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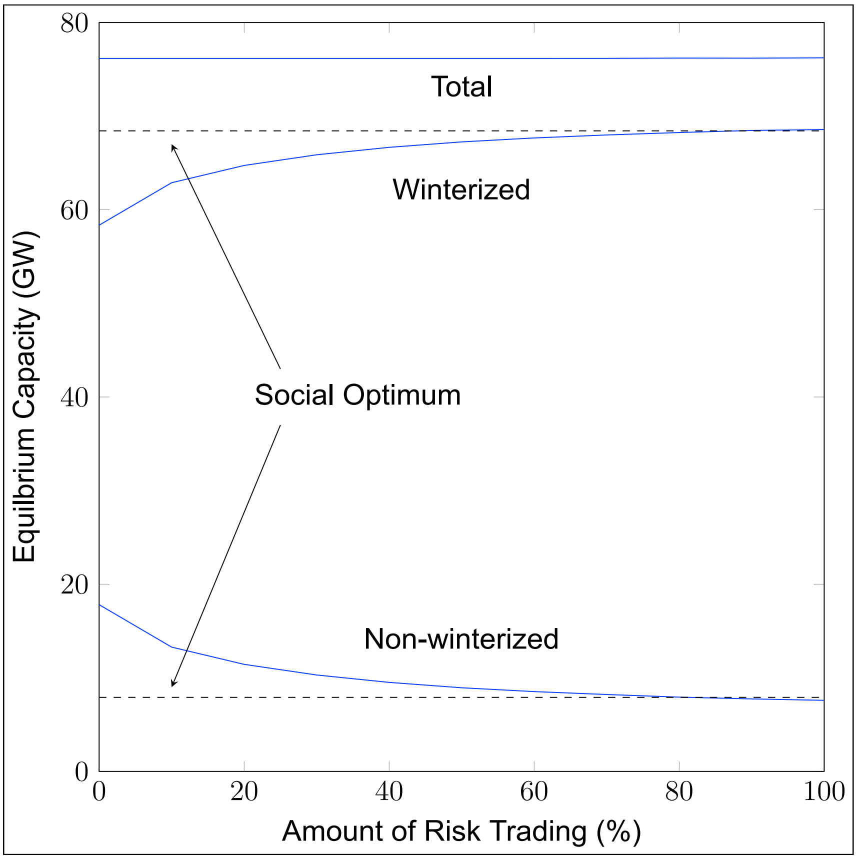

Energy-only electricity markets, such as the Electric Reliability Council of Texas (ERCOT), rely on the decentralized investment decisions of market participants to lead to a resource mix, providing an efficient level of reliability. During an exceptionally cold winter storm in February 2021, ERCOT experienced generation shortfalls on an unprecedented scale. Focusing on the role of incomplete markets in risk, this paper argues that frictions in risk trading make decentralized markets prone to underinvestment in resilience to rare events.

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Highlights

Investments in liberalized electricity markets depend on the ability to trade risk

Incomplete contracting can make decentralized systems vulnerable to extreme events

Facilitating or mandating contracts along the supply chain can help ensure resilience

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Article

Private risk and social resilience in liberalized electricity markets

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SUMMARY

Energy-only electricity markets, such as the Electric Reliability Council of Texas (ERCOT), rely on the decentralized investment decisions of market participants to lead to a resource mix providing an efficient level of reliability. During an exceptionally cold winter storm in February 2021, ERCOT experienced shortfalls on an unprecedented scale, with nearly half of the generation fleet experiencing outages at the peak. The depth of the resulting blackouts invites questions regarding the ability of systems relying on decentralized planning to appropriately prepare for and withstand rare events. Based on two mild assumptions, risk aversion among investors and incomplete risk trading, this paper provides an explanation for why decentralized markets are prone to underinvestment in resilience. We describe the nature of the incomplete risk trading that arises in the context of electricity markets and discuss potential remedies, including mandatory contracting obligations for retailers and compensation to end users for unserved energy.

Context & scale

In the decades since electricity market restructuring, system operators and regulators have debated the most efficient way to ensure adequate supply under all conditions. Hoping to derive the greatest possible benefits from competition, some systems have pursued a completely decentralized framework, relying entirely on market participants to project needs and invest accordingly. Despite their potential to introduce inefficiencies, other systems retain the aspects of centralized planning, e.g., in the form of capacity markets that pay generators for their expected ability to provide energy during scarcity situations. Using the catastrophic failures that affected the state of Texas in February 2021 as a case study, this paper reassesses the viability of a completely decentralized resource adequacy paradigm. The paper argues that frictions in risk trading between market participants leave decentralized systems prone to underinvestment in resilience to rare events.

INTRODUCTION

During Winter Storm Uri in February 2021, the Electric Reliability Council of Texas (ERCOT) experienced generation shortfalls on an unprecedented scale. Although grid operators had planned for an "extreme" scenario with peak demand of 67.2 and 14 GW of outages,[1] the actual event saw demand forecasts as high as 76.8 GW with 30 GW of outages.[2] The resulting rolling blackouts led to unserved energy on the order of 1,000 GWh over a 4-day period from February 15 through February 18.[3] ERCOT was expected to experience only 2.3 GWh of unserved energy per year,[4] implying that Texans sustained over 400 years' worth of supply-related outages in the event. In an attempt to protect critical loads, many circuits were excluded from the blackouts, leading to extended outages for many others. Despite these steps, some critical loads were affected: lack of power at gas compressor stations, for example, contributed to problems with fuel delivery to power plants, while outages at water treatment facilities led to boil water notices for houses lacking electricity to boil water. These infrastructure failures contributed to the over 200 deaths attributed to the winter storm.[5]

This paper considers the lessons of the event for electricity market design, both in Texas and around the world. Among US systems, ERCOT has a unique approach to resource adequacy, with no explicit requirement placed on load serving entities to procure supply in advance of operations.[6] Instead, ERCOT commits to producing strong price signals to induce generator performance in times of scarcity, counting on the decentralized actions of market participants rather than a centralized calculation to determine what resources are needed to prepare for periods when shortages may occur. Under assumptions of perfect competition and complete markets in risk, the potential for high scarcity prices in systems with a sufficiently high price cap should encourage consumers to contract for energy in advance and lead to a system that efficiently manages trade-offs between cost and reliability. Until February 2021, this "energy-only" market design appeared to be performing largely as anticipated, with reserve margins that were thin by the standard of other systems but consistent with the level targeted by regulators. The scale of the failures in February 2021, however, raises serious doubts about the design.

In diagnosing what went wrong with the energy-only design, our focus is on the assumption of complete markets in risk. Formally, a complete market in risk includes an Arrow-Debreu security corresponding to any future potential scenario that may arise, allowing participants to construct a portfolio that hedges against uncertainty in future outcomes.[7] Although this assumption is implicit in the theoretical framework supporting the energy-only design,[8] real-world financial markets experience frictions preventing ideal risk allocation across market participants.[9–11] More generally, incomplete contracting emerges and governance institutions matter because transaction costs are positive, information is incomplete and asymmetric, and the allocation of decision rights affects market and contractual performance.[12–16] In liberalized electricity markets, a specific concern is that incomplete markets could lead to higher risk premia for investors and therefore insufficient generation capacity.[17–21] Many risk premia are difficult to observe, and establishing the strength of the effect is difficult in practice. A central empirical issue relates to the extraordinarily high value of reliable electricity service. The analysis of ERCOT in Newell et al.,[4] for example, predicts that a 25% increase in the cost of the marginal entrant would result in only a 1% reduction in the equilibrium reserve margin. Given this low elasticity, many years of data would be needed to detect underinvestment under normal circumstances. The abnormal conditions and significant underperformance of generation in the February storm, however, offer much stronger evidence of the effect, with market incompleteness preventing parties from investing in the physical hardening that would have supported reliability during the event.

To illustrate the role of market incompleteness and its implications for resilience, we construct an instance of the stochastic equilibrium model in Mays et al.,[22] with the example deviating from prior studies[7,23–26] in its explicit focus on rare events. A central point of the example is that the effect of incomplete markets may be most salient with respect to rare events. In the model, risk-averse investors build generation capacity based on the distribution of possible future world states. Because financial hedging arrangements affect the relative ranking of different future states and risk-averse investors weigh the impact of negative outcomes more heavily than positive outcomes, the equilibrium resulting from the model is dependent on the assumed level of risk trading. In the general form of this modeling framework, if market participants have unrestricted ability to trade risk based on their individual beliefs and preferences, then market participants converge on a shared, socially optimal assessment of the risk-adjusted probability of future states (see proposition 3 in Gérard et al.[27]). Accordingly, complete trading should prepare systems for a full set of foreseeable contingencies. Incomplete trading instead gives rise to a mismatch between societal risk preferences and those of investors. Because risk-averse investors discount the substantial scarcity rents they may earn in rare but significant tail events, this mismatch has acute consequences for system resilience. The situation changes if the investment is hedged, converting the volatile cash flow into a more stable one. Because the worst-case outcome for a hedged producer may be a failure to deliver on its contractual obligations, it is more likely to invest in the physical hardening necessary to ensure delivery.

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We supplement the numerical example with a more detailed discussion of four links in the electricity supply chain where incompleteness can arise, as well as possible ways to address each flaw. The first, which has received the most attention in the economics and operations research literature and is the focus of the numerical example, is limits to contracting by generators with financial institutions, retailers, and end users. The second is a lack of firm fuel supply contracts for natural gas generators, with a particularly important source of incompleteness codified in force majeure clauses. The third relates to the counterparty credit risk faced by participants in the wholesale market. The fourth is embedded in contracts between retailers and end users, where rolling blackouts have the effect of reducing the former's obligations without providing compensation to the latter. We then assess the proposed reforms and argue for a regulatory approach focused on reducing transaction costs and market incompleteness, an important aspect of which is a mandatory contracting requirement placed on retailers.

RESULTS

Explaining underperformance

The ERCOT design relies on investors anticipating high prices during scarcity and building resources appropriate to limiting scarcity situations to an efficient level. Here, we describe the basic failure of the theory in the February event and then consider three steps in which the link between spot prices and investment decisions may be broken: the formation of the spot prices themselves, the ability of investors to forecast the distribution of those spot prices, and the translation of that distribution of spot prices into forward-looking investments. The first two categories of potential flaws in ERCOT's design include several opportunities to improve the analysis of the markets but can offer only a partial explanation of its poor performance in the February storm. The section therefore concludes by describing the role of incomplete markets in risk in driving system failures during Winter Storm Uri.

We rely on two documents to describe how the system was expected to perform. The first is ERCOT's Winter 2020/2021 Seasonal Assessment of Resource Adequacy (SARA),[1] completed in November 2020. Although the SARA has no direct bearing on the design of the market, it reflects shortcomings in the analysis of the market. The second is the 2018 Update of the Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region (hereafter, "2018 Reserve Update"),[4] which conducts a detailed simulation of a projected 2022 ERCOT system to assess the impact of key market design parameters on cost and reliability outcomes. As discussed in this section, there are good reasons to question both the methodology leading to the estimated market equilibrium and the assumptions behind the claimed economic optimum.

To illustrate the degree of underperformance of generation during the February 2021 Winter Storm, Figure 1 plots actual generation by fuel type against forecast and extreme capacity scenarios from the Winter 2020/21 SARA. All major generation types underperformed relative to their forecast capacity with the exception of solar power, for which capacity additions had likely rendered its production estimates conservative. Compared to forecast capacity, the remaining four generation types underperformed by 46% (wind), 43% (coal), 37% (natural gas), and 21% (nuclear). Relative to their respective extreme scenarios, however, the picture differs. On this metric, wind actually outperformed, producing nearly double its extreme low wind scenario. Nuclear produced at roughly its extreme scenario, with one reactor going offline on February 16,[28] while coal and gas underperformed even their

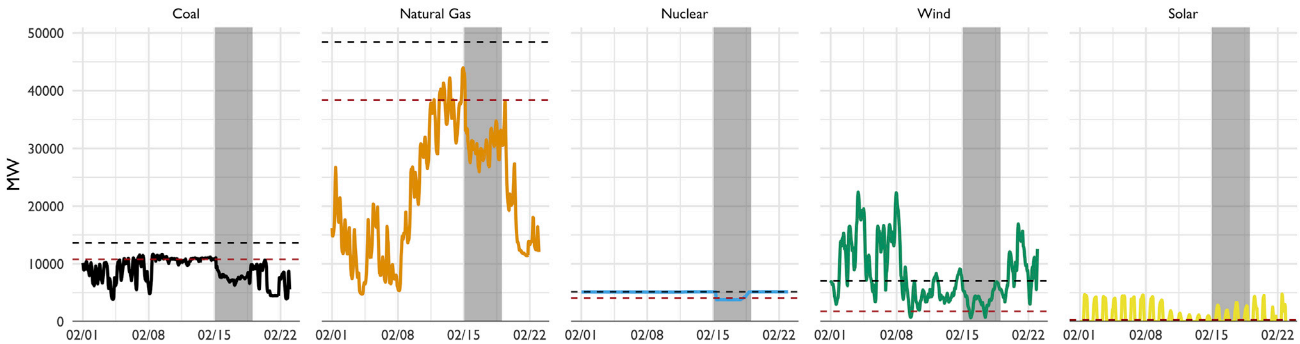

Figure 1. Generation performance versus forecast and extreme capacity scenarios (February 2021)
Forecast capacity from the Winter 2020/21 Seasonal Assessment of Resource Adequacy shown in black dashed lines. Extreme case capacity from the Winter 2020/21 Seasonal Assessment of Resource Adequacy shown in red dashed lines. Period of load shed represented by gray shaded areas from February 15 1:00 a.m. through February 19 1:00 a.m.

extreme outage scenario by 28% and 21% respectively. In short, nearly all generator types were adversely affected by the storm; none were sufficiently up to the task of maintaining reliability during the event.

More detailed descriptions of the sequence of failures leading up to and during the event can be found in Busby et al.,[2] Cramton,[29] Giberson,[30] and King et al.[31]

Forming spot prices

The first impulse among many commentators in the immediate aftermath of the event was to claim that it shows generators in ERCOT had insufficient incentive to invest in reliability. Given the extraordinary profits available to any resource capable of supplying energy during the event, this argument may rightly be viewed with suspicion. Nevertheless, we first consider the possibility that spot prices formed under ERCOT's design are inefficiently low. Three assumptions, each of which warrant reexamination in light of the February storm, give rise to this possibility: the chosen value of lost load (VOLL), the loss of load probability (LOLP) estimated at any given level of operating reserves, and risk neutrality. We discuss these assumptions in Note S1.

Although each of these three assumptions deserves further scrutiny, they cannot themselves explain the February failures. If the true VOLL were higher than $9,000/MWh, for example, it would militate toward a higher reserve margin and lower expected unserved energy. It would not, however, explain why the market was unable to achieve the level of reliability anticipated for the VOLL used at present.

Projecting spot prices

Even if spot prices themselves are efficient, resource adequacy could be threatened if investors are unable to correctly evaluate the distribution of prices that may arise over the life of potential projects. Along these lines, we turn to the second category of potential flaws, i.e., deficiencies in rare event simulation leading to market participants underestimating the frequency and severity of tail events. A full simulation would entail first modeling the underlying weather conditions that drive electricity demand and available generator capacities and then sampling correlated outages driven by common mode failures among fuel suppliers, thermal generators, and renewable generators from a conditional distribution based on those weather conditions. Because we cannot observe the modeling of market participants, we focus in Note S2 on that performed by the system operator.

Although ERCOT did not model anything resembling the February event, however, its failure to do so does not constitute a flaw in the market design. A premise of liberalized electricity markets is the belief that the aggregated knowledge of market participants will provide a more accurate view of the future than the one constructed by a central planner. What matters for market outcomes is not the view of the system operator but the degree to which market participants themselves similarly misjudged or were unable to prepare for the probability of the winter storm and its associated consequences. With complete markets in risk, explaining the February underperformance requires the assumption that not just the system operator but every individual market participant underestimated the probability of the event. Given the experience of the 2011 outages and subsequent investigation by FERC and NERC, embracing such a strong assumption is difficult. The governance and market design question is how the institutional framework can better enable market participant foresight and enable participants to trade risk with each other in mutually beneficial ways, through ERCOT markets and contracting along the supply chain. In this context, we now turn to the role of risk aversion and incomplete contracting.

Translating projected prices into investments

Market incompleteness can have negative consequences for resource adequacy if investors implicitly make decisions based on forward prices that are lower than what would be seen in a complete-trading equilibrium. To demonstrate how incomplete contracting could affect resilience, we adapt the two-stage stochastic equilibrium model from Mays et al.[22] to focus on rare but significant events. Details of the numerical example are given in Note S3. In the model, risk-averse investors build generation resources and trade risk with a risk-averse consumer in the first stage. The second stage represents a year-long economic dispatch, the outcome of which depends on investment decisions as well as the outcome of random variables. Under the assumption of complete trading, i.e., with Arrow-Debreu securities corresponding to every state of the world, this equilibrium model can be reformulated as a risk-averse optimization model that identifies a socially optimal resource mix.[7,24,32] It should be understood that the stylized model abstracts many aspects of the system and does not replicate the February event precisely.

Two technologies are available: a basic combined cycle gas turbine (CCGT) with an investment cost of \$70,000/MW per year and a winterized CCGT (w-CCGT) with an investment cost of \$80,000/MW per year. The incremental investment of \$10,000/MW per year can be thought of as expense incurred to ensure reliable operations in extreme scenarios, e.g., dual-fuel capability.[33] There are two sources of uncertainty in the model: demand and failures of the basic CCGT plants.

At the social optimum, computed using a "complete-trading" optimization model, investors construct 7.91 GW of basic and 68.43 GW of winterized plants for a total installed capacity of 76.34 GW. In other words, given a VOLL of \$9,000/MWh and the assumed failure distribution, it is optimal to spend the incremental investment required for winterization on most of the capacity in the system. However, achieving something like this social optimum depends on the ability of investors to hedge their risk by trading with consumers. To model a situation with incomplete risk trading, we allow trade in a heat rate call option,[34] modulating liquidity in the market by constraining the volume of contracts able to be traded to a percentage of the installed generation capacity. Generation investors and consumers endogenously choose the

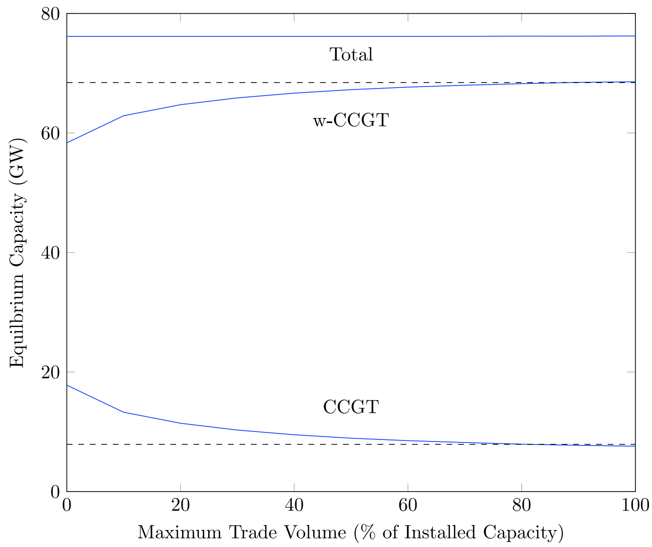

Figure 2. Shift to winterization with increased hedging
Total installed capacity shows weak dependence on the availability of contracts. The financial obligation to perform in all scenarios, however, causes a shift toward winterized capacity. A resource mix close to the socially optimal, complete-trading result (dashed lines) is achieved at high levels of trading.

quantity of contracts to sell or buy subject to this constraint on the total trade volume. We discuss specification of the contract in Note S3. The contract allows risk-averse generators to trade uncertain scarcity rents for a fixed option premium and risk-averse consumers to limit the cost of energy during scarcity. As shown in Figure 2, when trade at a level of 100% of installed capacity is permitted, this single instrument nearly completes the market for risk and leads to a near-optimal resource mix. When trade is restricted, however, the resource mix exhibits a marked shift from w-CCGTs to CCGTs (i.e., away from the winterized technology). Notably, the total installed capacity in the system changes only slightly as a result of reduced trading. Along these lines, a shift toward less winterization would not be discernible under traditional measures of the planning reserve margin.

The primary explanation for the preference for basic CCGTs in the no-trading case is shown in Table 1. Because winterizing pays off only in the rare circumstance of simultaneous widespread outages and high demand, the distribution of returns to winterizing exhibits heavy positive skewness. Risk-averse investors in generation place more weight on situations with negative outcomes. For uncontracted generation, the worst-case scenarios have low demand, no emergencies, and an absence of scarcity pricing. Uncontracted generators discount the low-probability windfall events caused by failures of the basic CCGT, leading to a high incremental internal rate of return required for winterization. The worst outcome for contracted generation, on the other hand, is being unavailable when prices are high because they have to buy back their position at a large loss. Having traded the potential for high scarcity prices for a fixed option premium, cash flows for contracted generation are much more stable, with a resulting drop in the cost of capital.

Diagnosing incompleteness

Several institutional, regulatory, political, and economic issues can contribute to incomplete risk trading. Figure 3 shows a simple representation of the supply chain

Table 1. Implied weighted average cost of capital in equilibrium solution

	Uncontracted case	Contracted cast
CCGT	4.6%	4.6%
w-CCGT	7.7%	4.4%
Winterization	25.1%	3.1%

In the "contracted" case, investors in generation trade future scarcity rent for a fixed option premium, reducing overall investment risk. The effect is strongest for incremental investment in winterization (i.e., upgrading from CCGT to w-CCGT), which pays off only in rare resilience events.

for electricity. We divide the discussion into four sections based on four links in the supply chain, with the nature of the incompleteness in each link considered in Notes S4–S7.

DISCUSSION

The results above highlight the challenges decentralized systems face in attempting to achieve something like the ideal of complete markets and the severe implications incompleteness can have for resilience. Given these challenges, electricity market operators and regulators may consider a variety of reforms to help ensure they deliver a level of performance commensurate with social expectations. Although some reforms may be geared specifically toward winter storms, the more general challenge in ERCOT and elsewhere is to ensure an appropriate framework to prepare for a range of potential threats. Here, we consider several potential market reforms, as well as the market implications of several non-market interventions that have been proposed in the wake of the disaster.

Mandatory contracting and capacity markets

The analysis in this paper supports a mandatory forward contracting obligation placed on retailers to resolve the fundamental incompleteness problem. Although this paper does not give specific guidance on the design of such an obligation, here we describe three key considerations: the strength of underlying spot prices, the contractual form, and qualification standards for suppliers of the contracts.

The hallmark of the energy-only market design is formation of spot prices that are high enough, in theory, to support an efficient level of reliability in the long run. Mandatory forward contracting for energy around full-strength spot prices could resolve incomplete risk sharing between generators and retailers while preserving the benefits of scarcity pricing. Any deviations from contracted amounts would create risk at the margin for the deviating party and, accordingly, encourage active participation from flexible generators, storage operators, and other flexible sources (including demand) to fill these voids. Experience with capacity markets used elsewhere in the U.S. shows that capacity markets make it difficult to design effective resource adequacy mechanisms, partly because they suppress scarcity prices. One consequence is that the direct financial penalties for non-performance in these markets are smaller than the financial incentive for performance in ERCOT.[35] Structuring the requirement as a financial hedge settling against full-strength energy prices, rather than attempting to define capacity as a separate commodity, can help ensure strong performance incentives.[36,37]

Complete markets in risk would include a menu of contracts, allowing market participants to select those adapted to their risk profile and preferences. In keeping with this principle, the Retailer Reliability Obligation used in the Australian National Electricity Market allows many contractual forms to contribute to satisfying obligations,

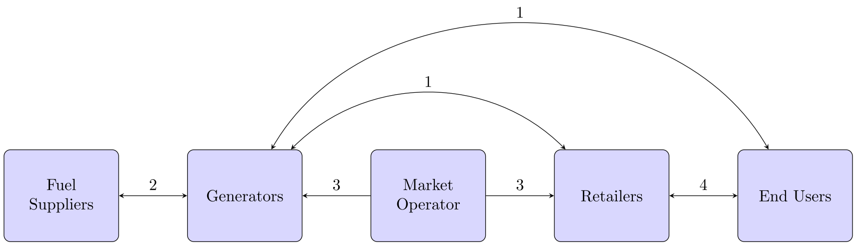

Figure 3. Links in the electricity supply chain
We highlight four connections vulnerable to incomplete risk trading.

necessitating a methodology to rate the relative "firmness" of each contract.[38] Although this flexibility is possible in a bilateral context, centralized auctions for contracts instead require some degree of standardization. One natural candidate for contractual form is a call option with a high strike price,[36,37] but this instrument has the potential to skew the resource mix toward natural gas.[22] Given the risk posed by increased dependence on the gas system, a broader approach to improving contracting may be more effective in promoting resilience. An example of such an approach is described in Wolak,[39] which defines contracts with a shape determined ex post by the actual consumption of end users. Compared to call options, this approach is likely to provide a stronger hedge for retailers, as it covers a much larger portion of the expected cost to serve load. With that being said, the effect of contractual form on equilibrium results remains an important question for future work.

Given the default risk associated with a purely financial requirement, a mandatory contracting obligation could further require physical backing for all contracts. A physical requirement is especially warranted in markets with weak scarcity pricing, where penalties for non-performance may be insufficient. It is worth noting, though, that the requirement for physical backing raises difficult questions about how to measure the capability of those physical assets. The Winter 2020/21 SARA, which overestimated the contribution of all resource types during Uri, is indicative of the challenge. In general, a greater level of administrative oversight is sensible only if central planners are better suited to evaluate requirements than market participants. Along these lines, successful implementation of a mandatory contracting obligation, especially one that requires physical backing, relies on investment in the analytical and administrative capacities of system operators and regulators.

Demand for operating reserves

This paper argues that the problem is not in real-time price formation but in translating those real-time prices into forward-looking investments. Accordingly, proposed reforms that focus on increasing spot prices by adjusting the demand for operating reserves are unlikely to have the desired effect without solving the incompleteness issue. We discuss additional aspects of pricing reserves in Note S8.

Supply chain weatherization

Following outages in February 2011, stronger weatherization standards for energy systems (e.g., freeze protection systems, insulation, and wind breaks) were suggested but not mandated.[40] Given the similarity between the failures that occurred across the interconnected electricity and natural gas infrastructures in the two storms, implementing the suggested standards would have significantly improved outcomes in the 2021 storm. In a setting with mandatory contracting, weatherization standards have the additional benefit of making the task of resource accreditation easier. This benefit partly arises from the fact that weatherization of the natural gas system falls outside the purview of power system operators and partly from the fact that weatherization of the natural gas system would provide diffuse reliability benefits across gas generators. We discuss considerations for weatherization standards in Note S9.

Uncertainty, forecasting, and information

Setting mandatory contracting requirements or weatherization standards requires a set of expectations around future meteorology. We discuss the challenges associated with generating these expectations in Note S10. Given the challenges involved, expert forecasts can inform the wisdom of the crowd that decentralized markets hope to reveal. Centralized knowledge processes offer a way to appropriately generate long-term meteorological forecasts, consistently quantify their impacts and consequences across interconnected infrastructure systems, and improve setting and meeting reliability targets. Availability of a robust set of long-term forecasts and their consequences can also reduce information asymmetries among market participants, facilitating contracts and promoting market completeness.

Clearinghouse rules

A market remedy that would create more complete markets for risk would be for ERCOT to increase collateral requirements and mutualize credit risk. Instead of calculating collateral requirements based on historical and estimated future obligations, ERCOT could demand that parties post enough collateral to meet the obligations they would incur during extreme events. In addition, ERCOT could require that members contribute to a default waterfall fund that could be drawn upon to meet a defaulting members' obligations.

These reforms would reduce the likelihood of revenue shortfalls during extreme events, but they might also reduce competition among retailers. Increasing collateral requirements and forcing retailers to contribute to a default waterfall fund would increase retailer costs. If small retailers are unable to bear those costs, they would leave the market. Reforms that would improve reliability by reducing revenue shortfalls might therefore also increase market concentration, amplifying the trend toward retail market concentration over the past several years.[41]

Retail contracts

Economists have long recognized the potential for time-varying retail rates to facilitate demand-side flexibility, encourage investment in distributed energy resources (DERs), and improve overall efficiency in electricity systems. Despite the potential, neither regulators nor customers have shown significant interest in real-time pricing contracts such as those offered by Griddy, in part due to the price risk such a plan entails. For the efficiency benefits of real-time pricing to be achieved, however, customers need only be exposed to those prices on the margin. As an alternative to banning such retail plans, either allowing or mandating price insurance contracts for residential customers on real-time pricing contracts would provide a backstop for residential customers in extreme high-impact, low-frequency situations such as the February events. Indeed, Griddy was planning to launch just such an insurance product for their customers in March.

Retail customers also face reliability risk, but very little is known about the heterogeneous and subjective preferences that different customers have over reliability (even within the residential customer class). The value of avoiding an outage varies across customers, time, and devices operated by each customer. However, in the absence of markets for reliability risk, no systematic mechanism exists for targeting curtailment to less critical usages. At present, some customers can insure physically against reliability risk through DER investments. As with price risk, reliability risk could be hedged contractually through the purchase of a reliability insurance contract,[42] grounded in the more general concept of priority service contracts.[43,44] Offering such contracts would expand the system's capacity for risk trading.

Without separate priority service contracts, a change to the form of retail contracts could ensure customers are compensated for their VOLL (or some approximation of it) when an outage occurs. For example, such compensation would occur automatically for customers on a real-time pricing plan that had fully hedged their consumption. This idea reflects Coase's concept of assigning liability to the party that is the least cost avoider of the harm[45] and would better align incentives to make investments to avoid reliability risk. The same logic applies in regulated service territories, as well as to outages caused by transmission or distribution failures. Given that the incidence of blackouts is unequal across feeders and neighborhoods,[46] such an approach could improve outcomes both in terms of efficiency and equity.

Conclusions

The ideal of a complete competitive market holds appeal due to its potential to attract efficient investment in socially beneficial infrastructure with fewer of the incentive issues associated with regulated monopolies. The catastrophic failure of the ERCOT system in February 2021 prompts serious questions regarding how to ensure that markets deliver on their promise of socially efficient outcomes. Since the disaster, many commentators have focused on the parameterization of the demand for operating reserves in explaining the failures. This explanation is not satisfactory. Others have focused on ERCOT's failure to prepare market participants for the possibility of such an event occurring. Given the decentralized nature of decision-making in ERCOT, however, this failure is shared by all involved.

In formal models of complete markets with risk-averse participants, trading has the effect of aligning private interests with social preferences. In the February event, by contrast, several market participants went bankrupt and others incurred substantial losses, while some suppliers of uncontracted natural gas made windfall profits. Beyond monetary losses, over 200 people lost their lives. The stark divergence in outcomes reflects severely misaligned incentives, reinforcing that successful reforms will focus on the allocation and sharing of risk. This paper argues that merely relying on refinements to spot pricing or improved modeling of correlated failures will not solve this fundamental issue. Instead, regulatory interventions to facilitate contracting along the supply chain are needed to ensure resilience in liberalized markets.

EXPERIMENTAL PROCEDURES

Resource availability

Lead contact

Further information and requests for resources and materials should be directed to and will be fulfilled by the lead contact, Jacob Mays (jacobmays@cornell.edu).

Materials availability

Not applicable.

Data and code availability

The code and data used for numerical tests in this study are available in a public repository.[47]

SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.joule.2022.01.004.

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AUTHOR CONTRIBUTIONS

Conceptualization, J.M., M.T.C., L.K., J.C.M., B.S., and H.S.; methodology, H.S. and J.M.; writing – original draft, J.M., M.T.C., L.K., J.C.M., B.S., and H.S.; writing – review & editing, J.M., M.T.C., L.K., J.C.M., B.S., and H.S.; supervision, J.M.; project administration, J.M.

DECLARATION OF INTERESTS

The authors declare no competing interests.

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