APPENDIX C. WRITTEN TESTIMONY AND ASSOCIATED DOCUMENTS

ARKANSAS
ENERGY & ENVIRONMENT

April 9, 2021

Greetings:

On March 3, 2021, Governor Asa Hutchinson signed Executive Order 21-05 to establish the Energy Resources Planning Task Force. The Task Force, of which I have the honor of chairing, is made up of the Arkansas Department of Energy and Environment, the Oil and Gas Commission, the Liquefied Petroleum Gas Board, and the Department of Commerce. The Task Force will review lessons learned from the February winter storms, including those from surrounding states, and gather information from pre-filed responses and hearing testimony.

On behalf of the Task Force members, I am pleased to invite you to provide valuable input that will be sent to Governor Hutchinson upon the completion of our report, which is due on September 30, 2021. As Chair of the Task Force, I respectfully request that your written responses to the attached testimony questions be sent to ERPTaskForce@arkansas.gov on or before **April 30, 2021**. While there will be an opportunity for public testimony at a date to be determined, your pre-filed responses will ensure that our report to the Governor reflects the Task Force's most comprehensive and judicious recommendations and priorities.

Your participation is key as we look for solutions to better prepare our state's energy infrastructure in the event of another statewide emergency. Thank you for your time and consideration of this important matter.

Sincerely,

Becky W. Keogh

Becky W. Keogh
Cabinet Secretary, Arkansas Energy & Environment
Chair, Energy Resources Planning Task Force

Energy Resources Planning Task Force

Response to Testimony Questions of Ted Thomas, Chairman, Arkansas Public Service Commission[1]:

1. Please summarize the Public Service Commission's understanding of the causes of the electric and natural gas shortages that occurred during the February winter weather event.

Record cold temperatures caused record demand for energy while also severely disrupting natural gas production[2]. Although review is ongoing, Southwest Power Pool independent market monitor Keith Collins states, "Fuel supply issues, primarily natural gas, were a primary cause of outages and resource scarcity."[3] This is best demonstrated by review of the gas production charts on page 8 of the American Gas Association presentation and on page 3 of the SPP independent market monitor report. Final conclusions about the causes of the electric and natural gas shortages should be made only upon completion of the various pending investigations.

2. Please summarize the policies, programs, procedures or technical aspects that Arkansas had in place that, in comparison to other states, minimized the power shortage impacts in Arkansas during the February winter weather event.

All utilities in Arkansas are members of one of the two Regional Transmission Organizations (RTO) in Arkansas, Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO). Roughly speaking, the SPP area of Arkansas includes the SWEPCO, OG&E, Empire District and municipal utilities surrounded by those service

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[1] The views expressed in this document are the views of Ted Thomas, not the Arkansas Public Service Commission.

[2] See *The Effects of Winter Storm Uri on Natural Gas Utilities* slide presentation from the American Gas Association on April 21, 2021 to the NARUC Committee on Gas, pages 3 and 8. The full slide deck is attached hereto.

[3] *Market Review of Winter Event* slide presentation to the Southwest Power Pool RSC (State Regulator stakeholder group in SPP) by Keith Collins, independent Market Monitor for SPP at page 16. The full slide deck is attached hereto.

territories and the MISO area of Arkansas includes the Entergy service territory and municipal utilities surrounded by that service territory. Electric cooperatives are in some ways managed as if they are in both RTOs and in other ways those cooperatives closest to SPP territory are in SPP and likewise for MISO.

An RTO is a non-profit entity that manages the grid that is owned by utilities to ensure that generation resources have access to the grid even if the generation asset is owned by an entity other than the utility that owns the transmission assets. This allows for a wholesale electricity market and regional transmission planning which are managed by the RTO.

"Reserve margin" is (capacity minus demand)/demand, where "capacity" is the expected maximum available supply and "demand" is expected peak demand. It is calculated for electric systems or regions made up of a number of electric systems. By definition, a smaller geographic area has a higher reserve margin than a larger geographic area. In an RTO, the reserve margin is calculated for the entire RTO, not for individual state utilities within the RTO. A lower reserve margin means that fewer resources are needed and the resulting cost savings is the primary reason for joining an RTO.

A state loses some degree of autonomy when its utilities join an RTO because system reliability is then measured on an RTO basis and not a state specific basis. Each state's policy contributes to the RTO's reliability but the transmission system is managed on a regional basis, thus when both RTOs had load shed events the rolling blackouts were done proportionally across the region[4] rather than on a state basis. While states maintain jurisdiction over generation recourses, usually through a planning process called integrated resource planning, those state specified resources are managed collectively by the RTOs.

[4] In SPP, the load shed event was distributed to the entire footprint. In MISO, the load shed event was limited to MISO south because of transmission constraints between MISO north and MISO south.

A comparison of reliability between states in the same RTO cannot be made in that each state in the RTO has the same reliability because the grid is managed on a regional basis. However, a regional comparison can be made between SPP, MISO and ERCOT, the RTO that manages the grid in most of Texas.

Generally speaking, comparisons of RTO performance during the winter weather event were driven by geography. The temperature's impact on load and fuel availability was worse to the west and south of the combined SPP, MISO and ERCOT region. The ability to import electricity from other regions was also less the in the south and west of the combined region. As a result the outages and cost spikes were less severe in MISO, more severe in SPP and most severe in ERCOT.

In SPP a more significant load shed event was avoided by imports from other regions[5]. Furthermore, the load shed events in SPP were highly correlated with import curtailments because of transmission constraints in MISO[6], which borders SPP to the east. Electricity was being imported to SPP from MISO and PJM, the RTO to the east of MISO. On page 9 of the referenced slide deck, both of the load shed events are marked in yellow and are preceded by reductions in imports.

MISO south had a load shed and MISO north did not. This is because of transmission constraints between MISO south and MISO north as demonstrated by the MISO independent market monitor's focus on transmission in the "lessons learned" report submitted to MISO board of directors[7].

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[5] *Market Review of Winter Event* slide presentation to the Southwest Power Pool RSC (State Regulator stakeholder group in SPP) by Keith Collins, independent Market Monitor for SPP at page 8.

[6] *Market Review of Winter Event* slide presentation to the Southwest Power Pool RSC (State Regulator stakeholder group in SPP) by Keith Collins, independent Market Monitor for SPP at page 9.

[7] *IMM Quarterly Report: Winter 2021* slide presentation to the MISO Markets Committed by Dr. David Patton, independent market monitor for MISO at page 10-11. The full slide deck is attached hereto.

The ERCOT regions of Texas, which includes the major metropolitan areas of Texas and approximately 80% of the load, has a unique jurisdictional arrangement whereby they are not subject to FERC jurisdiction because power flows in ERCOT are not in interstate commerce because the ERCOT grid is fully severable from the rest of the electric grid. The limited ability to import electricity from other regions contributed to the severity of the event in Texas, as did lack of winterization of electric generating assets as well as natural gas production assets.

3. To what extent did the implementation of energy efficiency programs by the utilities in accordance with the Public Service Commission rules reduce the need to shed load during the February winter weather event? Are their changes to the energy efficiency rules, targets or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

Energy efficiency programs are designed to reduce consumption in order to save costs related to the production of energy and costs related to having the capacity on hand at any moment to produce enough energy to meet all of the demand for energy without waiting in line. Electricity efficiency savings are measured both in terms of MWh of energy used and in terms of MW of capacity, the amount of resources needed at peak so that anyone can use as much as they want without waiting. Natural gas efficiency savings are measured in therms which is a measurement of heat produced by burning a standard unit of natural gas.

In May of each year the seven investor-owned electric and gas utilities report to the Public Service Commission on the verified energy savings achieved during the prior year's Energy Efficiency Programs. The electric utilities also report on the demand savings achieved by the programs. The results shown below indicate a total demand savings of 99 MW in 2019 for the three largest electric utilities, Entergy (78 MW), SWEPCO (16 MW), and Oklahoma Gas & Electric Company (5 MW). The 2021 energy and demand savings realized, including the effects of the February 2021 winter event will not be measured, evaluated, and reported on until May 2022. Results achieved during 2020 will be reported by the utilities on May 3, 2021. Owing to the Covid-19 pandemic and the ongoing requirements for social distancing and the impact the pandemic has had on business operations, it is possible that the energy and demand savings achieved by the utilities in 2020 will not substantially resemble the results for energy and demand savings for 2019 and previous years.

The Commission has now pending a docket (No. 21-036-U) in which the utilities are being asked to report on the causes and impacts of the Winter Weather Event and may be requested to provide information regarding how the energy efficiency programs performed in producing a demand reduction on the electric systems during the Event, especially given the impact on winter electric heating loads during the extreme cold. It seems likely that energy efficiency programs targeting direct load control (e.g., dispatchable smart thermostats) and residential and commercial weatherization and HVAC tune-ups and highly-efficient HVAC upgrades/replacements contributed to electric loads being lower than would otherwise have been the case in February's Event.

Even before the Winter Weather Event, the topic of how utility energy efficiency measures and programs can provide electricity demand reductions as well as energy savings is receiving considerable attention. See the December 23, 2020 PowerPoint update to a 2019 Report by the Lawrence Berkeley National Laboratory on "Peak Demand Savings from Efficiency: Opportunities and Practices" at:

https://eta-publications.lbl.gov/sites/default/files/peak_demand_21_01_07_report.pdf The update includes input on the results from Entergy Arkansas, LLC's energy efficiency programs, as well as those of 51 other large utilities. See also a report issued on April 15, 2021, by the American Council for an Energy-Efficient Economy: "Utilities Can Lessen Winter Power Outage Risk by Investing in Home Efficiency": https://www2.aceee.org/webmail/310911/826688635/a68cbab6c8aea86ae3a5f1083b15ddb79d72276c5db8ee4e5a486d079b6fc0f5

Tables 1 thru 4 below demonstrate the reported savings for the Arkansas 2019 Energy Efficiency Programs and a comparison to prior years' savings.

Table 1 – 2019 Demand and Energy Savings for Electric Utilities

Electric Utility	Net Energy Savings	
	Demand MW	Energy MWH
Entergy	78	248,663
SWEPCO	16	35,952
OG&E	5	26,071
Empire	0	320
TOTAL Arkansas	**98**	**311,006**

Table 2 – Five-Year Energy Savings for Electric Utilities

Savings (MWh)	PY 2014	PY 2015	PY 2016	PY 2017	PY 2018	PY 2019
Entergy	205,507	230,341	253,290	264,992	255,997	248,663
SWEPCO	30,056	31,462	34,357	33,667	36,735	35,952
OG&E	13,794	20,543	23,257	21,131	22,557	26,071
EMPIRE	147	212	220	155	210	320
Total	**249,504**	**282,558**	**311,124**	**319,945**	**315,499**	**311,006**

Table 3 – 2019 Energy Savings for Gas Utilities

Natural Gas Utility	Net Energy Savings
	Energy Therms
CenterPoint	3,831,747
Black Hills	1,268,914
AOG	492,071
TOTAL Arkansas	**5,592,732**

Table 4 – 5-Year Energy Savings for Gas Utilities

Savings (Therms)	PY 2014	PY 2015	PY 2016	PY 2017	PY 2018	PY 2019
CenterPoint	2,743,851	2,938,212	2,963,465	3,423,918	3,790,589	3,831,747
Black Hills	1,138,776	1,417,271	1,540,466	1,261,851	1,262,524	1,268,914
AOG	591,591	535,479	534,421	536,202	500,829	492,071
Total	**4,474,218**	**4,890,962**	**5,038,352**	**5,221,971**	**5,553,942**	**5,592,732**

As discussed above, reliability is managed on a regional basis by RTOs. While the cost savings of the energy efficiency program flow to Arkansas utility customers, the reliability benefits are shared regionally. Reductions in demand in the Entergy service territory reduced the load shed event in MISO south by 78 MW and the load shed event in SPP by 21 MW when compared with baseline usage that existed prior to the implementation of the efficiency program. But for the efficiency program, the load shed caused by the winter weather event would have been larger.

4. Please briefly summarize the issues that the Public Service Commission will examine with respect to understanding in more detail the power shortage events that occurred during the February winter weather event.

The Arkansas Public Service Commission will investigate in detail the preparation, response, operational performance, and communication practices regarding the winter weather event with respect to electric and natural gas utilities and RTOs in Arkansas. A commission order stating the scope of the investigation will be issued on the near term and this answer will be updated with a copy of that order.

5. Are there any recommendations that the Public Service Commission would like to present to the Task Force in regard to addressing energy supplies during extreme events?

First, policy recommendations regarding the winter storm event should be considered in conjunction with other related policy issues, particularly the climate policy of the new federal administration. Intermittent renewable resources can cause reliability problems at high levels of penetration, yet such resources can mitigate the cost of compliance with expected federal carbon regulation. Placing reliability issues and carbon issues in separate silos would be a significant mistake.

Given that aspects of reliability are managed on a regional basis, continued engagement in the RTO stakeholder processes that are study these issues is essential. Also essential is that questions involving system reliability be addressed by applying rigorous engineering standards, not by the application of political muscle. The rigor brought by the RTOs to this subject matter is demonstrated by the attached documents *Integrated Markets and Operations Update* dated April 26, 2021 and *MISO's Renewable Integration Impact Assessment (RIIA) Executive Summary* dated February 2021.

Second, the "stupid fuel wars" debate approach will bring neither reliability nor emission reductions. The "fuel wars" is my description of corporate and industrial trade group public relations efforts regarding the national climate debate, elements of which have entered the reliability debate prompted by the February winter weather event. The fuel wars debate approach focuses on soft positive reaction to industry groups rather than effective policy debate. I refer to the fuel wars as stupid because in the context of the climate debate this approach has failed to associate calls for climate "action" with potentially large increases in costs to consumers.

The failure of this approach can be demonstrated by the shift in public attitudes regarding climate policy over the past several years and the failure to attempt to include cost to consumers when measuring public opinion on climate policy. The failed public relations strategy of the American Petroleum Institute (API) is symbolic of industries failure to stand up for its customers. API recently announced that it supported the concept of a carbon tax, presumably to accommodate public opinion on the climate issue. Cost will be imposed on consumers with no promise of a solution to the problem and no discussion of international cost allocation issues that have yet to be resolved. Write a check first, solve the problem later. The "stupid fuel wars" approach has been a failure with respect to the climate debate and it will also fail with respect to examination of system reliability of the winter weather event.

Third, a reliable, cost effective system that complies with expected federal carbon mandates is in my view achievable only through policy that rigorously examines all possible new and existing technologies. This will only occur if decisions are made based on engineering and economics rather than by political muscle.

Resource Adequacy Reforms

OMS Spring Seminar

May 24, 2021

Purpose & Key Takeaways

Key Takeaways:

- MISO is looking at refinements to the accreditation proposal that meaningfully address stakeholder concerns while sufficiently mitigating reliability risks
- MISO has extended overall timeline to allow sufficient stakeholder engagement to support a FERC filing now planned for September 2021
- Directional changes were shared at a RAN workshop on May 21st ; these preliminary design changes will continue to be refined with additional detail for the June RASC

MISO will increase transparency in the planning horizon coupled with market price signals to incent needed resource capabilities

Current Hypothesis

Market Redefinition

RESOURCE ASSESSMENT

MISO will provide a forward assessment to provide stakeholders with transparency of forecasted system needs (for capacity and flexibility) versus expected system capabilities based on the aggregation of member plans

MEMBER CAPACITY TO MEET FORECASTED NEEDS

Proposing changes to the current RA construct to assess members' capacity to meet forecasted needs; Planning to move to sub-annual Planning Resource Auction (PRA) construct

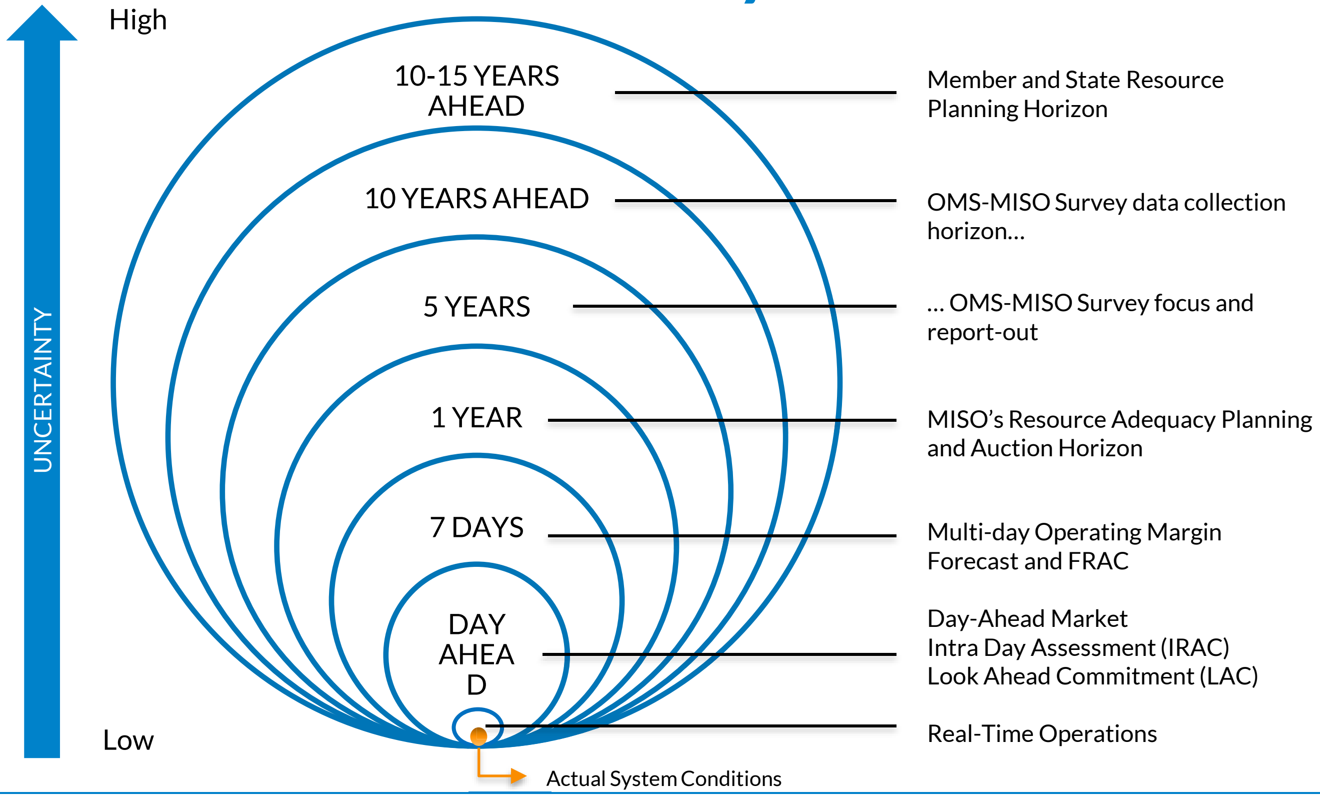
PRA MECHANISM AND AUCTION STRUCTURE

PRA process remains as mechanism to ensure compliance with reserve margin requirement with no substantive changes to auction structure

INCREASED RELIANCE ON ENERGY MARKET SIGNALS

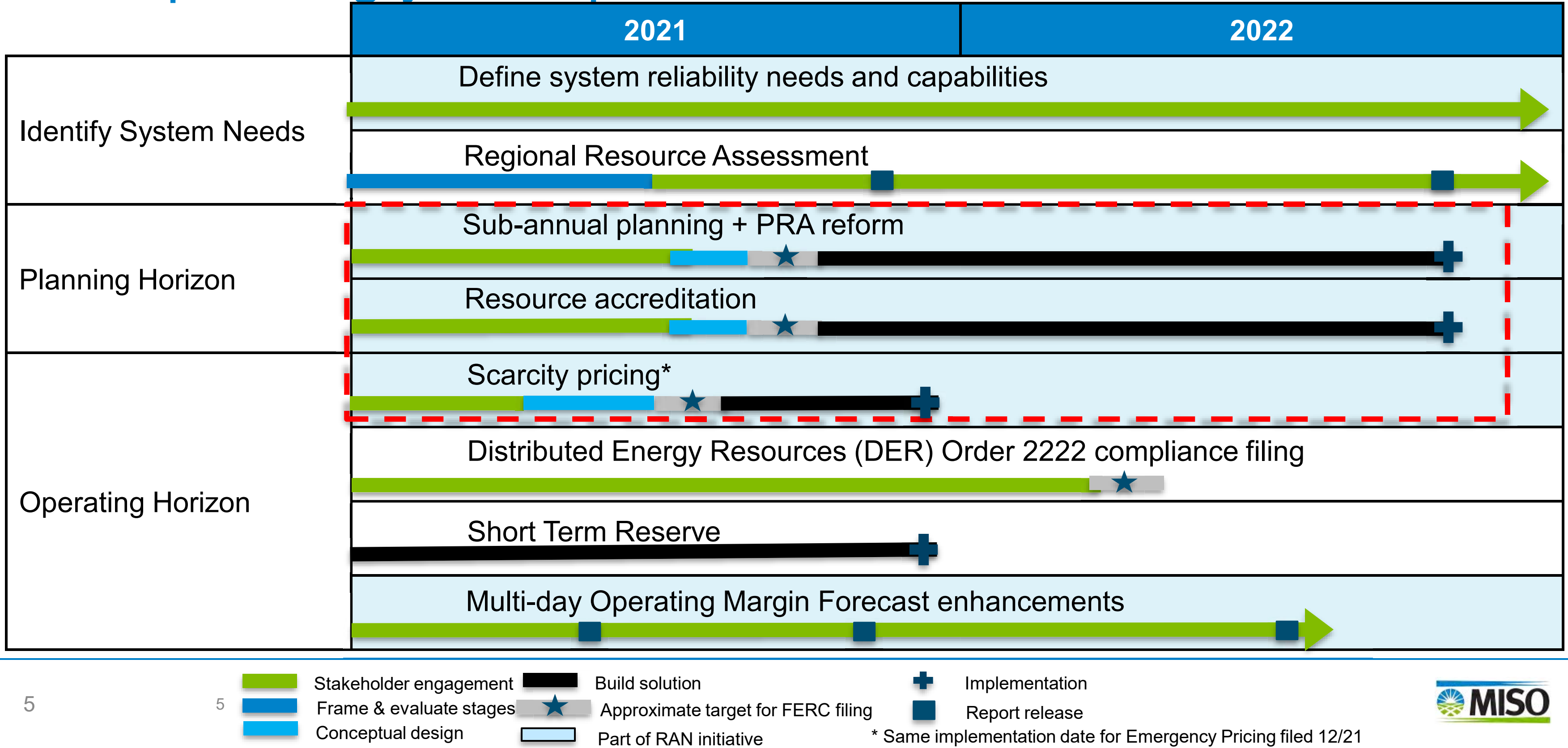
Energy markets to address the challenges of the changing fleet; leverage energy and ancillary service markets to incentivize resources to provide sufficient energy and ramping capabilities in the operating horizon

Resource Availability timeline



OMS = Organization of MISO States   FRAC = Multi-day Forward Reliability Assessment Commitment   IRAC = Intra Day Assessment Commitment

MISO is working with stakeholders on multiple FERC filings (dotted red lines) in Q2 and Q3 of 2021 targeting a 2023-2024 planning year implementation



LOLE analysis to set seasonal requirements

MISO proposes a range of design elements to determine seasonal resource adequacy requirements to reflect analysis findings and stakeholder feedback

	MISO Proposal	Rationale	Preliminary findings
Seasonal Risk Target	Round seasonal targets up to a minimum 0.01 without adjusting other seasons' Loss of Load Expectation (LOLE) target if greater than 0.01	Avoid artificially inflating requirements for seasons with risks greater than 0.01 Meet the BAL-502-RF standard requirement	Increase in requirement may not be trivial if adjusting seasons with LOLE risks greater than 0.01 to compensate for having minimum 0.01 in other seasons
Season Definition	Include September in Summer season	September load shapes generally resemble summer month load shapes	Notable decrease in Fall resource adequacy requirements with minimal impact on summer requirements
Seasonal CIL/CEL	Conduct seasonal transfer limit analysis to determine seasonal CIL/CEL	Capture seasonality of transfer limits in determining Local Clearing Requirements	Variation observed in seasonal transfer limits driven by seasonal conditions

MISO proposes to round seasonal LOLE risk targets up to a minimum 0.01 to set seasonal resource adequacy requirements PRM/LRRs

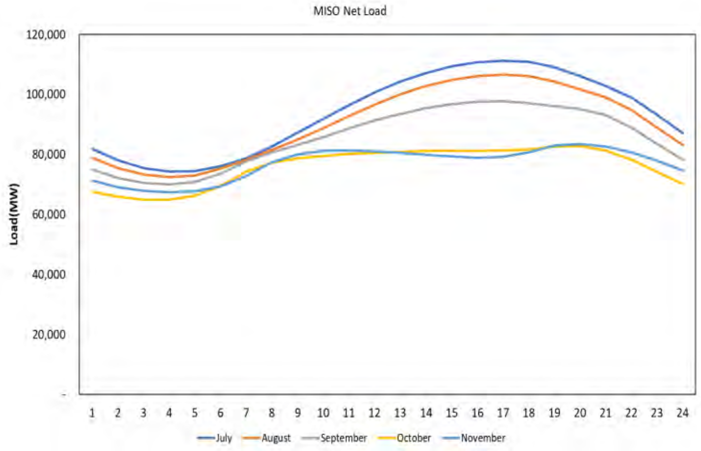
The goal of setting seasonal risk targets is to determine seasonal resource adequacy reserve requirements PRM/LRRs

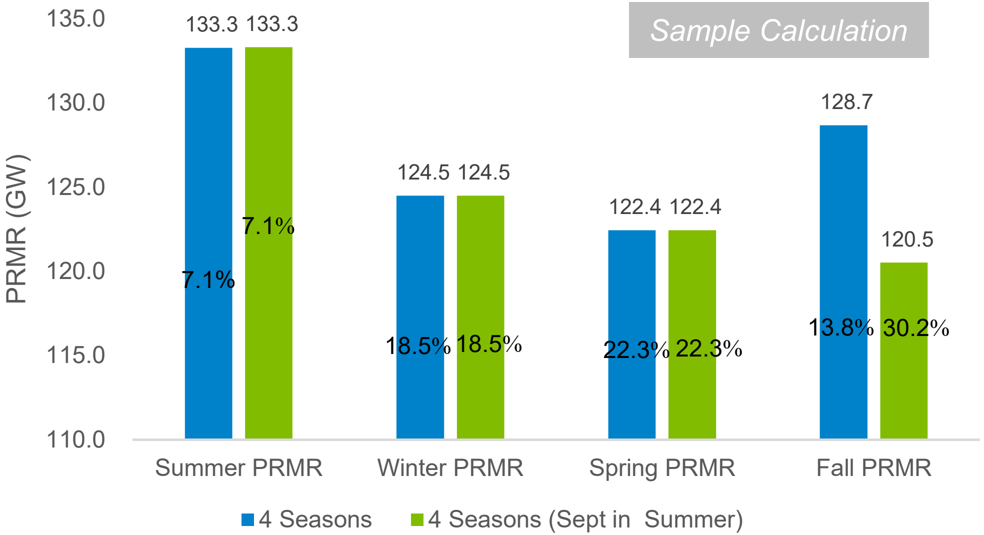
Options	Pros	Cons
Round seasonal targets up to a minimum 0.01 without adjusting other seasons' LOLE	• Only requires an additional modeling run for seasons with LOLE <0.01 • Keep reserve requirements for the seasons with risks as is • Meet the BAL-502-RF standard requirement	• Results in an annual LOLE slightly above 0.1d/year standard
Round seasonal targets up to a minimum 0.01 and adjust other seasons' targets down to maintain a 0.1d/year annual LOLE	• Total 0.1d/year annual LOLE • Meet the BAL-502-RF standard requirement	• Requires additional runs for all seasons to rebalance seasonal targets to meet 0.1 annual LOLE • Increase requirements for seasons where there are risks and procure more capacity than needed, which can be costly

	0.1 Summer LOLE Target*	0.07 Summer LOLE Target*	Difference
PRM %	7.1%	7.7%	0.6%
Summer PRMR (GW)	133.3	134.0	0.7

* The analysis is based on PY21 sub-annual LOLE modeling assumptions
PRM = Planning Reserve Margin | LRR = Local Resource Requirement

MISO is recommending including the month of September to the summer season





- September load shape more closely resembles the summer month load shapes
- Notable decrease in Fall resource adequacy requirements with minimal impact on summer requirements

- The analysis is based on PY21 sub-annual LOLE modeling assumptions
- PRMR – Planning Reserve Margin Requirement

Revised resource accreditation proposal

MISO proposes refinements to the accreditation proposal that meaningfully address stakeholder concerns while sufficiently mitigating reliability risks

	Proposal presented at Feb RASC	Current Revised Proposal	Address Stakeholder Concerns
Hour Selection	Availability during top 5% of tightest hours across the year	Availability across all hours with a two-tiered weighting structure between tight condition hours and non-tight hours	Focus on availability during times of need while reflecting general availability across the year
Recognize coordinated outage planning	N/A	Leverage and enhance RAN Phase I outage planning processes; Include planned outage exemption rules; Refine planned outage modeling in LOLE	Recognize and enhance prudent outage planning; better align modeled and actual outages
Stability in RA planning	Small set of tightest hours selected over three-year period	Account for all hours across the year over a rolling three-year period	Reduce year to year volatility in seasonal accreditation values
Lead time of offline resources	24 hours for identifying tight condition hours, not considered for accreditation calculation	24 hours for identifying tight condition hours and calculating accreditation	Better align with Day Ahead market processes, will monitor and enhance as resource mix evolves

MISO is refining planned outage treatment by leveraging and bolstering RAN Phase 1 provisions

Address Existing Gaps

- Validate how outages* are treated in CROW
- Tighten up language around coding outages
- Improve supporting process for verification and penalties

Develop Enhancements

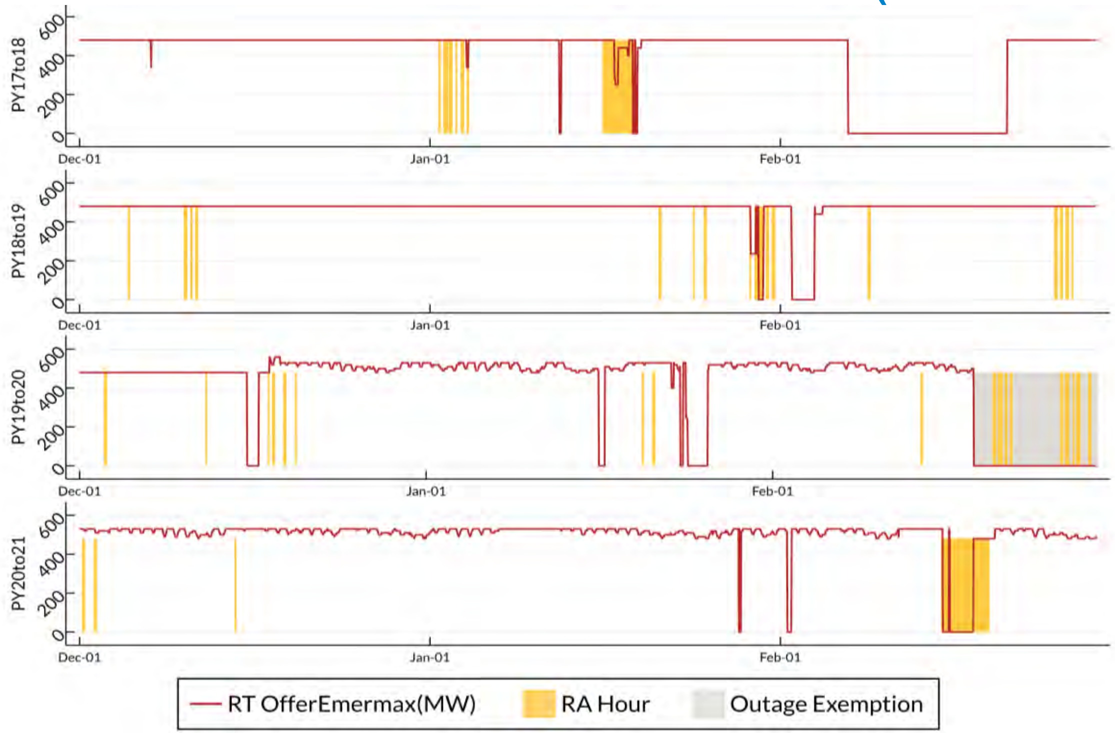
- Expansion of hours applicable for RAN Phase I provisions
- Bolster magnitude of accreditation penalties
- Limit on total MWs of outages and outage extensions

Outages* includes forced and planned outages and de-rates

Proposed enhancements to RAN Phase I are incorporated into the revised proposal

- Address Existing Gaps:
  - Validate: By using offers, de-rates only have a pro rata impact on accreditation as intended
  - Tighten: The revised proposal ensures all non-exempt (insufficiently coordinated) outages are treated like forced outages when they overlap with capacity emergency conditions
  - Improve: The revised proposal accounts for unreported or misreported outages which have been a significant issue based on reporting by the IMM
- Develop Further Enhancements:
  - Expand: The revised proposal considers non-MaxGen tight hours such as conservative ops in addition to MaxGen alerts/warning/events as recently recommended by some stakeholders
  - Bolster: Under RAN Phase 1 non-exempt outages during times of need typically only had a 0.1%/day impact to accreditation
    - Under the revised proposal a tiered approach focused on the tightest 3% of hours creates a 33x multiple that is then discounted by the weighting between the tiers
  - Limit: To support reliability and equity, the revised proposal limits exempt outages regionally and requires reasonable expectation of seasonal availability to participate in each auction

RA hours that occur when a resource is on an exempt outage or didn't clear the seasonal auction are removed from accreditation assessments (illustration for a single resource)



Winter	RA Hours	Exempt* Hours
PY 18-19	87	0
PY 19-20	64	34
PY 20-21	65	0

For tier 2 the proposal only considers RT offers in non-exempt hours which would be 30 hours in PY 19-20

*There are no exempt hours prior to spring 2019 when RAN Phase 1 was approved

Tier 2 tight condition hours are defined across the year based on retrospective tight supply time periods and MaxGen event hours[1]

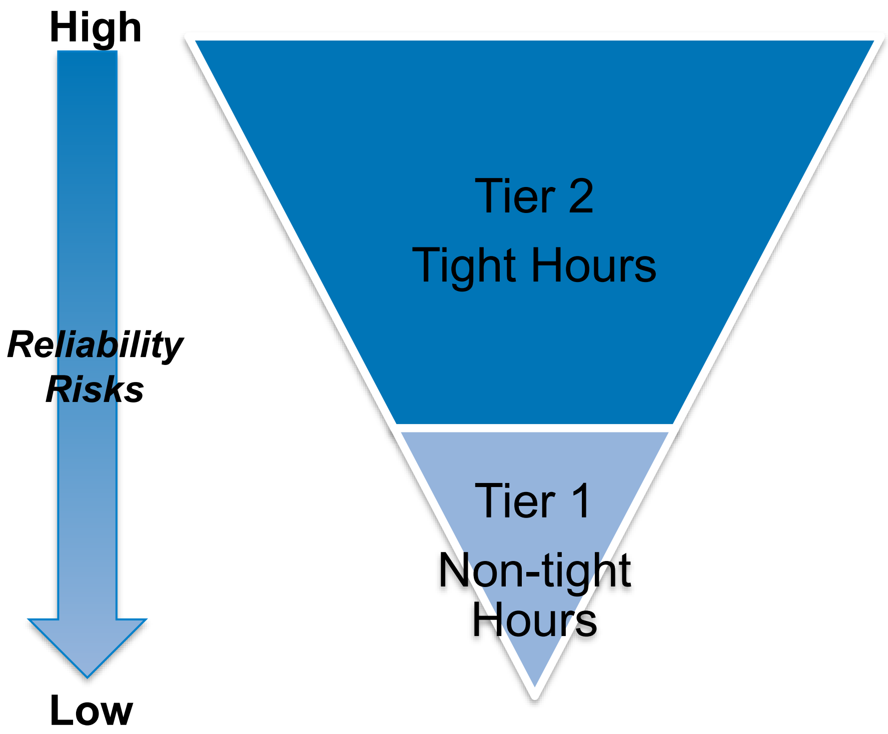
- RA hours are defined as tight margin hours and emergency hours over three historical planning years
  - Margin (%) = online margin + offline margin (24-hour lead time) / RT load
  - For the analysis presented tight margin hours are selected using the tightest 3% of hours across each season in each year, for Central+North and South separately

Sample Calculation

	Central + North						South				
Planning year	**Summer**	**Fall**	**Winter**	**Spring**	**Total**		**Summer**	**Fall**	**Winter**	**Spring**	**Total**
2017-2018	66	66	64	117	**313**		66	67	87	111	**331**
2018-2019	73	65	65	66	**269**		79	67	64	73	**283**
2019-2020	66	65	65	66	**262**		79	65	65	66	**275**
Total	**205**	**196**	**194**	**249**			**224**	**199**	**216**	**250**	

1 Detailed hourly margin data and MaxGen indicators are posted with workshop materials.
2 RT Offer uses EmergencyMax ranges. LMRs and EDRs are excluded. Resources offline with lead time of 24 hours or less are included.

All Hour Availability - MISO proposes a two-tiered weighting approach to reflect general availability while emphasizing availability during times of need



- A tiered weighting accreditation structure will
  - Reflect general availability across the year by counting non-tight hours in accreditation
  - Emphasize availability during times of need by applying higher weighting to tight condition hours
  - Provide a level of stability to inform better resource planning
- Tier 2 includes MaxGen hours overlaying with the top 3% of tightest hours across each season while Tier 1 including all the remaining hours across each season

The diagram is for illustrative purposes only and represents impact to accreditation

MISO's revised accreditation proposal reflects findings from impact analysis and stakeholder discussion

Design Elements		Proposal presented at Feb RASC	Revised Proposal with a two-tiered Weighting structure
Hour Selection	Top X% of tightest margin hours	Top 5% of hours across the year	Tier 1: all hours excluding tight hours in Tier 2 Tier 2: Max Gen hours supplemented with top 3% of tight margin hours
	Max Gen hours	YES	YES
	Regionality (N+C/S) (tight margin and max gen hours)	NO	YES
	Leadtime for offline units (tight margin calc)	24 hours	24 hours
Accreditation Calculation	Annual vs Seasonal	Seasonal	Seasonal
	Tiered Weighting	N/A	Tier 1 20%; Tier 2 80% [1]
	Leadtime for offline units	NO	24 hours
	RT offer considered	Emergency Max	Tier 1 EcoMax; Tier 2 Emergency Max
Planned Outage Exemption	RAN Phase I Enhancement	NO	YES
LOLE modeling	Planned outage modeling	Optimal	Flexible as discussed at May RASC

[1] Weighting factors are indicative and subject to further refinement, 20/80 assigns heavier weighting towards tight condition hours to better incentivize availability during times of need

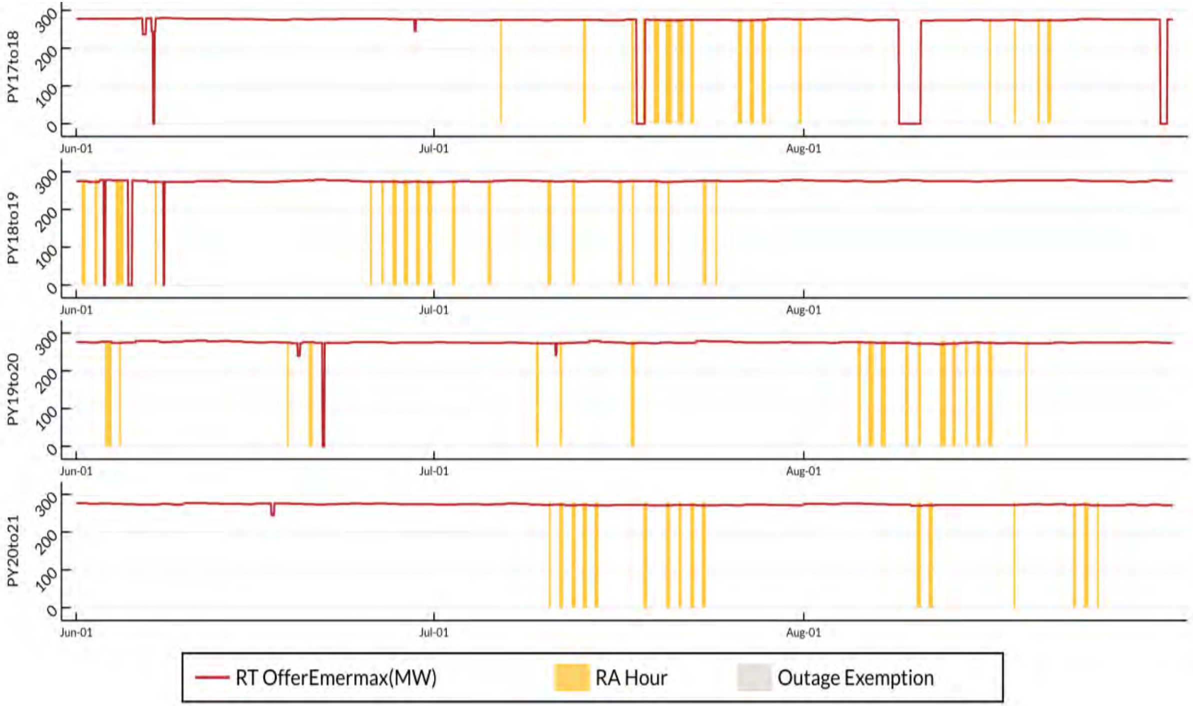
Seasonal PRMR adjustment using a conversion ratio preserves surplus supply

Sample Calculation

Seasonal Conversion of Requirement (MW)		
Seasonal Coincident Peak Forecast	122,398	A
Seasonal Requirement (UCAP)	131,088	B = A * 1.071
Seasonal Thermal UCAP	116,632	C
Seasonal Non-Thermal UCAP	24,678	D
Total Seasonal UCAP	141,310	E = C + D
Seasonal UCAP Surplus/Shortfall	**10,222 (7.8% of req)**	**F = E - B**
Seasonal Thermal Accredited MW	108,039	G
Seasonal Conversion Ratio[1]	0.9263	H = G / C
Adjusted Seasonal Requirement	121,430	I = B * H
Seasonal Non-Thermal Accredited MW	22,860	J = D * H
Total Seasonal Accredited MW	130,899	K = G + J
Seasonal Surplus/Shortfall	**9,469 (7.8% of req)**	**L = K - I**

[1]Thermal resources not within the LOLE model or without Real-Time offers were excluded from conversion ratio

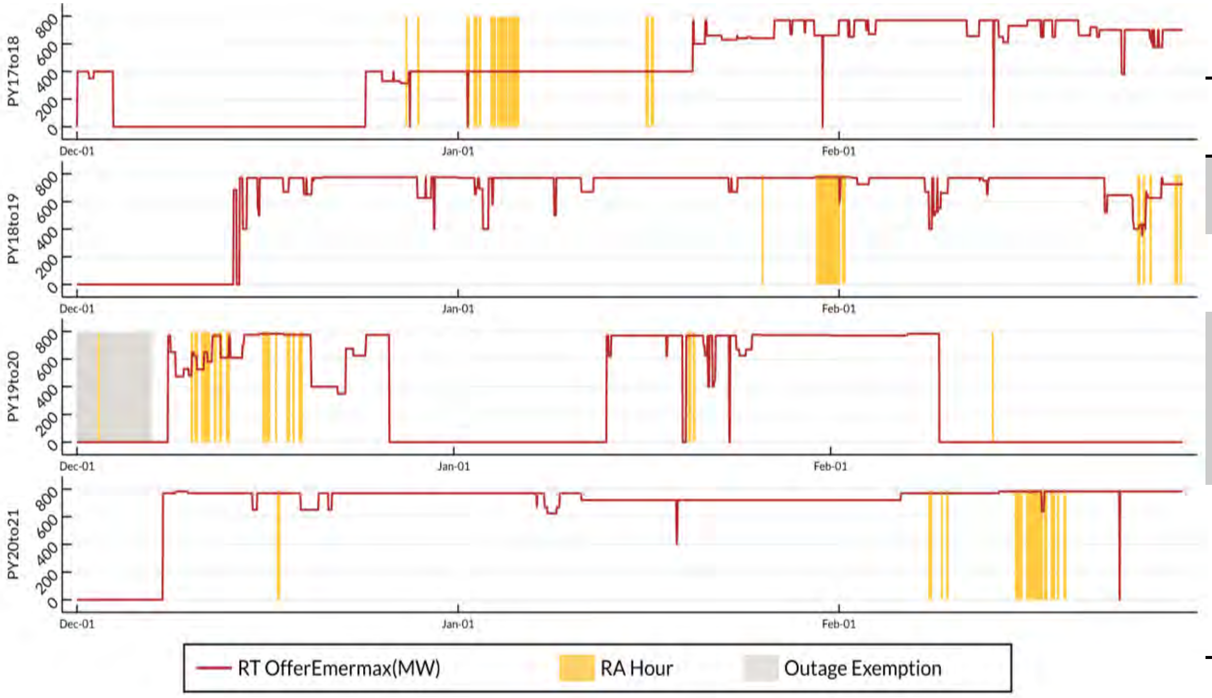
Resources that tend to offer their full availability and don't miss tight hours receive full credit



Season	Winter	Summer*
ICAP	279	276
UCAP	272	260
Accredited Capacity PY17-20**	274	273
Accredited Capacity PY18-21**	277	273

Summer* means June–August, not September
PY17-20** Proposed accreditation based on offers in 3 previous seasons

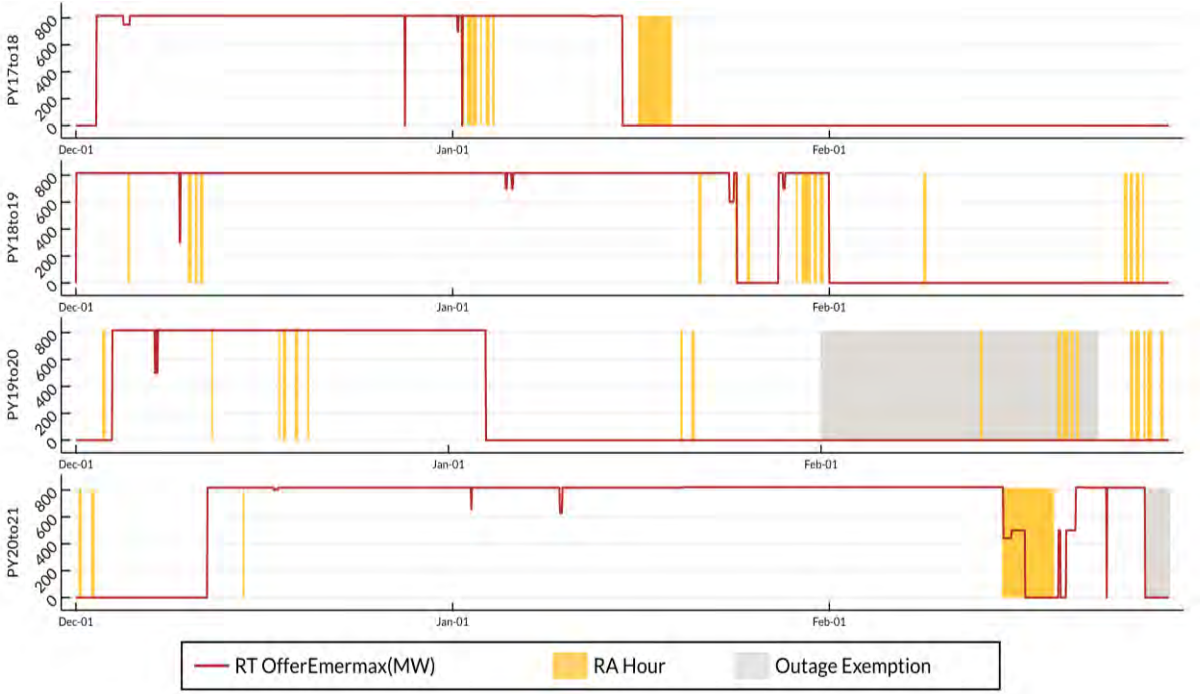
The revised proposal recognizes coordinated outages as exempt and values availability when it counts the most



Season	Winter	Summer*
ICAP	774	771
UCAP	728	705
Accredited Capacity PY17-20**	467	575
Accredited Capacity PY18-21**	680	590

Summer* means June–August, not September
PY17-20** Proposed accreditation based on offers in 3 previous seasons

The proposal also recognizes when resources are frequently unavailable during times of need without sufficient coordination to receive an outage exemption



Season	Winter	Summer*
ICAP	814	815
UCAP	757	777
Accredited Capacity PY17-20**	520	787
Accredited Capacity PY18-21**	348	746

Summer* means June–August, not September
PY17-20** Proposed accreditation based on offers in 3 previous seasons

Next Steps

Monthly view of discussions, impact reviews and additional opportunities to provide input

Workstream	May	June	July - August
LOLE requirements	Seasonal LOLE targets, zonal CILs, conversion ratio, consider state & LSE resource planning processes	Zonal CEL/LCRs; Review and refine seasonal PRMR targets	Refine requirement calculations
Resource accreditation	Lead time cutoffs for offline units, incentives for coordinated outage planning	System and Zonal accreditation impacts, seasonal outage limits	Review zonal positions and effectiveness of availability incentives to fine tune design
PRA specifics	Impact to outage rules and CONE settlement, pace of change [deferred to June]	Transition needs, potential for prompt, sequential	Finalize detailed design elements and implementation
DA performance obligation	Capacity market power protections [deferred to June]	Evaluate physical withholding exemption	Review and refine seasonal obligations and compliance monitoring
Tariff filing	Discuss outline, filing strategy, key arguments and evidence [also June]	Post available draft tariff language	Post and review needed tariff changes
Input and impacts	Review and comment on zonal impacts and exemptions for prudent planned outages	Review and comment on changes to supply and demand in each zone	Review and comment on conceptual design and draft tariff language

CONE = Cost of New Entry | LRZ = Load Resource Zone | LSE = Load Serving Entity

Next Steps

- Continue conceptual design phase of the proposed RA construct changes and analysis to develop and refine detailed design elements
- Conduct May RAN workshop to review revised RA construct proposal and detailed analysis results

							2021				2022				2023				2024			
Issue ID	Associated IDs	Project Name	Proposed By	Current Phase	Impact	Priority	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Resource Adequacy Subcommittee (RASC)																						
RASC 10	2018-5 IR095 IR096	**Resource Accreditation** Sub Issue of IR025 - (RAN)	Stakeholders, MISO, IMM	Concept Design	MECT	High	C	C	F	F	B	B	B	I	I	V						
RASC 11	2014-5 IR094	**Resource Adequacy Construct** Sub Issue of IR025 - (RAN)	Stakeholders, MISO	Concept Design	MECT	High	C	C	F	F	B	B	B	I	I	V						
RASC 12		**Reliability Requirements & Metrics** Sub Issue of IR025 - (RAN)	MISO	Concept Design	MECT, MSE	High	C	C	F	F	B	B	B	I	I	V						

FRAME	EVALUATE	FERC FILING	BUILD	IMPLEMENT	VALIDATE

Contact Information

Scott Wright
swright@misoenergy.org

Appendix

Overview of Resource Adequacy construct design decisions developed and under development

	LOLE Analysis Establish RA requirements	Resource Accreditation Register resources and qualification	Planning Resource Auction Demonstrate compliance	DA Performance Obligation Ensure availability
Developed	4 seasonal requirements Planning Reserve Margin (PRM) and Local Clearing Requirements(LCRs)	Seasonal accredited values	4 independent seasonal auctions at one time	Seasonal must offer requirements for cleared seasons
Under Development	• Season definition • Seasonal risk target allocation • Seasonal Capacity Import Limit (CIL) and Capacity Export Limit (CEL)	• Accreditation based on resource availability • Registration and qualification • Seasonal Wind Effective Load Carrying Capability (ELCC)	• Seasonal Auction participation eligibility • Capacity replacement • Minimum capacity requirement	• Cost of New Entry (CONE) calculation and settlement • Capacity market power protections

RA construct changes decisions developed
Design decisions under development

The conceptual design timeline runs from January to August with targeted FERC filing in September

Qualitative and Quantitative Evaluation of RA construct options

Conceptual design of proposed RA construct changes

We are here

Development of RA construct tariff language

August - December | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **Sept.**

RASC & Evaluation Workshops (8/05 – 12/31)
- Develop criteria for evaluation
- Define scenarios and inputs
- Discuss construct options
- Review evaluation results

RASC (1/06)
- Review *initial* RA construct proposal
- Initiate Conceptual Design phase

RASC (2/03)
- Review RA construct proposal
- Discuss conceptual design scope

RASC (3/10)
- Review initial RA construct design options

RASC (4/14)
- Review Stakeholder feedback and motion on Accreditation proposal

RASC &Workshop (5/12 & 5/21)
- Review revised proposal and design options

RASC (6/09)
- Review RA construct design

RASC (7/07)
- Review RA construct design
- Initial draft tariff language

RASC (8/04)
- Review final RA construct design
- Review revised draft tariff language

RASC (9/01)
- Review final tariff language

Note: green indicates opportunity for formal feedback

Conceptual design workshop

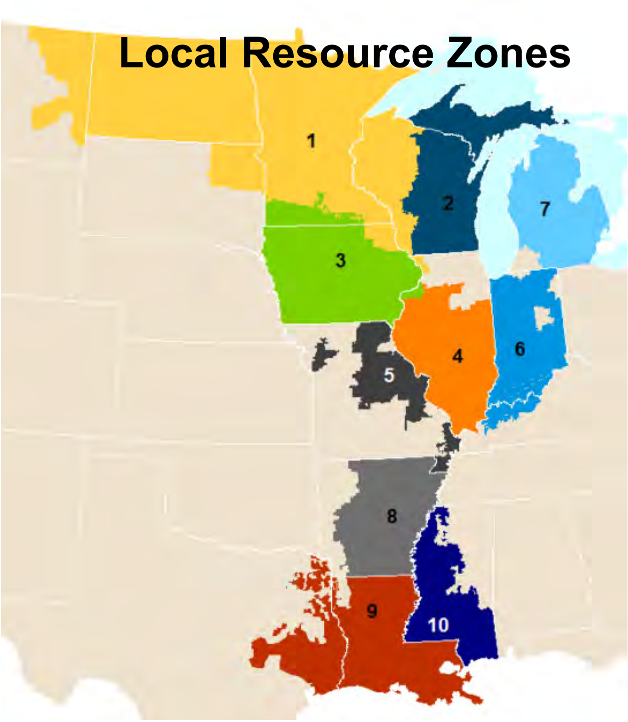
MISO conducted seasonal transfer limit analyses to assess seasonality of CIL using existing methodology in BPM-011

Models	Summer	Winter	Spring	Fall
Powerflow Model	MISO20 Series 2021 Summer Peak (effective date 7/15/2021)	MISO20 Series 2021 Winter Peak (effective date 1/15/2021)	MISO20 Series 2021 Spring Peak (effective date 4/15/2021)	MISO21 Series 2021 Fall Peak (effective date 10/15/2021)
Generation Dispatch	• Local Balancing Area (LBA) NR dispatch • Wind unit output = capacity credit • Solar unit output = 50% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline	• Local Balancing Area (LBA) NR dispatch • Wind unit output = 40% capacity factor • Solar unit output = 0% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline	• Local Balancing Area (LBA) NR dispatch • Wind unit output = 28.5% capacity factor • Solar unit output = 0% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline	• Local Balancing Area (LBA) NR dispatch • Wind unit output = 28.5% capacity factor • Solar unit output = 31% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline
Projects Included	MTEP20 Appendix A and Targeted A	MTEP20 Appendix A and Targeted A	MTEP20 Appendix A and Targeted A	MTEP21 Appendix A and Targeted A
Monitored and Contingencies	PY21-22 annual transfer limit input files	PY21-22 annual transfer limit input files with winter model updates	PY21-22 annual transfer limit input files with Spring model updates	PY21-22 annual transfer limit input files with Fall model updates

MISO proposes to conduct seasonal transfer limit analysis to reflect seasonality of CIL/CEL values

Sample Calculation

Zone	PY21-22 ZIA (MW)	Winter ZIA	Spring ZIA	Fall ZIA
1	5,059	4,120	2,839	4,359
2	3,599	3,526	3,952	4,383
3	4,556	6,355	6,080	5,198
4	5,141	7,343	5,418	5,495
5	4,384	4,712	4,227	5,313
6	6,738	5,834	6,118	6,237
7	4,888	4,925	5,383	6,778
8	5,155	5,340	4,598	4,460
9	3,284	3,427	4,769	5,017
10	3,283	1,100	2,268	2,508



- Large variations occur in zonal CILs across seasons mainly driven by topology and generation dispatch

ZIA – Zonal Import Ability

MISO proposes to adjust requirements on seasonal basis using a conversion ratio to better align accreditation and requirements

UCAP Calculation in LOLE

- Calculate thermal resource UCAP values for each season by removing external resources, Wind/Solar and Load Modifying Resources (LMRs)
- Use sub-annual Loss of Load Expectation (LOLE) modeling assumptions to determine seasonal resource adequacy requirements

New Accreditation Calculation based on offers

- Calculate thermal resource availability for each season by averaging the availability of the RT offers over three-year period with a two-tiered weighting structure

Conversion Ratio from LOLE model to accreditation

- Determine MISO system wide and zonal level conversion ratios by dividing total thermal offer based accredited values by total UCAP values
- Adjust PRMR and LCR requirements by multiplying requirements derived from LOLE analysis by corresponding conversion ratios

Seasonal accreditation calculation based on RT offers Example

- Seasonal accredited value is determined by averaging all hours in Tier 1 weighted by 20% and adding it to the average of the RA hours in Tier 2 weighted at 80% [1]
  - Tier 1 average = 100 MW; Tier 2 average = 120 MW
  - Accredited Value = 100 MW * 0.2 + 120 MW * 0.8 = 116 MW

[1] Weighting factors are indicative and subject to further refinement, 20/80 assigns heavier weighting towards tight condition hours to better incentivize availability during the times of need

RAN phase I has enabled better outage scheduling processes as the basis for further improvements

- Planned outages and derates that overlap MaxGens are exempted from accreditation penalties if
  - The outage request is made at least 120 days in advance or
  - Requested 14 to 119 days in advance with positive Maintenance Margin for the duration of the outage or
  - Outages are moved per MISO request
- The RAN Phase 1 accreditation penalty applies to non-exempt planned outages and derates that overlap MaxGens (alerts, warning & events) by treating just the overlapping days as forced outages (1 day out of 1,095 in a 3-year accreditation period)
- Improvements made on outage coordination processes through RAN Phase I created a stepping stone for further enhancements

INTEGRATED MARKETPLACE AND OPERATIONS UPDATE

BRUCE REW, PE

SENRIO VICE PRESIDENT, OPERATIONS

Helping our members work together to keep the lights on... today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

SPP INTEGRATED MARKETPLACE UPDATE

- Marketplace Operational Highlights
- Historical Load and Wind Trends
- Marketplace Highlights and Information
- Enhancements implemented and under development

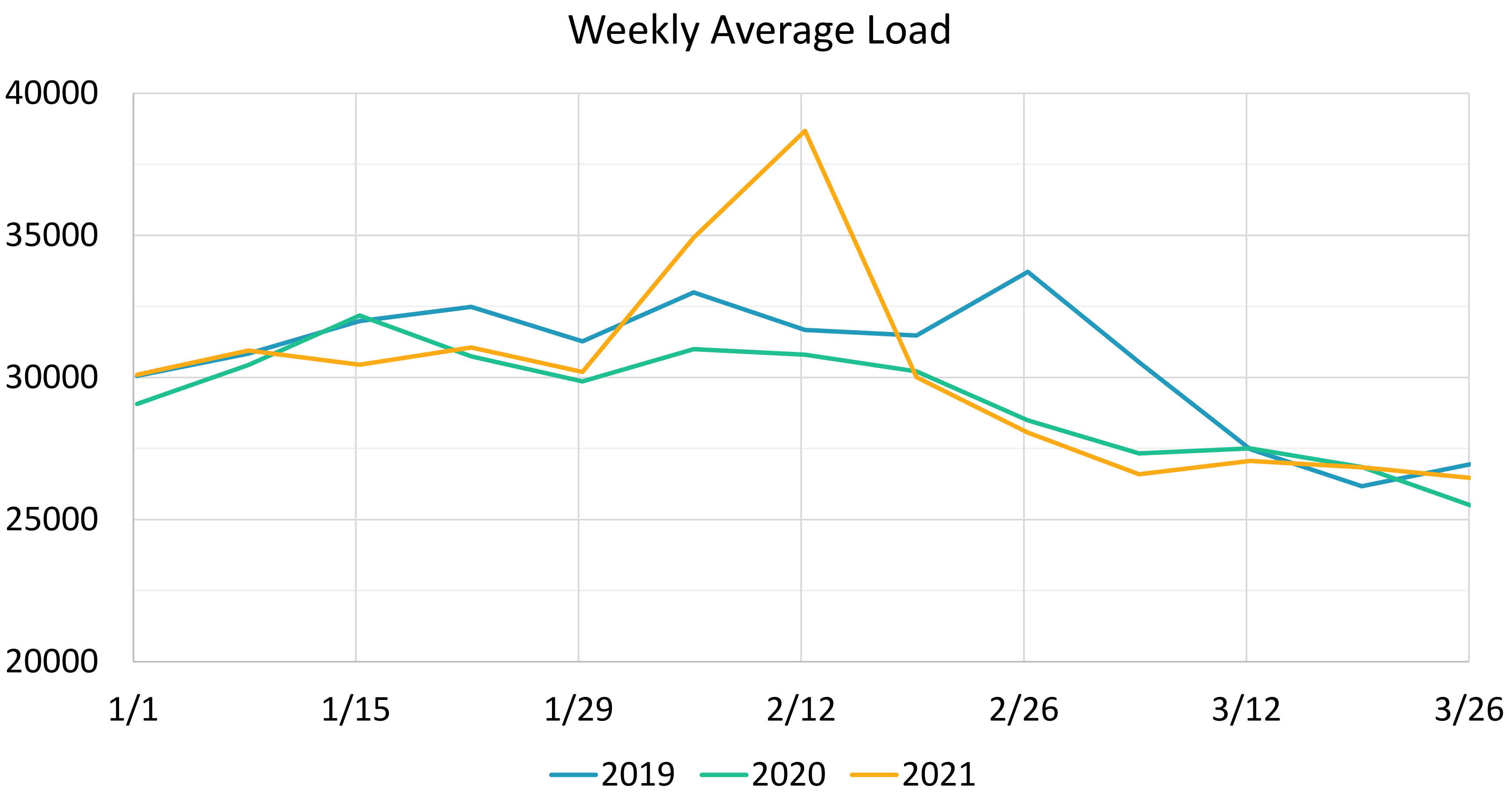
New Records set during the quarter!

- New Historical Max Winter Load peak during the quarter
  - Total MW peak of 43,661 MW on 02/15 at 08:58
- New Historical Max Wind Penetration (as % of BA Load) peak during the quarter
  - Total peak of 81.85% on 03/29 at 04:33
- New Historical Max Wind generation output peak during the quarter
  - Total MW peak of 21,133 MW on 03/29 at 07:35
- New Historical Renewable Penetration peak during the quarter
  - Total peak of 84.2% on 03/29 at 04:33
- New Renewable Total (Wind+Solar+Hydro+Waste) peak during the quarter
  - Total MW peak of 22,685 MW on 03/29 at 07:35

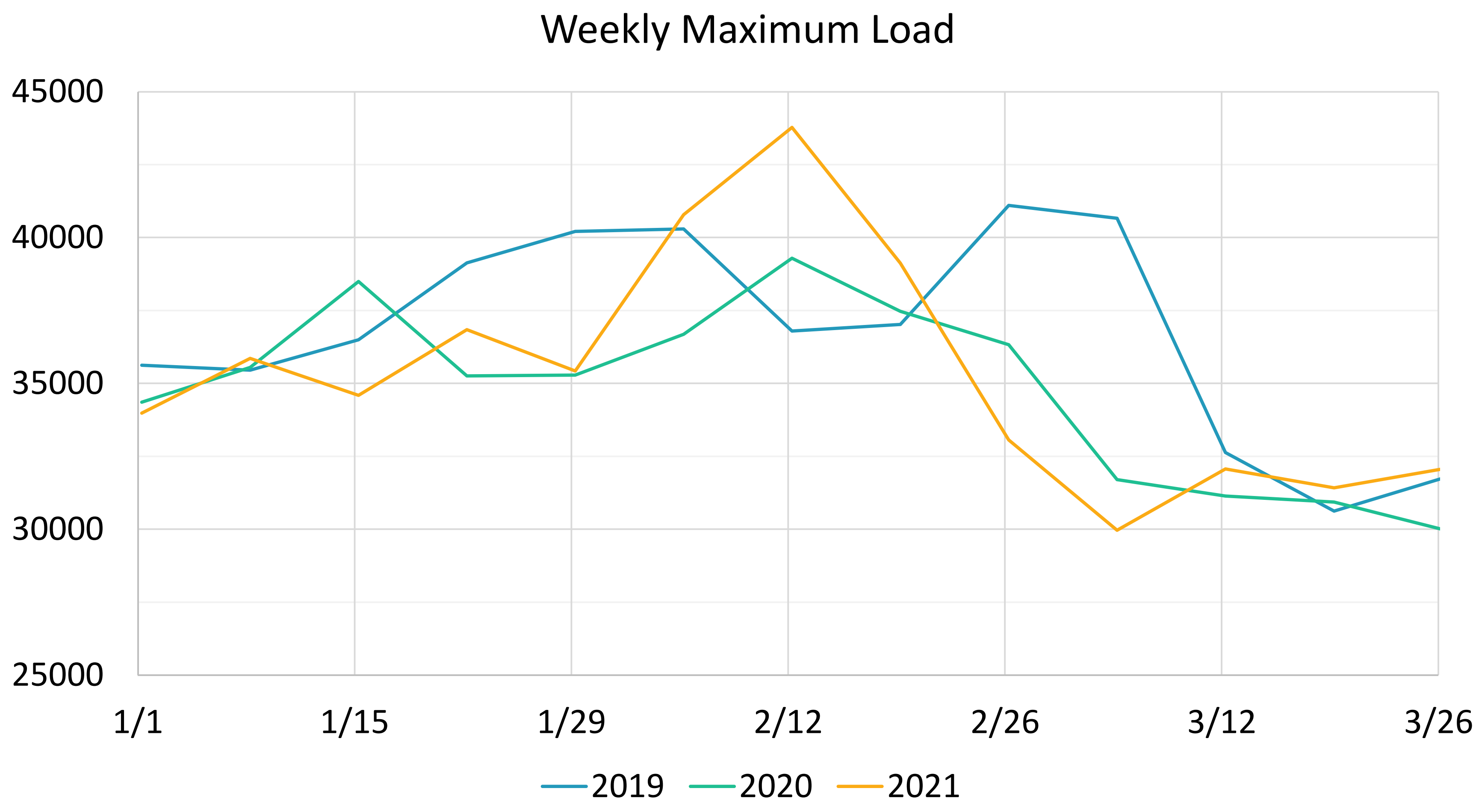
Marketplace Operational Highlights

- Forecasting Accuracy Error averages for the quarter
  - Load forecast error was 2.05%, compared to 1.68% in Q1 2020
  - Wind forecast error was 4.60%, compared to 5.20% in Q1 2020
  - Solar forecast error was 4.88%, compared to 5.63% in Q1 2020
- Currently 27.61 GW of wind registered in the market
- Significant icing event affected Wind generation on Monday, February 8
  - Operations issued a Resource Alert on the morning of the 8th due to wind uncertainty and cold weather
  - Forecast for max loss of 2 GW but experienced loss of over 5 GW of wind
  - Freezing rain and freezing fog contributed to wind loss
- Winter Storm Uri impacts (February 13-17)
  - Set new Winter Peak Load
  - Load shed of 1.5% for less than hour on February 15
  - Load shed of up to 6.5% during a 3 hour period on February 16

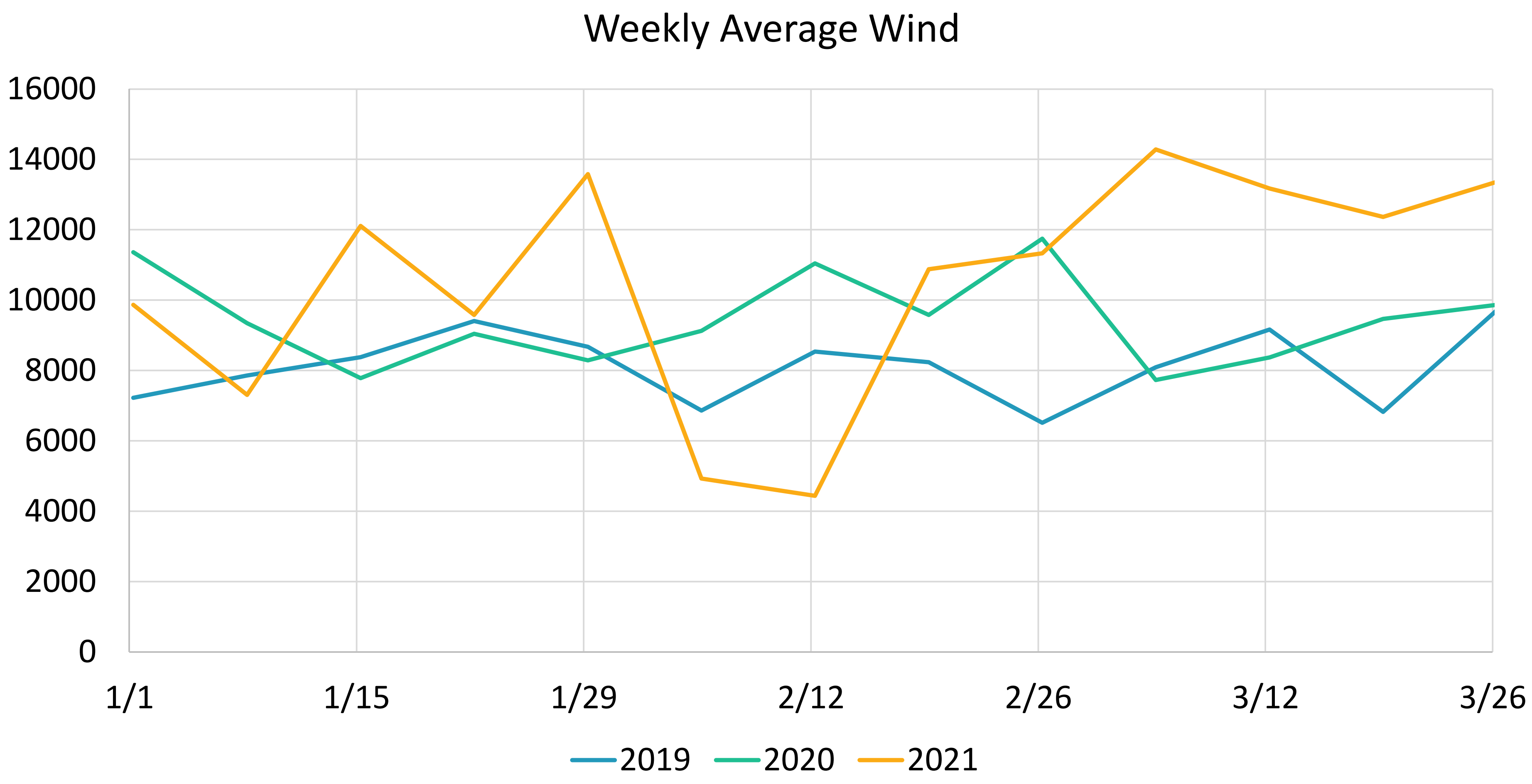
SPP Weekly Average Load profile: January - March (comparing 2019, 2020, 2021 years at same date)



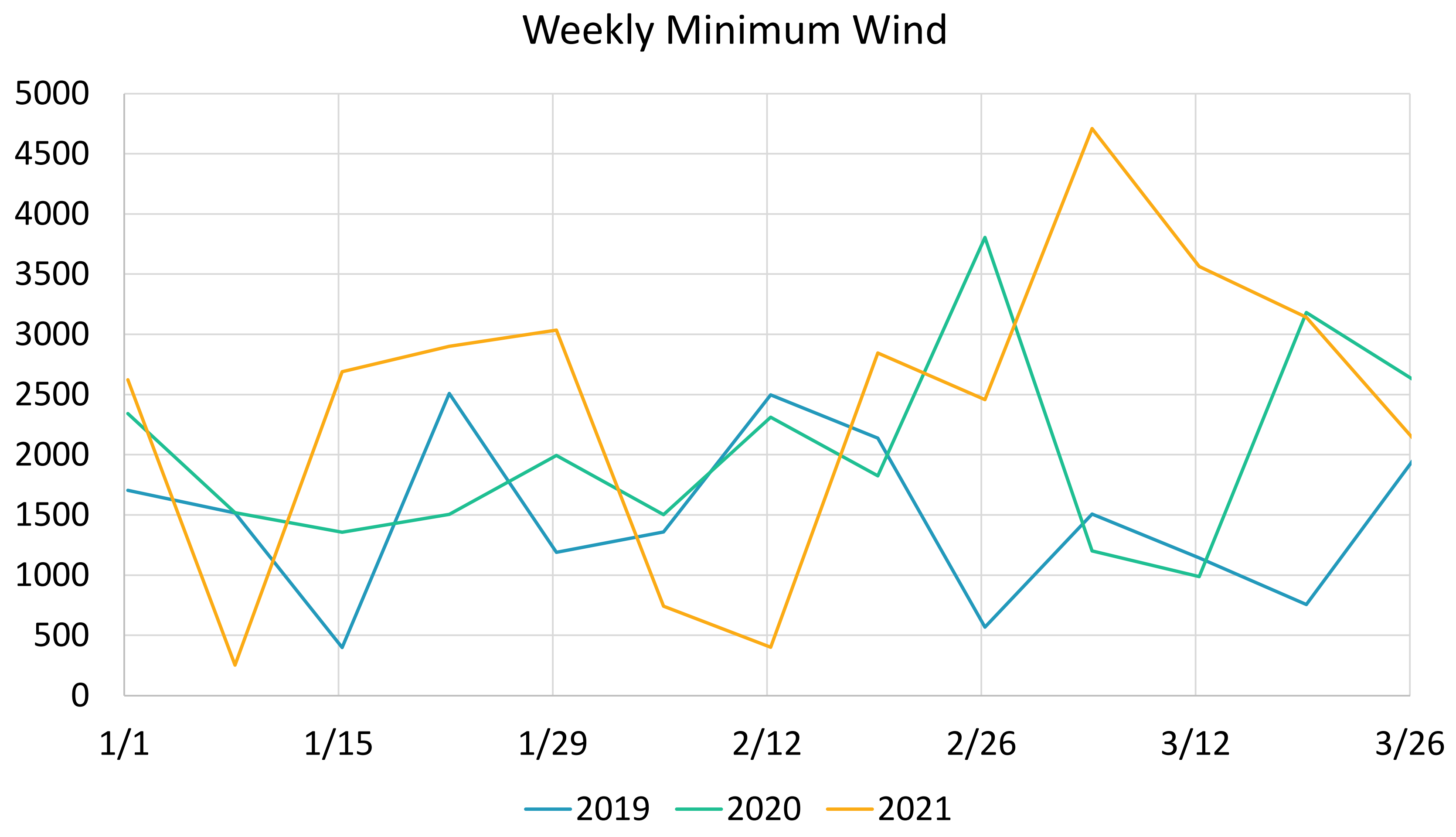
SPP Weekly Maximum Load profile: January - March (comparing 2019, 2020, 2021 years at same date)



SPP Weekly Average Wind profile: January - March (comparing 2019, 2020, 2021 years at same date)



SPP Weekly Minimum Wind profile: January - March (comparing 2019, 2020, 2021 years at same date)



WIND OUTPUT: JAN – MAR 2021

	@ Max Wind Output	@ Min Wind Output
MW Wind	21,133.26 MW	252.32 MW
Time	03/29 @ 07:35:28	01/09 @ 10:06:00
SPP Load	29,109.39 MW	32,867.79 MW
Gen Mix Percent		
Wind	70.5%	0.8%
Coal	14.3%	48.3%
Nat. Gas	7.2%	40.0%
Nuclear	2.7%	6.2%
Hydro	5.1%	4.4%
Other	0.1%	0.2%

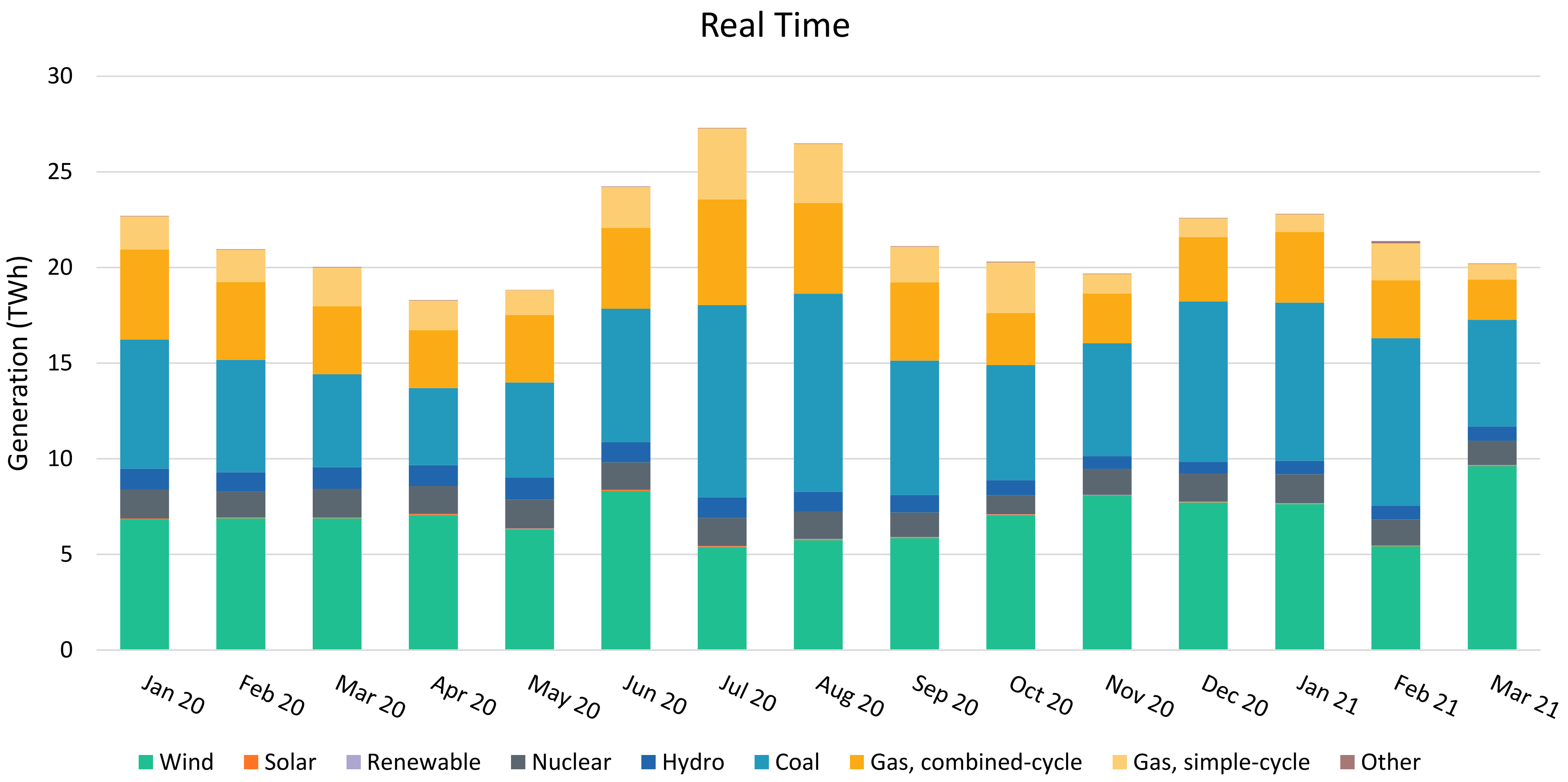
WIND PENETRATION: JAN – MAR 2021

	Max Penetration	Min Penetration
Wind Penetration	81.8% of load	0.77% of load
Time	03/29 @ 04:33:28	01/09 @ 10:06:00
SPP Load	23,901.67 MW	32,867.79 MW
Wind Output	19,563.69 MW	252.32 MW
Gen Mix Percent		
Wind	77.0%	0.8%
Coal	12.2%	48.3%
Nat. Gas	5.2%	40.0%
Nuclear	3.2%	6.2%
Hydro	2.2%	4.4%
Other	0.1%	0.2%

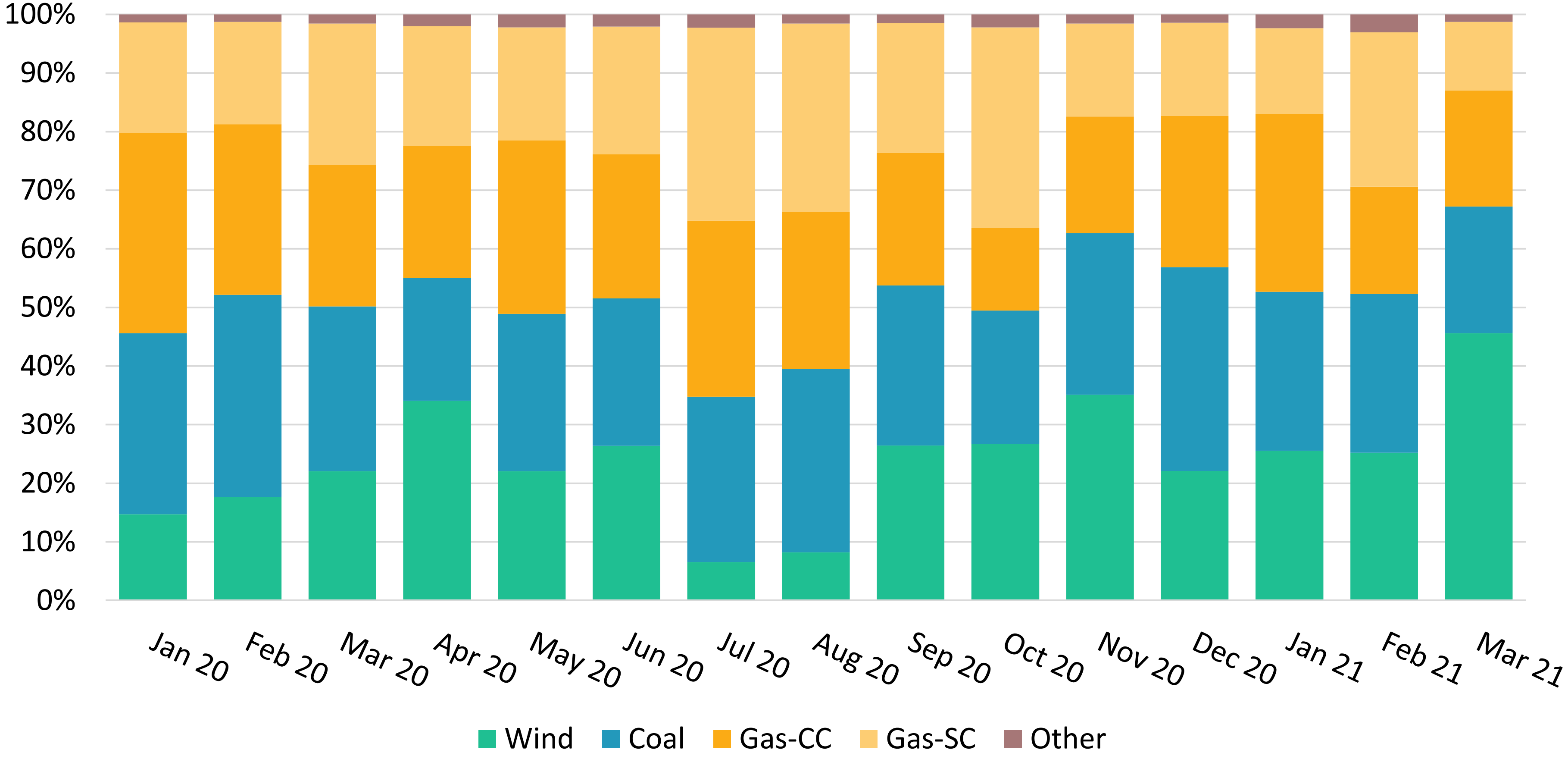
MARKETPLACE OVER LAST 12 MONTHS

- 270 Market Participants
  - 172 financial only and 98 asset owning
- SPP BA has successfully maintained NERC control performance standards (BAAL & CPS)
- High System availability
  - Day-Ahead Market results have posted 99.29% on time in past 12 months
  - Real-Time Balancing Market has successfully solved 99.9% of all intervals in the past 12 months

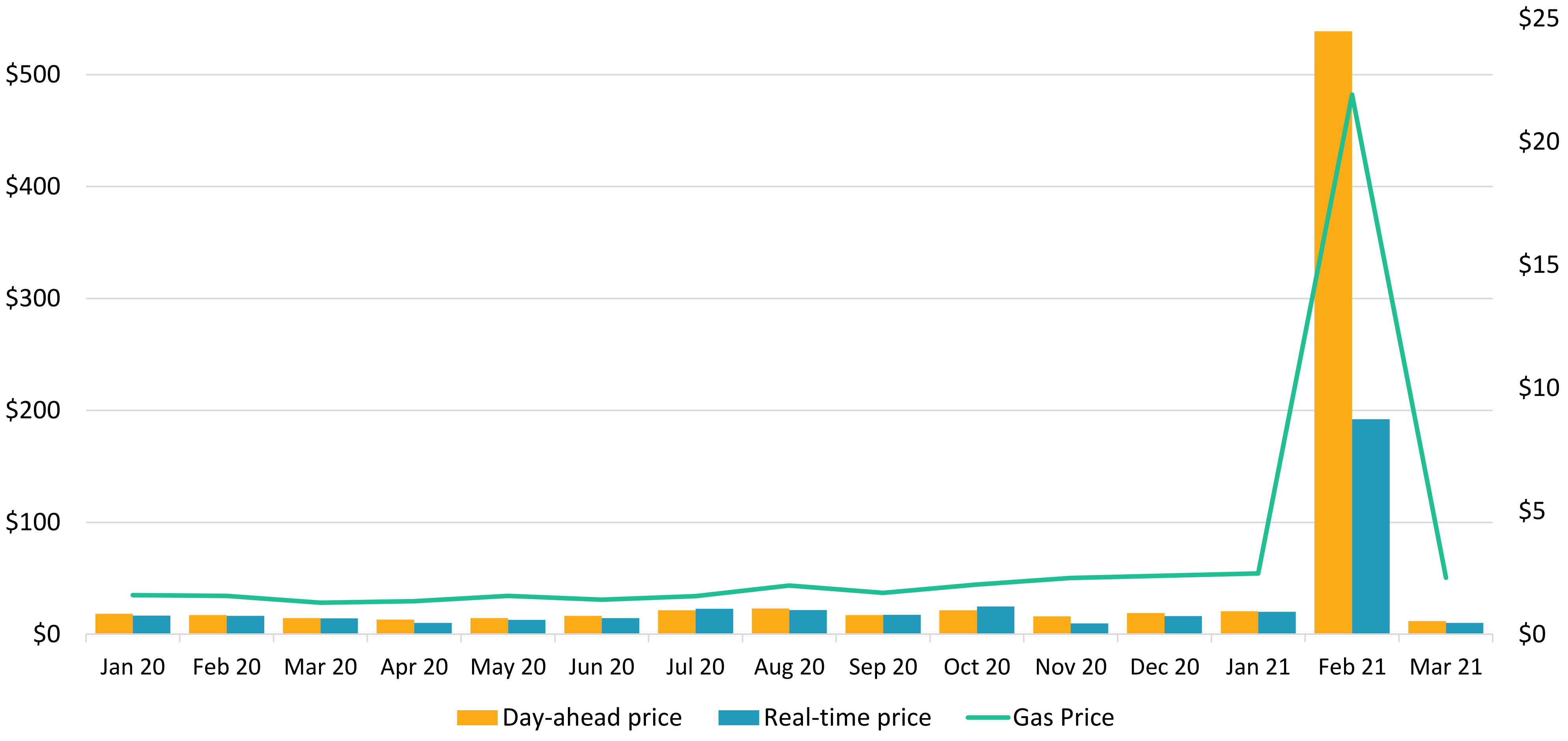
DISPATCH BY FUEL TYPE



FUEL ON THE MARGIN IN REAL-TIME

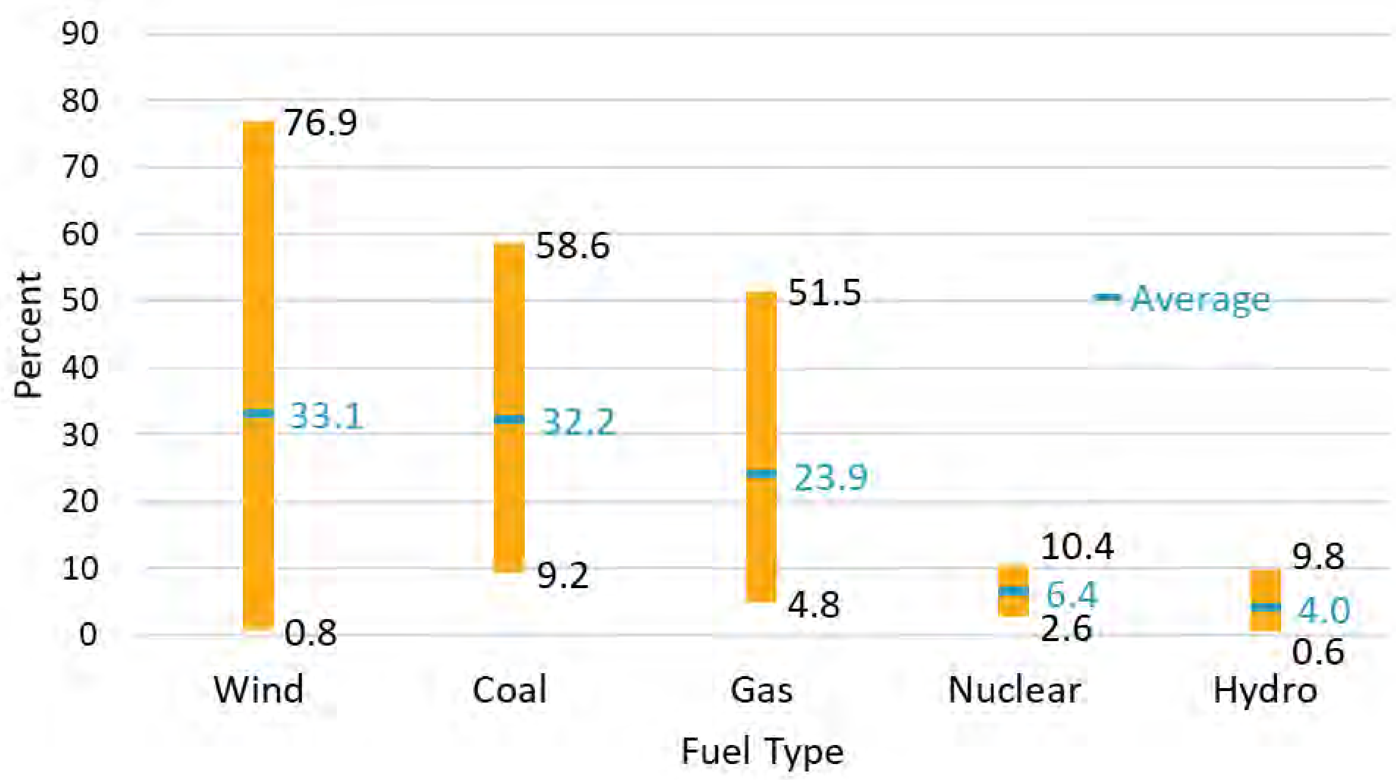


REAL-TIME VERSUS DAY-AHEAD PRICING



* These prices are average SPP trading hub LMPs

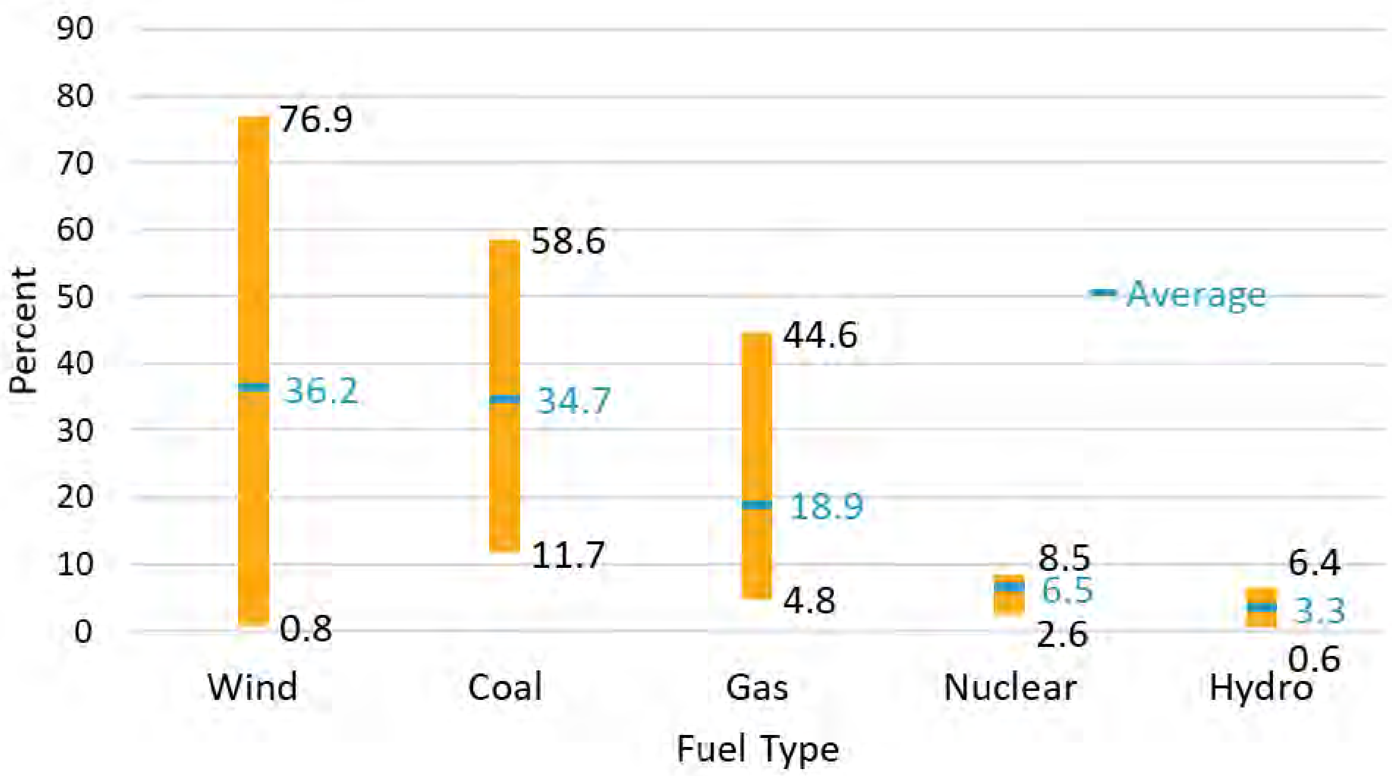
Min and Max Percent of Generation Mix Per Fuel Type - Last 12 Months



*RTBM 5-minute average

SPP

Min and Max Percent of Generation Mix Per Fuel Type – Q1 2021



*RTBM 5-minute average

INTEGRATED MARKETPLACE ENHANCEMENTS TIMELINE

- In-Process and Upcoming work
  - RR323: Order 841 – Compliance ESR;
    - August 5, 2021 effective date
  - RR361: Ramp capability products;
    - November 2021 planned implementation
  - RR288: DVER Dispatch Instruction Rules clean-up
    - Implemented with Ramp project, November 2021
  - RR375/402/420: Fast start
    - May 2022 planned implementation

OUR MISSION:
HELPING OUR MEMBERS WORK TOGETHER TO KEEP THE LIGHTS ON … TODAY AND IN THE FUTURE.

The Effects of Winter Storm Uri on Natural Gas Utilities

John Gunnells, Manager, State Affairs
Juan Alvarado, Director, Energy Analysis
NARUC Gas Committee Monthly Meeting
April 16th, 2021

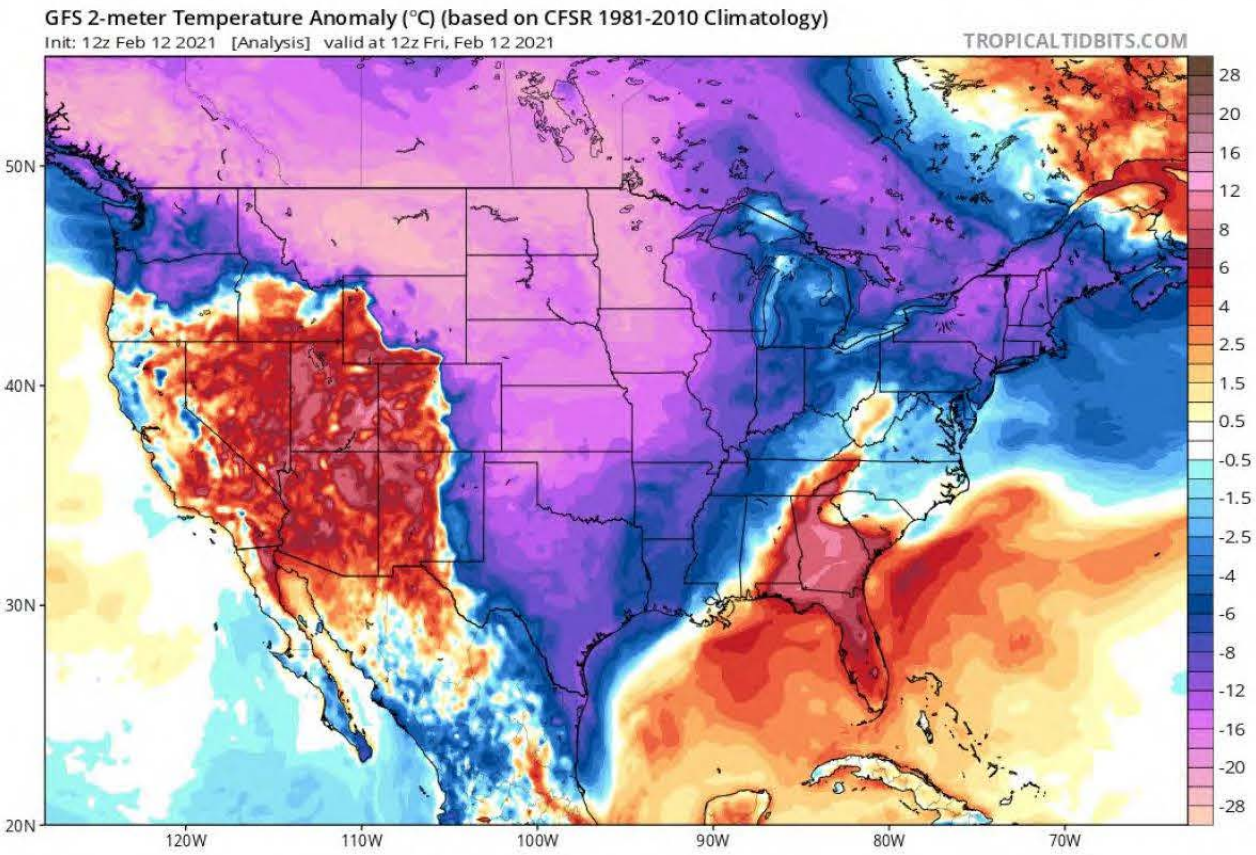
American Gas Association

The American Gas Association (AGA) represents companies delivering natural gas safely, reliably, and in an environmentally responsible way to help improve the quality of life for their customers every day. AGA's mission is to provide clear value to its membership and serve as the indispensable, leading voice and facilitator on its behalf in promoting the safe, reliable, and efficient delivery of natural gas to homes and businesses across the nation.

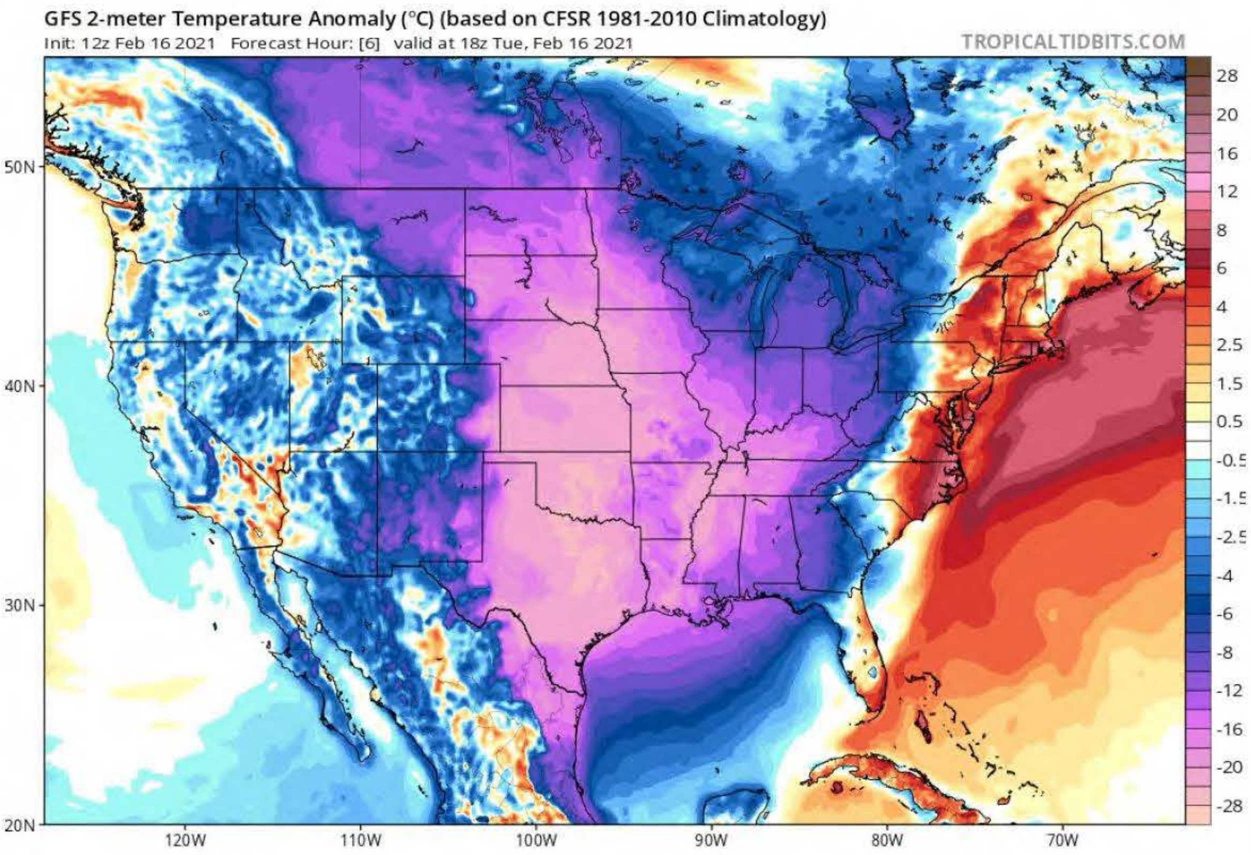
Committed to utilizing America's abundant, domestic, affordable and clean natural gas to help meet the nation's energy and environmental needs.

An arctic air mass led to colder-than-normal conditions in all but six states.

US temperature anomaly map
Friday, Feb. 12

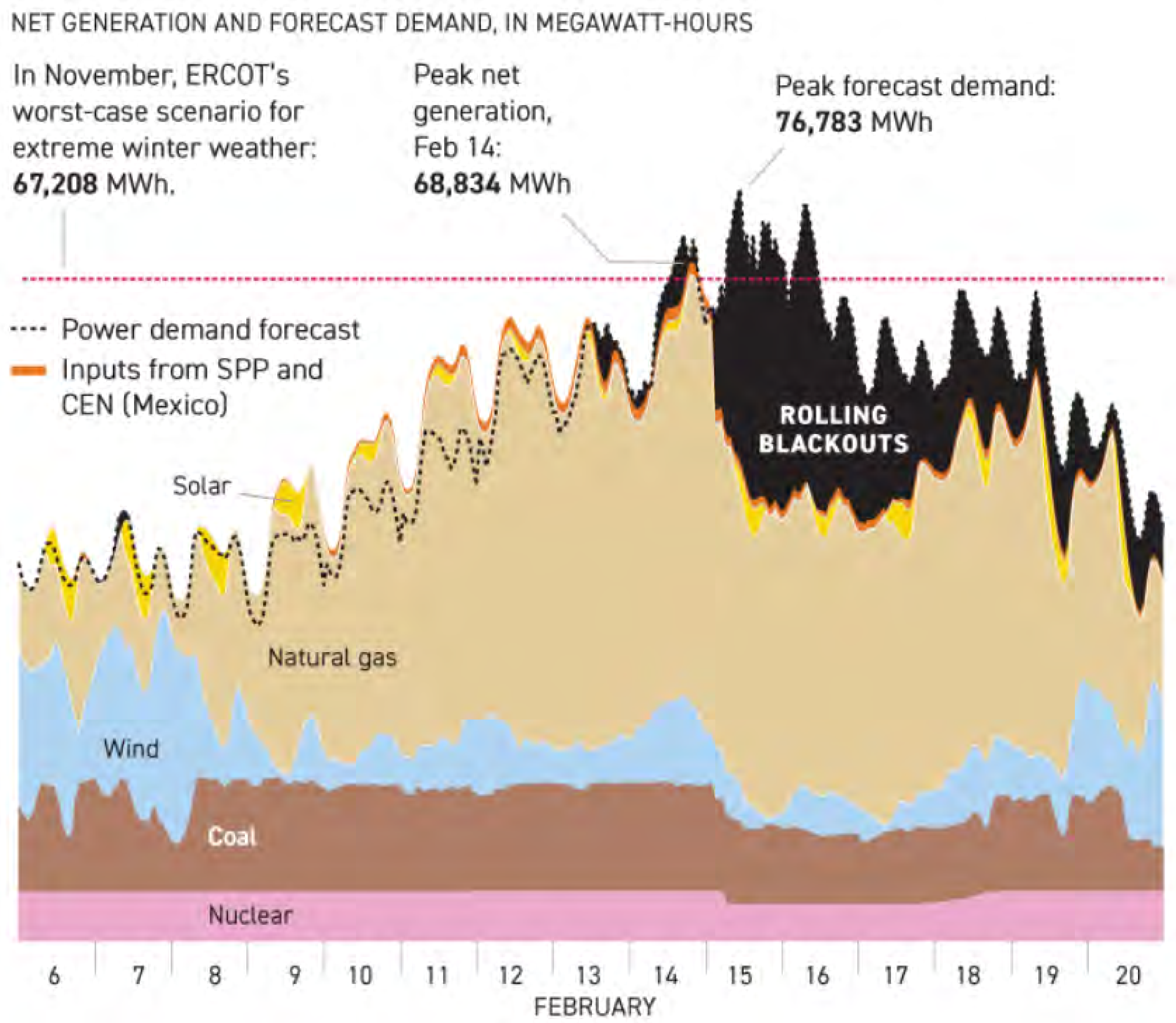


US temperature anomaly map
Tuesday, Feb. 16



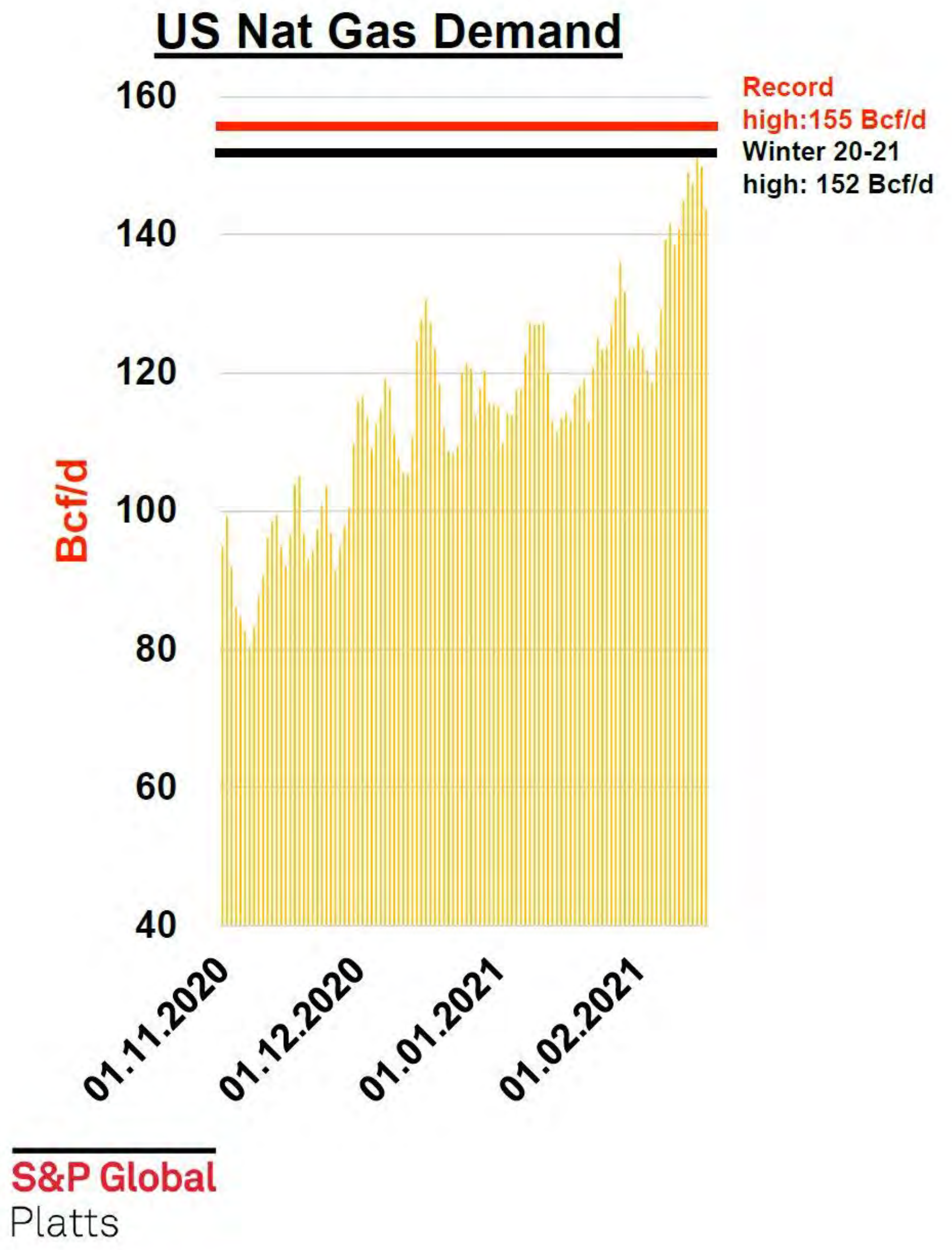
Source: Tropical Tidbits

HDD Source: NOAA and Paul Pierson



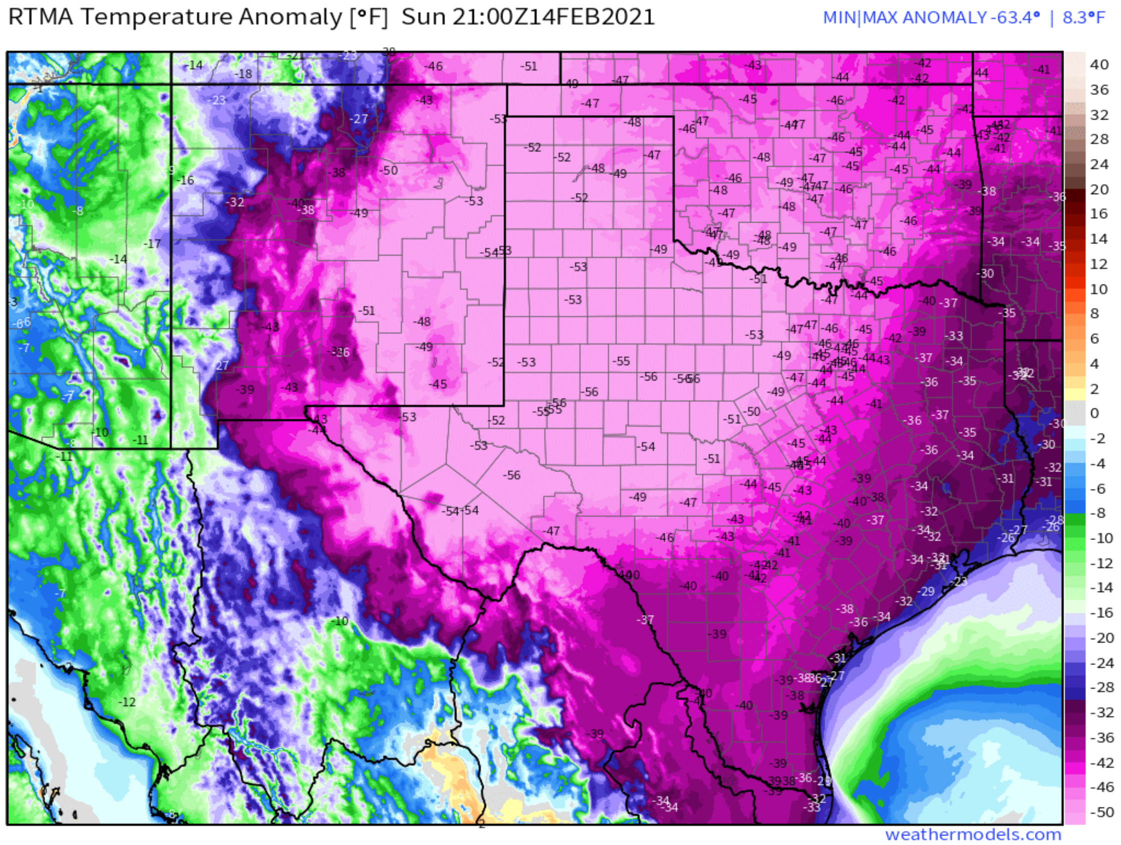
Graphic: Politico

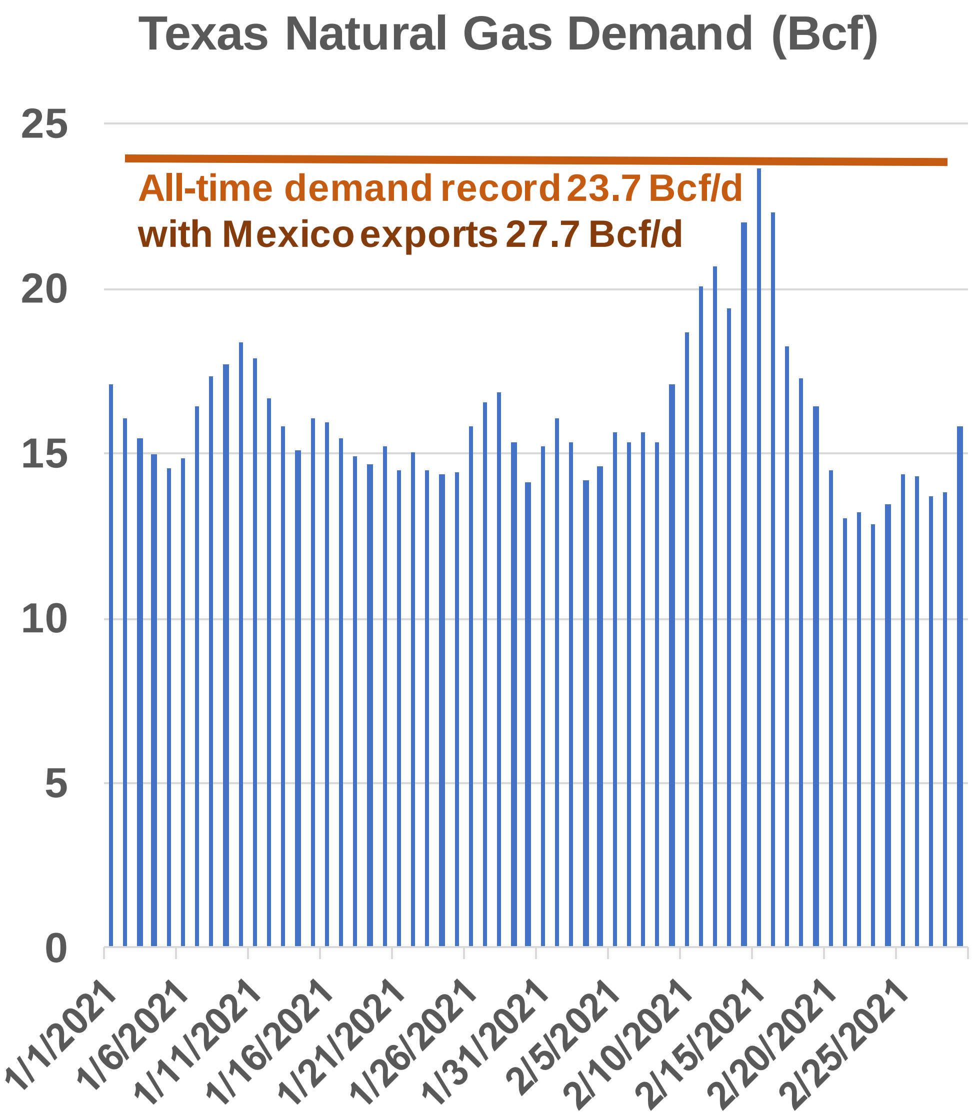
US natural gas demand set a two-day record on February 14 and 15.



Texas set a new demand record for natural gas consumption during the cold event.

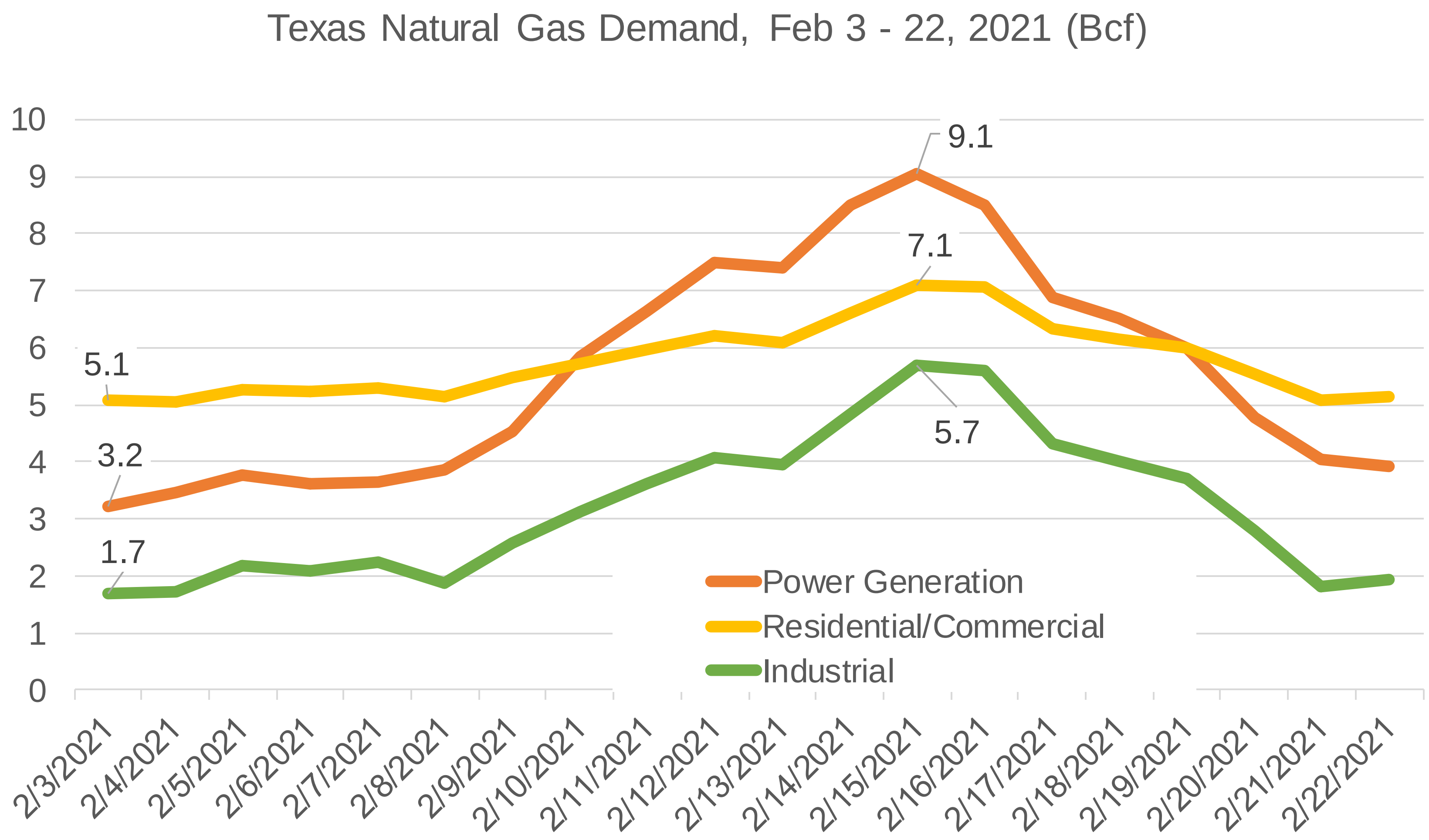
Temperature Deviation from Normal, Feb 14, 2021





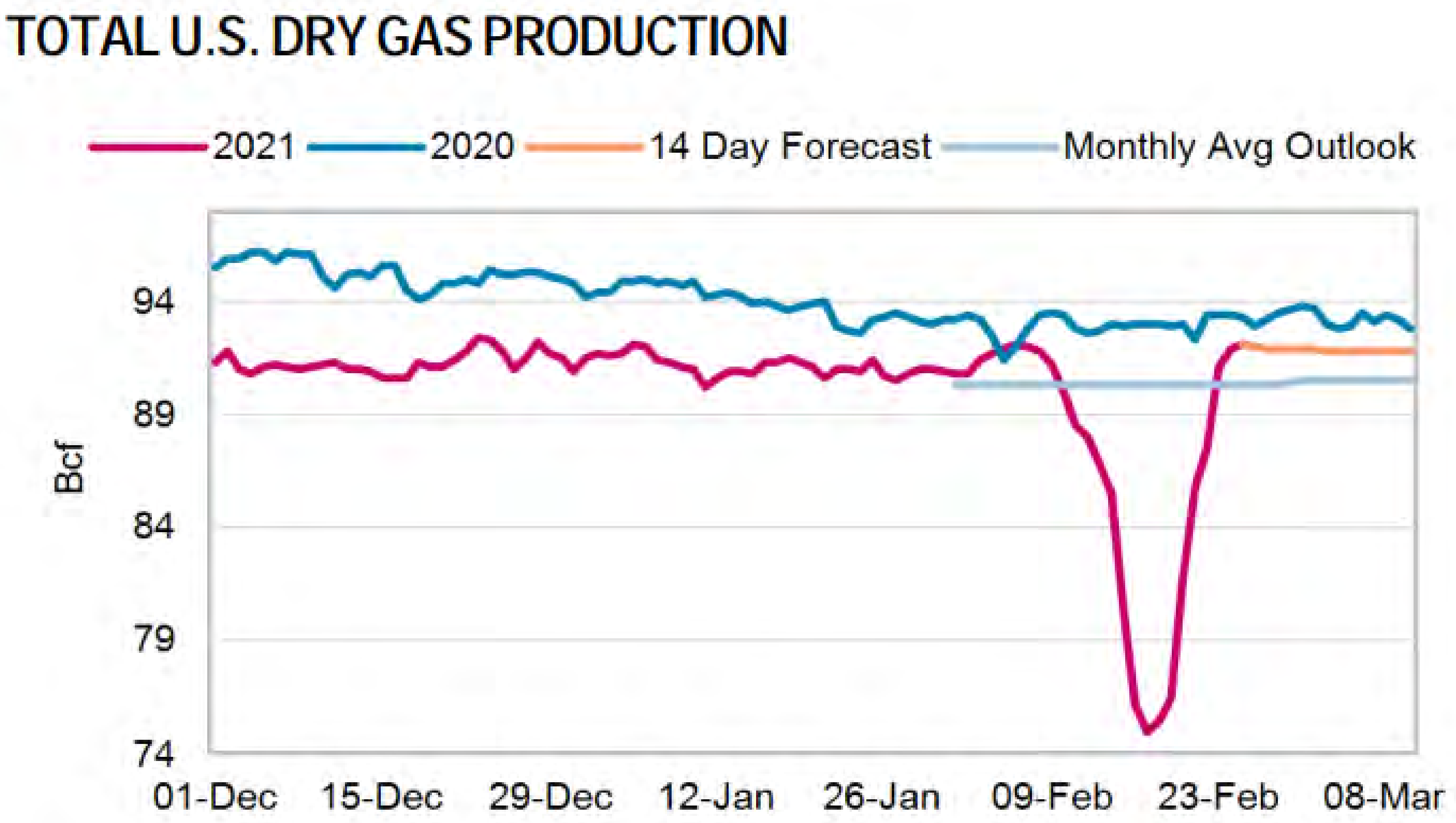
S&P Global Platts

Natural gas served to all Texas customers increased dramatically during the coldest days.



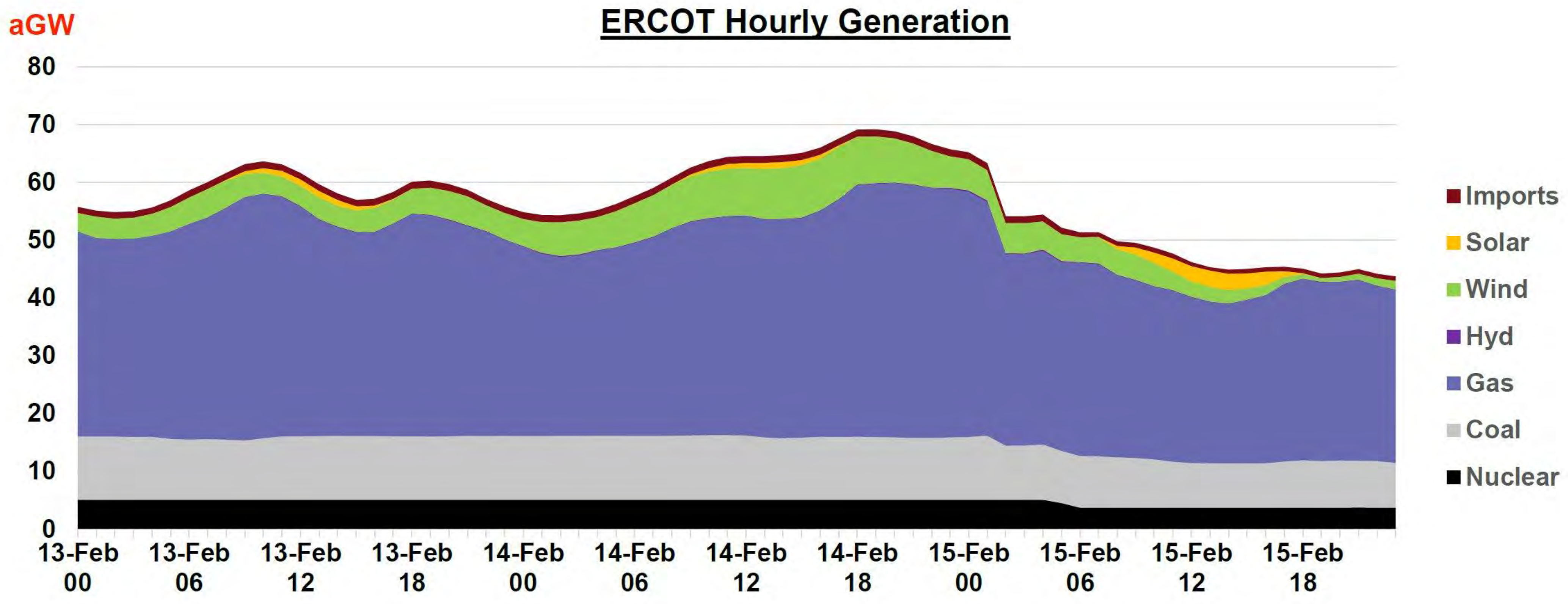
Data: S&P Global Platts

Natural gas production declined sharply as temperatures dropped, and then rebounded quickly.



S&P Global Platts

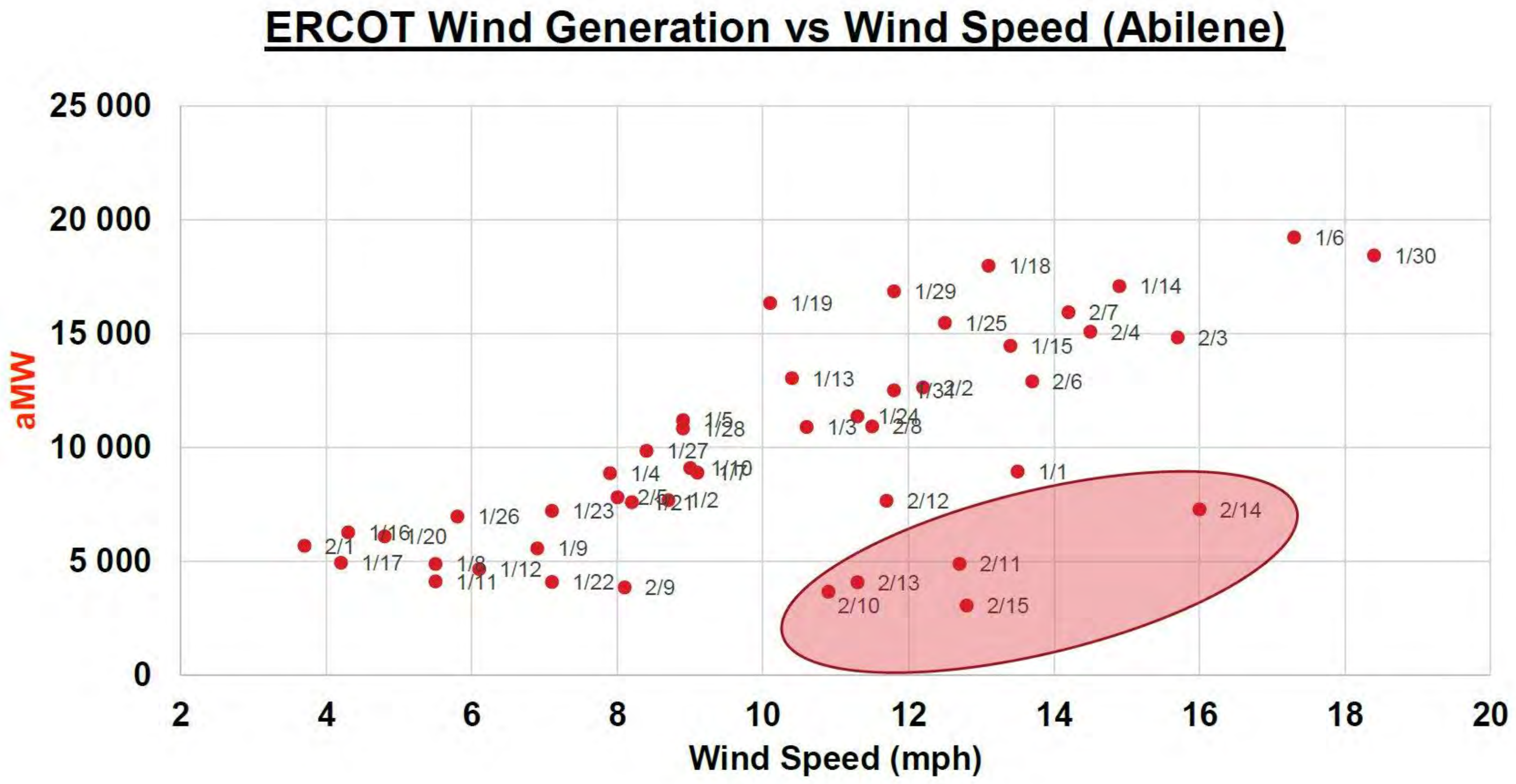
The largest declines in Texas (ERCOT) generation were due to gas-fired units. But, as you can see, natural gas continued to do the heavy lifting even as the grid was stressed under unprecedented demand.



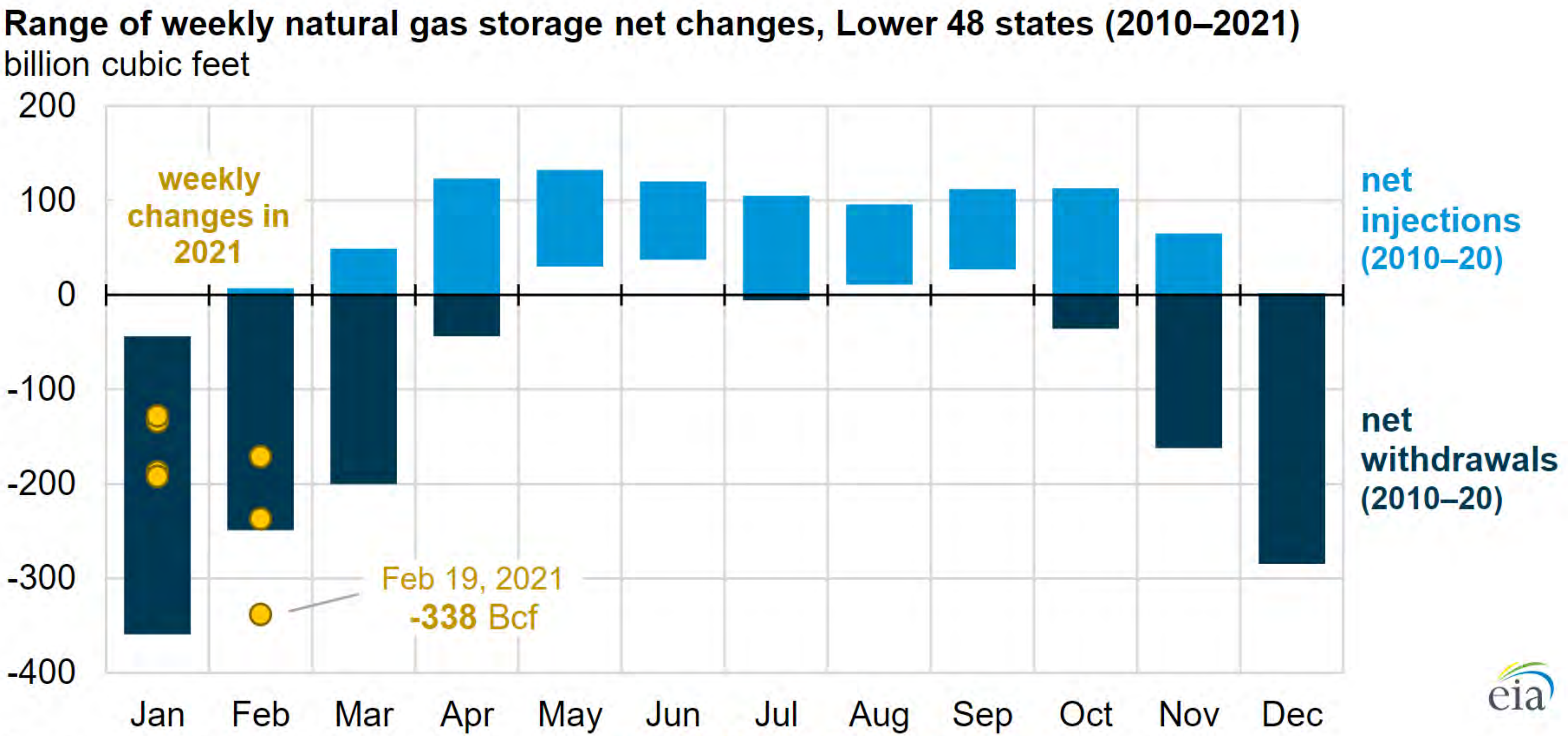
Source: ERCOT, S&P Global Platts Analytics

S&P Global Platts

Wind generation in Texas (ERCOT) was well below levels at prevailing wind speeds only days and weeks before the cold event, suggesting severe temperatures were affecting equipment operation.

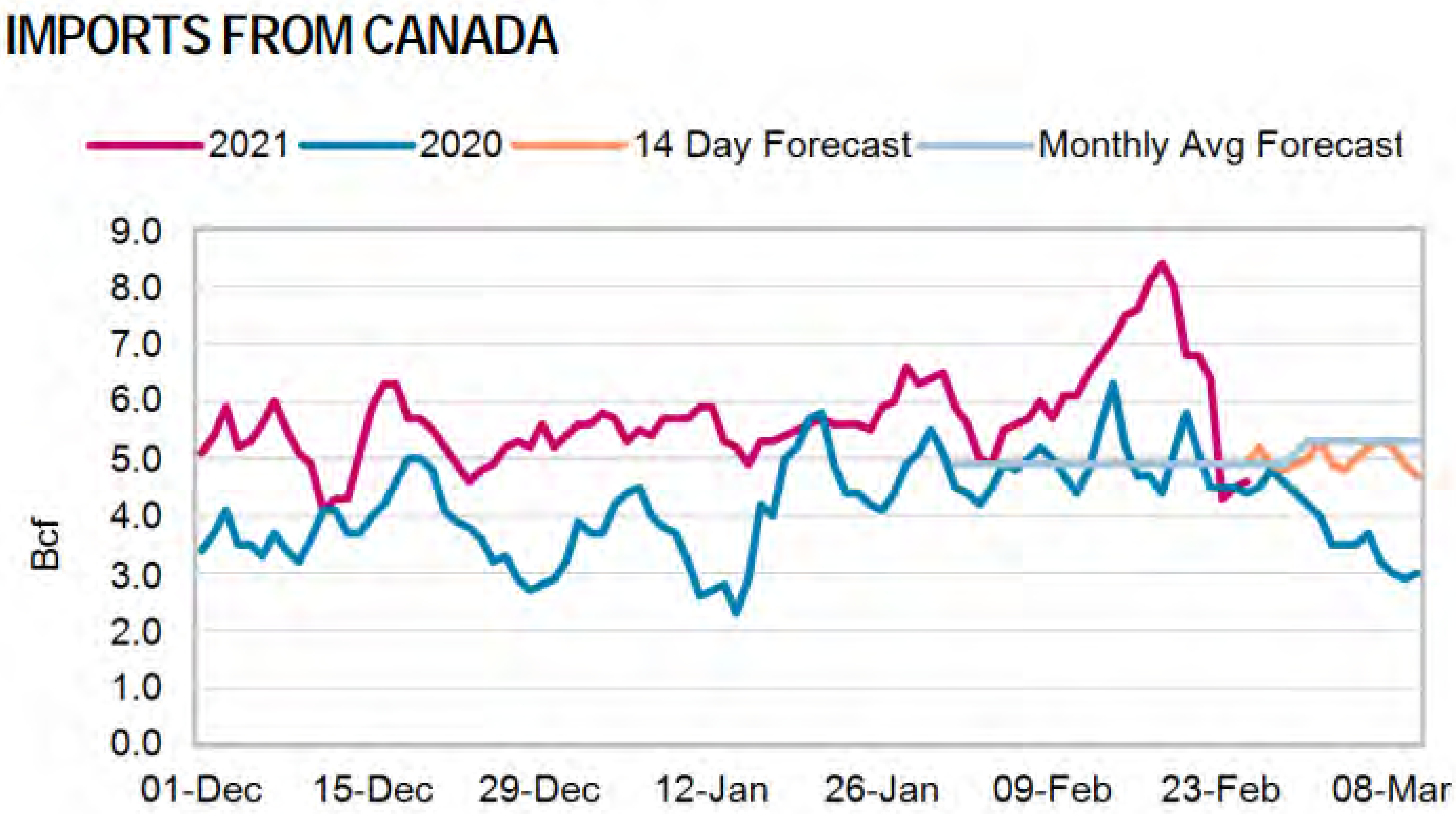


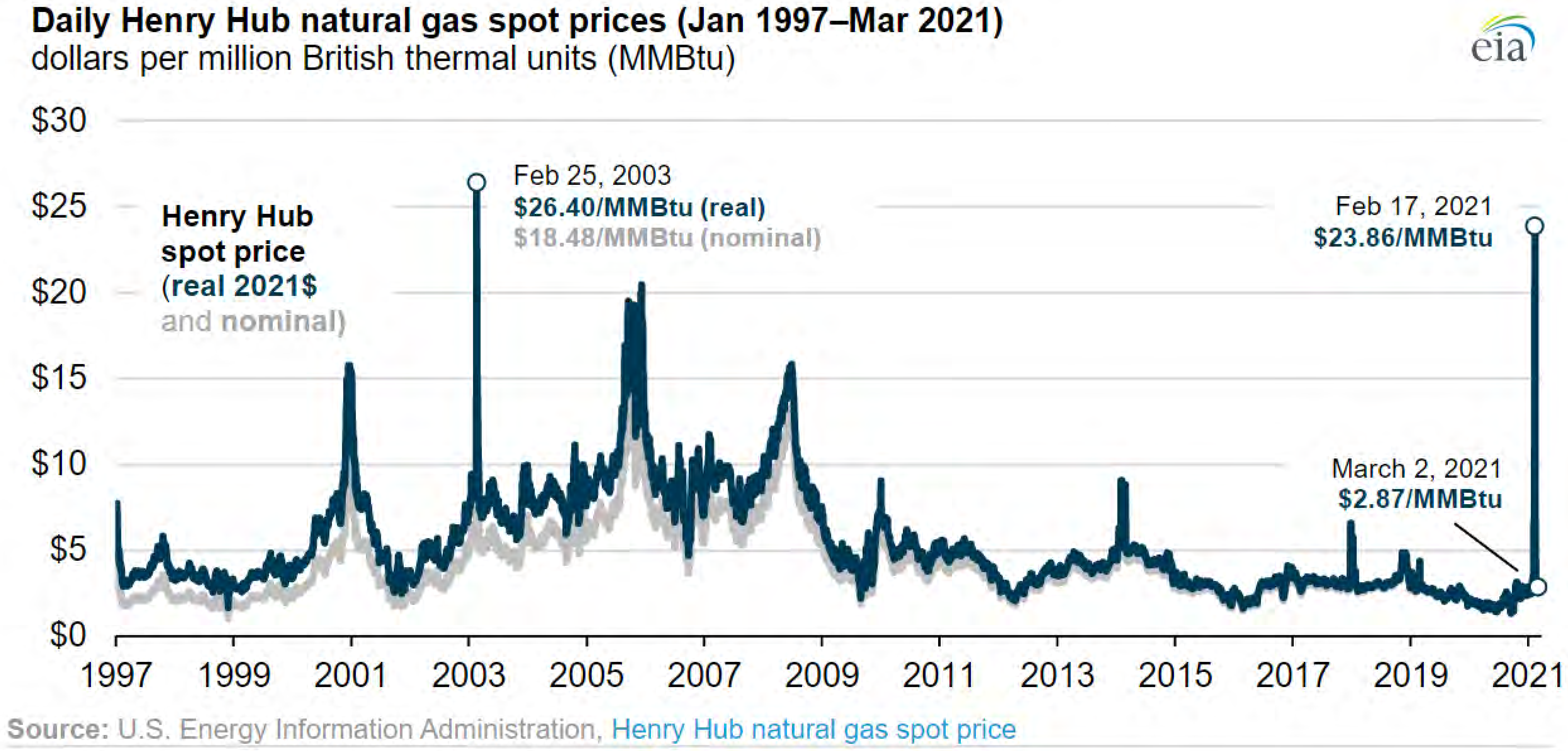
Natural gas storage stepped up in a big way to meet demand across the country.



Source: U.S. Energy Information Administration, *Weekly Natural Gas Storage Report*

The Canadian gas market played a key role.




Daily Henry Hub natural gas spot prices (Jan 1997–Mar 2021)
dollars per million British thermal units (MMBtu)
eia
Henry Hub spot price (real 2021$ and nominal)
Feb 25, 2003
$26.40/MMBtu (real)
$18.48/MMBtu (nominal)
Feb 17, 2021
$23.86/MMBtu
March 2, 2021
$2.87/MMBtu
$30
$25
$20
$15
$10
$5
$0
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
Source: U.S. Energy Information Administration, Henry Hub natural gas spot price