

LESSONS FROM THE TEXAS BIG FREEZE

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INTRODUCTION

In the week following Valentine's Day 2021, Texas experienced a series of severe winter storms that turned into an even bigger disaster when the electricity grid had to initiate rotating outages under imminent threat of blackout and left millions of homes without power. The stories of children freezing to death and people dying of carbon monoxide poisoning are heartbreaking.

More broadly, the outages resulted in widespread suffering, immense costs, burst pipes, and lack of potable water. Enki Research estimates more than \$90 billion in economic damage.¹ In the aftermath, many electric power retailers, municipal utilities, and cooperatives were pushed to bankruptcy, while other load-serving entities incurred billions of dollars in incremental costs, which probably will be passed on to their customers.

A clear systematic failure occurred in the Texas energy system during "the Big Freeze." This brief examines how ERCOT's market design, as part of a larger system, failed both to prepare the state for such a crisis and to acceptably manage the crisis. The brief identifies lessons that can be learned for policymakers in Texas and elsewhere, as well as possible solutions for better preparedness.

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BASIC CHRONOLOGY OF THE EVENT

The basic chronology of the Big Freeze is clear, even if the full story of what happened in the energy system and related markets may take longer to emerge.

The accompanying slide (Figure 1) created by electric industry analyst Brian Bartholomew gathers many of the essential facts as they relate to the Electric Reliability Council of Texas (ERCOT)—the independent system operator for the grid island that covers most of Texas.² Though grid trouble began in the early morning of February 15, forward markets for electricity and natural gas delivery on the InterContinental Exchange started signaling trouble as early as February 10, and price spikes over \$1,000 per megawatt-hour (MWh) appeared on February 11.

A sudden dip in the system frequency around 1:25 a.m. on February 15 signaled possible disaster: the total collapse of the ERCOT grid. Frequency drops are the result of insufficient supply to meet demand—if frequency drops too low, equipment designed to run at 60 hertz begins to malfunction and break, and cascading outages begin to occur. This dip was caused by the rapid failure of much of the

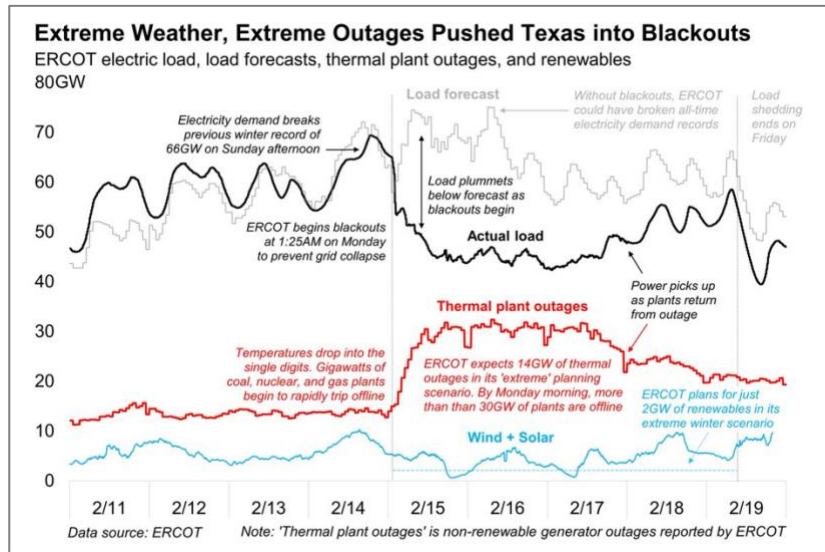


Figure 1. ERCOT data posted to Twitter by Brian Bartholomew (@BPBartholomew)

Texas generation fleet from a combination of frozen equipment and sensors as well as a precipitous decline in fuel availability for the natural gas fleet.

THE LARGER CONTEXT

The energy system that delivers electricity from central power stations to Texas customers via poles and wires is part of a greater whole. It is dispatched and financed based on the security-constrained economic dispatch engine at the heart of the ERCOT system, it depends on a supply of natural gas via pipelines to gas generators (supply regulated by its own market mechanisms), roads are needed to provide crews with access to maintain and repair elements, and so on. Switchgear, information

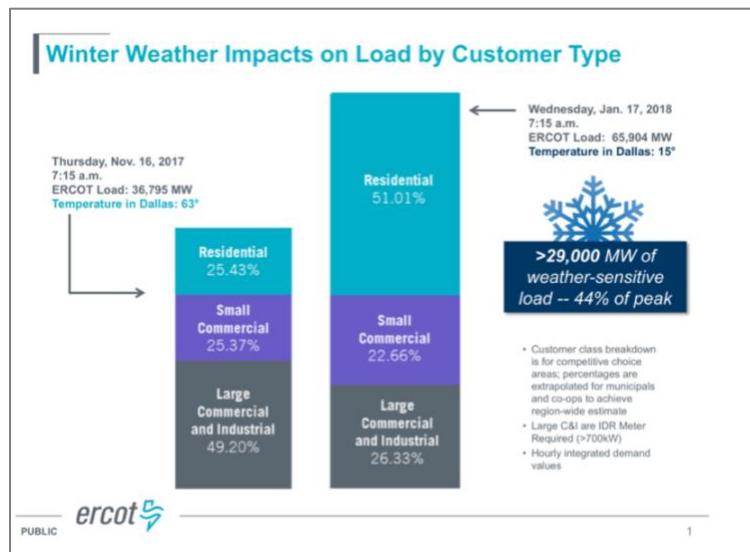


Figure 2. ERCOT slide of weather impacts on electricity consumption

technology, and protection equipment govern how electricity is monitored, routed, and used to isolate parts of the grid to protect the rest when supply and demand are imbalanced. The efficiency of homes and appliances affect how much electricity is ultimately consumed. Shortages in electricity not only affect customers directly but can further impact the energy system by disabling gas furnaces or key compressor stations, disrupting water supply, and affecting traffic signals and gasolines pumps—sometimes with detrimental feedback effects on electricity supply.

From this 30,000-foot view, the Big Freeze entailed failure across multiple parts of the entire energy system and the markets that govern it. Some parts, like the natural gas markets and building codes, are even more lightly regulated than the bulk power system, while other parts are under stricter cost-of-service regulation, like the transmission and distribution utilities (TDUs).

Starting with building codes: Texas building codes were impotent for homes built before 2001 (representing two-thirds of building stockⁱ), especially when it comes to energy efficiency. The immediate effect during the Big Freeze was huge incremental demand for both natural gas and electricity coming from poorly insulated homes. On top of that, about 60 percent of heating in Texas is electrical heating, often in inefficient forms: either resistive heating or heat-pumps that revert to resistive heating under cold conditions (newer cold-weather models do not need to do this, but there has not been much call for them in Texas). The accompanying ERCOT chart (Figure 2) showing winter weather impacts from 2017 to 2018 is particularly instructive. Incremental load due to cold weather on January 17, 2018, was on the order of 29 gigawatts (GW); scaled up for increased population and even colder temperatures in 2021, the actual increase was possibly on the order of 35 GWs. Most of this increase comes from the residential sector, where loads may have increased up to 250 percent during the Big Freeze.

Another big failure during the Big Freeze was that the TDUs failed to manage the rolling blackouts equitably. When facing ever-increasing load-shedding demands from the grid operator, the procedures for determining which circuits to black out and for how long proved to be insufficiently granular. Some customers, usually on big circuits near critical facilities, had power round the clock while others suffered without power for days. Furthermore, as with so many negative externalities in the power sector, this power lottery was weighted against historically disadvantaged communities.

The biggest failure during the Big Freeze was in the natural gas system. According to the Energy Information Administration (EIA), while demand for natural gas surged, production fell by 45 percent in Texas (21 percent nationally) as a result of frozen equipment at wells, frozen pipes, and lack of electricity at compressor stations.³ Since most generators are not on firm contracts—

ⁱ Texas last upgraded its state building codes in 2015 based on the 2015 International Residential Code (IRC) and the 2015 International Energy Conservation Code (IECC). They now receive a 6.5/9 grade from the ACEE 2020 State Energy Efficiency Scorecard on building codes, but only a grade of 1/20 for utility efficiency programs.

or at best contract for only some of their needs ahead of time—there was not enough gas to supply many gas generators, even if they were not affected by the freeze themselves. Huge spikes in gas prices happened in an opaque market⁴ that saw spot gas prices reach somewhere around \$400/MMBtu at an important Texas gas trading hub (Katy)⁵—more than 100 times normal. (Even worse, one excellent gas industry insider’s account mentions prices as high as \$1,000/MMBtu near Dallas.⁶) This converts to marginal prices for gas generation around \$4,000/MWh. The shortages and high prices produced disastrous effects on the electricity system and spiked direct costs for natural gas fuel used in generation and homes. CPS Energy, the municipal electricity and gas utility serving San Antonio, had to pay huge premiums for the extra electricity it could not generate on its own, extra fuel for its generators, and extra gas for its customers’ furnaces—all expenses it had not planned on. It expects to owe \$200 million for electricity to ERCOT and \$800 million in fuel charges (together more than \$1,200 per customer) because of the Big Freeze.⁷

HOW EXTREME WEATHER BROKE ERCOT’S WHOLESALE ELECTRICITY MARKET

During the Big Freeze, the **electricity market failed in two major ways**: it **did not deliver on demand** for more than three days and it **produced (“printed”) huge prices** for a period of more than a hundred hours. It is important to acknowledge that despite these failures, heroic efforts on ERCOT’s part prevented a total blackout that might have taken weeks to fully recover from. Still, Brian Bartholomew tabulated the difference between cleared day-ahead load (a proxy for desired consumption) and actual day-of-generation to estimate that ERCOT failed to serve a staggering 1.6 million MWh of electricity between the beginning and the end of rotating outages.⁸ By contrast,

estimates for California’s August 2020 blackouts add up to 1,500 MWh of unserved energy,⁹ with a maximum outage length of ninety minutes.

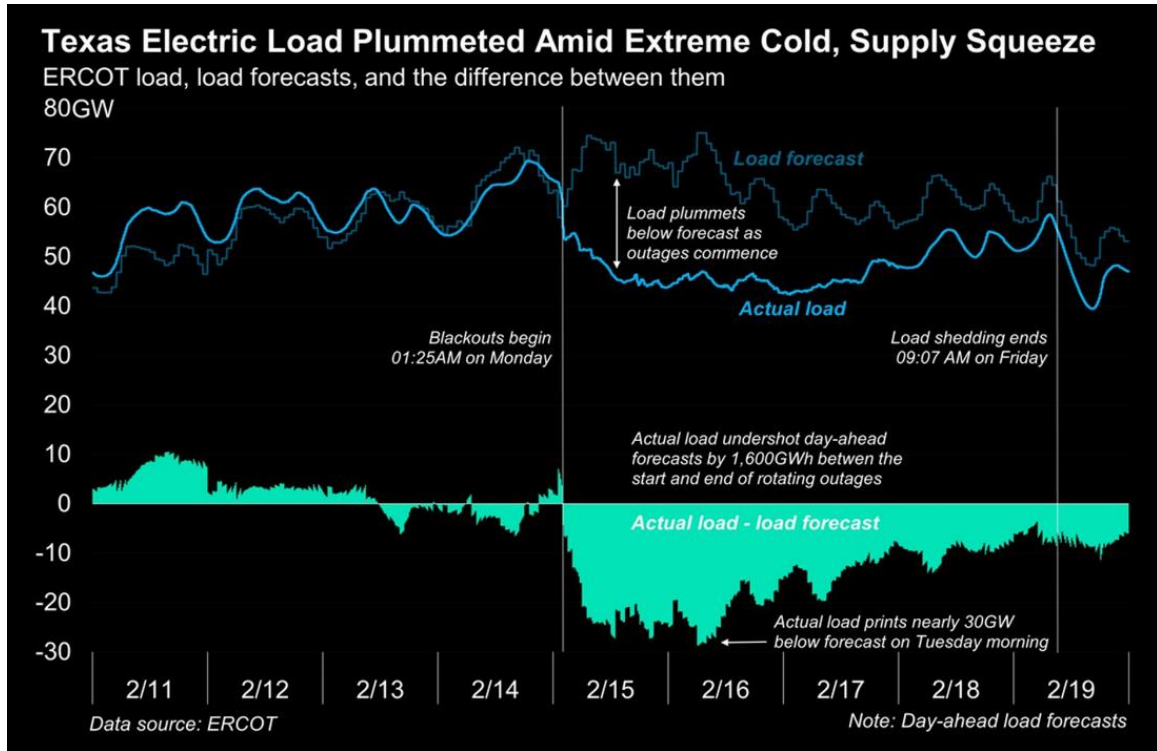


Figure 3. ERCOT data collected by Brian Bartholemew – via Twitter

Even if some of the gap between expected demand and actual MWhs supplied was due to conservation, Bartholomew’s estimate for the Texas Big Freeze’s unserved energy is three orders of magnitude larger than what happened in California. During the rotating outages, and during some of the hours leading up to the outages, real-time prices at the four regional market hubs were hundreds of times above normal.

PRICES IN CONTEXT

A look at the average real-time prices at these hubs (hub average prices) allows one to identify a period of more than 100 hours—from 10:00 p.m. on February 14 to 8:00 p.m. on February 19—in which most of the price spikes occurred. If we multiply the hourly load by these prices, then add in what was paid in the ancillary services market, the total incremental bill to ERCOT customers from this single event reaches an unimaginable \$52.6 billion. Spreading that out over the rest of 2021 works out to an extra \$135/MWh for every hour in 2021 on top of the usual \$25-\$35/MWh average system price we might expect for the rest of the year—four to five times the normal wholesale

electricity part of a customer's bill. With average residential electricity rates at \$114/MWh,¹⁰ directly passing all of these costs to consumers would nearly double average electricity bills if spread over all customers in 2021. Any way you cut it, the Big Freeze has had a huge effect on ERCOT customer prices.

Fortunately, \$52.6 billion represents only the gross price impact of the Big Freeze. Most retail customers are hedged against large excursions in prices because their tariffs are not directly indexed to wholesale prices. Their retail providers in turn hedge their exposure to spikes in electricity markets via long-term supply arrangements or financial arrangements (see sidebar). These arrangements mean that the *net* flow of money from customers to generators was much smaller than the total bill above. Yet it is worth considering that most of the insurance that retailers purchased would have been insufficient.

Retailer arrangements were likely insufficient because the \$135/MWh bump from the Big Freeze to the 2021 average is well beyond normal variations in the average annual wholesale electricity price. These more modest variations come from a combination of trends in fuel costs and scarcity pricing events. For example, 2019 saw a rare surge in scarcity pricing in August and September, which accounted for much of the difference (about \$10/MWh) between the 2019 average and the average in 2018 or 2020. It is unlikely that the insurance or hedging strategies employed by retailers was sufficient to protect them, and ultimately their customers, from an annual rate bump ten times larger than normal driven by high prices and surging demand during the Big Freeze.

As an example, consider a hypothetical retailer (see sidebar) protected from a possible surge in prices and demand with a \$200/MWh call option for up to 150 percent of expected demand.

HEDGING EXAMPLE

A retailer with 1 million customers expects customers to consume on average 30 kWh per day, but hedges for as much as 45 kWh per day. But during the Big Freeze, consumers used 75 kWh daily for four days, leaving 30 kWh per day uninsured.

The retailer hedged using a long-term contract (swap) for 30 kWh at \$30/MWh and a call option for up to 15 kWh more at a \$200/MWh strike price. The retailer sells electricity (ignoring T&D charges) at a fixed \$50/MWh (5c per kWh).

The retailer normally would have made a profit margin over four days of:

$$\text{Normal Profit} = 1,000,000 \times 4 \times (\$50 - \$30) \times 30 / 1,000 = \$2,400,000$$

Instead, the retailer lost:

$$\text{Loss} = \text{Normal Profit} - 1,000,000 \times 4 \times [(\$200 - \$50) \times 15 + (\$9,000 - \$50) \times 30] = \$1,080,600,000$$

Despite this protection, they still paid such high prices on the spot market purchasing electricity for their uncovered part of the surge in demand that losses were overwhelming. This type of mismatch explains why many smaller retailers have declared bankruptcy while larger ones—which can seek shelter under corporate parents’ big balance sheets—are consolidating market share by picking up their customers. This situation could reduce choice in retail providers, trapping customers in an oligopoly with few regulatory protections and making a mockery of the retail-choice competitive market model meant to operate in ERCOT.

Customers will feel the impacts of the Big Freeze high wholesale prices for many years to come through revenue recovery in municipal systems, diminished choice in suppliers, and higher embedded insurance cost in retail offerings.¹¹ The San Antonio municipal utility CPS presents a clear example of direct financial impacts from high prices: CPS will need to recover its \$1 billion loss from its customers over the next decade. Other customers will suffer from reduced competition in retailers and the need for surviving retailers to hedge more going forward. Apart from the insurance premium retailers charge to insure the wholesale part of customer bills with fixed rate schedules under “normal” variations, they may need to add another 30 percent to 40 percent in insurance premiums to guard against the possibility of another Big Freeze event. Since much of the increased demand during the freeze came from residential consumers, these consumers can expect the biggest rate hikes to cover this newly exposed seismic risk in the market.

It will be a while, if at all, before a clear picture emerges of the net monetary transfers in the electricity sector that resulted from the Big Freeze. They will represent only a fraction of the printed \$52.6 billion cost of supplying power during that event (though other damages, as from burst water pipes, will likely dwarf that figure). But the gross flow represented in that underlying figure is so huge that it still destabilized the financial fabric of the ERCOT market ecosystem—like running an engine too long in the red zone. Beyond leaving many customers with large bills to come, this huge flow has created somewhat random winners and losers—parties that never anticipated such a surge and its financial consequences. This prompts fundamental questions about ERCOT’s energy-only market design, or at least brings up the need for guardrails.

PRICES AND PERFORMANCE: SUPPLY-SIDE

Policymakers will surely ask what running a lightly regulated market with a high price cap—the essence of the so-called “energy-only” market design—is buying the Texan consumer. What does this design mean in terms of reliability and resilience, and does it require a willingness to accept gross price shocks in the tens of billions?

A principal advantage of an energy-only market is that under normal operating conditions it precisely signals when generation is most valuable, with juicy profits available to those able to invest in resources most likely to collect on scarcity prices, which kick in when grid conditions get tight, or to avoid those charges on the retail side. In lieu of centralized planning, the theory goes

that prices allocate and distribute the risk of outages more efficiently to the market participants (generators and retailers) best positioned to manage such risks. Despite what many may think, high but infrequent spot market prices do not force resources to depend on a lottery to cover their capital expenditures. Developers can finance new projects (at least in part) through bilateral contracts with parties seeking insurance against such spikes. Investments can be made in demand-side management to avoid these charges, as well. Suppliers make investments in anticipation of scarcity with either direct cost recovery during price spikes or bilateral arrangements to protect counterparties from these spikes.

Unfortunately, a price signal based on anticipation does not work if market participants (retail utilities and generators) do not anticipate or plan for rare, albeit increasingly frequent, high-impact events. Five days straight of \$9,000/MWh spot prices may not be lucrative enough an incentive if the conditions underlying such sustained scarcity prices seem impossible. But if perfect foresight about energy market prices had been possible, generators would have had ample incentive to find ways to invest in capital equipment and alternative fuels to weather the Big Freeze and avoid shutdown. Two examples, wind farms and natural gas plants, illustrate how opportunity costs for resource types that failed to perform (see Figure 4 for performance against ERCOT expectations by generation types) compare with the costs to better prepare—the revenues from this one-time event would have handily covered these costs.



Figure 4 ERCOT data collected by Blake Shaffer via Twitter¹²

A calculation of the costs of winterizing wind farms shows that potential benefits during the Big Freeze far outweighed these costs. ERCOT estimates 10 to 12 GW of wind nameplate capacity was offline due to weather issues, amounting to about 2 GW of missing production on average during the Big Freeze. This is a small fraction of the capacity ERCOT planned on in the event of a winter reliability event, but it still represents a big lost opportunity for those particular wind farm owners. Adding up prices during the pricing window we defined above, the opportunity cost of not generating during the Big Freeze for a perfect generator was around \$900 per kilowatt (kW). Assuming an average 20 percent wind turbine capacity factor, the forgone revenue from this one

event was \$180/kW. Informal polling of industry experts reveals that a winterization package adequate to the conditions would have added around \$15/kW to the one-time cost of a wind farm (a roughly 1 percent increase in total capital cost¹³), with a small annual operations and maintenance cost increment. In retrospect, forgoing this investment was a terrible decision for owners.

Analysis of the gas fleet's 10 to 20 GWs of missing capacity relative to ERCOT seasonal reliability assessment, which has been at the center of blame for supply shortages, reveals a similar dangerous disconnect between the theory and practice of achieving reliability through scarcity pricing. A gas plant in the ERCOT market fully functional during the crisis could have collected the \$900 per kW. Even at \$400/mmBTU gas spot prices (prices the gas market reached), at least half of that energy market revenue would have been pure profit for gas plants. Putting that profit in perspective, \$900/kW is close to the cost of a brand-new combustion turbine and a large fraction of the cost of a new combined cycle. It is hard to get a firm read on the cost of winterizing a gas plant, but 2011 winterization cost estimates for El Paso Electric referenced in a joint NERC/FERC report¹⁴ point to a range of \$1-10/kWⁱⁱ. After the 2011 cold snap, however, many plants were supposed to have winterized but did not do so.¹⁵ For plants that failed due to lack of fuel supply, alternative fuel supply was possible. Industry estimates from a 2018 PJM report show that adding dual-fuel use (oil or liquified gas) to a gas plant might cost, on an annualized basis with relevant ongoing expenses, about \$9.50 per kW-year for a combined cycle plant and \$5.60 per kW-year for a gas turbine.¹⁶ At a frequency of one event every ten years, perhaps even every 30 years, it seems this cost of resilience should have been worth it for gas generators. Once again, a 100-hour price cap event was just not in investors' imagination.

The rationale for a multi-day maximum price event as a principal element to guide long-term investment in reliability is weak—at least in the context of events like the Big Freeze. In theory, in an energy-only approach to ensuring reliability, the possibility of huge weather-related price spikes incentivizes producers to invest in protecting their equipment or build backup resources. For this to be a meaningful incentive, producers must see occasional windfalls at the expense of consumers. Consumers accept this as the price of reliability and can take their own measures (by managing their own demand or entering into hedges) to minimize their individual exposure to high prices. But since so many generators missed the opportunity to cash in on the Big Freeze windfall—the ticket for entry, investing in weatherization, was 12 times less than the payoff—it is hard to argue that the huge cost to consumers of a 100-hour price cap saturation during this event was worth it. It represents a huge gross outlay for customers on an incentive with such poor results in stimulating sufficient supply.

ⁱⁱ This would include heat tracing and insulating a power plant, with potential additional cooling tower upgrades. Some annual cost might also be incurred if protection from the elements were put in place and removed seasonally.

Even if high prices failed to guide long-term investment, another rationale for these prices is that they were necessary to incentivize more near-term supplier actions. Some plant-owner decisions happen a lot closer to real-time than whether to winterize. For example, owners must decide how much to spend to avoid possible outages even under regular conditions, and their plant operators must schedule maintenance. Since real-time prices also play a role in ensuring reliability closer to real-time, it is worth considering the value of scarcity pricing in this timeframe. One of the benefits of strong scarcity price signals when it comes to summer peak events is to incentivize generation plant owners to have their plants at the ready when they are most needed. In past summers with tight conditions this has mostly held true, although Texas has yet to be tested by an exceptionally long series of hot days that might cause peaker plants to break down.ⁱⁱⁱ Still, fossil fuel plants usually have all their maintenance done in time for summer peaks and have demonstrated a good track record of participation during heat waves.

Sadly, this was not the case during the Big Freeze. Since winter loads are usually much lower than summer ones, many plants were on planned maintenance outages by the time tight conditions started. The high-impact but low-probability prospects of a sharp cold snap did not seem sufficient to change plant manager decisions as to plant maintenance (although maintenance does need to happen, a month or two earlier or later might have been better). So the prospect of high-scarcity prices failed to motivate a substantial part of the ERCOT generation fleet to either winterize or better manage its maintenance schedules.

Still, sharply higher prices were necessary simply to enable gas plants to run. At spot gas prices of \$400/mmBTU, and heat rates of up to 12 mmBTU/MWh, it is conceivable that a combustion turbine might need to be paid as much \$4,800/MWh to cover its short-term marginal costs. That does not explain mandating prices be set at the price cap, as ordered by the Texas PUC. But without relief on the gas price side, any price cap below that margin would result in even more capacity pulling out of the market to join plants that could not access any gas at all. Potential fuel shortages and price spikes are clear downside risks of relying on gas plants for capacity, belying a weakness in the planning side that trickled down to ineffective incentives to operate reliably in real-time. Other fuel-based resources struggled as well. As the plant outage chart shows, coal and nuclear plants with “on-site” fuel also struggled—and no price inducement could bring them back on faster.

The price surge during the crisis was more than enough to recoup winterization expenses and justify an all-hands-on-deck approach on the part of plant operators. Generation companies with that mindset (and the advantage of newer assets) profited handsomely from high prices.¹⁷ Yet this incentive did not make sufficient capacity available to the market in a time of crisis. The natural conclusion is that some events are rare enough that scarcity pricing will not be adequate to attract the matching investment to cover system needs—not because the money is not there on a

ⁱⁱⁱ August 2011 did, however, see runs of multiple hot days with demand well above forecasted peak.

probabilistic basis but rather because there is a failure of imagination or ignorance of the probability of events and the size of the windfall is too uncertain. While scarcity pricing might be sufficient to incentivize investment in the face of some well-understood extremes (like periodic summer heat waves), policymakers must acknowledge the possibility that extended bouts of scarcity pricing are not enough to motivate investment to ride through even rarer extremes (like a weather event combined with a failure of a key supply system). While high prices provided some operational signal to high-cost plants to keep selling energy, exposing ERCOT customers to \$52.6 billion in costs did not translate into system adequacy as intended.

PRICES AND PERFORMANCE: DEMAND SIDE

ERCOT reports that 73 percent of its load is with competitive-choice customers representing 6.7 million electric-service meter IDs (premises).¹⁸ According to the U.S. Department of Energy, since 2010 Texas has received \$54.2 million from the Weatherization Assistance Program and \$23.4 million from the State Energy Program.¹⁹ As a result, 10,440 homes have been weatherized (also producing jobs and other benefits) at a cost of around \$7,400 per home weatherized. These homes now consume less energy, and better protected their residents during the Big Freeze. If 6.7 million premises were weatherized, the total bill would come to just under \$50 billion—less than the four-day gross transfer from consumers to suppliers in the Big Freeze. These are just crude estimates, but they do give a strong sense of how money spent on incentivizing generators might have been more productively spent directly on customer premises. High prices in the energy market not only have a role to play on the supply side, but they also provide an important signal to retailers and consumers.

To understand what role prices could or should play in the context of a demand-side response to extreme weather events like the Big Freeze, it helps to consider how pricing in the wholesale markets affects customer bills. Customer bills essentially have two parts. First is the energy charge, which pays for the actual electricity used; second is utility fees associated with delivering that power to homes via poles and wires, along with various other programmatic charges (like an advanced metering surcharge or city taxes). The actual rates that ERCOT customers pay to their municipal utility or Retail Electric Provider (REP) involve fixed recurring monthly charges and a volumetric (per kWh) rate tariff with a fixed schedule for how much each kWh costs based on when it is consumed. Consumers have the option to buy as much electricity as they want under these tariffs.

Providers of electricity (retailers, municipal utilities, and cooperatives) must hedge their exposure to wholesale electricity markets to offer the price protection customers expect. To do so without going bankrupt, they need to manage both electricity price risk and quantity risk (see sidebar above). These can be financial hedges, like swaps (fixed long-term price for a given amount of supply) or call options (options to buy electricity at a fixed capped price if necessary), or they can be physical hedges (like directly owning or contracting with a generator). Hedges play an important

role in stimulating supply because they provide counterparties—ultimately the electricity suppliers—with the revenue certainty to invest in equipment; they are a key feature in making electricity markets work.

Unfortunately, if suppliers are not anticipating how the revenue stream from a Big Freeze might make certain investments desirable, load-serving entities probably will not anticipate a Big Freeze itself either—they will not seek a level of hedge coverage that will provide financial security in such an event. The possibility of a low-probability, multi-day scarcity pricing event has yet to prove sufficient to drive the specific hedging behavior, and thus stimulate investment, for managing the risk of a Big Freeze. Perhaps after the 2021 crisis there will be more incentive to find coverage for rare high-impact events, but this probably will create significant new customer costs and may not be easy to arrange, market, or regulate.

Customers, however, can be more than passive consumers. Consumers can make investments that reduce costs under normal circumstances and provide great value in extreme events. A prime example is home upgrades and weatherization, as discussed above. Under normal weather lows and highs, this type of investment can materially reduce needs for peak power. Under even greater extremes, such investment has an even greater payoff in terms of comfort, bill savings, a livable house, and survival should extended outages occur. Most homes today consume far more energy than necessary to meet their heating needs.²⁰ Anecdotal reports speak of well-insulated houses that never dropped below 61 degrees Fahrenheit in Austin despite long power outages. In the wake of the Big Freeze, policymakers should contemplate another fundamental disconnect in the ERCOT market design: even though consumers are participants in the wholesale market (however indirectly) and theoretically wield important tools for managing electricity demand risk, consumers are not opting to do so, either by choice or because they can't.

This disconnect is a complex topic with many components, but from a simple economic perspective most customers are not necessarily interested in or incented to spend money to upgrade their homes and may not have the working capital to do so. Retail customers usually prefer not to be directly exposed to price spikes of short or long duration and are thus unable to collect benefits from avoiding consumption near the wholesale price cap (\$9/kWh versus typical rates around 10c/kWh). People are also accustomed to limitless fixed rate schedules that enable them to consume as much electricity as they want at any time.

It is especially problematic that during a power-shortage crisis consumers are so financially insulated from the immediate costs of their extra consumption. Consumers have agency to directly react to system shortages on an operational timescale, if only they have the right social signals and incentives. We can all turn down thermostats, turn off lights, delay or forgo dryer use, and so on. Customer outreach and voluntary demand reduction helped California to navigate its August 2020 power crisis. Meanwhile, Houstonites freezing in the dark were treated to the sight of blazing lights in downtown Houston office buildings.²¹ Clearly more could have been done to communicate with Texans about the need for conservation going into the big winter storm. Whether conservation in

the moment could have yielded the 10 to 20 GW of demand reduction needed is unclear, but it certainly would have helped. If customers had at least some price exposure above their basic electricity needs, more demand reduction might have materialized.

The entity that would benefit financially from reduced consumption during a crisis—the retail electricity provider—is not necessarily in a great investment position to support demand management either. Providers do not control customers’ premises, nor do they have a long-term and certain relationship with any one consumer, so they would not directly invest in weatherization for fear of losing that value if customers moved on to another provider. Also, efficiency tends to reduce sales and hence revenues²²—even monopoly utilities with better recovery mechanisms available for investing in customer efficiency do not have a great track record of making investments to upgrade customers’ homes. Yet weatherization is a huge, missed opportunity to protect customers physically and financially against extreme weather events. A more efficient housing stock probably would have created much less gas and electricity demand and allowed the grid to ride through the storm without a crisis, despite the generator outages. Furthermore, other long-term investments in distributed energy resources also could have reduced system stress and provided customers a physical safe harbor from the cold.

One final unfortunate part of this story speaks to one of the many inequities that emerged in the wake of the Big Freeze. It is possible that for some REPs, rotating outages were a big financial plus. Imagine a REP that had arranged for generation delivery or hedges that it is no longer needed because many of its customer were blacked out. The REP then could resell that power to other entities at a tidy profit—a profit that would not serve its unlucky customers. In fact, there was one case almost like this: Austin Energy, one of the municipal utilities with territory outside of retail competition, had a lot of disconnected customers and so was able to sell off surplus power.²³ We know this because the utility announced that it would use these gains to help customers affected by the outage. These customers benefited from their relationship with a more member-centric municipal utility.

In summary, it seems the market design, broadly speaking, failed on the demand side as well as the supply side. There was insufficient hedging against an extreme system failure, money was not spent on measures that would have insulated customers and the system from the worst impacts of weather, conservation was not incentivized or encouraged early enough, and the physical impacts and monetary consequences of the crisis were not equitably felt.

LESSONS FROM TEXAS: SUPPLY IN THREE PERIODS

To understand the energy system failure in Texas, it is useful to think about three components of energy procurement and risk management. There are the **everyday market intervals** where prices fluctuate around \$20/MWh under regular up-and-down shifts in demand. Then there are **more extreme times** when supply is almost exhausted, operating reserves need to be watched, and

scarcity pricing occurs in sporadic spikes. Finally, there are **high-impact common-mode events** like the Big Freeze. These events have large impacts due to failure across many power plants or electricity system components but are unfortunately exponentially more probable than one might expect if the probability of outage from individual components were truly independent of any other. This enhancement in the likelihood of simultaneous failures is due to a common mode: an outside driver—for the Big Freeze, weather combined with a failure in the gas system—that can create unanticipated correlated failures in the generation fleet or the whole system.

On the supply side, the ERCOT market design is working relatively well for the first two kinds of periods. Electricity has been supplied cheaply and efficiently to Texan consumers for many years. Competition has attracted lower-cost resources and triggered the exit of more expensive (and dirty) ones. System-wide investments in transmission have been a successful part of this story, too.

The market design has also served ERCOT well when it comes to more typical extremes (mostly seen in the summer). Scarcity pricing through the high \$9,000 system-wide offer cap and the operating reserves demand curve (ORDC) have attracted new resources and rewarded existing ones for tuning their assets to be prepared when summer system stress looms. These high prices offer the necessary incentive: the ORDC acts much like the cane that empowers a blind person to navigate public spaces with autonomy in that it signals the value of incremental generation to the market when a reliability cliff is near. This combination has served ERCOT just as well, if not better, than capacity markets found in other regions and at substantially lower cost.

But what happens when the market slips and slides right off the cliff? It is unclear whether a capacity market would have improved ERCOT's supply and demand situation during the Big Freeze. The same blind spot that led generators to forgo investment in winterization and miss the earning opportunity of a decade is just as likely to have affected capacity market administrators who set capacity demand based on forecasts during "normal" conditions, and not necessarily accounting for multi-system failures. After the 2011 dress rehearsal for the 2021 Big Freeze, recommendations were made, reporting requirements with affidavits ensued,²⁴ and yet many generators were still caught unprepared in 2021. On top of that, even winterized gas plants could not run without gas supply. Before the Big Freeze, dual-fuel requirements made sense for New England, at the end of the pipeline, but not for Texas, at the center of the oil and gas universe.

However, even if an electricity market design with a capacity market would still have led to shortages, at least wholesale electricity markets with a capacity obligation usually have a much lower price cap. This would make a big dent in the \$52.6 billion bill, so at least the market would not entrain financial ruin. Because gas fuel costs hit all-time highs, though, low price caps might have still made matters worse. Any way you cut it, the **failures in the gas system were going to cause trouble** for the ERCOT electricity market. The true lesson here may be that all **market regulators and policymakers need to have a plan for high-impact common-mode events**. Some amount of supply hardening, like installing dual-fuel capabilities, may help, but ultimately the least-cost solutions likely lie elsewhere—on the demand side.

LESSONS FROM TEXAS: DEMAND IN THREE PERIODS

Returning to our three periods (normal, extremes, high-impact common-mode events), but now in the demand-side context, the Texas electricity market looks different. In normal times one can assume that Texans are pleased with their low electricity bills, but even then, a market failure exists. Efficiency measures that would deliver electricity savings and increased comfort and utility are simply not being deployed at their full potential,²⁵ especially in the residential sector. This brief does not delve into the complex reasons or revisit the mismatch in economic incentives, but this issue warrants flagging as a major market failure.

For extreme periods, the situation is more mixed. In past summer peak events, ERCOT has seen tangible voluntary load curtailment—enough to make a difference. But this was mostly due to participation from industrial and commercial loads (either avoiding summer 4CP^{iv} demand charges or responding to tariffs based on real-time pricing). To this author’s knowledge, there is little evidence that REPs have engaged much dynamic price response from most residential customers. This market failure is not unique to Texas—in a typical year, market failures to incentivize more demand-side investment and behavior change lead to increased consumer costs.²⁶ ERCOT is seeing the early effects of dynamic price response from demand, but there is still a long way to go.

It is unfortunate that the Texas legislature passed a sweeping bill that, among other measures, outlaws customer rates indexed to wholesale prices.²⁷ This provision is probably attributable to the plight of a small minority of customers in the highly visible news stories about a small REP called Griddy saddling some of its customers with \$10,000 bills. But customers exposed to the wholesale market via rates indexed to spot prices did not need to be so nakedly exposed. Another retailer offering indexed rates, Octopus Energy, retroactively covered their customers and plan to offer bill insurance going forward. Requiring some bill insurance is a much better approach than outlawing indexed prices. The CEO of Octopus wrote a compelling editorial explaining why indexed customer rates *with price protection* should have a continued if not a growing role in the Texas marketplace.²⁸ In fact, rate structures and customer engagement models that do not motivate conservation during a power crisis should be counted as part of the market failure. Electricity needed to keep a home heated over a livable 65°F, to maintain water integrity, and to prevent food spoilage is much more valuable than electricity used to heat homes to 75°F, run dryers, or illuminate empty buildings. Everyone needs an electric grid and a market design that recognize the difference between customers’ critical needs and more optional loads in a crisis—prioritizing serving the first while making the latter available at increased prices.

^{iv} 4CP stands for “Four Coincident Peaks” and refers to a demand charge on ERCOT’s commercial and industrial market participants’ bill that is proportional to their share of coincident peak in each of the four months of June through September.

The failures of the market design, broadly considered, to incentivize more demand-side investment and behavior change did not just raise consumers' costs in typical years. During the high-impact common-mode Big Freeze event, these failures proved disastrous. Demand-side investments and voluntary conservation schemes with proven value under less extreme times would have seen that value multiplied manyfold during the Big Freeze, and perhaps avoided rotating outages altogether if done at scale. Residential demand rose to as much as 250 percent of normal, creating the necessary condition for supply shortfalls and exacerbating extreme weather's impact on the electricity system.

To plan for and mitigate the effects of a high-impact common-mode event, market participants, policymakers, and market regulators must work on a much more holistic level: they must consider the interaction of various systems (electricity, gas, heating, transportation, IT infrastructure, and other drivers of demand) both in creating potential challenges and in resolving them.

Modern cars not only have ABS brakes and rear-view cameras—innovations that help prevent crashes and accidents—but also feature crumple zones and seatbelts to improve the chance that passengers can walk away mostly unharmed in the event of a serious crash. Similarly, **critical infrastructure like the electricity grid and its market and commercial processes need plans and investment for managed failure.** For example, TDUs could more equitably distribute grid failure impact across customers. The concept of rotating outages is meant to minimize losses from spoiled food, burst pipes, and death among humans and their beloved pets and to spread the pain of involuntary curtailment, making sure nobody is affected for too long and that all share in the sacrifice. Unfortunately, this sacrifice was implemented too coarsely. The feeders that were switched on and off covered too large a set of customers at one time, and customers on feeders containing critical infrastructure won the lottery, while others suffered longer—often along already unequitable geographic lines. Furthermore, smart meter infrastructure that has been deployed across Texas at great expense was not leveraged to help make outages more surgical and even. Looking at Texas as a whole, we can take comfort that ERCOT succeeded admirably in averting a disaster of an even greater magnitude: the complete failure of the Texas grid. The natural gas distribution network managed to keep service to its firm retail customers. But neither the electricity market nor the gas market had a good plan for managed failure, i.e., a set of emergency protocols and procedures in the case of extended shortages. The same can be said for the TDUs' outage plans and the customer relationships of retailers, cooperatives, and municipal utilities.

SUMMARY OF LESSONS FROM TEXAS AND POSSIBLE SOLUTIONS

The February 2021 freeze in Texas yields two broad lessons for industry leaders, policymakers, and legislators:

- (1) Risk buckets should be divided into three categories: ordinary conditions, extreme conditions, and high-impact common mode events. **High-impact common-mode events**

necessitate a qualitatively different and more holistic approach to risk mitigation than do normal conditions and extremes. These kinds of events tend to be driven by unusual correlation between typically unrelated failure modes driven by factors outside the usual scope of consideration. Proper risk analysis requires considering linkages with other systems, e.g., the gas market, building codes, and water services. Not only should various holistic risk scenarios be developed and explored, but these linkages should also shape investment in mitigation solutions.

- (2) No matter the amount of preparation, systems will fail. **Decision-makers need to make plans for managed failure.** For electricity markets, this might mean a more thoughtful plan for public communication and pricing rules under extended outages in multiple circumstances (not just summer peak). For a TDU, this might mean a better plan for implementing outages and isolating and protecting critical infrastructure as a whole and at individual customer locations. For customer-facing retail utilities, such plans might include a kind of emergency tariff and communication plan to rapidly conserve precious resources and avoid extended exposure to sky-high prices beyond what can reasonably be hedged or insured financially.

Although it is still a little early to tell what these solutions will look like in practice, and the context will be different in every geography or jurisdiction, possible reforms and policy improvements for ERCOT and other jurisdictions may include:

- (A) **Competitive Electricity Market Operators:** The ERCOT energy-only market should **develop a new emergency-mode circuit-breaker in its market price formation for periods of extended scarcity.** For example, after the average price has sustained high levels over an extended period, an emergency price cap at a set price, similar to that in the Australian National Energy Market (\$300/MWh), can be put in place to continue incenting demand-side reductions but reduce the flow of money from customers to generators. Gas generators requiring a higher price to cover their marginal costs on a short-term basis would be guaranteed repayment at cost post-event (they would still make handsome profits before the emergency threshold kicks in). These emergency uplift payments can be recovered from load-serving entities on a load-weighted basis after the fact. Market prices would provide payouts similar to or even partly exceeding “normal extremes” but would avoid paying all generators a stratospheric clearing price over multiple days in the case of systemic failures outside the market operator’s control.
- (B) **Building Code Authorities:** **Cost and benefit analysis used in building code development should factor in benefits from extreme events and high-impact common-mode events.** Doing so may lead to wiser resiliency investment over time.

- (C) **Public Utility Commissions: Utilities could be required to collect money for a resilience fund targeted at mitigating or avoiding the worst impacts from high-impact common-mode events.** This pool of money could be funded in similar ways to other general benefit infrastructure like transmission. Fund managers would ideally cast as wide a net as possible for solutions to finance, looking outside just the bulk power system for the cheapest and most broadly beneficial investments. Resilience investments that dovetail with other benefit streams (so-called “value stacking”) should be of particular interest.
- (D) **Grid Regulators and Planners: Some degree of grid hardening might be worth consideration,** like more electricity or gas storage deployment or inter-regional high-voltage DC lines connected to regions with different weather dependencies. Grid hardening could also include standards or incentives for weatherizing generation and fuel supply. One thing to keep in mind, though, is that supply-side solutions for mitigating the impact of high-impact common-mode events can quickly become quite expensive to support if they are rarely needed—even if they are relatively easy to identify, at least for utilities or other large players on the generation, transmission, and distribution side.
- (E) **Public Utility Commissions: Direct investment is needed to enable the distribution grid to conduct more surgical outages and rotate them more widely among customers during emergencies.** For market-minded Texas, a market-based approach could entail capacity subscriptions (as illustrated in a paper by G.L. Doorman²⁹), whereby REPs or customers pay extra for a certain amount of load to have priority during emergencies (with low-income subsidies or set-asides for essential service or medical priorities). Emergency tariffs could be put in place to incent emergency conservation above a certain threshold level of service.
- (F) **Cities and Vulnerable Localities: Local resilience solutions should also support the wider grid; cities and localities should demand or advocate for payment streams that support that role.** Solutions for mitigating the effects of high-impact common-mode events overlap significantly with solutions for improving individual customer resilience. For example, resources targeted at protecting electric service, or at least critical services, in a load pocket in the event of transmission issues—like California’s public service power shutoff—are an important resiliency concern. Distributed resources meant to cover critical load or provide refuge and some energy access to residents in a crisis also have value during a system-wide crisis because they can generate extra power for the grid, and because they imply some local planning for managed failure—focused on taking the edge off the worst negative impacts of power failure. At the individual meter level, technology for smart panels that can prioritize circuits in the event of power failure (usually in the context of distributed storage) are likely to become more prevalent. As they gain market

share (perhaps with some public incentives meant to promote resiliency), they should become part of disaster preparedness and crisis management planning.

- (G) **State Energy Agencies: Behavioral conservation measures should be leveraged.** When policymakers focus on financial incentives and the micro-economics of markets, they can lose sight of other motivational factors. Yet people have an instinct to chip in and contribute in times of crisis. Well-designed and pre-planned public engagement and information strategies can be a powerful resource in managing extreme and high-impact common-mode events. During the August 2020 power crisis in California, state agencies used an array of media to ensure widespread awareness, including freeway signage, social media, and website and app updates. For example, they coordinated with data center customers of Silicon Valley Power to move nearly 100 MW of load to onsite backup generation facilities, coordinated with the U.S. Navy and Marine Corps to disconnect 22 ships from shore power and move a submarine base to backup generators, and activated several microgrid facilities for about 23.5 MW of load reduction. While each reduction may seem small in the face of a multi-GW deficit, in the aggregate such reductions can greatly mitigate supply deficits.

CONCLUSION

In a recent book by the Bank of International Settlements, “The Green Swan: Central Banking and Financial Stability in the Age of Climate Change,” a passage addressing financial systems seems just as pertinent for energy systems:

Integrating climate-related risk analysis into financial stability monitoring is particularly challenging because of the radical uncertainty Traditional backward-looking risk assessments and existing climate-economic models cannot anticipate accurately enough the form that climate-related risks will take Even more fundamentally, **climate-related risks will remain largely unhedgeable** as long as system-wide action is not undertaken.³⁰ (Emphasis added).

The Bank of International Settlements advocates for coordinated action among many players, including governments, the private sector, civil society, and the international community, both to reduce greenhouse gas emissions and to prepare for climate impacts already baked in from previous emissions.

Any lessons learned from the Big Freeze, and solutions that follow, must take climate change into account. And fossil-intensive grids cannot provide consistent resilience against climate risks they are simultaneously exacerbating. Historically rare events will likely become more frequent, and traditional risk management strategies will fail. A top priority for policymakers everywhere should

be implementing new risk management strategies with a holistic focus on mitigating the risk of high-impact common-mode events and preparing for potential failure.

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