ERCOT MARKET COLD WEATHER FAILURE 10-19 FEBRUARY 2021: WIND ENERGY FINANCIAL LOSSES AND CORRECTIVE ACTIONS

Prepared by

Gregory S. Poulos, Principal Atmospheric Scientist, PhD

William Johnson, Renewable Energy Analyst, MS

Jerry Crescenti, Director, Energy Analysis Team, MS

Mark Stoelinga, Lead, Atmospheric Science Innovation and Applications, PhD

John Bosche, Principal Engineer

ArcVera Renewables

1301 Arapahoe Street, Suite 105

Golden, Colorado 80401 USA

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Preparer(s): Gregory. S. Poulos, Principal Atmospheric Scientist; William Johnson, Renewable Energy Analyst; Jerry Crescenti, Director, Energy Analysis Team; Mark Stoelinga, Lead, Atmospheric Science Innovation and Applications

Reviewer(s): Jerry Crescenti, Director, Energy Analysis Team; John Bosche, Principal Engineer, Sydney Strauss, Technical Editor, External Advisors

Final Review and Approval by Greg Poulos, Principal Atmospheric Scientist

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EXECUTIVE SUMMARY

In this study, we find that during the ERCOT operational crisis caused by cold weather 10-19 February 2021, its wind farms sustained financial impacts of more than $4 billion – more than twice their annual gross revenues.

By failing to allow prices to float in the Electrical Reliability Council of Texas (ERCOT) market during a portion of the 10-19 February 2021 cold weather event, ERCOT itself proved that its market structure fails to provide adequate electricity security. ERCOT's $9000/MWh override of market pricing was an ill-advised attempt to cause electricity generators to return to service because it did not address the root cause of the outages. Cold weather was the culprit, and no timely emergency weatherization measures could be deployed. ERCOT's market override appears to have exaggerated financial turmoil, windfalls, and losses among investors.

While ERCOT's studies have shown that disruption of natural gas electricity generation was the primary cause of rolling blackouts during the event, wind energy production was severely limited as well, primarily because ice accumulation rendered wind turbine blades inoperable.

The goal of this study is to quantify the lost wind energy production and financial impact of the Texas winter weather event spanning 10-19 February 2021, to examine broader implications for wind energy finance and ERCOT, and to describe potential corrective actions. The production and financial impact results are based on an in-depth time series analysis of site-specific wind energy project data: key variables are wind speed, net capacity factor, and hub settlement pricing. Results are categorized into wind energy projects with hedge financing structures and those without. The focus of the study is on wind farm outages reported by the Electrical Reliability Council of Texas (ERCOT) for the period of 14-19 February, 2021. Three repricing scenarios are evaluated using market pricing prior to the imposition of $9000/MWh prices by ERCOT.

21,888 Megawatts (M.W.) of wind farm nameplate capacity, 87% the 25,121 MW ERCOT wind capacity, are evaluated. 12,495 MW, or 57 percent, of the 21,888-MW total, is estimated to be subject to a hedged financial structure. There are 191 wind farm ERCOT Units and 114 wind farms or 94 wind farm clusters. Individual wind farm results are not presented in this report. We estimate the uncertainty of the financial impact dollar values presented herein, based on proprietary information from owner/operators, for the downtime periods studied, to be approximately 15 percent.

Average icing event air density values were 8-10 percent above long-term average air density during the event, which increased proxy energy production. Site-specific wind speeds and direction have been derived from ERA5 hourly wind time series, adjusted to site hub height using validation sources. In turn, based on wind energy resource assessment practice and turbine and wind plant specifications, we estimated the hourly proxy net capacity factor and production for all wind farms with reported outages.

We find that the lost energy production from wind farms that would have otherwise operated, were it not for the icing event, was 629,700 Megawatt hours (MWh). The average wind speed and net capacity factor during the downtime period, aggregated across all wind farms, were found to be 6.3 m/s and 30.6 percent, respectively.

The financial impact of this lost production, whether the financial loss to the owner or gain by others, for the 14-19 February outage periods studied, was $4.18B. The maximum financial impact for a project was found to be $172.5M. The average financial impact across all projects was determined to be $44.4M. For hedged projects, the financial impact of this lost proxy production is $2.59B. The maximum financial impact for any wind farm cluster was found to be $172.5M. The average financial impact on any wind farm cluster is found to be $45.4M.

Repricing Scenarios

Given that the market demand was decreased by ERCOT with blackouts, so that production balanced that reduced demand, market prices may have been high but not near the $9000/MWh imposed value. It is not possible to predict power prices had ERCOT not mandated maximum pricing. Three repricing scenarios show reduced financial impacts from the $4.2B baseline value:

- based on the $1826/MWh average electricity price during the 24 hours before 0800 14 February 2021, we find that the overall financial impact drops by 75.9 percent to $1.01B,
- based on the $2186/MWh average electricity price during the 24 hours before ERCOT began load shedding (0125 15 February), we find that the overall financial impact drops by 61.8 percent to $1.60B, and
- based on the $6007/MWh average electricity price during the 24 hours before 1700 15 February, when ERCOT imposed the $9000/MWh pricing mandate, we find that the overall financial impact drops by 26.3 percent to $3.08B.

Broader Implications and Potential Corrective Actions

1. Hedged financial structures with guaranteed production for wind farms in ERCOT are misdiagnosed with respect to weather risk because of asymmetric price risk, meteorologically unrealistic production assurances, and strike prices that do not reflect long-term hub-settled electricity prices.
2. For hedged projects in Texas, given the asymmetric price risks, owner/operators should consider wind farm icing mitigation and/or, if hedged with production assurance, that the hedges should be priced to account for occasional, expensive, icing-related downtime.
3. Future Texas fixed-volume and proxy generation-based contracts should reflect a price, likely between $30/MWh and $40/MWh, that accounts for icing events and the very highest pricing possible for a few days per year.
4. Appropriate *force majeure* clauses in hedge agreements could potentially mitigate this asymmetric price risk, but that would not help the physical availability of wind generation as renewables penetration of energy markets increases.
5. Icing mitigation measures would have cost less than half of the financial impact on wind farms in Texas during the ERCOT February wind turbine icing event. Regulatory action may still be required to incentivize the installation of ice mitigation systems as renewables penetration increases over time.

Regarding Long-term ERCOT Planning and Weather-Driven Electricity Production

Weather-driven production is inevitable as economically advantaged renewable energy comes to dominate generation capacity in ERCOT. Our analysis and observations, taken together, clearly describe a condition where, with greater attention to atmospheric science analysis and extreme weather phenomena when assessing the risks of weather-driven electricity production and demand during peak events, an adequately resilient and interconnected ERCOT electricity system can be created. ERCOT planning should consider those cold-weather events worse than that experienced February 10-19, 2021 are possible.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS AND ABBREVIATIONS

B	billion
CfD	Contracts-for-Difference
ERA5	ECMWF Re-Analysis version 5
ECMWF	European Centre for Medium-range Weather Forecasting
ERCOT	Electric Reliability Council of Texas
GFS	Global Forecast System (U.S. National Weather Service weather model)
G.W.	gigawatts
HRRR	High Resolution Rapid Refresh (U.S. National Weather Service weather model)
kg m^{-3}	kilograms per meter cubed
m	meters
m/s	meters per second
mb	millibars
M	million
M.W.	megawatts
MWh	megawatt hours
PPA	power purchase agreement

1 INTRODUCTION

A cold-weather event severely impacted Texas, and the Electrical Reliability Council of Texas (ERCOT) service territory, from 10-19 February 2021. Outages of all forms of electricity production occurred during the event and market prices were overridden to their maximum by ERCOT on 15 February 2021.

By failing to allow prices to float in the ERCOT market during a portion of the 10-19 February 2021 cold weather event, ERCOT itself proved that its market structure fails to provide adequate electricity security. ERCOT's $9000/MWh override of market pricing was an ill-advised attempt to cause electricity generators to return to service because it did not address the root cause of the outages. Prolonged and ongoing cold weather was the culprit, and no timely emergency weatherization measures could be deployed. ERCOT's market override of pricing appears to have exaggerated financial turmoil, windfalls, and losses among investors.

While ERCOT's studies have shown that disruption of natural gas electricity generation was the primary cause of rolling blackouts during the event, wind energy production was severely limited as well, primarily because ice accumulation rendered wind turbine blades inoperable. With rising renewable energy penetration across ERCOT, there are significant implications of this shutdown for wind energy finance and ERCOT structure and peak electricity demand planning.

The goal of this study is to quantify the lost wind energy production and financial impact of the Texas winter weather event spanning 10-19 February 2021, to examine broader implications for wind energy finance and ERCOT, and to describe potential corrective actions. These proxy production and financial impact results are based on an in-depth hourly time series analysis of site-specific wind energy project data: key variables are wind speed, net capacity factor, and hub settlement pricing. Results are categorized into wind energy projects with hedge financing structures and those without. The focus of the study is on wind farm outages reported by the Electrical Reliability Council of Texas (ERCOT) for the period of 14-19 February, 2021. The report also estimates financial impacts, generally losses or lost opportunity for revenues, but also windfalls for others, based on proxy generation lost due to icing. We assess three repricing scenarios and assess broader implications for the finance structure of both wind farms and the ERCOT grid planning.

The analysis uses outage periods documented by ERCOT for 191 wind farm Units (see Appendix A) to examine site-specific, and importantly, hub-height bias-corrected air-density-adjusted hourly wind speed and net electricity production hourly time series data. The analysis is bolstered by the use of meteorological wind speed, temperature, and pressure data sets, wind speed corrections to project hub height, site-specific air density estimates, and experience-based gross-to-net losses.

Throughout this document, we refer to the winter storm event that caused the wind farm outages as the "icing event." This icing event was especially difficult for iced and inoperable wind farms in ERCOT because of record-breaking, unusually prolonged cold weather, starting as early as 10 February 2021.

A total of 21,888 MW of wind farm nameplate capacity is evaluated, of which 57 percent (12,495 MW) is subject to a hedged financial structure. There are 191 wind farm ERCOT Units, 114 wind farms, or 94 wind farm clusters. Individual wind farm results are not presented in this report. We estimate the uncertainty of the financial impact presented herein to be 15 percent, based on spot checks of proprietary information from owner/operators for the downtime periods studied.

1.1 Event Weather Summary

The icing event was associated with a synoptic-scale (continental) winter weather system that moved slowly through Texas beginning 10 February 2021. Abilene, which is located near many wind farms in western Texas and just east of the Sweetwater wind farm complex, experienced nine consecutive days with temperatures below freezing – an all-time 135-year record. Similarly, Austin experienced an all-time record for consecutive below-freezing temperatures of six days and 20 hours. Midland broke its all-time low for maximum daily temperature on all but two days between 11 and 20 February. Electricity demand steadily grew throughout the first several days of the event, eventually exceeding ERCOT's peak winter demand scenario.

A freezing rain precipitation event occurred on 11 February, with up to 0.75 inches of ice accumulating in south-central Texas (Figure 1). This event caused the weather system's first round of widespread wind turbine icing within ERCOT. Due to a combination of debilitated aerodynamic lift from the coating of ice and additional weight added to the turbine blades, wind turbine energy production generally ceased. Although many wind energy power plants were not operational 11-14 February due to icing, their lack of operability did not impact ERCOT's ability to meet electrical load because the bulk of the cold air, and associated electricity demand, had not yet seriously affected the majority of ERCOT. ERCOT (2021 [3]) noted that 28,000 MW of capacity were already unavailable for various reasons as of 14 February 2021, of which 12,000 MW were wind farms that were already iced.

Figure 1. Photograph of the result of icing from freezing rain in Llano, Texas, prior to the significant impacts on the ERCOT grid and power prices (NWS Austin, 2021).

Depending on location, up to several icing events occurred, and icing events varied from thick ice coatings caused by freezing rain to rime ice resulting from freezing fog—the icing built over consecutive days in some cases. Exacerbating the problem was the unprecedented days-long period of cold air, which lingered over Texas and prevented ice melt.

The unusually cold temperatures and generally high pressure combined to create abnormally high air density, as high as 1.35 kg/m^{-3} on the Texas Gulf Coast, where temperatures dropped to -8°C with 1025 mb high pressure on 15 February 2021. Average air density values were 8-10 percent above long-term average air density during the icing event outages, which, because wind energy production is directly proportional to air density, increased potential (or proxy) energy production.

Figure 2 demonstrates that a winter storm warning was in place for all of Texas on 15 February 2021. Figure 3 shows the timeline of repeated icing, cold weather, and snowfall events in south-central Texas during 10-18 February 2021. Figure 4 shows a time series of temperatures in major Texas cities and statistics for consecutive freezing hours.

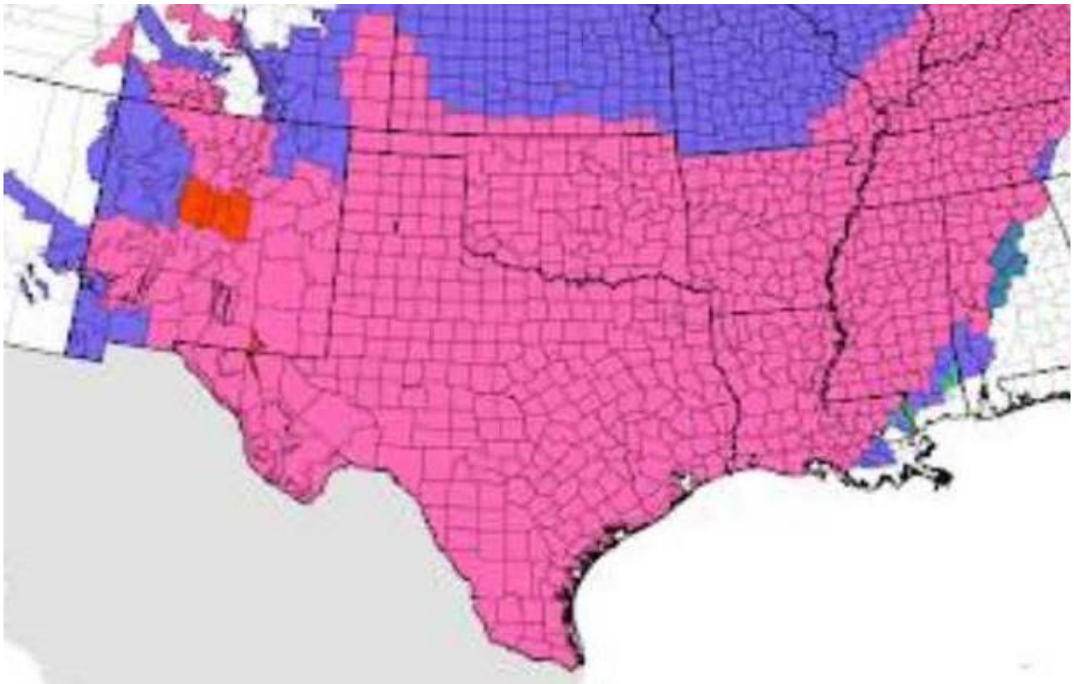

Figure 2. Winter storm warning areas, covering all of Texas, as of 14 February 2021 (NWS Austin, 2021).

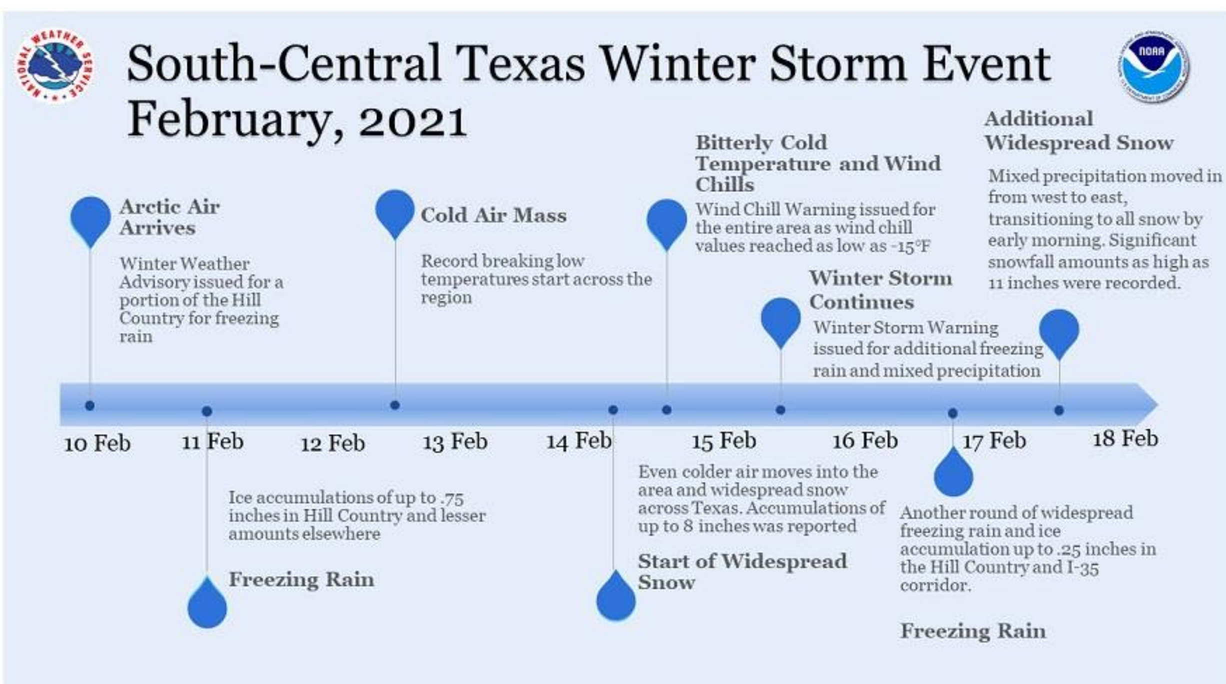

Figure 3. Cold weather event timeline, south-central Texas (NWS Austin, 2021).

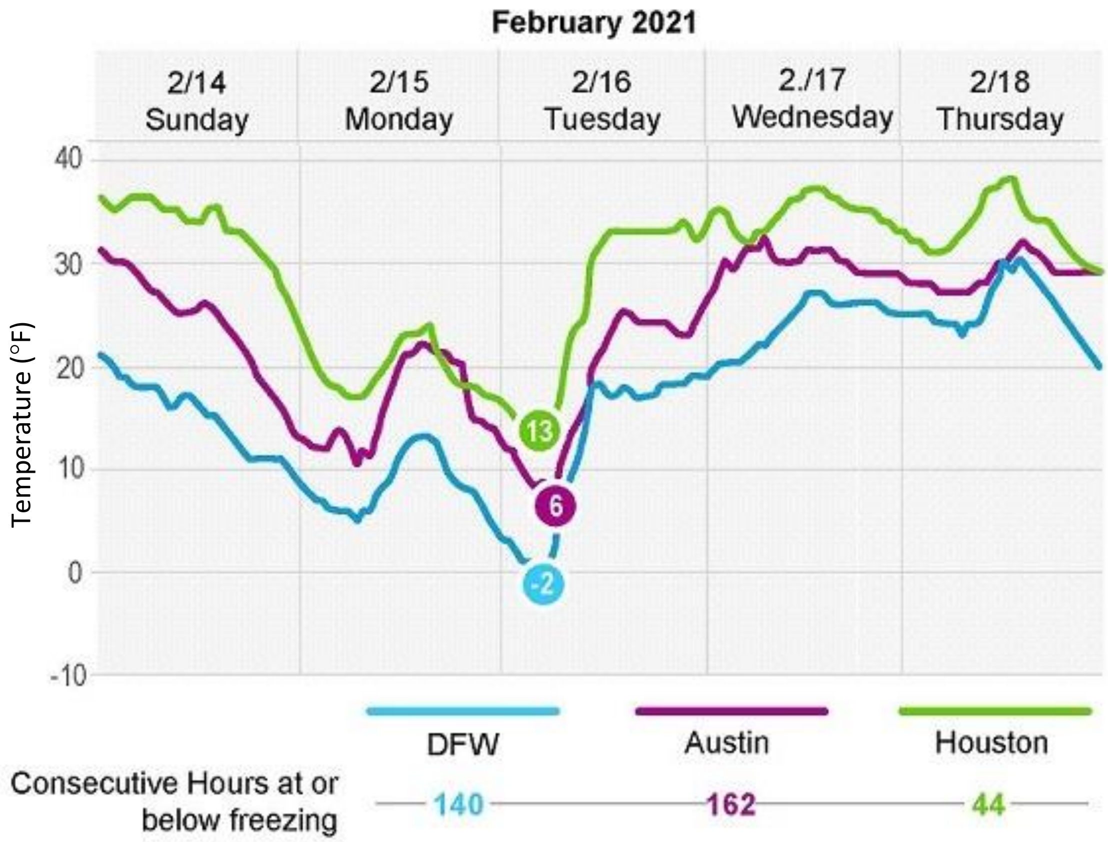

Figure 4. Temperature time series at Dallas (DFW), Austin, and Houston during the ERCOT cold weather event for the period from Sunday, 14 February to Thursday, 18 February 2021 (adapted from ERCOT, 2021 [2]).

1.2 Electricity Production and Pricing

Between 14 and 19 February 2021, the ERCOT grid experienced extensive icing-induced wind farm downtime, lost energy production, and high electricity prices. Electricity prices rose above $1000/MWh 0800 14 February 2021, never again falling below $1000/MWh until 19 February; $1000/MWh is 50 times the average 2020 rate of $20/MWh. The hub settlement price averaged over $7800/MWh from that time until a decrease from $9000/MWh to $825/MWh during 0800 to 0900 19 February 2021, and another decrease to near-average prices ($25/MWh) by 1000 19 February (Figure 5).

During the cold weather, a large fraction of the ERCOT system's natural gas electricity-generation capacity, as well as a smaller fraction of said capacity for solar, coal, and nuclear power plant, experienced outages that created unsafe grid operating conditions relative to spiking demand for electricity. As shown in Figure 6, near midnight on 14 February and through 0200 15 February, 2,000 MW of coal, 2,500 MW of wind energy, and 7,500 MW of natural gas -- 12,000 MW in total generation -- went offline. To keep the grid from faltering, and having announced Emergency Operations Level 3 between 0123 and 0200 15 February, the system operator ordered 10,500 MW of load-shedding (see the vertical orange bar in Figure 6), resulting in the first widespread blackouts during the event.

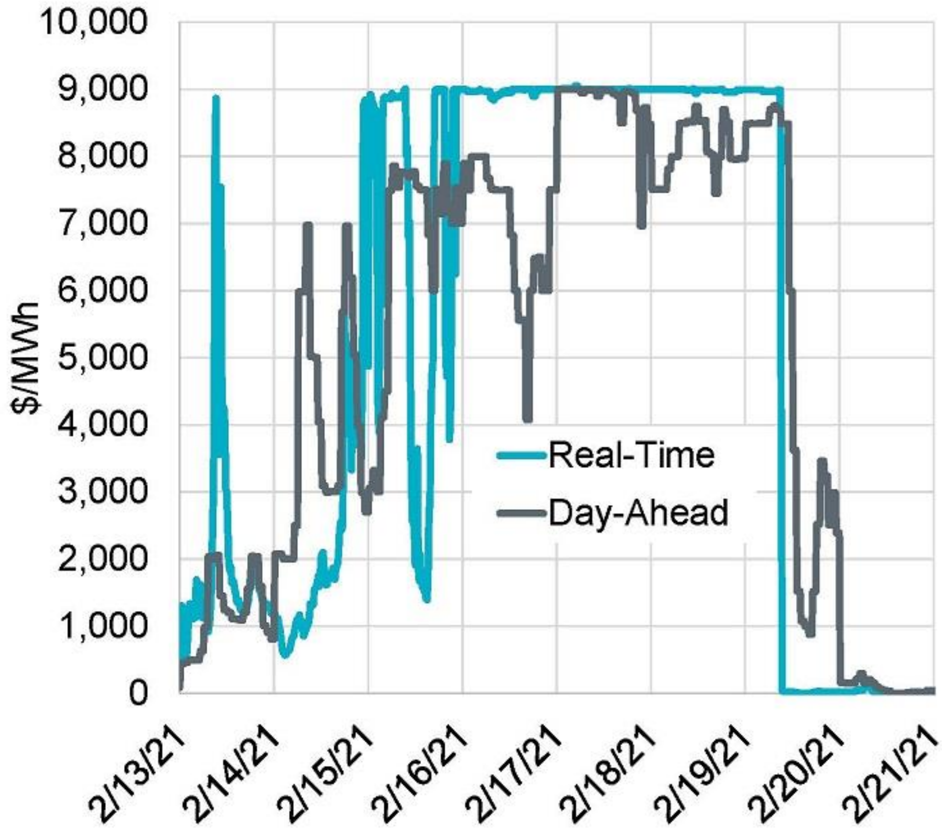

Figure 5. ERCOT electricity prices during the cold weather event for the period Saturday, 13 February to Sunday, 21 February 2021 (ERCOT, 2021 [2]).

On 1600 15 February, as load shedding was still near its maximum of 20,000 MW, ERCOT mandated that the hub settlement price be set to $9000/MWh in an attempt to entice additional power plants online. Little, if any, net gains in electricity generation occurred as a consequence because the cause of the outages, cold weather-related effects, was ongoing, and timely mitigation measures could not be implemented by generation sources. Settlement hub pricing at all hubs remained above $8000/MWh, and primarily at $9000/MWh, from 2100 15 February 2021 to 0800 19 February 2021. Hub settlement prices dropped to $800/MWh at 0900 19 February 2021 and to $25/MWh at 1000 19 February 2021.

At the maximum point of load-shedding early on 15 February, 18,000 MW of wind energy capacity, 16.7 percent of total ERCOT installed capacity from all sources, were offline (Figure 6). At least 21,888 MW of wind capacity were impacted at one time or another during the icing event, according to records released by ERCOT (2021, [3]).

The event ended as warmer temperatures on 18 February decreased electricity demand and allowed all forms of generators to begin a return to service by mid-morning 19 February.

In this study, we investigate how the financial impact of the icing event on wind farms would have changed under three alternative scenarios based on actual pricing before the mandated $9000/MWh pricing. The repricing scenarios are described in Section 3.

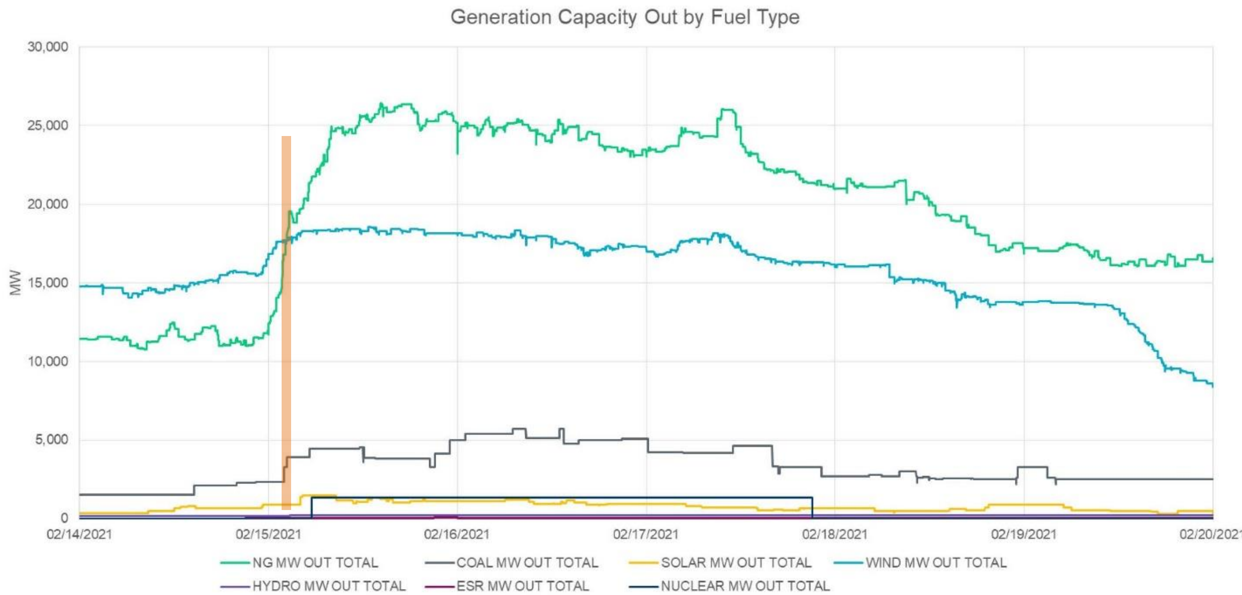

Figure 6. Generation capacity outages by fuel type 14 February to 20 February 2021. The transparent orange rectangle indicates the 0123-0200 15 February period when 10,500 cumulative M.W. of load shedding were ordered, coincident with 12,000 MW of generation experiencing outages (ERCOT, 2021 [2]).

2 METHODOLOGY

2.1 Motivation for Accurate Wind Speed Time Series

The single most important factor in accurately estimating proxy wind generation, defined as generation that would have occurred if a wind farm had not been shut down during the icing event, is an accurate time series of wind farm project hub height wind speed. Accomplishing this task requires detailed knowledge of the uncertainties in weather model wind speed estimates and access to data that allows, in the absence of on-site meteorological tower data, for a reasonable correction of bias in such data sets. In many cases, meteorology tower data were compromised by ice accumulation on anemometers and other equipment. Well understood, bias-corrected, highly correlated weather model data can be used effectively to estimate wind speed in the case of the ERCOT wind farm icing event.

Further, ERCOT (2021, [4]) reported to the Public Utility Commission that caution is required in the assessment of wind farm energy production estimates:

> All generator outage and derate values reflected in the graphs are based on generator nameplate capacity—i.e., the maximum possible M.W. output specified by the generator manufacturer. Because wind and solar output is typically much lower than the specified nameplate capacity, the outage and derate M.W. values used for those units to develop this report are generally much higher than the actual amount of power that would have been available in the absence of the outage or derate.

This note from ERCOT emphasizes that “the actual amount of power that would have been available in the absence of outage…” due to wind speeds that vary and are often below the wind speed required to reach wind turbine rated capacity, is lower than such estimates based on total wind farm nameplate capacity. In other words, without realistic wind speed data for the wind farms during the icing event, it is not possible to accurately estimate their potential energy production.

2.2 Brief Overview of Methods

We have devised a method to determine reasonably accurate estimates of hourly hub height wind speeds and net energy production at the wind farms that experienced outages during the icing event.

Site-specific hourly wind speeds were derived from the ERA5 hourly wind time series and adjusted to site hub height using public and proprietary validation sources. In turn, based on our extensive experience with wind energy resource assessment practice, and knowledge of wind turbine and wind plant specifications (including power curves and losses from gross energy based on wind direction), we estimated hourly net capacity factor and energy production.

To make these estimates, the following steps were taken:

1) Gather list of wind farms experiencing outages and the hourly time series and ascertain which wind farms are hedged.
2) Gather wind farm metadata (turbine model and specifications, nameplate capacity, ERCOT hub).
3) Gather hourly average hub settlement pricing time series for outage periods.
4) Gather ERA5 hourly time series wind speed, wind direction, temperature, and pressure data for each wind farm location.
5) Remove bias from the wind speed data using nearby highly correlated hub height extrapolated measurements to adjust hourly wind speed time series to hub height.
6) Use temperature and pressure data to determine hourly air density during the outage period.
7) Apply the air-density-adjusted turbine power curve for each wind farm to the bias-corrected site-specific wind speed time series to determine gross energy.
8) Use experience with Texas wind energy resource assessments and wind direction, where applicable, to apply losses from gross energy to determine the wind farm's net energy production time series.
9) Multiply the net wind farm production time series by that of hub settlement pricing to determine the hourly financial impact of the outage for hedged and all wind farms.
10) Sum the financial impact by the wind farm, and in aggregate for all wind farms, and those that are hedged.

Assuming that wind farm outage and hub settlement pricing data are accurately reported by ERCOT for the 14-19 February 2021 period, for accurate wind speed estimation, the critical part of this work is, first, wind speed bias correction, and second, air density correction. To avoid error, sound meteorological judgment and knowledge of wind measurement sources across Texas is required. The next most critical part of this analysis is the assessment of gross-to-net losses, which requires long-term validated experience with wind energy resource assessments as well as an in-depth understanding of how wind-farm-atmosphere interaction(Poulos, 2021) losses change with wind direction. In practice, we have found that the latter aspect is considerably less important than the wind speed and air density, with a net effect on aggregate financial impact calculations of less than a few percent. Without wind speed and air density correction, however, the results would contain additional uncertainty of 20-40 percent.

The hub height wind speed and air density bias corrections could be improved further by using site-specific data. In this case, however, acquiring such proprietary data for every wind farm that experienced an outage, in a short time frame, was not possible.

2.3 Wind Farm Outage Data Source

Wind farm outage information was derived from ERCOT (2021, [3]) records for all generator outages experienced during the icing and cold weather event for the 14-19 February 2021 period only. These data were parsed into 191 wind energy "Units." These data were further organized into time hourly outage periods for each of the ERCOT Units that reported outage data, resulting in an outage time series. In all, 21,888 MW of nameplate capacity wind farms, or their ERCOT Units, were organized.

The ERCOT outage data that were obtained are from 14 February 2021 to 20 February 2021. According to ERCOT records, a description of the data set, our inspection of the data set, and our knowledge of actual wind farm downtime, there are outage periods that occurred prior to 14 February 2021. ERCOT (2021 [2]) records clearly indicate wind farm outages of 12,000 MW prior to 14 February 2021. In some cases, outage records appear to be absent prior to 16 February 2021. As additional data are released by ERCOT, or as additional site-specific outage information becomes available, the analysis herein may be revised. The total financial impact of the icing event would be larger if the period from 10-13 February 2021 were included in this analysis; in some cases, we estimate losses prior to 14 February to be up to 30% higher. Likewise, 13% of the 25,121-MW of ERCOT wind capacity either did not report data or did not experience icing event outages; financial impacts to this group of wind farms are not estimated in this study.

The outage data set provided by ERCOT also contains fractional derating information for each wind farm. In this study, we have not accounted for fractional derating information; instead, we assumed that if at least part of a wind farm was iced, then the entire wind farm was iced and unavailable for the outage/derating period. This assumption is consistent with proprietary information received from owner-operators that had wind farms involved in the icing event. If fractional derating had been accounted for, the production and financial impact results would be 75 percent lower.

To determine which wind farms are hedged, we combined internal knowledge, project operator interviews, and data from Wilson (2021). 12,495 MW of hedged projects with outages, out of the 21,888 MW of outage wind farms listed by ERCOT, have been identified with considerable certainty. This analysis may be updated as additional information regarding wind farm outages, hedged or otherwise, is obtained.

2.4 Wind Farm Metadata

Determining the net energy production from a wind farm requires analysis of various wind farm metadata. For each wind farm, the turbine model(s), turbine nameplate capacity, hub height, specifications (including air-density-adjusted turbine power curves), and ERCOT settlement hub were gathered. Sources were internal or proprietary, or public, from sources such as the U.S. Wind Turbine Data Base (uswtdb.org).

2.5 Settlement Hub Pricing Time Series

ERCOT settlement hubs, North, South, West, and Houston, 15-minute time series pricing data for the icing event were obtained from publicly available records at the ERCOT website (ercot.com). The 15-minute time series were converted to hourly averages to match the hourly time series of wind, climate, and energy production time series. Nodal and load-zone pricing were not used in this study but could be used in future studies to refine or modify the results.

2.6 ERA5 Baseline 100-m Wind and Climate Data, Bias-Corrected, and Gross Energy

The next step taken was to simulate weather conditions at every wind farm using state-of-the-art reanalysis data and bias correction techniques.

ERA5 global weather reanalysis data comprise hourly three-dimensional data assimilated from many local and global sources of information, such as weather radiosondes (weather balloons), satellites, airport climate weather stations, aircraft, and other sources. These data are available globally on a 0.25° by 0.25° latitude/longitude grid. ERA5 data are made available by the European Centre for Medium-Range Weather Forecasts (ECMWF). ERA5 data are in common use within the wind energy industry and are known to be highly correlated to actual weather conditions in Texas, due in part to the vast sources of weather information that are assimilated in that region.

For the purpose of this study, an ERA5 data time series of wind speed, wind direction, temperature, and pressure were downloaded for the point nearest the latitude/longitude centroid of each wind farm at 100 m above ground.

As with most high-quality synthetic or modeled sources of weather data, such as those that are available from U.S. National Weather Service sources (e.g., HRRR or GFS weather model data), ERA5 too is highly correlated to actual weather conditions experienced at the wind farm sites in this study. Each synthetic weather source, however, is also biased relative to weather observations, especially for wind speed. The wind speed bias correction and air density calculation are significant drivers of accuracy in net energy production calculations; a lack of bias correction would otherwise cause bias and lead to uncertainties of 10-40 percent. Air density was calculated directly from ERA5 observations of air pressure and temperature and was adjusted to turbine hub height using standard methods.

The ERA5 100-m wind speed hourly time series was bias corrected to turbine hub height using our internal database, with publicly available or otherwise non-proprietary measured wind speed data extrapolated to hub height. A wind speed ratio bias correction was established between the measurement data and ERA5 data for February for each wind farm and applied to the ERA5 wind speed time series. The resulting bias-corrected hourly wind speed time series was used to calculate gross energy based on the air-density-adjusted turbine power curve for each wind farm.

2.7 Gross-to-Net Losses and Net Energy

Based on wind farm metadata, wind-farm-atmosphere interaction losses with wind direction, and typical gross-to-net losses for wind farms in different parts of Texas, hourly gross-to-net losses were estimated for each wind farm. The gross-to-net loss, expressed as an efficiency, was applied to the hourly gross energy to determine net energy by the hour for each wind farm. In practice, we found that modifying gross-to-net losses by wind direction effects on wind farm-atmosphere interaction was not a significant factor: A single gross-to-net loss could be applied to each wind farm.

2.8 Time Series Financial Impact Calculation and Aggregation

The hourly net energy time series for each wind farm was multiplied by the concurrent hourly average settlement hub price time series to determine the hourly time series of the financial impact of an outage at each wind farm. These individual wind farm financial impacts, for all 21,888 MW and 191 wind farm ERCOT Units, were aggregated into a table of total financial impact. These data were further delineated into those wind farms with hedges and those without. Since hedge and PPA prices are not known completely, and they represent 0.2% to perhaps 3% impact on the results (e.g., $30/MWh is 0.5% of $6000/MWh price), we have not subtracted these values from our calculations. Individual wind farm financial impacts are not shown in this document.

3 RESULTS: AGGREGATE WIND SPEED, NET ENERGY, and FINANCIAL IMPACT SCENARIOS

The analysis was completed, following the sequence of steps described in Section 2, for each wind farm in the ERCOT list (Appendix A). These results form a baseline for the potential financial impact of the outages at ERCOT wind farms during the icing event. Section 3.1 describes three alternate pricing scenarios as well as alternative financial impacts associated with those scenarios.

3.1 Baseline Pricing Scenario: All Wind Farms and Those Hedged

The actual financial impact on any given wind farm varies greatly depending on the financial structure. For projects with a typical busbar power purchase agreement (PPA), the financial impact of the icing event outage is the lost ability to produce electricity; this, in turn, is a lost opportunity to sell that power into the ERCOT grid during a period of very high electricity price at the settlement hub.

For projects with hedges with fixed-shape/fixed-volume production (often delineated by the hour and month based on a monthly-diurnal pattern and a percentage of total possible production), such as in proxy generation or proxy revenue swaps, the financial impact is reflected in payments owed to the hedge provider. Icing events, in this case, or other weather events that might cause outages, do not impart *force majeure* protection to the owner. If the project owner has business interruption insurance, the financial impact may be mitigated. In the case of an outage caused by the ERCOT icing event, the project owner will owe the proxy hedge provider for energy that, had the project been operating normally, would have sold into the ERCOT market. Virtual PPA/Contracts-for-Difference (CfD) structures do not typically have fixed-shape proxy generation obligations and are settled at the hub based on actual generation, and these would not be subject to payments due (if iced, such projects would lose the opportunity to sell power). In this study, we are not able to distinguish those hedged projects with fixed-shape or proxy generation risk from those without that risk, so our results average all hedged projects together.

Proxy swaps and fixed-volume hedges do not necessarily incorporate 100% of potential production into the hedge; the amount of total projected production that is hedged may be based on the 1-in-100 amount (P99) or 80% of P50, or another percentage. As such, the losses incurred by such contracts are split into a portion associated with the amounts owed to the hedge provider and the lost opportunity to sell the remaining unhedged electricity into the real-time market.

We tallied individual wind farm results into aggregate values. Table 1 summarizes the wind speed and net capacity factor results for the aggregate of the 21,888 MW of nameplate capacity represented by the 191 wind farm Units in the study. Wind farms with multiple designated ERCOT Units that are part of a wind farm cluster are treated as one wind farm in some cases, resulting in 114 wind farms.

	Proxy Outage Wind Speed (m/s)	Proxy Outage Net Capacity Factor (%)
Average	6.3	30.6%
Maximum	12.8	75.8%

*averages are nameplate MW weighted

Table 1. 114 Wind Farm Average Proxy Hub Height Wind Speed and Net Capacity Factor

The average (proxy) wind speed during the downtime period, aggregated across all wind farms, was determined to be 6.3 m/s. The average proxy net capacity factor of the wind farms studied during the period was 30.6 percent. This net capacity factor is relatively low compared to the long-term average annual net capacity factor for wind farms in Texas, which typically falls between 40 percent and 50 percent.

Table 2 shows the aggregate proxy generation during the outage periods and the financial impact of not being able to produce the proxy generation for all 191 ERCOT wind farm Units, or 114 wind farms. We found that the lost (proxy) energy production from wind farms that would have otherwise operated were it not for icing shutdown was 629,700 MWh. The financial impact of this lost production, whether the financial loss to the owner or gain by others, is $4.18B.

This estimate accounts for the elevated power prices during the icing event; at a more typical 2020 average $20/MWh price, the proxy icing event generation would be valued at $12.6M, or 331 times less. Alternative pricing scenarios are presented in Section 3.2.

The maximum financial impact for a project was found to be $172.5M. The average financial impact across all wind farms was determined to be $44.4M.

	Proxy Outage Generation (MWh)	Proxy Outage Financial Impact ($M)
Total	629700	4175.0
Wind Farm Average	6700	44.4
Wind Farm Maximum	20100	172.5

*average generation is nameplate MW weighted

Table 2. 114 Wind Farm Average Proxy Generation and Financial Impact

Table 3 shows the aggregate hedged project proxy generation and financial impact during the outage periods. For the 61 hedged wind farm projects evaluated, the financial impact of this lost production is $2.59B. The maximum financial impact for a wind farm cluster was found to be $172.5M. The average financial impact for all wind farms was determined to be $45.4M.

	Proxy Outage Generation (MWh)	Proxy Outage Financial Impact ($M)
Total	372200	2590.4
Wind Farm Average	7300	45.4
Wind Farm Maximum	20100	172.5

*average generation is nameplate MW weighted

Table 3. 61 Hedged Wind Farm Average Proxy Generation and Financial Impact

These results indicate that iced wind farms in ERCOT during the icing event were significantly financially impacted by being unable to operate during the high electricity price conditions. These results naturally lead to the conclusion that fixed production volume-based hedges, without anticipating such severe events and mitigation, are at risk of default. In subsequent sections, we comment further on this issue.

3.2 Three Repricing Scenarios

3.2.1 Repricing Study Motivation

Why evaluate repricing scenarios?

According to the *Texas Tribune*, 4 March 2021, during the icing and cold weather event:

> Potomac Economics, the independent market monitor for the Public Utility Commission of Texas, which oversees ERCOT, wrote in a letter to the Public Utility Commission that ERCOT kept market prices for power too high.

And, on 11 March 2021, the *Texas Tribune* reported on pricing imposed during the icing event:

> In a separate 11 March meeting of the State Senate Jurisprudence Committee, Bill Magness, ERCOT's president and CEO until 30 May, acknowledged that ERCOT's decision to price energy at the $9,000/MWh cap was "a judgment call," but it was needed because ERCOT needed to send a signal "throughout the market" to ensure the stability of the grid.

Given that ERCOT decreased market demand with rolling load-shedding blackouts, the production by generators remaining in operation was more nearly balanced to that now-reduced demand. In that instance, some owners/operators have argued that, based on actual real-time pricing prior to the ERCOT-mandated $9000/MWh price, hub settlement prices would have been elevated but not to the $9000/MWh value. In that instance, with imposed non-market-driven pricing, artificially high financial benefits would accrue to some wind farm owners, investors, and financial institutions, and artificially high losses would be imposed on others.

Based on the $9000/MWh price mandate from ERCOT, we investigated three pricing scenarios that represent electricity pricing evolution before the mandate. It is not possible to predict power prices had ERCOT not mandated maximum pricing in the late afternoon of 15 February, and these scenarios may or may not, therefore, represent realistic estimates of financial impacts outside that mandate. Each scenario uses an average price based on a 24-hour period to smooth daily fluctuations.

3.2.1 Market Pricing to Motivate Electricity Generators

Each type of electricity generation has a different break-even price, and gas peakers, which are intended to operate during high electrical loads and to ensure anticipated peak demand can be addressed by the electrical grid, are considered the most expensive, costing between $150/MWh and $200/MWh. Economically, peakers will tend to operate only when the market price is sufficiently high.

At what hub settlement price are companies operating gas peakers, such as natural gas turbines or engines, motivated to operate, given that the price of electricity generated from such plants is near $200/MWh? In the three scenarios below, power prices exceed nine (9) times the $200/MWh gas peaker economic threshold, which we assume is a sufficiently high price to motivate gas peaker operation, along with all other forms of electricity generation.

The actual pricing during the event resulted in financial impacts of $4.2B; percent change is computed relative to this baseline value in the subsections that follow.

3.2.2 Pricing Scenario 1

Scenario 1 assumes that the $1826/MWh average electricity price during the 24 hours before 0800 14 February 2021, when average hub settlement prices first rose above $1000/MWh, would have prevailed without the ERCOT $9000/MWh pricing mandate for the remainder of the icing event.

In this case, we find that the overall financial impact of the icing event on non-operational wind farms, compared to the baseline pricing scenario, drops by 75.9 percent to $1.01B.

3.2.3 Pricing Scenario 2

Scenario 2 assumes that the $2816/MWh average electricity price during the 24 hours before ERCOT began load shedding (0125 15 February) would have prevailed without the ERCOT $9000/MWh pricing mandate for the remainder of the icing event.

For Scenario 2, we find that the overall financial impact of the icing event on non-operational wind farms, compared to the baseline pricing scenario, drops by 61.8 percent to $1.60B.

3.2.4 Pricing Scenario 3

Scenario 3 assumes that the $6007/MWh average electricity price during the 24 hours before 1700 15 February, when ERCOT imposed the $9000/MWh pricing mandate, would have prevailed during the remainder of the icing event.

For Scenario 3, we find that the overall financial impact of the icing event on non-operational wind farms, compared to the baseline pricing scenario, drops by 26.3% percent to $3.08B.

4 BROADER IMPLICATIONS AND POTENTIAL CORRECTIVE ACTIONS

4.1 Hedge Risk Asymmetry Observations

In the course of this study, we have observed that the average financial impact, $45M, of the February 2021 Texas icing and cold weather event on an individual Texas wind farm, without icing mitigation capability and based on common net capacity factors of Texas wind farms, exceeds its typical nominal annual revenue by more than two times. The financial impact is many times a wind farm's annual net income, and, therefore, depending on the wind farm's financial structure, negates a large fraction of a project's lifetime return and creates a significant risk of default.

Climatologically speaking, similar, if most likely shorter, icing and cold weather events will occur several times during the 30-year useful life of a wind farm in much of Texas. (These conditions are less likely for Gulf Coast wind farms, but these producers are more likely to be affected by a different extreme weather event, hurricanes.). For example, after the 2011 cold weather event, which also caused rolling blackouts, FERC and NERC (2011) reported that similar events had occurred in 1983, 1989, 2003, 2006, 2008, and 2010. Therefore, especially if icing mitigation capability is not present, such risks must be accounted for in financial modeling, and pricing should be adjusted upward to account for this risk, lest the project is unable to meet its obligations in time of a production crisis.

The financial structures that require this risk assessment are those where potential production (proxy generation) or long-term mean hourly electricity production (fixed-shape) must be delivered to the financier by operator purchase should the project be unable to operate for any reason. This pricing risk is highly asymmetric. In Texas, the hedge provider price risk is limited to the strike price (up to $20/MWh, or more if prior to 2019) plus the value of the production tax credit, for a value near \$40/MWh; asymmetrically, project owner price risk is the maximum possible hub settled price minus the strike price, near \$9000/MWh. In ERCOT, unmitigated proxy or fixed-shape hedged price risk for project owners is 225 times larger than that of the hedge provider. We conclude that all such hedges, from a realistic atmospheric science perspective, without turbine icing mitigation, are fundamentally misdiagnosed, with previously unaccounted-for risks and highly asymmetric windfall advantages to the hedge provider. Business interruption insurance, per-megawatt daily caps, to limit risk asymmetry, and/or avoiding fixed-volume hedges and using only as-generated hedges are all possible solutions.

4.2 Revisit ERCOT Electricity Pricing Post-Icing Event

Average wholesale 2020 electricity prices in ERCOT are near \$20/MWh, and that ERCOT 2020 energy consumption was 381,000,000 MWh (ERCOT 2021 [1]); wholesale electricity purchases in 2020 were \$7.6B. The energy purchases during the ERCOT winter event totaled \$46B, or six times higher than the 2020 annual total. We conclude, assuming one such event per decade and 2020 average pricing, that the effective realized decadal average ERCOT electricity price is, \$30/MWh, 50 percent higher than reflected in the 2020 annual average. According to Energy Information Administration (EIA) wholesale pricing data (https://www.eia.gov/electricity/wholesale/#history), ERCOT prices have averaged between \$20/MWh and \$40/MWh since 2014. If structural changes are not made to the ERCOT grid and market operation, future Texas contracts should reflect a price, likely between \$30/MWh and \$40/MWh, that accounts for icing events and the very highest pricing possible for a few days per year. As-generated production hedges remove the asymmetric risk, although the lost opportunity to sell electricity in icing conditions remains a risk.

4.3 Considering Weatherization

Weatherization packages are available from wind turbine manufacturers and from third-party after-market suppliers. These can take the form of cold-weather packages, including heaters and special lubricants to allow operation at colder temperatures. These cold-weather packages are commonly purchased, and many wind farms in Texas have done so. In addition, anti-icing and de-icing packages are available from wind turbine manufacturers as options or from third-party providers as after-market retrofits. The use of such systems is common in Nordic countries and other locales where icing is frequent and generation must be assured. Anti-icing and de-icing systems take the form of coatings applied to the exterior of blades to discourage ice from sticking, mats with resistive heating applied to critical locations on the blades, or heaters and fans in the blade roots with air chambers that direct heated air through the blades. One company in Canada outfitted a helicopter with an aerial cleaning and de-icing system that can be used to clear ice off of wind turbine blades (Froese, 2017).

Texas currently has 25,121 MW of wind capacity, mostly unprotected from icing events. Costs of anti-icing and de-icing systems are not widely published, but one publication (Moran 2021) estimates that icing mitigation adds approximately 5-10 percent to turbine price or \$50,000 to \$100,000 per M.W. at \$1,000,000 per M.W. at purchase. Thus, upfront icing mitigation of all wind turbines in Texas would have cost \$1.25B to \$2.50B. The cost of icing mitigation, therefore, would have been less than the \$4.18b impacts of the icing event. In hindsight, many project owners likely wish they had purchased an ice mitigation option for their wind turbines. However, that is only because market prices were artificially elevated to \$9000/MWh. For most wind farms with fixed-price PPAs, or those that do not experience such unusual market conditions, selection of an ice mitigation option often does not make sense. When a developer is bidding for an offtake agreement, the added cost of an anti-icing or de-icing system harms the competitiveness of a project. Therefore, with the exception of some high elevation locations in New

England and mid-Atlantic regions, wind farm developers tend not to select these ice mitigation options. Indeed, the helicopter company in Canada found that their retrofitted de-icing helicopter went unused “for over a year," and their de-icing system “sat unused for lack of interest” (Froese, 2017).

As the penetration of renewables increases over time, it will be more important for system operators to rely upon wind energy generation during cold weather ice events such as that experienced in Texas in February 2021. However, project economics do not incentivize developers to install such systems. Installation of additional weatherization equipment may be incentivized if wind farms received capacity credits and capacity payments. These payments could potentially be tied to a requirement that ice mitigation equipment is installed. With sufficiently high penetration of renewables, it might even become necessary for regulators to require weatherization packages, much as aviation lighting is currently mandated. With the widespread use of weatherization packages, perhaps encouraged by the need for resilience in wind energy generation during extreme cold weather events, there would likely be more competition in the market, and prices would likely drop far below the less attractive current rate of 5% to 10% of turbine price.

Based on our analysis, we find the following:

1. Hedged financial structures with guaranteed production for wind farms in ERCOT are misdiagnosed with respect to weather risk, asymmetric price risk, meteorologically unrealistic production assurances, and strike prices that do not reflect long-term electricity prices from all electricity generation sources based on the current regulatory structure in ERCOT.
2. For hedged merchant projects in Texas, developers should consider asymmetric price risks when assessing the cost/benefit of icing mitigation and/or, if hedged with production assurance, should be priced to account for the asymmetric risk borne by the owner/operator.
3. Future Texas fixed-volume and proxy generation-based contracts should reflect a price, likely between \$30/MWh and \$40/MWh, that accounts for icing events and the very highest pricing possible for a few days per year.
4. Appropriate *force majeure* clauses in hedge agreements could potentially mitigate this asymmetric price risk, but that would not help the physical availability of wind generation as renewables continue to penetrate energy markets.
5. Icing mitigation measures would have cost less than half of the financial impact on wind farms in Texas during the ERCOT February wind turbine icing event, but regulatory action may still be required to incentivize the installation of ice mitigation systems as renewables penetration increases over time.

5 REGARDING WEATHER-DRIVEN PRODUCTION & LONG-TERM ERCOT PLANNING

We believe the ERCOT winter weather event, and the frailties it revealed in its electricity system planning and operation, is a clear mandate that such planning for the ERCOT balancing authority must now more stringently apply atmospheric science-based risk assessment, particularly with regard to extreme weather and peak demand operational scenarios.

ERCOT has more installed wind energy capacity than any state in the United States. It is projected that its renewable energy capacity will exceed 60 gigawatts (G.W.) within three years and will dominate regular ERCOT generating (not storage or peaker) capacity within a decade.

Electricity production is accelerating toward predominantly wind and solar energy sources, whose fuel, wind, and solar radiation, are governed by the weather at any particular power plant location. Electricity usage, in particular, extreme electricity usage, is similarly governed primarily by changing weather conditions, such as high and low-temperature events. Weather-driven peak electricity demand is clearly understood.

These two statements plainly indicate the need to restructure electricity system resilience and reliability to account for weather-driven production and weather-driven demand, concomitant with the pace of the transition to renewable-energy-dominated production.

Based on atmospheric science principles, we know how solar radiation and wind vary, both temporally and spatially. For example, as relevant to ERCOT, extreme synoptic-scale weather events that persist for one to two weeks over areas the size of Texas can be predicted in advance. We also know that there are always sufficient supplies of electricity produced by wind and solar available across the contiguous United States; with sufficient transmission, this electricity may be transported to any location experiencing a local or regional shortage. We also know that at any given time at a particular wind and solar power plant location, the resource may be zero.

Weather-driven electricity production is inevitable as economically advantaged renewable energy comes to dominate generation capacity in ERCOT. ArcVera's analysis and observations, taken together, clearly describe a condition where, with greater attention to atmospheric science details when assessing the risks of weather-driven electricity production and demand, an adequately resilient and interconnected ERCOT electricity system can be created. ERCOT planning should consider that cold-weather events worse than the recent February 10-19, 2021 event are possible.

6 SUMMARY AND CONCLUSIONS

This study quantifies the lost energy production and financial impact of a rare Texas winter weather event that occurred 10-19 February 2021using an in-depth time series data analysis of wind energy project site-specific wind speed, net capacity factor, and hub settlement pricing.

We find that the lost energy production from wind farms that would have otherwise operated, were it not for icing event shutdown 14-19 February 2021, was 629,700 MWh. The average wind speed and net capacity factors during the outage period, aggregated across all wind farms, were found to be 6.3 m/s and 30.6 percent, respectively. The financial impact of this lost production, whether the financial loss to the owner or gain by others, for the shutdown period, is $4.18B. For hedged projects, the financial impact of this lost proxy production is $2.59B.

Three repricing scenarios prior to mandated ERCOT $9000/MWh pricing show reduced financial impacts from the $4.2B baseline, dropping the financial impact by 1) 75.9 percent to $1.01B, 2) 61.8 percent to $1.60B, and 3) 26.3 percent to $3.08B.

Broader implications of our findings and potential corrective actions for wind energy finance, electricity pricing in ERCOT, wind turbine weatherization, the transition to weather-driven production by renewables, and ERCOT planning are described.

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APPENDIX A: LIST OF ERCOT-OUTAGE-AFFECTED WIND FARMS/UNITS

		Total (MW)
ERCOT		21888
Wind Plant Station Name	**Unit Name**	**Capacity (MW)**
AMADEUS WIND 1	UNIT1	37
AMADEUS WIND 1	UNIT2	36
AMADEUS WIND 2	UNIT3	178
ANACACHO	ANA	100
AVIATOR WIND	UNIT1	180
AVIATOR WIND	UNIT2	146
BAFFIN WIND PROJECT	UNIT1	100
BAFFIN WIND PROJECT	UNIT2	102
BARTON CHAPEL WIND FARM	BCW1	120
BLUE SUMMIT	UNIT2_17	7
BLUE SUMMIT	UNIT2_25	90
BLUE SUMMIT	BLSMT1_6	124
BRISCOE WIND FARM	WIND	150
BRUENNINGS BREEZE	UNIT1	120
BRUENNINGS BREEZE	UNIT2	108
BUCKTHORN WIND	UNIT1	45
BUCKTHORN WIND	UNIT2	56
BUFFALO GAP WIND FARM	UNIT1	121
BUFFALO GAP WIND FARM	UNIT3	170
BULL CREEK WIND	WND1	88
BULL CREEK WIND	WND2	90
CALLAHAN Windfarm FPL	WND1	114
CAMERON WINDFARM	UNIT1	165
CANADIAN BREAKS	UNIT_1	210
CAPRICORN RIDGE	CR3	201
CAPRICORN RIDGE	CR1	232
CAPRICORN RIDGE	CR2	150
CAPRICORN RIDGE	CR3	201
CAPRICORN RIDGE 4	CR4	122
Cedro Hill Wind Farm	CHW1	75
CFLATS SUBSTATION	U1	148
CHAMPION WIND FARM	UNIT1	127
COTTON PLAINS WIND	COTTONPL	50
COTTON PLAINS WIND	OLDSETLR	151
CRANELL WIND	UNIT1	220
DERMOTT WIND	UNIT1	127
DERMOTT WIND	UNIT2	127
DEWOLF EAST	UNIT1	199
DIGBY SUBSTATION	UNIT1	99
DIGBY SUBSTATION	UNIT2	131
EL RAYO WIND FARM	UNIT1	101
EL RAYO WIND FARM	UNIT2	99
ELBOW CREEK	ELBCREEK	119
ENA Snyder Wind	ENA1	63
FALVEZ ASTRA	UNIT1	163
FERMI Substation	WIND1	122
FERMI Substation	WIND2	27
Flat Creek Switch	SSI	53
FLAT TOP WIND SUBSTATION	UNIT_1	200
FLUVANNA WIND	UNIT1	80
FLUVANNA WIND	UNIT2	76
FOREST CREEK AND SAND BLUFF	SBW1	90
FOREST CREEK AND SAND BLUFF	FCW1	124

Table continued ...

Wind Plant Station Name	Unit Name	Capacity (MW)
GOAT WIND	GOATWIN2	70
GOAT WIND	GOATWIND	80
GOPHER CREEK WIND FARM	UNIT1	82
GOPHER CREEK WIND FARM	UNIT2	76
GRANDVIEW WIND FARM	COLA	100
GRANDVIEW WIND FARM	COLB	100
GRANDVIEW WIND FARM	GV1A	107
GRANDVIEW WIND FARM	GV1B	104
GREEN MOUNTAIN ENERGY BRAZOS	WND1	99
GREEN MOUNTAIN ENERGY BRAZOS	WND2	61
GREEN PASTURES WIND	WIND_I	150
HACKBERRY WIND FARM	HWFG1	164
HEREFORD WIND	WIND_G	100
HIGH LONESOME	WGR2A	25
HIGH LONESOME	WGR3	128
HIGH LONESOME	WGR4	102
HORSE CREEK WIND	UNIT1	131
HORSE CREEK WIND	UNIT2	99
HORSE HOLLOW 1	WND1	230
HORSE HOLLOW 2	WIND1	184
HORSE HOLLOW 3	WND_1	241
HORSE HOLLOW 4	WND1	115
HORSE HOLLOW GENERATION TIE	CALLAHAN	114
INADALE	INADALE1	95
INADALE	INADALE2	102
INDIAN MESA ENRON	INDNENR	66
INDIAN MESA ENRON	INDNENR_2	66
INDIAN MESA ENRON	UNIT_1B	24
INDIAN MESA ENRON	UNIT_2B	15
INDIAN MESA NWP	INDNNWP2	92
JAVELINA WIND ENERGY PROJECT	JAVEL18	20
JAVELINA WIND ENERGY PROJECT	JAVEL20	230
JAVELINA WIND ENERGY PROJECT 2	JAVEL2_B	74
JAVELINA WIND ENERGY PROJECT 2	JAVEL2_A	96
JAVELINA WIND ENERGY PROJECT 2	JAVEL2_C	30
KARANKAWA1 WIND FARM	UNIT2	103
KARANKAWA1 WIND FARM	UNIT1	103
KARANKAWA2 WIND FARM	UNIT3	100
KEECHI WIND	U1	110
LANGFORD WIND POWER LLC	LANGFORD	160
LOCKETT WIND	UNIT1	184
LORAINE WINDPARK PROJECT LLC	G1	48
LORAINE WINDPARK PROJECT LLC	G2	51
LORAINE WINDPARK PROJECT LLC	G3	26
LORAINE WINDPARK PROJECT LLC	G4	24
LOS VIENTOS 2	LV2	202
LOS VIENTOS III	UNIT_1	200
LOS VIENTOS WINDPOWER	LV1A	200
LOS VIENTOS WINDPOWER IV LLC	UNIT_1	200
MAGIC VALLEY I	MV1A	100
MAGIC VALLEY I	MV1B	104

Table continued …

Wind Plant Station Name	Unit Name	Capacity (MW)
MAVERICK CREEK WIND EAST	UNIT5	71
MAVERICK CREEK WIND EAST	UNIT6	33
MAVERICK CREEK WIND EAST	UNIT7	22
MAVERICK CREEK WIND EAST	UNIT8	20
MAVERICK CREEK WIND EAST	UNIT9	77
MAVERICK CREEK WIND WEST	UNIT1	202
MAVERICK CREEK WIND WEST	UNIT2	11
MAVERICK CREEK WIND WEST	UNIT3	34
MAVERICK CREEK WIND WEST	UNIT4	22
MESQUITE CREEK WIND	WND1	106
MESQUITE CREEK WIND	WND2	106
MESTENO WINDPOWER	UNIT_1	202
MIDWIND SUBSTATION	UNIT1	163
NIELS BOHR	UNIT1	197
Notrees Windfarm	NWF2	60
Notrees Windfarm	NWF1	93
OCOTILLO WINDFARM	OWF	59
PANTHER CREEK 2	PANTHER2	116
PANTHER CREEK 2	PANTHER3	200
PANTHER CREEK NORTH	PANTHER1	143
PAPALOTE CREEK	PAP1	180
PAPALOTE CREEK II	PAP2	200
PENASCAL II WIND PROJECT	UNIT3	101
PENASCAL WIND POWER	UNIT1	161
PENASCAL WIND POWER	UNIT2	142
PRAIRIE HILL WIND PROJECT	UNIT1	153
PRAIRIE HILL WIND PROJECT	UNIT2	147
PYRON WIND FARM	PYRON1	122
PYRON WIND FARM	PYRON2	128
RANCHERO WIND FARM	UNIT1	150
RANCHERO WIND FARM	UNIT2	150
RATTLESNAKE	G1	104
RATTLESNAKE	G2	103
RED CANYON	RDCNY1	90
ROSCOE WIND FARM	ROSCOE	114
ROSCOE WIND FARM	ROSCOE2A	95
ROUTE 66 WIND POWER	WIND1	150
RTS2 WIND PROJECT	U1	90
RTS2 WIND PROJECT	U2	90
SAGE DRAW WIND PROJECT	UNIT1	169
SAGE DRAW WIND PROJECT	UNIT2	169
SALT FORK	UNIT1	64
SALT FORK	UNIT2	110
SALVATION	UNIT1	125
SALVATION	UNIT2	125

Table continued …

Wind Plant Station Name	Unit Name	Capacity (MW)
SAN ROMAN WIND I	WIND_1	95
SANTA CRUZ	UNIT1	151
SANTA CRUZ	UNIT2	98
SENATE WIND FARM	UNIT1	150
SHAFFER	UNIT1	226
SHANNON WIND PROJECT	UNIT_1	204
SHERBINO II WIND FARM	SHRBINO2	132
SOUTH PLAINS PHASE II	WIND21	149
SOUTH PLAINS PHASE II	WIND22	152
South Trent Wind Farm	T1	98
SPINNING SPUR WIND TWO	WIND_1	161
SPINNING SPUR WIND TWO	SS3WIND1	96
SPINNING SPUR WIND TWO	SS3WIND2	98
STELLA WIND	UNIT1	201
STEPHENS RANCH PHASE 1	SRWE2	165
STEPHENS RANCH PHASE 2	UNIT1	211
SWEETWATER WIND 1	WND1	43
SWEETWATER WIND 2	WND2	111
SWEETWATER WIND 2	WND24	17
SWEETWATER WIND 3	WND3A	34
SWEETWATER WIND 3	WND3B	117
SWEETWATER WIND 4	WND4A	125
SWEETWATER WIND 4	WND4B	112
SWEETWATER WIND 5	WND5	85
TAHOKA WIND	UNIT_1	150
TAHOKA WIND	UNIT_2	150
TORRECILLAS	UNIT1_25	150
TORRECILLAS	UNIT2_23	23
TORRECILLAS	UNIT2_25	128
TRINITY HILLS WIND FARM	TH1_BUS1	103
TRINITY HILLS WIND FARM	TH1_BUS2	95
TYLER BLUFF WIND	UNIT1	126
VERA WIND	UNIT1	12
VERA WIND	UNIT4	22
VERA WIND	UNIT2	7
VERA WIND	UNIT3	101
VERA WIND	UNIT5	101
VERTIGO WIND	WIND_I	150
WAKE WIND ENERGY	G1	115
WAKE WIND ENERGY	G2	142
WILSON RANCH SUBSTATION	UNIT1	200
WOODWARD 1	WOODWRD1	92