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Beyond capacity: Contractual form in electricity reliability obligations

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ABSTRACT

Liberalized electricity markets often include resource adequacy mechanisms that require consumers to contract with generation resources well in advance of real-time operations. While administratively defined mechanisms have most commonly taken the form of a capacity obligation, efficient markets would feature a broad array of arrangements adapted to the risk profiles and appetites of market participants. This article considers how the financial hedge embedded in alternative resource adequacy contract designs can induce different responses from risk-averse investors, with consequences for the resource mix and market structure. We construct a stochastic equilibrium model describing a competitive market with incomplete risk trading and compute investment equilibria under different contracting regimes. Two policy recommendations result. First, to avoid creating inefficiency by crowding out other forms of risk sharing, system operators should allow resources contracted through other means to opt out of mandatory capacity mechanisms, with their contribution to those requirements subtracted from administratively defined demand curves. Second, if they wish to promote a single contractual form, regulators should consider replacing existing option-like capacity mechanisms with a shaped forward contract for energy. Beyond these recommendations, we discuss the tension that liberalized systems face in seeking to promote both reliability and competitive outcomes.

1. Introduction

The volatility of electricity spot prices has raised concerns worldwide about the ability of organized markets to deliver on their stated aim of achieving reliability at the lowest possible cost to consumers. In February 2021, Winter Storm Uri led to unprecedented supply shortfalls in the Electric Reliability Council of Texas (ERCOT), leading many observers to question the role of market design in contributing to the system's lack of resilience (Baker and Coleman, 2022; Gruber et al., 2022; Mays et al., 2022). In June 2022, the Australian National Electricity Market (NEM) was suspended for a ten-day period when the Australian Energy Market Operator (AEMO) claimed that it had become impossible to secure electricity through the market (AEMO, 2022). On a longer timescale, high gas prices and supply interruptions due to the ongoing Russo-Ukrainian War have to led to an energy crisis in Europe, with political leadership in several countries calling for a return to the average cost pricing characteristic of regulated monopolies rather than the marginal cost pricing inherent to competitive markets (European Commission, 2022).

Both for consumer protection and to avoid the underinvestment that can result from financial and political instability, regulators and system operators have an interest in mitigating the effects of volatility. In the first instance, it might be questioned why there must be any centrally designed component to risk sharing, as opposed to counting on market participants to allocate risk efficiently according to their preferences (Hogan, 2005). The first answer to this question is based on "missing money" and the second on "missing markets". First, due to operator interventions and market power mitigation measures, many jurisdictions fail to produce spot prices that are high enough to support an adequate level of resources (Joskow, 2008; Cramton et al., 2013). Lacking full-strength spot prices, generators need a supplemental revenue stream to support investment. Most commonly, this supplemental revenue takes the form of a capacity payment. While design details vary substantially across jurisdictions, the financial effect of capacity payments is similar to that of a call option: generators receive a consistent monthly or annual payment in exchange for the potential for the high prices they would otherwise see in times of scarcity. The particular form of risk transfer implied by capacity payments is a side effect of the chosen response to the missing money problem, rather than a deliberate design choice. Even if spot prices are high enough to avoid the missing money problem, however, long-standing concern about missing markets for risk sharing means that some form of obligation that retailers contract with generation resources could be

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warranted (Neuhoff and De Vries, 2004; Newbery, 2016; Simshauser, 2018; Mays et al., 2022). In both Texas and Australia, the two most prominent examples of markets that have committed to full-strength scarcity prices and avoided contracting obligations to date, recent events have motivated regulators to reexamine some form of capacity mechanism.

In this context, the goal of this paper is to consider the effects that different forms of contracting obligations may have on the resource mix, market structure, cost, and reliability outcomes in liberalized systems. In theory, achieving near-optimal investment outcomes requires a menu of contracts adapted to the risk profiles of different market participants (Willems and Morbee, 2010). In this vein, there is no theoretical reason to privilege the particular option-like contractual form embedded in capacity markets. Because the payout structure built into capacity markets is well-adapted to peaking plants, Mays et al. (2019) argues that existing mechanisms can tilt the resource mix in that direction. The European crisis highlights that although they can improve resource adequacy, capacity mechanisms offer relatively little price protection to consumers and represent an incomplete solution to the problem of missing markets (Batlle et al., 2022a,b). More concretely, we address two questions of immediate relevance to resource adequacy debates:

- **Question 1:** If capacity markets continue in something like their current form, how should variable and energy-limited resources contracted through other means participate in them?
- **Question 2:** Would the standardized fixed price forward contract proposed in Wolak (2022) offer a superior alternative to current capacity markets?

To address these questions, we construct a stochastic equilibrium model describing a competitive market with incomplete risk trading and compute investment equilibria under different contracting regimes. In the model, generation investors build capacity and take long-term contract positions in order to maximize risk-adjusted profits across potential future operating scenarios. Mandatory contracts condition the residual risk that must be managed by market participants themselves through complementary instruments. Accordingly, the equilibria results depend not only on the mandated contract but also on assumptions about hedging by other means. Under the extreme assumption of complete markets in risk, an obligation imposed by the regulator or system operator may have no effect: participants could simply unwind their mandated position through other channels. Without this assumption, the analysis requires characterizing the potential responses of participants to their residual risk exposure.

The appropriate treatment of variable renewables in capacity markets has attracted substantial recent attention along two dimensions. The first dimension is how much capacity non-traditional resources should be allowed to sell, e.g., on the basis of their effective load carrying capability (Bothwell and Hobbs, 2017; Schlag et al., 2020). From an idealized economic perspective, the need to assess a capacity value emerges from failures in the design of capacity markets: if penalties in the capacity market were strong enough, then any resource should only be willing to take on an obligation that they are able to deliver on. With risk neutral investors, efficiently calibrated non-performance penalties for capacity would provide the same incentive as full-strength spot prices for energy (Cramton et al., 2013), and several authors have argued that capacity mechanisms should be designed as call options to make that link explicit (Vazquez et al., 2002; Oren, 2005; Hogan, 2005). In practice, capacity mechanisms take a wide variety of forms (Bublitz et al., 2019; Duggan, 2020), with a particular concern arising in U.S. markets due to the weak non-performance penalties they assess relative to what would result from a call option. Throughout the numerical studies we abstract away from these nuances, employing a call option as reflective of the cash flow implications of capacity mechanisms. In that vein we exclude the possibility of bankruptcy and retain full-strength spot prices, providing an efficient penalty for non-performance on contracts, but we return to the implications of weaker penalties later in the discussion. The second dimension is how to incorporate resources supported by state-initiated contracts (Macey and Ward, 2021). Seen in the context of missing markets for long-term risk sharing, these contracts have typically supported low-carbon technologies that are disadvantaged by capacity markets. Accordingly, while in the U.S. some have argued that these contracts interfere with price formation in capacity markets, our modeling framework treats them as complementary instruments leading to a more complete "hybrid" market (Joskow, 2022). This more optimistic view, however, depends on an assumption that the state-initiated contracts can be treated not merely as subsidies, but instead as hedges that are efficiently incorporated in the portfolios of risk-averse retailers (Simshauser, 2019).

For Question 1, our results in Section 3 suggest that instead of current attempts to fit variable resources into capacity markets, it is more efficient to simply remove them and correspondingly reduce the administratively defined demand for capacity. In a risk neutral analysis, the two approaches are identical. When risk aversion is considered, however, compelling a variable resource to participate in the capacity market necessitates that they sell a contract that would be unlikely to arise in any self-organizing market. Both in theory and in practice, it is unnatural to expect variable resources to sell hedging instruments with a constant volume. When securing contracts, wind and solar producers typically seek to match the shape of their offtake agreements with the shape of their production, e.g., through a proxy generation power purchase agreement (Bartlett, 2019). In taking on a capacity obligation, by contrast, wind and solar make a commitment they can only physically support some fraction of the time. With theoretically efficient non-performance penalties, selling capacity leaves variable generators exposed to significant non-performance risk. Accordingly, attempting to fit the square peg of variable generators in the round hole of capacity markets can create inefficiencies, with generators charging risk premia or withholding supply from the market. A related prediction is that the willingness of variable resources to participate in current capacity markets is in part a reflection of the relatively weak penalties they employ.

While Question 1 implies a more moderate reform that keeps existing capacity markets in place, Question 2 envisions a more significant overhaul of resource adequacy toward long-term contracts for energy, along the lines of those used in Chile and Brazil (Moreno et al., 2010; Muñoz et al., 2021). Motivated by the context of California, Wolak (2022) describes a standardized fixed-price forward contract (SFPFC) approach in which generators sell a quantity of energy at a given price, with the shape of the contract determined ex post to match the actual consumption of loads on the system over the course of the delivery period. In this way, the contract mimics a full requirements contract but covers a fixed volume, leaving incentives on the margin intact. The proposal envisions auctions for these standardized contracts occurring on a regular basis, with retailers required to cover an increasing percentage of its expected load as the relevant delivery period approaches. A key difference from capacity markets is that the price of energy delivered under the contract is determined in advance; while capacity obligations require generators to offer in real time, they typically do not specify a price at which they must offer. In the SFPFC approach both price and shape risk are shifted from retailers to generators, resulting in a much stronger hedge for consumers. For this reason, the SFPFC may be particularly attractive in jurisdictions without retail competition.

Examples in Section 4 show that compared against the option contract we use to mimic a capacity market, SFPFCs result in equilibria with greater surplus, lower cost for comparable reliability, and substantially lower volatility in the price seen by consumers. In other words, if regulators and system operators wish to promote a single instrument for long-term risk sharing, the SFPFC approach may be seen as superior to capacity markets. However, two caveats apply. The first is that, while SFPFCs outperform options when each is the only contract available, they are not able to match the efficiency achievable with a larger number of instruments. The second is that, since sellers of SFPFCs bear risk related to both price and shape, there is an incentive for sellers to create portfolios of assets protecting against both. As such, just as missing markets for risk sharing between generators and retailers can lead to vertical integration in energy-only markets (Simshauser, 2021), the SFPFC design could create pressure toward more consolidation among generators.

While the mandatory contracts considered here can improve resource adequacy, they cannot completely resolve reliability risks along the electricity value chain. First, our analysis neglects distinctions between reliability needs at the customer and device level (see, e.g., Billimoria and Poudineh (2019) and Billimoria et al. (2022)). Second, a point of emphasis in the context of the 2022 European energy crisis as well as the 2021 Texas outages is the security of supply of input fuels, most importantly natural gas. Mandatory contracting between generators and retailers for resource adequacy implicitly assigns the responsibility for ensuring security of supply to the generators, who will be unable to deliver on their obligations if they fail to procure input fuel. While this assignment of responsibility may be an improvement over a situation in which no entity has clear responsibility, it does not in itself resolve the issue. With that said, programs for resource adequacy are clearly implicated in security of supply to the extent that they encourage dependence on different fuels. Third, while our analysis of the first question posed above emphasizes non-performance risk for variable resources, traditional thermal resources are also subject to unexpected failures. Unless generators of all types can efficiently insure against non-performance, there is a potential for excessive risk premia or the use of bankruptcy as a hedge.

2. Modeling framework

The results center on two sets of numerical examples employing a two-stage stochastic equilibrium model describing capacity investment in a perfectly competitive market with risk-averse agents and incomplete financial markets. Here we describe the modeling framework, which largely follows Mays et al. (2019). In the first stage, agents make investments and financial trading decisions. In the second stage, system operators perform a year-long economic dispatch to determine spot prices and generation output. Compared to previous models of this form (Ehrenmann and Smeers, 2011; Ralph and Smeers, 2015; Philpott et al., 2016; de Maere d'Aertrycke et al., 2017; Abada et al., 2017; Mays et al., 2019), our most important change arises in our second set of examples, in which we allow investors to build portfolios containing multiple technologies rather than having each technology represented by a single representative agent. This change enables a discussion of potential incentives for horizontal integration resulting from contracting mandates. As with these previous models, however, our description of market structure is incomplete in that we assume no vertical integration between generators and loads. Such integration could substitute for the contracting that occurs in our model and reduce the quantities traded in the forward markets.

The numerical experiments consider three sources of uncertainty. We use the random variable D^{+} with scenarios $s \in \mathcal{S}$ to represent an exogenous demand shock in all time blocks, A_{gt} with scenarios $r \in \mathcal{R}$ to represent generation availability, and C^{EN}_{gf} and D^{-} with scenarios $f \in \mathcal{F}$ to represent fuel cost and a downward demand shift that is positive correlated with fuel cost. This leads to of a total of $|\mathcal{S}| \times |\mathcal{R}| \times |\mathcal{F}|$ scenarios with equal probability. For each agent $a \in \mathcal{A}$, we calculate a risk measure ρ_a as a convex combination of expected value and CVaR of surplus. In this approach, each agent performs a risk-averse optimization implicitly assigns higher probability to the events within its own α-tail of outcomes. The models are implemented in Julia (Bezanson et al., 2017) using JuMP.jl (Dunning et al., 2017) and solved with Gurobi (Gurobi Optimization, LLC, 2020).

2.1. Notation

Sets:

- $g \in \mathcal{G}$: set of all generation technologies
- $t \in \mathcal{T}$: set of time blocks
- $s \in \mathcal{S}$: set of demand shifter
- $r \in \mathcal{R}$: set of generator availability profiles
- $f \in \mathcal{F}$: set of scenarios for fuel prices
- $a \in \mathcal{A}$: set of market participants (generators g and consumers c)

Parameters:

- B: value of non-price-responsive load (\$/MWh)
- L_t: length of time blocks t (h)
- C^{INV}_{g}: amortized investment cost of generator g per unit capacity (\$/MW)
- C^{EN}_{gf}: per unit production cost of generator g under fuel cost scenario f (\$/MWh)
- D^{fix}_{t}: baseline level of non-price-responsive demand in time block t (MW)
- D^{res}: amount of price-responsive demand (MW)
- D^{+}_{s}: positive demand shift under demand shifter s (MW)
- D^{-}_{f}: negative demand shift under fuel price shifter f (MW)
- A_{grt}: availability of generator g in time block t under profile r (%)
- α_a: tail probability at which CVaR is evaluated by market participant a, $0 < \alpha_a \le 1$
- β_a: weight given to expected value of surplus in risk measure for market participant a, $0 \le \beta_a \le 1$
- p_{frs}: nominal probability of scenario (f, r, s)
- $\underline{v}_a$ / $\overline{v}_a$: minimum/maximum volume of contract to be traded by market participant a

Provisional parameters (i.e., values calculated by agents):

- λ_{frst}: price of energy in time block t under scenarios (f, r, s) (\$/MWh)
- π_{gfrst}: profit per available unit of generation g under scenarios (f, r, s) in time block t (\$/MW)
- ϕ^{k}: price of contract k incurred in the first stage (\$/MW-yr)
- η^{k}_{frs}: payout of contract k under scenario (f, r, s) (\$/MW-yr)

Variables:

- x_g: capacity installed for generation technology g (MW)
- y_{gt}: power production by generation g in time block t (MW)
- d^{fix}_{frst}: amount of served non-price-responsive demand in time block t under scenario (f, r, s) (MW)
- d^{res}_{frst}: amount of served price-responsive demand in time block t under scenario (f, r, s) (MW)
- ρ_a: risk measure for market participant a (\$)
- v^{k}_{a}: volume of contract k sold or purchased by market participator a (MW)
- VaR_a: value at risk for market participator a (\$)
- u^{a}_{frs}: surplus for market participator a under scenarios (f, r, s) (\$)
- u^{a+}_{frs}: auxiliary variable of market participator a for calculating VaR (\$)

2.2. Economic dispatch

The economic dispatch (ED) problem for each scenario is to find the power output of all generators leading to the lowest possible operating cost while maintaining system constraints. It is modeled as a convex quadratic problem. The outputs of the ED problems are parameters that enter the generator model and consumer model (see Eqs. (1a)–(1e) given in Box I).

$$(\mathrm{ED})_{frs} \quad H_{frs} = \underset{y,d}{\text{maximize}} \quad \sum_{t\in\mathcal{T}} L_t B\left(d^{\text{fix}}_{frst} + d^{\text{res}}_{frst} - \left(d^{\text{res}}_{frst}\right)^2 / \left(2D^{\text{res}}\right)\right) - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} L_t C^{\text{EN}}_{gf} y_{gfrst} \tag{1a}$$

$$\text{subject to} \quad (\lambda_{frst}): \quad d^{\text{fix}}_{frst} + d^{\text{res}}_{frst} + D^+_s - D^-_f = \sum_{g\in\mathcal{G}} y_{gfrst} \quad \forall t\in\mathcal{T} \tag{1b}$$

$$(\pi_{gfrst}): \quad 0 \le y_{gfrst} \le A_{grt} x_g \quad \forall g\in\mathcal{G}, t\in\mathcal{T} \tag{1c}$$

$$0 \le d^{\text{fix}}_{frst} \le D^{\text{fix}}_t \quad \forall t\in\mathcal{T} \tag{1d}$$

$$0 \le d^{\text{res}}_{frst} \le D^{\text{res}} \quad \forall t\in\mathcal{T}. \tag{1e}$$

Box I.

The objective function (1a) maximizes the total social surplus, which is equal to consumer surplus minus the total cost of production. Served demand is split into $d^{\text{fix}}_{frst}, d^{\text{res}}_{frst}, D^+_s, D^-_f$. As discussed in Mays et al. (2019), we treat D^+_s, D^-_f as exogenous shocks to demand and exclude them from Eq. (1a), implying that serving it does not bring gain or loss to customers. Constraint (1b) maintains power balance, i.e., the total demand served equals total generation. Constraint (1c) states that power production is limited by the installed capacity of a given technology multiplied by its availability in the time segment. Constraints (1d) and (1e) model non-price-responsive and price-responsive demand. Note that λ_{frst} is the dual of (1b) and gives the energy price in the spot market, and π_{gfrst} is the dual of (1c), representing the operating profit of generator g per available unit of capacity.

2.3. Contracts

Market participants can trade a number of instruments to hedge risk. Here we provide a more detailed description of the four instruments implemented in the numerical examples. The first three instruments are tailored to the risk profiles of each generation technology. We denote by η^k_{frs} the payout of contract k under scenario (f, r, s). As our focus is on the impact of different contract designs rather than frictions in trading more generally, we assume no transaction costs.

Call options give the holder the right but not the obligation to obtain the specified energy at a specified strike price. When k indexes a call option with strike price λ^k that covers all the time blocks in a year, the payout is calculated as

$$\eta^k_{frs} = \sum_{t\in\mathcal{T}} L_t \max\{0, \lambda_{frst} - \lambda^k\}. \tag{2}$$

When k indexes a futures contract that covers all the time blocks at price λ^k, the payout is calculated as

$$\eta^k_{frs} = \sum_{t\in\mathcal{T}} L_t(\lambda_{frst} - \lambda^k). \tag{3}$$

A unit contingent contract is defined to track the availability of variable technologies so that the payout is proportional to the output. When k indexes a unit contingent contract at price λ^k for generator g, the payout is calculated as

$$\eta^k_{frs} = \sum_{t\in\mathcal{T}} A_{grt} L_t(\lambda_{frst} - \lambda^k). \tag{4}$$

The SFPFC is defined to track a shape determined ex post by the demand for energy. When k indexes an SFPFC that covers a whole year at price λ^k, the payout is calculated as

$$\eta^k_{frs} = \sum_{t\in\mathcal{T}} \frac{8760(D^{\text{fix}}_t + D^+_s - D^-_f)}{\sum_{t'\in\mathcal{T}} L_{t'}(D^{\text{fix}}_{t'} + D^+_s - D^-_f)} L_t(\lambda_{frst} - \lambda^k). \tag{5}$$

We note that our definition of the SFPFC shape excludes price-responsive load, but includes all fixed load regardless of whether it is served.

2.4. Generator model

A single representative agent is used to model investing in each generation technology. Generators make capacity decisions and sell contracts in the first stage and produce energy in the second stage. The generator model is stated as follows:

$$(\mathrm{GEN})_g \quad \rho_g =$$

$$\underset{v_g,u^g,u^{g+},\mathrm{VaR}_g}{\text{maximize}} \quad (1-\beta_g)\left(\mathrm{VaR}_g - 1/\alpha_g \sum_{f\in\mathcal{F}}\sum_{r\in\mathcal{R}}\sum_{s\in\mathcal{S}} p_{frs} u^{g+}_{frs}\right) + \beta_g \sum_{f\in\mathcal{F}}\sum_{r\in\mathcal{R}}\sum_{s\in\mathcal{S}} p_{frs} u^g_{frs} - \frac{\gamma}{2}\sum_{k\in\mathcal{K}}(\sum_{a\in A} v^k_a)^2 \tag{6a}$$

subject to

$$u^g_{frs} = \sum_{t\in\mathcal{T}} \pi_{gfrst} A_{grt} x_g - C^{\text{INV}}_g x_g - \sum_{k\in K} v_g(\phi^k - \eta^k_{frs}) \quad \forall f\in\mathcal{F}, r\in\mathcal{R}, s\in\mathcal{S} \tag{6b}$$

$$(\tau^g_{frs}): \quad \mathrm{VaR}_g - u^g_{frs} \le u^{g+}_{frs} \quad \forall f\in\mathcal{F}, r\in\mathcal{R}, s\in\mathcal{S} \tag{6c}$$

$$0 \le u^{g+}_{frs} \quad \forall f\in\mathcal{F}, r\in\mathcal{R}, s\in\mathcal{S} \tag{6d}$$

$$\underline{v}^k_g \le v^k_g \le \overline{v}^k_g \quad \forall k\in\mathcal{K}. \tag{6e}$$

The objective function (6a) is maximizing the risk-adjusted profits for each generation technology g. The first two terms in (6a) are the sum of a convex combination of expected value and CVaR of surplus, while the third term penalizes imbalances in contract volumes and is zero in equilibrium. Constraint (6b) states that the overall utility of each scenario is equal to operating profits in the scenario minus the investment cost minus the result of financial trades. Constraints (6c) and (6d) dictate the auxiliary variables u^{g+}_{frs} used in calculating CVaR. Constraint (6e) limits the quantity of financial trading.

2.5. Consumer model

Here a single representative consumer is modeled, with its decisions equivalent to a number of identical small consumers in a perfectly competitive market. The consumer signs contacts with generators in the first stage and consumes energy in the second stage. The consumer model is stated as follows:

$$(\mathrm{CON}) \quad \rho_c =$$

$$\underset{u^c,u^{c+},\mathrm{VaR}_c}{\text{maximize}} \quad (1-\beta_c)\left(\mathrm{VaR}_c - 1/\alpha_c \sum_{f\in\mathcal{F}}\sum_{r\in\mathcal{R}}\sum_{s\in\mathcal{S}} p_{frs} u^{c+}_{frs}\right) + \beta_c \sum_{f\in\mathcal{F}}\sum_{r\in\mathcal{R}}\sum_{s\in\mathcal{S}} p_{frs} u^c_{frs} \tag{7a}$$

subject to

$$u^c_{frs} = \sum_{t\in\mathcal{T}} L_t B\left(d^{\text{fix}}_{frst} + d^{\text{res}}_{frst} - \left(d^{\text{res}}_{frst}\right)^2 / (2D^{\text{res}})\right)$$

$$- \sum_{t \in \mathcal{T}} L_t \lambda_{frst} (d^{\text{fix}}_{frst} + d^{\text{res}}_{frst} + D^+_s - D^-_f)$$

$$- \sum_{k \in K} v_c (\phi^k - \eta^k_{frs}) \quad \forall f \in \mathcal{F}, r \in \mathcal{R}, s \in \mathcal{S} \tag{7b}$$

$$\text{VaR}_c - u^c_{frs} \le u^{c+}_{frs} \quad \forall f \in \mathcal{F}, r \in \mathcal{R}, s \in \mathcal{S} \tag{7c}$$

$$0 \le u^{c+}_{frs} \quad \forall f \in \mathcal{F}, r \in \mathcal{R}, s \in \mathcal{S} \tag{7d}$$

$$\underline{v}^k_c \le v^k_c \le \overline{v}^k_c \quad \forall k \in \mathcal{K}. \tag{7e}$$

The objective function (7a) maximizes the risk-adjusted utility for consumers, i.e., the sum of a convex combination of expected value and CVaR of surplus. Here, we do not include the third contract balance term as in (6a), which equals zero in equilibrium and thus does not affect interpretation. Omission of this term led to faster convergence in numerical experiments. Constraint (7b) states that the overall utility of each scenario is equal to the value of energy consumption minus the result of financial trades in scenario minus payments for energy. Constraint (7c) and (7d) dictate the auxiliary variables u^{c+}_{frs} used in calculating CVaR. Constraint (7e) limits the quantity of financial trading.

2.6. Reliability credit

In the mandatory trading example, a reliability credit is introduced such that the maximum quantity of options that generators can sell is the product of their capacity and the reliability credit. This accreditation is consistent with most real-world capacity markets, where physical resources are de-rated according to their estimated firmness. We calculate the reliability credit as the resource's expected availability when all generation is deployed to its maximum availability. This definition can be interpreted as the marginal contribution that adding one unit of generation would make to the system's effective load carrying capability.

(Reliability credit)

$$rc_g = \frac{\sum_{f \in \mathcal{F}} \sum_{r \in \mathcal{R}} \sum_{s \in \mathcal{S}} L_t A_{grt} \mathbb{1}\{\lambda_{frst} > C^{\text{EN}}_{\text{`peaking'} f}\}}{\sum_{f \in \mathcal{F}} \sum_{r \in \mathcal{R}} \sum_{s \in \mathcal{S}} L_t \mathbb{1}\{\lambda_{frst} > C^{\text{EN}}_{\text{`peaking'} f}\}} \quad \forall g \in \mathcal{G}, \tag{8}$$

where $\mathbb{1}\{\cdot\}$ is an indicator function. We note that the solution algorithm updates the reliability credit calculation each time the capacity mix is changed, implying a dynamic estimate of load carrying capability.

2.7. Algorithm

The multi-agent equilibrium problem requires simultaneous solution of the economic dispatch, generator model, and consumer model. The equilibrium conditions are as follows:

$$\sum_{a \in A} v^k_a = 0 \quad \forall k \in \mathcal{K}; \tag{9a}$$

$$0 \le x_g \perp \rho_g \ge 0 \quad \forall g \in \mathcal{G}. \tag{9b}$$

Eq. (9a) describes that every financial trade must be balanced, i.e., the amount of contracts sold by the generator should equal to the contract bought by the consumer. Complementarity condition (9b) is obtained from KKT conditions and can be interpreted as investment in technology g will continue until it no longer results in risk-adjusted profit (Ehrenmann and Smeers, 2011). The two conditions are used as the inner-loop and outer-loop stopping criteria respectively in the algorithm.

Here we implement an ADMM-style algorithm to solve this problem. Note that ε_1 and ε_2 are step sizes that used to update capacity and contract price, while σ and δ are small constants that are used as stopping criteria. The algorithm exhibits slow convergence near the equilibrium. As a measure of proximity to equilibrium, we compute $\max_{g \in \mathcal{G}} \left| \frac{\rho_g}{C^{\text{INV}}_g} \right|$, i.e., the largest distance from zero risk-adjusted profit across all generators, normalized by investment cost.

Algorithm 1

Require: An instance of equilibrium problem (EQ) defined by models (ED), (CON), and (GEN).
Ensure: near-equilibrium solution to (EQ)
 define $\sigma, \delta, \varepsilon_1, \varepsilon_2 > 0$; let $\rho_a = 0 \; \forall a \in \mathcal{A}$; initialize x, ϕ
 loop
  $x_g \leftarrow \max\{0, x_g + \varepsilon_1 \rho_g / C^{INV}_g\} \quad \forall g \in \mathcal{G}$
  solve $(ED)_{frs}$; update $\lambda_{frst}, \pi_{gfrst}, \eta^k_{frs} \; \forall (f, r, s) \in \mathcal{F} \times \mathcal{R} \times \mathcal{S}, k \in \mathcal{K}$
  solve (Reliability credit); update rc_g (only for mandatory case)
  Set the trading volume constraints
  solve (CON)
  solve $(GEN)_g \quad \forall g \in \mathcal{G}$
  while $\max_{k \in \mathcal{K}} |\sum_{a \in A} v^k_a| > \sigma$ **do**
   $\phi^k \leftarrow \phi^k + \varepsilon_2 \sum_{a \in A} v^k_a \quad \forall k \in \mathcal{K}$
   solve (CON); update v^k_c
   solve $(GEN)_g \quad \forall g \in \mathcal{G}$; update v^k_g
  end while
  if $\max_{g \in \mathcal{G}} |\rho_g| < \delta$ **then**
   return x and ϕ
  end if
 end loop

For generators selling SFPFC collectively, some modifications are made in the generator model and the algorithm. A single agent N is employed to represent all generation companies and trade with consumers. The generator model is in the same form as (6) except that its overall utility of each scenario is the sum of surplus of all generation technologies minus the result of financial trades as a whole.

$$(\text{GEN})_N \quad \rho_N =$$

$$\underset{v_N, u^N, u^{N+}, \text{VaR}_N}{\text{maximize}} \quad (1 - \beta_N) \left(\text{VaR}_N - 1/\alpha_N \sum_{f \in \mathcal{F}} \sum_{r \in \mathcal{R}} \sum_{s \in \mathcal{S}} p_{frs} u^{N+}_{frs} \right) + \beta_N \sum_{f \in \mathcal{F}} \sum_{r \in \mathcal{R}} \sum_{s \in \mathcal{S}} p_{frs} u^N_{frs} - \frac{\gamma}{2} (\sum_{a \in A} v_a)^2 \tag{10a}$$

subject to

$$u^N_{frs} = \sum_{g \in \mathcal{G}} \sum_{t \in \mathcal{T}} \pi_{gfrst} A_{grt} x_g - \sum_{g \in \mathcal{G}} C^{\text{INV}}_g x_g$$

$$- v_N (\phi - \eta_{frs}) \quad \forall f \in \mathcal{F}, r \in \mathcal{R}, s \in \mathcal{S} \tag{10b}$$

$$(\tau^N_{frs}): \quad \text{VaR}_N - u^N_{frs} \le u^{N+}_{frs} \quad \forall f \in \mathcal{F}, r \in \mathcal{R}, s \in \mathcal{S} \tag{10c}$$

$$0 \le u^{N+}_{frs} \quad \forall f \in \mathcal{F}, r \in \mathcal{R}, s \in \mathcal{S} \tag{10d}$$

$$\underline{v}_N \le v_N \le \overline{v}_N. \tag{10e}$$

When generators sell SFPFC collectively, the step in the algorithm for updating capacity is replaced with

$$x_g \leftarrow \max\{0, x_g + \varepsilon_1 \psi_g / C^{INV}_g\} \quad \forall g \in \mathcal{G}, \tag{11}$$

where $\psi_g = \sum_{f \in \mathcal{F}} \sum_{r \in \mathcal{R}} \sum_{s \in \mathcal{S}} (\tau^N_{frs} + \beta_N \cdot p_{frs})(-C^{\text{INV}}_g x_g + \sum_{t \in \mathcal{T}} \pi_{gfrst} A_{grt} x_g)$. Note that τ^N_{frs} is the dual variable of constraint (10c) and $\tau^N_{frs} + \beta_N \cdot p_{frs}$ implies placing higher weights to worst-case scenarios where τ^N_{frs} is nonzero. Hence ψ_g represents the risk-adjusted contribution of technology g to the overall profit of the portfolio of physical and financial assets held by the agent.

3. Mandatory contracting and portfolio crowding

Our first set of numerical examples considers the interaction between mandatory capacity markets and other forms of risk trading, such as government-initiated contracts for differences, corporate power purchase agreements, and bank hedges. As in Mays et al. (2019), the stylized system has three resources available: baseload, with a high upfront cost but low and certain operating cost, peaking, with a low upfront cost but high and uncertain operating cost, and variable, with a low upfront cost and zero operating cost but uncertain availability. Whereas Mays et al. (2019) considers the effect of capacity markets in the absence of complementary forms of risk trading, here we assume that complementary trades are available but participation in the capacity market is nevertheless mandated. In a setting with uncapped spot prices, risk-averse loads have a strong incentive to enter contracts. Imposition of a mandatory contract changes the risk profile of market participants, affecting the demand for other physical and financial assets. A price cap combined with a capacity mechanism, for example, can reduce the positive skewness typically associated with spot power prices, leading to weaker demand for other hedges (cf. Bessembinder and Lemmon (2002)). In our setting, the additional constraint degrades surplus and pushes the equilibrium capacity mix away from the variable resource.

For the numerical experiments, the nominal demand is based on the load curve of PJM for one year with hourly resolution. The three sources of uncertainty are fuel cost, demand, and the availability of the variable generator. Fuel costs and demand shifts are modeled as random variables with 10 scenarios each, while the availability of variable generation is modeled with 4 scenarios, leading to a total of 400 scenarios for the second-stage economic dispatch with equal probability. The four availability profiles for the variable technology are generated with an average availability of 37.5% and vary in their correlation with the fixed load. While large supply shortfalls due to correlated thermal outages have increasingly been recognized as an important risk (Mays et al., 2022), the examples assume that the baseload and peaking technologies have availability of 0.9 in all scenarios. To characterize the risk attitudes of market participants we use a weighted sum of the expected value of surplus, with weight β, and the conditional value at risk (CVaR) of the α tail of the surplus, with weight $1-\beta$. This weighted sum gives a coherent risk measure (Artzner et al., 1999), convenient for implementation in an optimization model (Rockafellar and Uryasev, 2000). The risk parameters are set to $\alpha = \beta = 0.7$ for retailers and $\alpha = 0.7$, $\beta = 0.2, 0.4, 0.6, 0.8$ for generators, with higher values of β implying less risk aversion. Exploratory tests with different values for α did not lead to meaningfully different conclusions.

With complete markets in risk, participants would be able to hedge though a set of 400 Arrow–Debreu securities corresponding to the 400 second-stage scenarios. With this assumption, a competitive equilibrium can be found by solving a risk-averse optimization problem (Ehrenmann and Smeers, 2011; Ralph and Smeers, 2015; Philpott et al., 2016; Ferris and Philpott, 2022). The complete trading model and the resulting equilibrium is described in Appendix A. With three sources of uncertainty, the system is able to achieve near-optimal results with three contracts that are adapted to risk profiles of the three generation technologies: a call option with strike price of \$1000/MWh,[1] a future settling at \$50/MWh,[2] and a unit contingent contract that matches the availability of the variable generator. Throughout the paper, we refer to this three-contract configuration as "unrestricted" trading and treat it as the benchmark against which surplus in other configurations is measured. All surplus comparisons are calculated within the same risk parameters; i.e., while greater risk aversion leads to lower surplus in expectation, our focus is not on this effect but rather on the influence of different contracting regimes. In the unrestricted case, retailers are responsible for signing different types of contracts with generators to assemble a near-efficient portfolio.

As a contrast with the unrestricted case, we construct a "mandatory" case in which retailers are obligated to purchase a certain minimum number of option contracts. The minimum quantity is set based on the effective load carrying capability of the equilibrium mix found in the unrestricted case, implying roughly equivalent reliability in the two settings. Two additional changes are needed to mimic a capacity market. First, we redefine the future and unit contingent contracts to pay only up to the option strike price, so that a generator does not "double sell" the revenue associated with scarcity prices. In this way, generators sell their output in two tranches: an energy component up to option strike price and a capacity component above the strike price. This is analogous to capacity markets where generators receive capacity payments and suppressed energy payments. Second, to avoid generators simply selling options in a speculative way to satisfy the purchase requirement, we also impose a limit on the maximum quantity of options that generators can sell. This capacity value is calculated for each resource based on its average availability during scarcity, i.e., the reliability credit in Eq. (8), reflecting the contribution of different generation resources to reliability.

Table 1 shows the impact of introducing the mandatory option on the resource mix and prices arising in the system. At all levels of β, the resource mix shifts away from the variable and peaking and toward the baseload resource, with overall reliability in the system roughly unchanged. A consequence of this changed mix is degradation in surplus, ranging from \$1044M with $\beta = 0.2$ to \$389M with $\beta = 0.8$. As the generators become less risk averse (i.e., with higher values of β), the effects of risk aversion and the contract mandate become smaller, with the resource mix in the two cases converging and the loss of surplus shrinking. The consumption-weighted average price paid by consumers including contracts is slightly higher than spot prices, reflecting the net effect of risk premia on the three contracts. Under both contracting regimes, consumers see relatively little of the underlying volatility in spot prices.

Contract volumes and risk premia are reported in Table 2. In the unrestricted case, each technology primarily trades contracts adapted to its risk profile: baseload plants sell futures, peaking plants sell options, and variable plants sell unit contingent. Peakers sell options beyond their physical capacity, indicating a purely financial aspect to the trade. In the mandatory option case, baseload is able to fully hedge its production by pairing options with an equal amount of the redefined futures. When $\beta = 0.8$, baseload sells futures slightly beyond what it is able to produce, with the willingness to engage in the speculative trade reflecting lower risk aversion. The peaker sells only options in most settings, adding a small number of futures only at higher levels of β. Similarly, when $\beta = 0.8$ the variable resource sells futures instead of unit contingent contracts in the mandatory case, indicating a willingness to take a position that is less well matched to its physical capability in exchange for higher risk-adjusted profits. Because consumers do not absorb the shape risk of the variable generator, this configuration corresponds to the lowest standard deviation of prices paid among the eight shown in Table 1. While risk premia for the futures and unit contingent contracts are not directly comparable due to the redefinition of both to exclude scarcity rents, the options contract is unchanged. At every level of β, the risk premium is higher under the mandatory case, reflecting the higher demand for this contract resulting from the obligation placed on retailers.

4. Load-shaped contracts and portfolio optimization

While the examples in the previous section compare the contract mandate against a situation of "near-complete" markets, the larger concern in many cases is market incompleteness. A greater degree of incompleteness expands the scope for regulatory interventions to improve outcomes. Perhaps the least interventionist approach currently

[1] PJM uses a soft offer cap of \$1000/MWh in the energy market. While prices can exceed this soft cap in some instances, we use it as an illustrative option strike price (PJM, 2022a).

[2] \$50/MWh is chosen to be within the range of historical annual load-weighted average LMP in the PJM market (PJM, 2022b).

Table 1
Effect of mandatory options contract. Four pairs of equilibria are shown in order of decreasing risk aversion (higher β). For each β, introducing a minimum quantity for the options contract degrades surplus and pushes the equilibrium mix away from the variable resource. Interannual volatility is calculated as the standard deviation in consumption-weighted prices in the second-stage operating year across all scenarios. Change in surplus is calculated against the unrestricted case at the same level of risk aversion.

	$\beta = 0.2$		$\beta = 0.4$	
	Unrestricted	Mandatory	Unrestricted	Mandatory
Capacity (GW)				
Baseload	31.1	58.3	32.0	50.8
Peaker	107.4	88.9	106.8	93.6
Variable	159.0	106.8	157.3	122.7
Average price ($/MWh)				
Spot	56.74	56.57	56.75	56.77
Hedged	58.96	60.02	58.94	59.74
Interannual volatility ($/MWh)				
Spot	23.26	23.22	23.23	23.61
Hedged	3.27	3.87	3.23	4.17
Expected unserved energy (GWh)	4.80	4.76	4.78	4.96
Proximity to equilibrium	0.024%	0.043%	0.031%	0.057%
Change in surplus ($M/yr)	–	−1044	–	−848
	$\beta = 0.6$		$\beta = 0.8$	
	Unrestricted	Mandatory	Unrestricted	Mandatory
Capacity (GW)				
Baseload	33.3	46.2	33.8	36.4
Peaker	105.7	96.6	105.1	103.7
Variable	155.4	131.6	154.8	149.2
Average price ($/MWh)				
Spot	56.75	57.15	57.15	56.81
Hedged	58.93	59.46	58.91	59.34
Interannual volatility ($/MWh)				
Spot	23.33	24.12	24.01	23.19
Hedged	3.15	4.41	3.07	2.38
Expected unserved energy (GWh)	4.85	5.27	5.25	4.76
Proximity to equilibrium	0.15%	0.098%	0.049%	0.054%
Change in surplus ($M/yr)	–	−662	–	−389

in use is Australia's Retailer Reliability Obligation (RRO), which allows the regulator to trigger a requirement that retailers hold contracts sufficient to serving their load, without specifying the particular form of those contracts. The RRO had not been triggered before the NEM's recent suspension, indicating that its design was insufficiently interventionist. An enhanced version of the RRO could simply be active at all times rather than requiring a trigger. In this case the system would still rely on decentralized contracting, subject to a centralized determination of the quality of different contracts and the total that must be held. Most systems instead define a particular contractual form (e.g., a capacity product), potentially promoting liquidity and market depth at the expense of flexibility.

The examples in this section assume that market participants share risk only through a single, centrally defined contract and investigates the question of what contractual form to choose. A targeted approach to defining a single product would be to identify the dimension along which incompleteness is the most salient and design an instrument along that dimension, leaving market participants to manage residual risk with supporting contracts. A more holistic approach, as in the SFPFC described in Wolak (2022), is to attempt maximal coverage of risk for consumers. The examples in this section compare the SFPFC with the option contract we use as a proxy for conventional capacity markets. In the SFPFC, the total quantity of covered energy is determined in advance for a delivery period (in our case, one year), but its shape is determined ex post to match consumer demand. Compared with call options, this approach provides a stronger hedge for retailers, covering a much larger portion of the expected cost to serve load.

Whereas the "unrestricted" case in the previous section featured three contracts adapted to the three technologies in the system, the shape of the SFPFC is not well matched to the production of any of the three technologies. As a consequence, sellers have an incentive to construct portfolios containing a mix of the three technologies. To illustrate this incentive, we model two cases where generators can sell either separately or collectively. When selling SFPFC separately, each technology is left with shape risk given that none follows load precisely. By selling SFPFC collectively, the generation technologies are better positioned to deliver contracted quantities. In the numerical experiment, we treat the generation company as a single agent who owns all technologies and trades with retailers, modifying the solution approach to enable adjustments in the capacity mix held by this representative agent.

Table 3 shows the equilibria resulting with the SFPFC sold separately and collectively, as well as a case where only options are traded. As should be expected, a single contract cannot match the performance of the three-contract "unrestricted" configuration shown in the previous section. However, the SFPFC clearly outperforms the option contract, especially when sold collectively, achieving social surplus that is much closer to the unrestricted trading case. This superior performance manifests primarily in lower prices; unserved energy is comparable between the options and collective SFPFC cases. The SFPFC has a particularly strong effect on interannual price volatility for consumers, bringing it below even the level of the three-contract case.

Three aspects of the results in Table 3 warrant further discussion. First, while the structure of the models constructed throughout this paper give rise to the possibility of multiple equilibria (Abada et al., 2017; Gérard et al., 2018), we were able to identify multiple equilibria only in the case of SFPFCs sold collectively. Alternate equilibria have comparable surplus to those shown in Table 3 and are discussed in Appendix B. Second, while the results show a large benefit when we allow SFPFCs to be sold collectively, no comparable benefit occurs when options can be sold collectively; results under this configuration

Table 2
Contract volumes and risk premia in three-contract cases. Generators primarily trade the contracts adapted to their risk profile. When options are mandated, baseload resources are able to fully hedge its production but variable resources are not. Risk premia for the options contract grow due to the purchasing obligation.

	$\beta = 0.2$		$\beta = 0.4$	
	Unrestricted	Mandatory	Unrestricted	Mandatory
Trade volume (GW)				
Baseload				
Futures	27.9	52.5	28.8	45.7
Options	2.5	52.5	2.6	45.7
Unit contingent	0	0	0	0
Peaker				
Futures	0	0	0	0
Options	120.0	80.0	119.4	84.3
Unit contingent	0	0	0	0
Variable				
Futures	0	0	0	0
Options	0	16.0	0	18.5
Unit contingent	159.0	106.8	157.3	122.7
Contract risk premium ($/MW-yr)				
Futures	16,470	5638	16,113	5839
Options	6747	17,366	6738	14,597
Unit contingent	3455	693	3315	773
	$\beta = 0.6$		$\beta = 0.8$	
	Unrestricted	Mandatory	Unrestricted	Mandatory
Trade volume (GW)				
Baseload				
Futures	30.0	41.6	31.2	33.7
Options	3.4	41.6	4.1	32.8
Unit contingent	0	0	0	0
Peaker				
Futures	0	0.08	0	0.3
Options	119.5	86.9	121.4	93.4
Unit contingent	0	0	0	0
Variable				
Futures	0	0	0	59.6
Options	0	20.1	0	22.4
Unit contingent	155.4	131.6	154.8	0.0002
Contract risk premium ($/MW-yr)				
Futures	16,033	6646	13,481	5524
Options	6261	10,108	3961	10,870
Unit contingent	3451	1171	3185	1125

are shown in Appendix C. Third, unserved energy is higher in the configuration with SFPFCs sold collectively than in the three-contract case. In Appendix D we show results with a mandatory requirement on purchase of SFPFCs, enabling the system to achieve equivalent reliability with moderate loss of surplus.

Contract volumes and risk premia are shown in Table 4. As in Table 2, risk premia tend to fall as the generators become less risk averse. Risk premia for the SFPFC are lower when sold separately, partially offsetting the effect of the higher underlying spot prices seen in this configuration. Trade volumes when selling SFPFC collectively are always smaller than when selling separately, indicating less hedging pressure when the technologies are combined in a portfolio. Whether sold separately or collectively, risk premia fall and trade volumes grow as the generators become less risk averse.

5. Discussion

The numerical results highlight that the definition of reliability obligations can affect resource mix, market structure, cost, and reliability outcomes in liberalized electricity markets. In the first set of experiments, imposing a capacity obligation crowds out other forward contracting and leads to worse outcomes for consumers. In the second, introducing a shaped forward contract instead of an option facilitates greater risk sharing and better outcomes for consumers. Taken together, the experiments demonstrate how the success of interventions facilitating or mandating risk sharing depends not just on the intervention itself but also on complementary mechanisms. Focusing on two policy recommendations, here we discuss the implications that these experiments have for debates about resource adequacy and consider aspects of the modeling that warrant further investigation.

The first recommendation concerns the incorporation of resources contracted through other means in mandatory capacity markets. In many jurisdictions, policymakers have introduced processes to award long-term contracts to renewables and storage. Beyond these state-initiated contracts, new resources are often able to contract directly with consumers of electricity (e.g., large firms with clean procurement goals). Such resources could be handled in either of two ways. First, the system operator could reduce the administratively defined demand for capacity, reflecting the lower probability of scarcity situations due to the presence of the resource. Second, the system operator could compel the resource to participate in the capacity construct. In risk-neutral terms the approaches should be equivalent, but when risk aversion is considered the first approach can be seen as preferable. For example, consider the results shown in Tables 1 and 2 and suppose that the regulator altered the mandatory requirement on options contracts by subtracting the reliability contribution of the baseload and variable resources. For $\beta = 0.2$, the purchase requirement of options in the mandatory case is set at 148.5 GW. In the mix resulting from unrestricted trading, we can calculate total reliability contributions (i.e., installed capacity times the reliability credit) of $(31.1\text{ GW}) \cdot 0.9 = 28.0\text{ GW}$ from the baseload resource and $(159.0\text{ GW}) \cdot 0.16 = 25.4\text{ GW}$ from the variable resource. The peaking resource, with a total reliability contribution of $(107.4\text{ GW})\cdot 0.9 = 96.7\text{ GW}$, would then be able to satisfy the adjusted mandatory requirement of $148.5\text{ GW}-28.0\text{ GW}-25.4\text{ GW} =$

Table 3
Comparison of options against load-shaped forward contracts. Change in surplus is calculate against the three-contract unrestricted case. SFPFC performs better than options when trading is limited to single instrument, particularly when sold collectively by a portfolio of technologies.

	$\beta = 0.2$			$\beta = 0.4$		
	Options	Sep	Col	Options	Sep	Col
Capacity (GW)						
Baseload	0.006	89.0	40.7	0.02	84.1	34.6
Peaker	137.3	72.5	99.9	135.2	75.0	104.4
Variable	163.4	26.0	143.2	176.2	36.9	153.6
Average price ($/MWh)						
Spot	62.22	61.69	57.49	61.31	61.30	57.39
Hedged	62.86	63.01	59.59	61.94	62.32	59.43
Interannual volatility ($/MWh)						
Spot	25.86	22.33	24.89	25.42	23.41	24.43
Hedged	13.79	1.02	1.75	13.63	1.17	1.69
Expected unserved energy (GWh)	5.54	4.05	5.83	5.53	4.58	5.52
Proximity to equilibrium	0.066%	0.058%	0.016%	0.029%	0.090%	0.004%
Change in surplus ($M/yr)	−5042	−3500	−517	−4206	−2906	−375
	$\beta = 0.6$			$\beta = 0.8$		
	Option	Sep	Col	Option	Sep	Col
Capacity (GW)						
Baseload	0.2	75.6	33.6	12.4	52.9	31.4
Peaker	133.6	79.6	105.4	122.6	92.8	107.0
Variable	185.0	57.1	154.3	177.3	109.8	157.7
Average price ($/MWh)						
Spot	60.41	61.00	57.44	59.40	60.23	57.59
Hedged	61.03	61.44	59.26	59.98	60.36	59.06
Interannual volatility ($/MWh)						
Spot	25.18	24.38	24.20	24.63	26.85	24.34
Hedged	13.61	1.28	1.38	13.45	1.36	1.14
Expected unserved energy (GWh)	5.52	5.35	5.35	5.53	6.83	5.39
Proximity to equilibrium	0.048%	0.071%	0.008%	0.073%	0.070%	0.012%
Change in surplus ($M/yr)	−3411	−2183	−212	−2448	−1243	−41

Table 4
Contact volumes and risk premia in one-contract cases. When technologies are allowed to sell SFPFC collectively, hedging pressure is lower and trade volumes decrease. Risk premia for the SFPFC are lower when sold separately, partially offsetting the effect of higher underlying spot prices.

		$\beta = 0.2$	$\beta = 0.4$	$\beta = 0.6$	$\beta = 0.8$
Options	Trade volume (GW)				
	Baseload	0.0	0.0	0.2	12.5
	Peaker	153.0	150.7	149.0	137.0
	Variable	7.4	8.2	10.1	8.2
	Contract risk premium ($/MW-yr)	2671	2643	2650	2473
Sep	Trade volume (GW)				
	Baseload	60.7	56.1	49.3	35.0
	Peaker	34.3	37.1	40.5	48.4
	Variable	5.0	7.2	10.6	16.6
	Contract risk premium ($/MW-yr)	9057	6564	1782	−582
Col	Trade volume (GW)	91.6	91.9	93.6	95.8
	Contract risk premium ($/MW-yr)	19,039	18,335	15,866	12,256

95.1 GW. In other words, the equilibrium from the unrestricted case would also be an equilibrium for this adjusted mandatory case.

This recommendation raises two issues. First, a change in approach would require changes in contractual terms: instead of receiving a payment for their capacity contribution directly, generators would need to monetize the decreased capacity obligation of offtakers, who may be seen as riskier counterparties than the system operator. Second, while we focus on contracted resources, merchant resources may be similarly reluctant to enter contracts that expose them to non-performance risk. In principle, mandatory contracting quantities for loads could also be reduced to account for lower outage probabilities with additional merchant generation on the system. However, such a reduction may be more difficult to implement than for contracted generators, since it is not clear which load's obligation would be reduced. More fundamentally, while allowing participants to opt out of contracting is efficient in theory, it operates against the premise of mandatory contracting obligations. Thus, for consumer protection and market power mitigation reasons, regulators might prefer to either compel the participation of merchant generators in the capacity market or ignore their potential contributions to reliability.

Rather than working around current capacity obligations, the second recommendation contemplates replacing them. Evaluated on their own, the modeling results suggest that SFPFCs promotes greater efficiency than current capacity obligations. However, several caveats apply. First, we note that the SFPFC as implemented in our model assumes the presence of full-strength spot prices and omits network constraints. As a result, we avoid two issues that have plagued real-world capacity markets, i.e., determination of non-performance penalties and resolving deliverability issues. Without ensuring full-strength spot prices, neither of these issues is resolved by a switch to the SFPFC. Second, as with the first recommendation, adopting this approach would create the need for changes in contractual arrangements that currently exist between generators and retailers. Since the SFPFC would hedge almost all consumption for retailers, a more natural counterparty for individual generators would instead be aggregators selling SFPFCs.

While our modeled approaches are not exhaustive, the implications for vertical and horizontal integration likely translate to other contractual forms. Many variants of the contracts studied are possible. For example, while our tests assume a year-long delivery period, many systems use or are contemplating monthly or seasonal resource adequacy products. A shorter delivery period can enable a better match between resource capabilities and commitments (due, e.g., to higher solar production in summer, more hydro availability in wet seasons, or different thermal ratings based on maintenance schedules or temperature-dependent failure rates). On the other hand, in the SFPFC, a longer delivery period may be advantageous since the quantity covered must be established by an administrative process. With a longer period, relative error between this estimated consumption and actual total consumption over the contract would likely be smaller. Beyond those included in the tests, systems may choose to pursue other contractual forms altogether (e.g., a shaped option) or combine multiple forms. Generically, we suggest that potential contracts can be assessed on two dimensions: (1) how strong a hedge they provide for loads and (2) how well matched their shape is to particular generators. Stronger hedges weaken the motivation for vertical integration between generators and loads, while less well-matched shapes can induce horizontal integration or hybridization among generators. As a result, while contracts can alleviate issues with market power in the spot markets (Wolak, 2000), they can create different challenges for monitoring and mitigation in the forward contracting. Several strategies may be deployed to promote competitive outcomes, e.g., (1) putting in place disclosure and reporting requirements to improve transparency, (2) implementing a centralized auction rather than bilateral trading for the resource adequacy product, or (3) placing a cap on the capacity that can be owned by an individual market participant. With regards to mismatched shapes, PJM has implemented an option for Aggregate Resources to participate in the capacity market. However, the primary intent of this current participation model is to give credit to an individual market participant when they submit a portfolio that can qualify as a larger capacity resource than the sum of the parts, rather than to facilitate financial hedging across different market participants. Since the results in this paper assume perfect competition, modeling the joint impacts of contract mandates, risk aversion, and market power represents a promising direction for further research.

Beyond the recommendations, the results reflect a more fundamental challenge for resource adequacy in liberalized markets. The observation common to both sets of experiments is that generators will be reluctant to take on obligations that they are not able to defend physically. Since all of our examples use a single representative agent for each technology, non-performance risk is inherently pooled across the fleet. In reality, each individual unit would sell its own obligation, leading to greater risk for individual sellers of any resource adequacy product. Throughout the examples we retained full-strength scarcity prices and excluded the possibility of bankruptcy, ensuring efficient penalties for non-performance on contracts. However, the examples point to the challenges these full-strength prices or penalties present: greater pressure for consolidation among generators and a need for stronger credit requirements or an insurance mechanism (cf. Billimoria and Poudineh (2019)) to prevent the use of bankruptcy as a hedge. In this way, the relatively weak performance incentives attached to current capacity markets can be interpreted as a way to preempt problems with market power and creditworthiness. At the same time, weak prices and penalties imply inefficient direct incentives for operations and investment. These insufficient financial incentives in turn imply a need for active oversight of the physical system (e.g., through the capacity accreditation process) to ensure performance. In other words, a purely financial mechanism for mandatory contracting between generators and loads will not by itself resolve challenges with resource adequacy even if the political will to sustain full-strength scarcity prices is assumed.

Along these lines, the results point to the question of how to find an appropriate balance between financial incentives and direct oversight when trying to ensure reliability in competitive markets, and the related question of how this balance should evolve with a shift to carbon-free resources. By avoiding full-strength prices or penalties, market operators effectively pool some non-performance risk, easing bankruptcy pressures and reducing demands on contracting. Non-performance risk for wind and solar may be more straightforward to quantify than for traditional thermal resources, since their key failure mode (i.e., the weather) is easily observable by system planners and regulators. Moreover, since variable renewables can do little to control the sun or wind underlying their performance, systems reliant on these resources may have greater latitude for pooling risk on behalf of generators without altering their performance. However, in doing so they may retain an inherent anti-competitive bias against resources for which physical contributions are less easily audited. Aggregations of distributed energy resources, for example, could find it difficult to validate their contribution physically several years in advance of delivery, given that the precise resources composing the aggregation may not have been identified at that point. Such a concern is not merely theoretical, as seen in PJM's efforts to block the participation of the SOO Green HVDC Link in its capacity market (Monitoring Analytics, LLC, 2021). Since the line does not specify the generation resources behind the power it will deliver from the neighboring MISO region, PJM and its market monitor argue that they cannot count on performance from the new competitor at the level expected from incumbents. The unstated admission underneath this argument is that the financial performance incentives for SOO Green would be inadequate under current market rules. Given the disadvantages of interfering with full-strength prices, finding more effective ways to facilitate risk sharing is likely to remain a central question in market design for resource adequacy.

CRediT authorship contribution statement

Han Shu: Conceptualization, Methodology, Software, Investigation, Writing – original draft, Writing – review & editing. **Jacob Mays:** Conceptualization, Data curation, Methodology, Writing – original draft, Writing – review & editing, Supervision.

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Appendix A. Complete trading

For comparison, we also construct a complete trading model, where the risk of market participants can be fully traded with no transaction cost. The complete trading equilibrium can be found through a risk-averse optimization using the intersection of risk sets of all agents in

Table A.5
Complete trading results. Change in surplus is calculated against the three-contract unrestricted case at risk aversion level $\beta = 0.6$ and $\beta = 0.8$ respectively.

β	Baseload (GW)	Peaker (GW)	Variable (GW)	Change of surplus ($ M/yr)
$\beta = 0.7$	34.2	105.2	153.7	34
$\beta = 0.8$	31.2	107.2	158.2	144

Table B.6
Multiple equilibria when selling SFPFC collectively. Change in surplus is calculated against the unrestricted case and is roughly consistent across the identified equilibria for each level of risk aversion.

	$\beta = 0.2$			$\beta = 0.4$		
	Initial 1	Initial 2	Initial 3	Initial 1	Initial 2	Initial 3
Capacity (GW)						
Baseload	40.7	51.9	78.7	34.6	44.4	49.8
Peaker	99.9	92.8	77.2	104.4	97.7	94.3
Variable	143.2	119.4	56.4	153.6	135.1	123.7
Trade volume (GW)	91.6	92.3	93.6	91.9	92.3	92.3
Contract risk premium ($/MW-yr)	19,039	18,726	17,029	18,335	18,176	18,550
Average price ($/MWh)						
Spot	57.49	57.53	57.84	57.39	57.40	57.38
Hedged	59.59	59.61	59.84	59.43	59.43	59.44
Interannual volatility ($/MWh)						
Spot	24.89	24.44	22.43	24.43	24.46	24.22
Hedged	1.75	1.62	1.25	1.69	1.60	1.61
Expected unserved energy (GWh)	5.83	5.45	4.20	5.52	5.51	5.32
Proximity to equilibrium	0.016%	0.017%	0.003%	0.004%	0.017%	0.012%
Change in surplus ($M/yr)	−517	−513	−694	−375	−367	−375
	$\beta = 0.6$			$\beta = 0.8$		
	Initial 1	Initial 2	Initial 3	Initial 1	Initial 2	Initial 3
Capacity (GW)						
Baseload	33.6	37.2	54.9	31.4	31.5	45.0
Peaker	105.4	102.8	91.3	107.0	106.9	97.7
Variable	154.3	147.5	111.2	157.7	157.4	131.8
Trade volume (GW)	93.6	93.6	94.2	95.8	95.7	96.2
Contract risk premium ($/MW-yr)	15,866	15,513	14,800	12,256	12,231	11 742.2
Average price ($/MWh)						
Spot	57.44	57.48	57.61	57.59	57.59	57.68
Hedged	59.26	59.25	59.33	59.06	59.06	59.10
Interannual volatility ($/MWh)						
Spot	24.20	24.17	24.11	24.34	24.34	24.39
Hedged	1.38	1.39	1.25	1.14	1.14	1.10
Unserved energy (GWh)	5.35	5.36	5.21	5.39	5.39	5.38
Proximity to equilibrium	0.008%	0.017%	0.001%	0.012%	0.017%	0.017%
Change in surplus ($M/yr)	−212	−210	−267	−41	−41	−71

Table C.7
Comparison of options when selling separately and collectively. Change is surplus is calculated against the three-contract unrestricted case at the same level of risk aversion.

	$\beta = 0.2$		$\beta = 0.4$	
	Sep	Col	Sep	Col
Capacity (GW)				
Baseload	0.006	9.7	0.02	3.1
Peaker	137.3	130.0	135.2	133.0
Variable	163.4	149.3	176.2	171.0
Trade volume (GW)	160.4	158.5	158.9	158.6
Contract risk premium ($/MW-yr)	2671	2911	2643	2646
Average price ($/MWh)				
Spot	62.22	62.15	61.32	61.27
Hedged	62.86	62.82	61.94	61.90
Interannual volatility ($/MWh)				
Spot	25.86	25.69	25.42	25.28
Hedged	13.79	13.71	13.63	13.62
Expected unserved energy (GWh)	5.54	5.44	5.53	5.46
Proximity to equilibrium	0.066%	0.017%	0.029%	0.009%
Change in surplus ($M/yr)	−5042	−4998	−4206	−4165
	$\beta = 0.6$		$\beta = 0.8$	
	Sep	Col	Sep	Col
Capacity (GW)				
Baseload	0.2	3.2	12.4	13.8
Peaker	133.6	131.3	122.6	121.7
Variable	185.0	180.4	177.3	174.9
Trade volume (GW)	159.3	159.2	157.7	156.5
Contract risk premium ($/MW-yr)	2650	2641	2473	2873
Average price ($/MWh)				
Spot	60.41	60.36	59.40	59.31
Hedged	61.03	60.99	59.98	59.96
Interannual volatility ($/MWh)				
Spot	25.18	25.11	24.63	24.47
Hedged	13.61	13.59	13.45	13.44
Expected unserved energy (GWh)	5.52	5.47	5.53	5.44
Proximity to equilibrium	0.048%	0.011%	0.073%	0.017%
Change in surplus ($M/yr)	−3411	−3367	−2448	−2431

the model. Using the optimal objective H_{frs} from model (ED), the complete trading model can be formulated as:

(SOC) $\rho_i =$

$$\underset{x,y,d,H,u^i,u^{i+},\mathrm{VaR}_i}{\text{maximize}} \left(1-\beta_i\right)\left(\mathrm{VaR}_i - 1/\alpha_i \sum_{f\in\mathcal{F}}\sum_{r\in\mathcal{R}}\sum_{s\in\mathcal{S}} p_{frs} u^{i+}_{frs}\right) + \beta_i \sum_{f\in\mathcal{F}}\sum_{r\in\mathcal{R}}\sum_{s\in\mathcal{S}} p_{frs} u^{i}_{frs} \tag{A.1a}$$

subject to

$$u^i_{frs} = -\sum_{g\in\mathcal{G}} C^{\mathrm{INV}}_g x_g + H_{frs} \qquad \forall f\in\mathcal{F}, r\in\mathcal{R}, s\in\mathcal{S} \tag{A.1b}$$

$$\mathrm{VaR}_i - u^i_{frs} \le u^{i+}_{frs} \qquad \forall f\in\mathcal{F}, r\in\mathcal{R}, s\in\mathcal{S} \tag{A.1c}$$

$$0 \le u^{i+}_{frs} \qquad \forall f\in\mathcal{F}, r\in\mathcal{R}, s\in\mathcal{S}. \tag{A.1d}$$

The objective function (A.1a) is maximizing the risk-adjusted net social surplus. Constraint (A.1b) states that the net social surplus of a scenario is equal to the total social surplus in operations minus the investment

Table D.8
Effect of mandatory purchase of SFPFC. Change in surplus is compared with the three-contract case.

	$\beta = 0.2$		$\beta = 0.4$	
	Unrestricted	Mandatory	Unrestricted	Mandatory
Capacity (GW)				
Baseload	40.7	48.2	34.6	33.7
Peaker	99.9	96.2	104.4	105.8
Variable	143.2	129.6	153.6	156.9
Trade volume (GW)	91.6	100.0	91.9	100.0
Contract risk premium ($/MW-yr)	19 039.4	51 195.6	15 866.1	42 685.4
Average price ($/MWh)				
Spot	57.49	54.22	57.39	54.91
Hedged	59.59	60.06	59.43	59.81
Interannual volatility ($/MWh)				
Spot	24.89	20.48	24.43	21.26
Hedged	1.75	1.11	1.69	1.18
Expected unserved energy (GWh)	5.83	3.20	5.52	3.69
Proximity to equilibrium	0.016%	0.009%	0.004%	0.017%
Change in surplus ($ M/yr)	−517	−710	−375	−540
	$\beta = 0.6$		$\beta = 0.8$	
	Unrestricted	Mandatory	Unrestricted	Mandatory
Capacity (GW)				
Baseload	33.6	34.4	31.4	31.6
Peaker	105.4	105.2	107.0	107.0
Variable	154.3	154.3	157.7	157.2
Trade volume (GW)	93.6	100.0	95.8	100.0
Contract risk premium ($/MW-yr)	15 866.1	29 820.2	12 256.2	15 734.8
Average price ($/MWh)				
Spot	57.44	56.01	57.59	57.23
Hedged	59.26	59.49	59.06	59.15
Interannual volatility ($/MWh)				
Spot	24.20	22.38	24.34	23.79
Hedged	1.38	1.22	1.14	1.27
Expected unserved energy (GWh)	5.35	4.30	5.39	5.06
Proximity to equilibrium	0.008%	0.009%	0.012%	0.024%
Change in surplus ($ M/yr)	−212	−302	−41	−70

cost of generators. Constraint (A.1c) and (A.1d) dictate the auxiliary variables u^{i+}_{frs} used in calculating CVaR.

The risk parameters for the social optimization are determined by the intersection of the risk sets across all market participants. Since α is the same for all agents in our examples, the intersection is determined by the highest value of β in the example; i.e., $\beta_i = \max \beta_a$. Thus, when $\beta = 0.2, 0.4$, or 0.6 for generators, the retailer is less risk averse than the generators and we use the parameter $\beta = 0.7$; when $\beta = 0.8$ for the generators, they are less risk averse and we use the parameter $\beta = 0.8$. The results of complete trading is shown in Table A.5.

Appendix B. Multiple equilibria when selling SFPFC collectively

We identified multiple equilibria when selling SFPFC collectively, with the equilibria identified by the algorithm depending on the starting point used. Change in surplus relative to the unrestricted case is consistent across the identified equilibria, leading to the same economic interpretation regardless of which is chosen. Nevertheless, characterizing these multiple equilibria represents an important topic for further research. The results presented in Table 3 for selling SFPFC collectively are obtained using initial capacities equal to the unrestricted case at the same level of risk aversion. We repeat these results in Table B.6 as "Initial 1". Other equilibria reported as "Initial 2" and "Initial 3" are obtained by setting starting points equal to the equilibrium capacities in the mandatory case and selling SFPFC separately case.

Appendix C. Options only

To compare the benefits when options can be sold collectively, we list the results in Table C.7. Trading volumes when selling options collectively are always smaller than when selling options separately, but the gap is very small when $\beta = 0.4$ and $\beta = 0.6$. Allowing options to be sold collectively brings slight benefits in terms of surplus, expected unserved energy, average price and interannual volatility, but the benefits are not comparable with allowing selling SFPFC collectively.

Appendix D. Unrestricted and mandatory SFPFC

Besides allowing selling SFPFC collectively, here we also impose a mandatory requirement on purchase of SFPFCs, pushing the system to achieve higher reliability with moderate loss of surplus. The results are shown in Table D.8. With a mandatory requirement, unserved energy is lower than both the three-contract case and the unrestricted SFPFC case but with lower surplus. As generators become less risk averse, the capacity mix becomes very close.

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