zero temperatures and the accumulation of ice and record snowfalls across the state. Although many of the state's regulated utilities performed admirably during this unprecedented weather event, the loss of power, entreaties to customers to conserve natural gas and electricity, and rolling blackouts point to a need for the Arkansas Public Service Commission (Commission) to ensure that utilities are doing all they can to ensure its systems are resilient, services are safe and reliable, and customers do not experience preventable loss of power or are saddled with exorbitant utility costs.

Pursuant to Ark. Code Ann. §§ 23-2-308, 23-2-309, and 23-2-310, the Commission hereby opens an investigation into the utilities' preparation, response, operational performance and communication regarding the winter weather events in February 2021, impacts on customers, best practices, and lessons learned going forward.

Additionally, utilities may have experienced significantly increased expenses related to fuel and transportation, purchased power, and other commodity and operational costs because of these events. As most utilities will soon be required to file for adjustments to riders which recover those costs from ratepayers,[1] the unabated impact of these increased costs could cause rate shock for utility customers.

Any utility which has experienced a significant impact from these increased costs is urged to propose procedures for cost recovery which avoid rate shock to its customers as the utilities file for rider adjustments. Procedures should protect the right of the utility for an opportunity to recover costs while balancing the impact on the utility's customer.

All jurisdictional electric, gas, and water utilities are hereby made parties to this Docket, and the Secretary of the Commission is directed to serve a copy of this Order on the parties. A procedural schedule for conducting the investigation will be set by subsequent order.

[1] For example, Energy Cost Recovery Riders, Cooperative Cost of Energy Adjustments, Gas Supply Rates, and Cost of Pumping Adjustments.

BY ORDER OF THE COMMISSION.

This _4th_ day of March, 2021.

Ted J. Thomas, Chairman

Kimberly A. O'Guinn, Commissioner

Justin Tate, Commissioner

Mary Loos

Mary Loos, Secretary of the Commission

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

____U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or
_✓_Electronic mail using the email address of each party as indicated in the official docket file.

Kate Donoven
Senior Assistant Attorney General
Direct Dial: (501) 682-8114
Email: kate.donoven@arkansasag.gov

April x, 2021

Re: Civil Investigative Demand (CID), Price Gouging Investigation 2021-0083 – Natural Gas Prices

Dear Municipal Utility:

The Consumer Protection Division of the Office of Arkansas Attorney General Leslie Rutledge is investigating the prices paid by Arkansas's utilities for natural gas supplies and pipeline services used during extreme weather that occurred in February 2021. Because some municipalities purchase natural gas in providing utility service to Arkansans, we need information from your municipality so that we can determine the sources and causes of high natural gas prices and whether those prices were cost-based or market-driven.

Governor Asa Hutchinson's February 10, 2021 winter weather emergency declaration triggered the protections of Arkansas's price gouging law that remained in effect until March 12, 2021. See Executive Order 21-02 attached. Arkansas's price gouging law, Ark. Code Ann. § 4-88-301, *et seq*., prohibits any person or business from charging more than ten percent (10%) above the pre-emergency price of goods or services. The scope of the law is broad and intended to cover anything that may be needed in the event of a state of emergency. As it relates to Executive Order 21-02, covered goods and services include, but are not limited to, natural gas used for space heating, electric generation and other consumer and business purposes. Ark. Code Ann. §§ 4-88-303, 4-88-102(4) and 4-88-102(7).

While the law sets a general 10% cap on price increases during an emergency, businesses may lawfully charge a higher price if they can establish that the higher price is directly attributable to additional costs for labor or materials used to provide the goods or service. In such a limited situation, the business may charge no more than 10% above the total of the cost to the business, plus the customary mark-up applied for that good or service in the normal course of business. Rates that are set by the Arkansas Public Service Commission or which are otherwise based on the costs incurred by the utility may fall within this "safe harbor."

Wholesale suppliers are not exempt from the price gouging law. If a supplier increases its prices for goods or services by more than 10% during a state of emergency, it may run afoul of the price gouging law if the increase is based on increased demand and shortages of natural gas during the state of emergency. To avoid liability under the price gouging law, the wholesale supplier must demonstrate that its price increases were based on increased costs and that its price complies with Ark. Code Ann. § 4-88-303.

If a business or individual violates the price gouging law, the Attorney General can seek injunctive relief, restitution to consumers, costs, attorneys' fees, and civil penalties up to $10,000 per violation. Criminal sanctions may also apply to violators.

When the Attorney General determines that an investigation should be made into whether a person has engaged in, is engaging in, or, shows evidence of intent to engage in price-gouging, she may: (1) require any person to file a statement or report in writing as to the facts and circumstances concerning the matter, together which such other data as may be reasonably related thereto; (2) examine any oath or take the deposition of any person; and (3) examine any records relating thereto. Ark. Code Ann. § 4-88-111(a). Similarly, the Attorney General may seek information from a consumer or any other person or business that may have information that is pertinent to its investigation.

To assist in our investigation of natural gas price increases, please provide the following information:

1) Please provide the following information relating to your municipality's purchases of natural gas supplies during the period from November 1, 2020, through March 12, 2021.

a. Identify your municipality's natural gas suppliers and pipeline service providers for February 10 - March 12, 2021 within five (5) business days. For each natural gas supplier or pipeline service provider listed in response to this question, please provide the name and mailing address of the supplier or provider and, if known, its agent for service of process.

b. Invoices for the purchase of natural gas supplies and pipeline services, including transportation, no notice and storage services within ten (10) business days.

c. If not provided on the invoice, the dates, quantities and prices for all natural gas supply and pipeline service purchases within a reasonable time period to be mutually agreed upon.

d. Purchase orders and/or contracts under which the natural gas supplies or pipeline services were purchased within ten a reasonable time period to be mutually agreed upon.

2) Please provide all correspondence between your municipality and the supplier related to the purchases of natural gas supplies and pipeline services identified in response to question #1 within a reasonable time period to be mutually agreed upon. Correspondence includes emails, letters, texts, instant messages, social media posts, faxes, and any other record of information exchanged.

3) All correspondence between your municipality and the supplier that is related to plans, preparation, actions, or strategies for meeting supply demand during weather disasters within a reasonable time period to be mutually agreed upon.

All information submitted in response to this inquiry is protected from disclosure under the confidentiality provisions of Ark. Code Ann. § 4-88-111. The Arkansas Deceptive Trade Practices Act (ADTPA) protects all information submitted in response to a CID from Freedom of Information Act (FOIA) requests and the Attorney General cannot be compelled to release any information without your consent and only if ordered by a court for good cause. Should the Attorney General use the information in court, materials that contain proprietary information and trade secrets can be presented in camera with approval of the court after notice to the person furnishing the material. Documents, statements, and information provided in response to a request by the Attorney General are subject to the following statutory safeguards:

> (b) Unless otherwise ordered by a court for good cause shown, no statement or documentary material produced pursuant to a demand under this section shall be produced for inspection or copying by, nor shall the contents thereof be disclosed to, any person other than the authorized employee of the Attorney General without the consent of the person who produced the material.
> (c) The Attorney General or any attorney designated by him or her may use the documentary material or copies thereof in the enforcement of this chapter by presentation before any court, provided that any such material which contains trade secrets shall not be presented except with the approval of the court in which the action is pending after adequate notice to the person furnishing such material. However, when material containing trade secrets is presented with court approval, the material and the evidence pertaining thereto shall be held in camera and shall not be part of the court record or trial transcript.
> (d) No statements, documents, or other information maintained or produced as a result of an ongoing investigation of possible violations of this chapter shall be disclosed to any person other than those persons specifically authorized by the Attorney General to receive such information.

We appreciate your cooperation with our office and are available to discuss if you have any questions or concerns. To facilitate our ability to comply with Ark. Code Ann. § 4-88-111(c), we request that any information provided in response to this CID that contains a proprietary fact or trade secret be clearly and distinctly designated as such. Bates stamps and bookmarked pdfs are appreciated but not necessary.

Sincerely,

Kate Donoven

Kate Donoven
Senior Assistant Attorney General

Encl: E0-21-02
Cc: Chuck Harder, Deputy Attorney General Public Protection,
Christina Baker, Assistant Attorney General, CURAD, and
Trent Minner, Assistant Attorney General

STATE OF ARKANSAS
EXECUTIVE DEPARTMENT

PROCLAMATION

EO 21-02

TO ALL TO WHOM THESE PRESENTS COME – GREETINGS

EXECUTIVE ORDER TO PROVIDE FUNDING, AS AUTHORIZED BY ARK. CODE ANN. §§ 12-75-114, AS AMENDED, FROM THE GOVERNOR'S DISASTER FUND, EMERGENCY RESPONSE FUND

WHEREAS: On or about February 9, 2021, a winter storm began and continues to cause freezing rain, sleet, snow, and ice with such severity to warrant executive action to alleviate hardship and suffering in the State of Arkansas; and

WHEREAS: Freezing rain, sleet, snow, and ice accumulation on roads and power lines due to the winter storm presents dangers that warrant executive action; and

WHEREAS: Great hardship has been wrought upon the citizens, businesses, and public and private property within the State of Arkansas; and

WHEREAS: Adverse circumstances have been brought to bear upon the citizens and public properties within the state; and

WHEREAS: These political subdivisions require supplemental assistance from the state to recover from these losses;

NOW, THEREFORE, I, ASA HUTCHINSON, Governor of the State of Arkansas, acting under the authority vested in me by Ark. Code Ann. §§ 12-75-101, *et seq.*, do hereby declare a state of emergency and direct the sum of $100,000.00 to be obligated from the Emergency Response Fund of the Governor's Disaster Fund to be used at the discretion of the Director, Arkansas Division of Emergency Management, to defray both program and administrative costs.

IN TESTIMONY WHEREOF, I have hereunto set my hand and caused the Great Seal of the State of Arkansas to be affixed this 10th day of February, in the year of our Lord 2021.

Asa Hutchinson, Governor

Attest:

John Thurston, Secretary of State

MISO RESPONSES TO ENERGY RESOURCES PLANNING TASK FORCE QUESTIONS

Question NO.: 1

Having had some time to do an analysis of your operations since the February winter event, could your organization provide a brief summary of your role in addressing the power outages during the February winter event.

RESPONSE: **See below** ☒ **See attached** ☐
RESPONSE DATE: **April 30, 2021**

As the Regional Reliability Coordinator and Balancing Authority, MISO is responsible for maintaining the safe, reliable operation of the Bulk Electric System (BES) in our operational control.

The arctic weather winter storm during the week of February 15 caused multiple days in sub-freezing temperatures and double-digit snowfall topped with significant ice accumulation, which made for a complex and unique event. MISO began its preparations several days before by declaring a Cold Weather Alert and Conservative Operations. These actions allowed MISO and its members to identify all available generation and known transmission issues before the event. All Real-Time Operations Alerts and Declarations are available on MISO's public website.

In addition to the operational alerts, MISO staff held daily calls throughout the event with operations, communications, and regulatory representatives of its affected members. There were four transmission-related load shed events and one Maximum Generation Load Shed event during the winter weather event:

- 2/15/21 Local Transmission Emergency – 800 MW, Western Load Pocket (SE Texas)
- 2/16/21 Local Transmission Emergency – 300 MW, Western Load Pocket (SE Texas)
- 2/16/21 Transmission System Emergency – 1000 MW, North-Central Louisiana
- 2/16/21 Transmission System Emergency – 130 MW, South-Central Illinois
- 2/16/21 Maximum Generation Event Step 5 – 700 MW, South Region (All South LBAs)

February 15, 2021
MISO declared a Local Transmission Emergency due to generation and transmission losses in Southeast Texas, also known as the Western Load Pocket. These led to a localized load shed event affecting Entergy Texas customers in the Dayton, Texas area. MISO had also begun to escalate through its Maximum Generation Alert and Event steps.

February 16, 2021
Morning – Due to worsening conditions on the Bulk Electric System, three transmission events temporarily interrupted power to parts of Southeast Texas, North-Central Louisiana, and South-Central Illinois.

Afternoon – Further issues began to emerge throughout the afternoon as 2500 MW of generation dropped between 2:30 and 5:00 pm central time.

Evening - MISO declared a Max Gen Event 2c at 5:37 pm. central time, requesting public appeals for conservation. Realizing the grid's stability was in danger and unable to import the needed energy to meet demand, MISO operators notified its Load Balancing Authorities (LBAs) in the South Region to collectively shed 700 MW of load to avoid wide-spread cascading outages.

LBAs in Arkansas, Mississippi, Texas, and Louisiana were each given their pro-rata share of load to shed from their systems. The entities then determined which customers would be impacted. The entire load shed event lasted two hours and twenty minutes. This marks the second system load shed event in MISO's history (Hurricane Laura was the first).

While control room operators were managing generation and transmission issues, other MISO staff worked with state and local officials to communicate and emphasize the importance of assisting fuel supply to the plants. Those activities included helping get roadways cleared for fuel delivery and emergency declarations so plants could operate.

Question NO.: 2

Did your existing emergency procedures work as intended and are there any improvements you will be implementing to deal with similar power shortages due to potential future events?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

MISO's procedures operated as designed. In addition, MISO is currently conducting an analysis of the causes and impacts of the Winter Storm, which will be finalized as a report by the end of May 2021. MISO is planning to provide the report publicly and it will be made available for stakeholders.

Question NO.: 3

Unlike the events in Texas, as discussed in your testimony to the Energy Committees, the larger multi-state system operated by SPP and MISO appeared to be a reason the power outages in Arkansas were not as extensive.

a. Describe your preparedness and allocation process for critical energy resources during extreme events.
b. Could you elaborate on why that structure was beneficial and how the two System Operators worked together to minimize the outages in Arkansas.

RESPONSE:	**See below** ☒	**See attached**	☒
RESPONSE DATE:	**April 30, 2021**		

a. MISO took the following operational steps ahead of the Cold Weather Event:
    - Requested members update offers and ensure Load Modifying Resource (LMR) data is accurate.
    - Extended or adjusted the start/stop times for generation resources in the South region to aid in availability during peak load times.
    - Confirmed planned outage and return-to-service dates/times for generation and transmission outages.
    - Committed additional generation with lead time enabling members to procure fuel.
    - Continued discussions with our members in the South Region about the potential need for a public appeal, if necessary, and coordinated communications with those members.

When developing Operating Procedures, Business Practice Manuals (BPMs), stakeholder presentations and various reports/studies, MISO considers industry best practices, such as the North American Transmission Forum (NATF) and relevant North American Energy Reliability Corporation (NERC)[1] documents.

To provide some background, MISO assisted the Federal Energy Regulatory Commission (FERC), NERC, and the regional reliability entities to provide information relevant to the January 17, 2018 cold weather event that was experienced across the South Central United

[1]*The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people.*

States. MISO made several positive changes as a result of the January 2018 event, including improved coordination with neighboring grid operators. One of the most notable enhancements was the development of a joint Regional Transfer Operations Procedure (RTOP) that is now used to govern MISO's use of the Regional Directional Transfer (RDT) with SPP. MISO carefully reviewed the 13 industry recommendations that came out of "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018" report, several of which reaffirmed recommendations that were included in the "Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011" (2011 FERC-NERC Southwest Task Force (SWTF) report. Additionally, MISO hosted staff from FERC, NERC, and the regional reliability entities on October 21-22, 2019 to further review MISO's overall cold weather preparedness and response to the cold weather report findings.

- MISO has multiple avenues for providing information to stakeholders on winter preparation including periodically updated reports/assessments/workshops and standing information on www.misoenergy.org.

Readiness Forum/Workshops

MISO conducts an annual Winter Readiness Forum/Workshop. The most recent one was conducted on October 27, 2020. In addition, MISO will hold a Summer Readiness Forum/Workshop on May 4, 2021.

These annual MISO workshops provide a forum for MISO stakeholders to come together and share information on a variety of topics related to winter and summer readiness.

NERC Lessons Learned Review

MISO has a newer effort to review NERC Lessons Learned. This occurs in the MISO stakeholder Reliability Subcommittee approximately once per quarter. A particular NERC Lesson Learned is selected in collaboration with MISO stakeholders. To date, two presentations have been conducted, one of which was related to cold weather lessons learned.

"Generator Performance During Severe Cold Temperatures in 2019 Lessons Learned Update" was discussed at the Reliability Subcommittee on September 3, 2020 and was related to NERC Lesson Learned LL20200601 "Unanticipated Wind Generation Cutoffs during a Cold Weather Event."

Winter Resource Assessment

MISO also conducts annual seasonal assessments, including the most recent 2020-21 Winter Resource Assessment to determine if adequate resources are projected to be available to cover demand and outages.

MISO's website on Winterization

MISO also maintains a webpage on weatherizing generating units at: https://www.misoenergy.org/markets-and-operations/reliability-information/winterization/ including MISO Winterization Guidelines page 4 of which contains links to various NERC webpages on winter preparedness. A copy of the MISO Winterization Guidelines is attached hereto as Exhibit 1.

- MISO conducts annual Generation Winterization and Gas Fuel Surveys. The winterization survey completed its second year and the gas fuel survey its seventh year in the fall/winter of 2020.

  For the 2020-21 winter season a summary of these surveys was presented to stakeholders at the Reliability Subcommittee on December 11, 2020.

- During real-time operation MISO monitors major gas pipeline availability for situational awareness. This is described in "Communications for Natural Gas Fuel Supply Availability" procedure SO-P-NOP-00-467. While Generation Operators/Market Participants are responsible for coordinating natural gas deliveries to their units, MISO will monitor relevant pipeline operating conditions for the benefit of MISO control center operations personnel. As noted in the procedure, MISO can also become aware of fuel supply issues through various internally generated reports and verbal communications by Market Participants.

- MISO has several Emergency Operating Procedures (EOPs) that are written to consider a variety of causes that could lead to the need to enter a particular EOP. In general, these procedures are written to address the reliability condition versus the reason the condition exists.

b. Having a significantly interconnected transmission system allows for entities like MISO and SPP to work together to take advantage of the diversity of load, weather and managed fleets to maximize the availability of resources to meet loads across very large regions. See also the response above to (a.), which also explains the improved coordination following the January 2018 event.

Question NO.: 4

As outlined in your testimony to the Energy Committee, the System Operators cooperated to provide assistance as necessary to assist the other System.

a. Were communication protocols in place prior to the February event for the System Operators to provide mutual assistance?
b. If not formal protocols, are there plans to establish more formal procedures between the System Operators in the future?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

a. Yes. MISO, its members, and its neighbors, including SPP, normally drill on emergency communications and regularly have to work together on day to day management of the systems, even under normal conditions. In addition to good communication during the event, MISO and others are required to follow NERC protocols which provide consistency in operations and expectations.

b. Every situation allows for new lessons learned on how we operate our systems, independently and in coordination. MISO will continue to review such events and improve how we communicate with our members and our neighbors.

Question NO.: 5

Given that communication between the System Operators is important, it is equally important to communicate with the public and affected parties of pending outages necessary to maintain the System.

a. Were the notification procedures in place at the time of the February event sufficient? What improvements to a notification process should be made?
b. When outages are necessary, who makes the determination which areas are required to shed load?
c. Are there protocols in place for determining which areas are chosen to shed load and/or consideration given to the types of facilities impacted?
d. Is there sufficient usage data to adequately determine the impact of outages in each area or on different types of infrastructure or facilities in those areas?
e. How does the end user appeal or request consideration of unique circumstances upon notification of service curtailment?

RESPONSE:	**See below** ☒	**See attached**	☒
RESPONSE DATE:	**April 30, 2021**		

a. Yes, and MISO's System Operations utilize the Energy Emergency Alert steps in its Capacity Emergency Procedures. These steps provide our members and neighboring Operators sufficient information to communicate system conditions.
Regarding public notifications, MISO utilized its designated communication channels to notify affected parties. This includes member company representatives (operations, regulatory, communications). MISO also provided messages via social media and added a "Current Grid Conditions" page to its Media Center as the primary location for public information.

   MISO executed its Crisis Communications plan and it worked as designed. However, we are always looking for opportunities to improve clarity and consistency as well as additional touch points for reinforcement. For example, MISO deployed its Mobile App in the first quarter. The operations notifications are also posted immediately to the site and pushed to the app.

b. MISO, as the Reliability Coordinator for its membership, is responsible for determining the need for load shed and directing it to the appropriate Local Balancing Authorities.

c. Yes, and consistent with its role as Reliability Coordinator and dependent upon the circumstances, MISO has protocols for identifying which LBAs should shed load. For example, in a local transmission emergency, MISO will direct a more targeted load shed to specific LBAs as was seen in four separate instances during the Arctic Weather Event, and those events limited the LBAs that were impacted. However, during the capacity deficiency event in the evening of 2/16, the existing protocol was to implement a pro-rata load shed based on the ratio of LBA load to system load at the time of the directive.

- MISO acts as the Balancing Authority (BA) with responsibility for declaring Load Shed Directives for Energy Emergency Alert Level 3 (EEA3) Events impacting areas within the MISO Balancing Authority Area. MISO Local Balancing Authorities (LBAs), such as the Entergy Arkansas Load Balancing Authority, are responsible for individual load shed programs, which take into account critical load identification, and perform the actual load sheds as directed by the MISO BA. Responsibilities around Firm Load Shed per Emergency Operating Procedure-011 (EOP-011) requirement 2.2.8 is delineated in the CFR00001. (The NERC Standard for Load Shed requirements is EOP-011, the Coordinated Functional Registration (CFR) delineates which parts of the NERC Requirements are the responsibility of MISO as BA and which are the responsibility of the LBAs as BAs).
- MISO procedural actions for EEA3 firm load sheds is included in MISO Procedure SO-P-EOP-002 MISO Market Capacity Emergency procedure section 4.2.13 shown below.
- Note that the respective LBA Firm Load Shed amounts are determined by applying a pro-rata share to each applicable LBA within the defined Event Area. For example, if the Event Area required 100 MW of load shed, and a specific LBA's load at the time of the Load Shed Directive was 15% of the Event Area load, then that LBA would be responsible for 15 MW of load shed.)
-

4.2.13 Max Gen Event Step 5 - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 5 or escalating from a Max Gen Alert/Warning or lower Event step, THEN **DECLARE** Max Gen Event Step 5 and EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions.

SM **Note**

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment provides additional information regarding sharing of load shedding with Slice of System PPAs.

2. **DETERMINE** manual Load Shedding requirements.

SM **Note**

Issuing Emergency Operating Instructions for firm Load shed is based on the ratio of LBA forecasted or actual Load to the total forecasted or actual Load of the declaration area, taking into account applicable transmission security requirements.

3. **ISSUE** Emergency Operating Instructions to LBAs, in declaration area, of MW amounts of load to shed via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions.

- LBA actions for EEA3 firm load shed directives received from the MISO BA is included in MISO Procedure SO-P-EOP-002 Market Capacity Emergency procedure section 4.3.11. (Note that each individual LBA has internal procedures for its own specific load shed processes).

4.3.11 Max Gen Event Step 5 - MISO Stakeholder Actions

LBA	1. **SHED** firm Loads per MISO issued Emergency Operating Instruction.	[ ]
LBA	2. **CONFIRM** actions taken with MISO RC via MCS Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions.	[ ]

More information about MISO's operating procedures during emergency or abnormal operating situations can be found in the document attached hereto as Exhibit 2.

d. MISO does not direct Load Serving Entities (LSEs) to shed load; MISO directs the Local Balancing Authorities (LBAs) to shed load and it is the responsibility of the LBA to work with the LSEs in its area on coordination of load shed plans. MISO's visibility is limited to current system-wide situational awareness on the demand and resource balance and, if the system is at risk, the amount of load that would need to be shed to maintain and reliably operating the bulk electric system.

e. MISO does not have direct visibility to the distribution grid. Because of this, it is MISO's role to direct the LBA load shed and it is up to the LBA to identify the distribution circuits impacted.

Question NO.: 6

Are there changes that integrated system operators need to consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event?

a. If so, what changes would you recommend?
b. Are there constraints in place from Federal Energy Regulatory Commission or North American Electric Reliability Corporation that would prevent implementation of such changes?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

a. MISO is always open for continuous improvement, but at this time we do not envision any changes to our dispatch process. Charging of facilities would be managed through normal market processes and it is up to each market participant to dictate how those assets will be offered into the system. Current systems, along with planned improvements to meet future FERC mandated storage participation in wholesale markets should provide for such energy management.

b. FERC (and MISO) have a variety of pending dockets that could potentially impact storage technologies. MISO is also focused on its Reliability Imperative to broadly address the complex and urgent challenges to electric system reliability in the MISO Region. More information can be found at the following website: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative/

Question NO.: 7

Are there any recommendations or areas of further investigation that your organization would like to bring to the attention of the Task Force with regard to addressing energy supplies during future events?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

- Efforts to continue to foster and enhance preparedness as we have discussed in question #3, as well as continue the high level of coordination with our neighbors as referenced in our response to question #4.
- Consider formalizing and expanding the ad hoc call (discussing securing fuel for certain generation facilities) into a leadership planning group that entails both Public and Private Organizations to cover impacts of extreme events. Those that were involved on the February 17th call were as follows:
-

Government

  - AR Governor's Office – Caleb Stanton
  - AR Public Service Commission – Chairman Ted Thomas
  - AR Economic Development Council – Mike Preston
  - Little Rock Mayor – Frank Scott
  - Department of Emergency – Scott Bass
  - Arkansas Research Alliance – Jerry Addams
  - State Police Colonel – Colonel Bill Bryant

Electric Utility Companies

  - Entergy – CEO Laura Ladeaux, SVP Charles Hall,
  - AECC – CEO Buddy Hasten & SVP Kirkley Thomas
  - MISO – Executive Director, Daryl Brown
  - SPP – Mike Ross

MISO is currently conducting an analysis of the causes and impacts of the Winter Storm, which will be finalized as a report by the end of May 2021. MISO is planning to provide the report publicly at a workshop currently planned for early June 2021 and the report will be made available for stakeholders.