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# Game-based investigation of standardized forward contracting for long-term resource adequacy

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#### ABSTRACT

High and growing shares of wind and solar generation can lead to economic retirements of controllable capacity, which creates the need for long-term resource adequacy mechanisms that compensate units needed to maintain system reliability. We use game-based simulation to compare two approaches for ensuring long-term resource adequacy: capacity markets and forward contracting. We also conduct "policy prototyping" of a specific implementation of forward contracting, Standardized Fixed-Price Forward Contracts (SFPFCs). SFPFCs are standardized forward energy products sold through a centralized procurement process in which 100% of expected demand is auctioned off several years ahead of energy delivery. SFPFCs retroactively adjust contract quantities in each covered hour according to that hour's share of total demand in the compliance period. This encourages generating companies to manage the risk of higher-than-expected demand in any given hour. Our game runs suggest that forward contracting can yield significantly lower cost to load than capacity markets because it removes the incentive for gencos to exercise unilateral market power in the short-term energy market. The SFPFC implementation in our games effectively maintained system reliability and delivered moderate costs to consumers while maintaining financial viability for gencos. It did this even in scenarios with high carbon prices and high renewable shares incentivized by a Renewable Portfolio Standard (RPS) with tradable Renewable Energy Certificates (RECs).

#### 1. Introduction

High and growing shares of wind and solar generation may adversely affect the economics of the controllable generating units that are needed for backup when wind and solar output are low. If the costs of maintaining and operating a generating unit outweigh its energy market revenue from generating electricity for a reduced number of hours each year, it may be retired by its owner. Economic retirements of dispatchable power plants in a market with a high share of renewable energy can adversely affect system reliability. For example, the combined retirement of 2254 MW of nuclear capacity and 8529 MW of gas-fired capacity in California between 2013 and 2019 was one of the factors that contributed to energy shortfalls in Northern California during the August 2020 heat wave (Wolak, 2022).

Long-term resource adequacy mechanisms are intended to ensure that sufficient dispatchable capacity remains available to meet system demand peaks. One such resource adequacy mechanism is the capacity market system used by the California Independent System Operator (CAISO) and other ISOs. This type of mechanism compensates generation unit owners for the "firm capacity" they commit to having available at a future point in time. However, the capacity market approach can break down as the share of intermittent renewable energy grows. Reliability failures in California are increasingly associated with high net demand events, where the difference between system demand and intermittent renewable energy supply is large, rather than a lack of absolute capacity. The firm capacity of a wind or solar unit is not a welldefined quantity, and the events of August 2020 illustrate how periods of low wind and solar output can yield an unserved net demand.

An alternative approach to resource adequacy is forward contracting for energy. When generating companies have already sold a significant quantity of energy in fixed-price forward contracts, they have a powerful financial incentive to physically hedge their quantity risk by ensuring they have generation available to supply that energy. They also have an incentive to offer their generation into the wholesale market at marginal cost up to the contracted quantity. Otherwise, they risk having to pay high prices to buy any shortfall relative to their contracted quantity on

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the spot market. Requiring load-serving entities to procure most or all of their expected demand several years ahead via fixed-price forward contracts thereby creates an incentive for the counterparties to these contracts (most likely, generating companies) to ensure that adequate supply is available—and available at moderate prices. One of the critical mistakes of California's electricity restructuring in the late 1990s was the failure to bundle forward contracts ("vesting contracts") with generating assets when these assets were sold off. This led to a situation where generating companies could benefit by exercising unilateral market power when there was low hydropower availability and less energy available from the rest of the Western Interconnection in 2000 and 2001 (Wolak, 2003).

Wolak (2022) proposed a new long-term resource adequacy mechanism involving a standardized forward contract product—Standardized Fixed-Price Forward Contracts (SFPFCs)—that would be auctioned off several years in advance of when the energy is needed. SFPFCs have three important features:

First, SFPFCs are a standardized product. Generating companies ("gencos") that sell SFPFCs are committing to a well-defined contract that operates in a known and transparent way. The use of standardized forward contract products is crucial to the success of regulatory mandates that load-serving entities hedge a certain portion of their customer demand. Otherwise, regulators are put in the difficult position of having to determine whether any particular contract is likely to provide a dependable hedge for consumers.

Second, SFPFCs are sold through a centralized procurement process. SFPFCs covering a substantial share (ideally, 100% or higher) of expected demand are auctioned off several years ahead, on a rolling basis. This avoids a characteristic problem of ad hoc, bilateral forward contracting, which is that early contract buyers face a "first mover disadvantage" in negotiating the contract price. When few contracts have yet been signed, gencos will demand high contract prices in exchange for giving up the opportunity to exercise unilateral market power in the short-term energy market. This is even more true if it is clear that energy supply will be tight relative to demand in a coming period. As more forward contracts are signed, however, those gencos without contracts face lower expected spot prices, because the gencos with contracts are incentivized to bid marginal cost up to their contracted quantities. This encourages uncontracted gencos to accept lower contract prices to ensure they can still sell significant quantities of energy. The first mover disadvantage for buyers is eliminated by a standardized procurement process covering most or all demand that takes place several years ahead of energy delivery. The expectation of full contract coverage of demand coupled with the threat of market entry means gencos are bidding to sell forward contracts under the assumption that there will be very limited opportunity to push up future spot prices through the exercise of unilateral market power.

Third, SFPFCs retroactively adjust hour-by-hour contract quantities to cover the *realized* load shape over the compliance period. This incentivizes gencos to proactively manage the risk that demand in any given hour may be higher than expected. By contrast, if a genco's contracted quantity in a given hour is precisely known, that genco may have an incentive in tight periods to bid a "hockey stick" offer curve, with marginal cost bids up to the contracted quantity and much higher bids once the contracted quantity is covered. Load-shape-adjusting contracts, such as SFPFCs, discourage this behavior by exposing gencos to the risk that their contract quantity in a particular hour might end up higher than expected, and efforts to exercise unilateral market power would thus prove very costly to them.

The operation of forward contracts in general—and SFPFC contracts in particular—is rarely intuitive at first to those unfamiliar with them. Since 2013, we have developed and used a web-based simulation game to allow students, regulators, and stakeholders to experience the operation of energy market mechanisms including forward contracts, carbon allowances, renewable energy certificates, and many others (Thurber and Wolak, 2013; Thurber et al., 2015). In this paper, we use the results of several such simulation exercises—conducted as part of workshops in 2018 with regulators and their staff in Boise, Idaho and Brasília, Brazil as well as a 2021 course at the Stanford Graduate School of Business<sup>1</sup>—to illustrate how forward contracts are superior to capacity payments for long-term resource adequacy and to illuminate the detailed functioning of the SFPFC mechanism. Our results demonstrate the value of game-based simulation for education and policy prototyping. For example, our experience with the 2021 classroom simulation caused us to revise our SFPFC proposal to remove one policy element—the "true-up auction"—that had some theoretical appeal but proved confusing to game participants and could easily be replaced by larger initial SFPFC purchases by retailers.

## 2. Capacity payments vs. forward contracting for resource adequacy

Resource adequacy problems may occur when high shares of wind and solar cause revenues from short-term energy markets to be insufficient to cover the costs of dispatchable energy resources needed to back up intermittent renewable resources. Unless they are provided with additional compensation, these dispatchable resources may be retired on economic grounds, putting system reliability at risk. Capacity payments and forward contracts are two different ways to compensate generators in an effort to ensure resource adequacy.

The idea behind capacity payments is conceptually simple: you pay generating capacity to be available to run, whether it actually runs or not. The additional revenue from capacity payments is intended to ensure that enough capacity remains financially viable that the market can avoid shortfalls in supply relative to demand.

Forward contracting approaches to resource adequacy do not mandate specific capacity requirements (although they can be combined with such mandates); instead, they ensure that most or all of consumer demand has already been purchased ahead of time via fixed-price forward contracts. The forward contracts themselves are strictly financial, with the sellers of the contracts (in this case, generators) paid difference payments of  $Q_{contract} * (P_{contract} - P_{spot})$  by the buyers of the contracts (in this case, retailers). If the spot price  $P_{spot}$  is less than the contract price  $P_{contract}$ , the generator receives a positive difference payment from the retailer for the contracted quantity Qcontract. If Pspot is greater than Pcontract, the difference payment goes the other way, from genco to retailer. As we explore further in Section 3, this simple financial contract establishes a powerful, self-enforcing incentive for the generator who has sold the contract to have sufficient capacity available-and offered in at marginal cost-to cover the contracted quantity. If the genco fails to do this, withholding capacity and/or submitting high offer prices, it risks pushing up the spot price of electricity and reducing its own generated quantity. If this generated quantity ends up being less than Q<sub>contract</sub>, the genco effectively has to buy out the shortfall at high prices in the spot market. (Equivalently, the genco's high bids increase the difference payment it must pay without a matching increase in its generation revenues from the spot market.) When generators have sold forward contracts, they are effectively buyers of energy up to the contracted quantity, which removes their financial incentive to create high spot prices through capacity shortfalls and/or high bids.

During separate workshops in Boise and Brasília, we used gamebased simulations to compare policy regimes in which we compensated generators through capacity payments and forward contracts, respectively. (We first allowed workshop participants, playing gencos, to demonstrate the resource adequacy problem by giving them the option to make economic retirements of dispatchable units in a high-

<sup>&</sup>lt;sup>1</sup> One of the authors (Passow) participated in this course (GSBGEN 336, "Energy Markets and Policy") as a student, one (Davis) developed all the software for the energy market game, and two (Thurber and Wolak) designed and administered the simulation as course instructors.

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renewables market; as expected, players made retirements that improved genco finances but significantly increased prices for consumers and threatened system reliability.)

Workshop participants were grouped into teams of three or four people each. Each team played the role of a genco in an electricity market with three other gencos and enough wind and solar output to meet about 50% of total demand. In addition to the wind and solar units they were required to hold, each genco built a dispatchable generating portfolio consisting of stylized Base, Intermediate, and Peak units—each with characteristic fixed and variable costs. Each genco then offered energy into the short-term energy market over two stylized days, where each day consisted of four hours with varying levels of demand (approximately 8,000 MWh at 4 am, 20,000 MWh at 10 am, 40,000 MWh at 4 pm, and 28,000 MWh at 10 pm). Demand was relatively inelastic, with a slope of -5 MWh/\$. Wind and solar output were random variables with expected value that varied by hour, with solar generating only at 10 am and 4 pm and wind expected to generate twice as much energy at 4 am and 10 pm as at 10 am and 4 pm.<sup>2</sup>

In the capacity markets scenario, we implemented a capacity auction in which the four gencos in each game placed bids for total capacity equal to 110% of expected demand in the 4 pm hour. (Renewable units were assigned a capacity value equal to their expected output in the 4 pm hour.) The auction was uniform-price, with all winning bidders receiving the market-clearing capacity payment for whatever amount of capacity they won. The floor price of the capacity payment in the auction was \$2/MW per hour (two-thirds of the fixed cost of a Peak unit). All gencos were required to hold capacity equal to or greater than whatever amount of capacity they won at auction. If they didn't have enough capacity at the outset to meet their capacity obligation, they were required to buy more units.

In the forward contracting scenario, we auctioned off forward contracts at the start of the game. The total forward contract quantity was equal to 100% of the expected demand over the two market days of the game, or 192,000 MWh. Each forward contract was pre-assigned a load shape over the eight hours of the two days that exactly mirrored the expected demand variation over those eight hours. Specifically, each forward contract for 1 MWh translated into contract quantities of 0.042 MWh in each of the 4 am hours of both days, 0.104 MWh in each of the 10 am hours, 0.208 MWh in each of the 4 pm hours, and 0.146 MWh in each of the 10 pm hours. Gencos could decide what prices were reasonable to bid for the forward contracts by considering the Levelized Cost of Energy (LCOE) of each generator in their mix of units (including the solar and wind units they were obligated to hold) and thus what contract price would yield revenue for them that was sufficiently above their costs. As in the capacity payment case, the auction was uniformprice, with all gencos that won forward contracts receiving them at the market-clearing price. Unlike in the capacity payment case, there was no constraint on how much capacity each genco was required to hold. However, workshop participants had seen in their initial training that they could incur significant losses if they turned out not to have enough physical capacity to hedge their forward contracts. This encouraged the gencos to plan for the possibility that renewables might fall short of their expected output. Perhaps in part for this reason, the average dispatchable capacity held by gencos in the forward contracting games was about 10% higher than the average dispatchable capacity held by gencos in the capacity market games.

The different incentives created by the two different resource adequacy mechanisms led to vastly different market outcomes. Crucially, the capacity market provided no disincentive to the exercise of unilateral market power in the short-term energy market. In multiple instances, gencos that won significant capacity in the capacity auction built large quantities of peakers and used them to bid up the electricity



**Fig. 1.** Market results for Day 2, 4 pm in Boise Game B, Capacity Markets scenario. (Colored rectangles represent offers by the gencos; horizontal black lines are marginal costs; the near-vertical black line is the demand curve; the red dotted line is the market-clearing price.).



**Fig. 2.** Market results for Day 2, 4 pm in Brasília Game A, Forward Contracting scenario. (Colored rectangles represent offers by the gencos; horizontal black lines are marginal costs; the near-vertical black line is the demand curve; the red dotted line is the market-clearing price.).

price, as in the hour shown in Fig. 1. By contrast, the gencos in the forward contracting games were incentivized to bid their units at marginal cost up to their contracted quantities to ensure they didn't have to purchase high-priced electricity in the short-term market to fulfill their forward contract obligations. This more frequently produced lower prices, even in hours where renewable output was low, such as, for example, the hour shown in Fig. 2. As a result of these different incentives, the cost to load was much higher in the capacity market games than the forward contracting games. Cost to load ranged from \$197 to

 $<sup>^2</sup>$  These stylized attributes reflect the fact that wind resources in California are richer on average at night than during the day.



Fig. 3. Illustrative examples of bidding incentives under: a) fixed-quantity forward contracts and expected demand, b) fixed-quantity forward contracts and higherthan-expected demand, and c) forward contracts whose quantity adjusts to cover realized demand.

Total variable profits = -\$149,000

\$242/MWh across the four capacity market games because of the high electricity prices that resulted from the exercise of unilateral market power. In the forward contracting games, on the other hand, breakeven forward contract prices for the gencos ranged between \$73 and \$80/ MWh. (In other words, gencos could profitably have served load in those games at a cost to load anywhere above those breakeven contract prices.)

The simulations in Boise and Brasília illustrated the key advantage of

a resource adequacy policy based on forward contracting: namely, forward contracts incentivize gencos to ensure that the desired commodity-energy-is available when and where it is needed, at a reasonable price. Availability of capacity, by contrast, does not necessarily translate into available and affordable energy. It was common in our capacity market games for one genco to end up with an outsize share of available capacity and then use its pivotal position to exercise unilateral market power in high-demand, low-renewable periods. (The

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high-demand, zero-wind, somewhat-low-solar periods shown in Figs. 1 and 2 could be thought of as representing heat-wave conditions in California.) By contrast, gencos that have already sold forward contracts for energy have no incentive to bid up electricity prices or take power plants offline, as doing so risks leaving them with a shortfall relative to their contracted quantities, which they would have to buy out of the spot market at high prices.

#### 3. Forward contracts that adjust to realized load shape

The Boise and Brasília resource adequacy games illustrate the advantages of fixed-price forward contracts relative to capacity payments. Standardized Fixed-Price Forward Contracts (SFPFCs) incorporate an additional feature relative to the forward contracts used in the Boise and Brasília games. The load shapes covered by these SFPFCs adjust retroactively to match realized load shapes rather than just expected ones. For example, an SFPFC for 1 MWh (what we term "1 SFPFC") might have an expected contract quantity of 0.208 MWh for the 4 pm hour on Day 1, just like the contracts described in Section 2 above. However, the actual contract quantity in that hour can turn out to be more or less, depending on what share of the total energy over the two days is actually consumed during that hour. If, for instance, energy demand for the 4 pm hour on Day 1 actually turns out to be 30% of the total two-day demand instead of 20.8% as expected, then the contract quantity for 1 SFPFC in that hour will be 0.300 MWh instead of 0.208 MWh. This uncertainty in the forward contract quantity gencos are responsible for in any particular hour incentivizes gencos to proactively manage quantity risk. One key way they can do this is by bidding marginal cost even on units beyond their expected forward contract quantity commitments. This helps to safeguard system reliability and ensure affordable costs to consumers even when there are unexpected demand excursions.

An example is helpful to illustrate how fixed forward contract quantities can allow the exercise of unilateral market power when there is unexpectedly high demand, and how retroactive adjustment of contract quantities removes this incentive. In Fig. 3, we consider a simple wholesale market with two gencos that each hold two, 1000-MW generating units, one unit with a marginal cost of \$20/MWh and the other unit with a marginal cost of \$45/MWh. In cases (a) and (b), each genco has sold a fixed-quantity, fixed-price forward contract for the hour in question, with a contract price of \$50/MWh and a contract quantity of 1000 MWh. The advance expectation is that total market demand will be 2000 MWh, so that 100% of expected demand will be covered by the forward contracts held by the two gencos. In all the cases we consider, the light gray genco bids both of its units at marginal cost, while the dark gray genco bids its lower-marginal-cost unit at marginal cost and its higher-marginal-cost unit at this market's offer cap of \$500/MWh.

In case (a), the actual market demand exactly matches the forecast market demand of 2000 MWh. The market clears at a spot price of \$20/ MWh, and both gencos run their lower-marginal-cost unit and do not run their higher-marginal-cost unit. Each genco obtains spot variable profits of \$0, since the spot price is exactly equal to the marginal cost of the units that run. Each genco also receives a difference payment under the contract of  $Q_{contract}$  \* ( $P_{spot} - P_{contract}$ ), or 1000 MWh \* (\$50/MWh - \$20/ MWh), which is \$30,000.

In case (b), actual market demand is 60% higher than forecast. (This is a much higher forecasting error than is generally observed in real markets, but we use it to illustrate the relevant concepts in a simple way.) Both lower-marginal-cost units run; the light gray genco's highermarginal-cost unit runs at full output, and the dark gray genco's highermarginal-cost unit (which it bid at the offer cap) runs at 20% output to meet demand. Both gencos are rational in bidding marginal cost on their first 1000 MW of capacity, as this ensures they have a physical hedge for their 1000-MWh contract. By bidding in this way, they effectively "procure" the 1000 MWh of energy they have sold forward either from their own unit, at a marginal cost of \$20/MWh, or from the spot market if the spot price is lower than that. The dark gray genco recognizes it can make more money by pushing up the spot price it receives for additional energy it generates beyond the 1000 MWh contracted quantity. It bids the offer cap on its last 1000 MW of capacity, pushing the spot price up to the offer cap. This yields it additional spot variable profits of 200 MWh \* (500/MWh - 445/MWh), or \$91,000, on the 200 MWh it ends up generating with the high-marginal-cost unit, for total variable profits of \$121,000.<sup>3</sup> (The light gray genco does even better; because it bid lower, it generates more output at this high spot price.)

While fixed-quantity, fixed-price forward contracts that cover expected market demand are superior to capacity payments, as shown in Section 2, case (b) illustrates the shortcomings of the fixed-quantity approach under conditions of unexpectedly high demand. Namely, if actual demand significantly exceeds the expected demand covered by contracts, wholesale prices could end up being very high—or worse, the market could end up with insufficient generation. Fixed-quantity forward contracts incentivize gencos to ensure they have capacity to cover their quantity obligation and that they bid in this quantity at marginal cost. However, such contracts do not incentivize gencos to manage the risk that demand might exceed their contract quantity obligation. In fact, gencos stand to benefit from such a high-demand case, as shown in case (b).

Case (c) shows how this situation can be addressed using forward contracts that retroactively adjust their quantities to cover realized demand. In this case, the contract quantities of both gencos are retroactively adjusted upward to 1600 MWh so that the total market demand of 3200 MWh is fully covered. Now the dark gray genco is penalized for the fact that it bid the offer cap on its higher-marginal-cost unit. Due to its high bid, the dark gray genco ends up with a shortfall of 400 MWh relative to its contract quantity of 1600 MWh, and it effectively has to buy this shortfall out of the spot market at a spot price of \$500/MWh. An equivalent way to look at it, as shown in Fig. 3(c), is that the genco has to pay a high difference between the spot price of \$500/MWh and the contract price of \$50/MWh, while it only earns the high spot price of \$500/MWh on the 1200 MWh of energy it actually generates. This leaves the dark gray genco with an overall loss of \$149,000 in the hour.<sup>4</sup>

With a fixed-quantity, fixed-price forward contract, gencos are incentivized to bid marginal cost up to the contract quantity, but they can potentially benefit from using additional generating units above the contract quantity to push up the spot price, as seen in case (b). By contrast, with a contract where the quantity retroactively adjusts to ensure actual market demand is covered, gencos are incentivized to bid marginal cost on enough units to cover whatever their contract quantity turns out to be. In other words, the adjusting-quantity forward contract incentivizes gencos to manage the risk that demand will turn out to be higher than expected.

Wolak (2022) outlines one possible implementation of the SFPFC concept that retroactively adjusts for realized load shape. SFPFCs are auctioned off on a rolling, continuous basis, four years ahead of the month in which their energy is to be delivered.<sup>5</sup> One SFPFC represents one megawatt-hour of energy sold forward through this auction, with a load shape that reflects the realized demand in each hour of the month in

<sup>&</sup>lt;sup>3</sup> As a comparison, if both gencos had bid both of their units at marginal cost, their total profits would have been the same as in case (a). The spot price would have been \$45/MWh, and they would have earned \$25,000 in the spot market (variable profits of \$25,000 on their lower-marginal-cost units and zero on their higher-marginal-cost units) and \$5000 from the contract (1000 MWh times the price difference between the \$50/MWh contract and the \$45/MWh spot price).

 $<sup>^4</sup>$  If the dark gray genco had instead bid marginal cost like the light gray genco, both gencos would have earned variable profits in this hour of 1000 MWh \* (\$45/MWh - \$20/MWh) + 600 MWh \* (\$45/MWh - \$45/MWh) + 1600 MWh \* (\$50/MWh - \$45/MWh), or \$33,000.

<sup>&</sup>lt;sup>5</sup> The four-year figure is somewhat arbitrary; the key point is that the auction take place far enough in advance of energy delivery to allow new entrants to come into the market.

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question. For example, let's say that total market demand in the month turns out to be 1,000,000 MWh, with demand of 500 MWh in hour 1 of the month, demand of 1000 MWh in hour 2 of the month, and demand of 1200 MWh in hour 3 of the month. That means a single SFPFC sold in the auction would represent a forward commitment in hour 1 of (500 MWh / 1,000,000 MWh) \* 1 MWh, or 0.0005 MWh, a forward commitment in hour 2 of 0.001 MWh, a forward commitment in hour 3 of 0.0012 MWh, and so on for all the hours in the month. SFPFCs equal to 100% of forecast market demand are sold through auctions ahead of the delivery of energy; for example, Wolak (2022) proposes that 85% of forecast demand could be sold four years ahead of delivery, increasing through supplemental auctions to 87% three years ahead, 90% two years ahead, 95% one year ahead, and 100% in the current year.

The total realized demand over the month covered by the SFPFC may of course differ from the advance forecast. The proposed SFPFC implementation in Wolak (2022) bridges the gap between forecast and realized demand by conducting a "true-up" auction after energy is delivered and realized demand is known. In the true-up auction, generating companies bid to sell additional SFPFCs for the month (if total demand for the month was greater than forecast) or buy back SFPFCs for the month (if total demand for the month was less than forecast). Different from the auctions in advance of energy delivery, the value of an SFPFC is explicitly known at the time of the true-up auction-it is simply the difference between the market-clearing price in the true-up auction and the demand-weighted average spot price for the month. Gencos bidding to sell additional SFPFCs in the true-up auction would never bid below the demand-weighted average spot price, and gencos bidding to buy back SFPFCs in the true-up auction would never bid above the demand-weighted average spot price. Whether the true-up auction ends up clearing at a price significantly different from the demand-weighted average spot price depends only on how competitive the auction is-i.e., the degree to which the gencos bidding try to undercut each other versus deciding that gains from bidding too close to the known demand-weighted average spot price are immaterial. To the extent gencos do earn additional revenue through the true-up auction, this revenue can be viewed as additional compensation for managing demand risk in the market.

When a true-up auction is used, as in the classroom games we conducted, two adjustments take place after the compliance period is concluded. First, the load shape is adjusted for each SFPFC contract that was auctioned off in advance. For example, if a particular hour ended up accounting for 1.1% of total energy demand for a month instead of 1.0% as expected, the contract quantity in that hour for 1 SFPFC is set retroactively to 0.011 MWh instead of 0.010 MWh. Second, additional SFPFCs are retroactively sold or bought back by gencos in the true-up auction so that total SFPFC coverage is equal to 100% of total demand over the compliance period. If a true-up auction is *not* used, only the first step—the load shape adjustment—takes place.

The true-up auction has a certain theoretical elegance in ensuring that 100% of actual demand is retroactively covered in each period. However, our practical experience in the gameplay suggests that it may add unnecessary confusion for market participants, in exchange for relatively minor benefits in terms of the incentives created for gencos. The retroactive load shape adjustment is the more fundamental element of the SFPFC. By creating the risk for gencos that their contract quantity in a particular hour may be significantly higher than expected, the load shape adjustment creates the desired incentives for gencos to manage quantity risk. This is true even if not exactly 100% of demand in each hour is covered due to higher- or lower-than-expected total demand over the entire compliance period.

Our speculation, which we discuss further in relation to the simulation results later in this paper, is that the true-up auction itself will be a comparatively minor contributor to overall genco compensation via the SFPFC mechanism. The fundamental impact of SFPFCs on genco behavior will come from the gencos' knowledge that: 1) the effective contracted quantity in a given hour will reflect *realized* demand in that hour, thus removing the incentives of gencos who have sold SFPFCs to be short on capacity or bid up prices once they have covered some predetermined contract quantity, and 2) around 100% of total market demand will be covered under forward contracts, so there will likely be limited opportunities for gencos to exercise unilateral market power. The true-up auction is simply an optional mechanism to help achieve *exactly* 100% coverage of total realized demand.

#### 4. Setup for game-based prototyping of the SFPFC mechanism

We used a game-based simulation to explore how the SFPFC mechanism might function in a market with high shares of renewable energy. This simulation was a modified version of the energy market game described by Thurber and Wolak (2013) and Thurber et al. (2015). Nineteen graduate students in our course on energy markets and policy at the Stanford Graduate School of Business were divided into eight teams to play the roles of gencos and retailers. Two separate markets (A and B) were played concurrently so that each team could play the role of a genco in one game and a retailer in the other without conflicts of interest. The simulation took place over two weeks at the end of the academic term, following eight weeks in which the students learned about different aspects of electricity market operation using simpler versions of the game.

The simulation was broken up into three stylized "years". Each year was divided into two "days," with each day composed of four, one-hour periods representing stylized electricity demand and renewable energy conditions at 4 am, 10 am, 4 pm, and 10 pm, respectively. The demand curve was linear and relatively inelastic, with a slope of -5 MWh/; the demand intercept was normally-distributed about the expected value in each period (8,000 MWh at 4 am, 20,000 MWh at 10 am, 40,000 MWh at 4 pm, and 28,000 MWh at 10 pm), with a standard deviation of 3% of the expected value. Output of a wind or solar unit in a given period was modeled as a normally-distributed random variable censored at zero. Expected output for a single wind unit was 1000 MWh at 4 am and 10 pm and 500 MWh at 10 am and 4 pm, representing a geography like California with higher nighttime wind output. Expected output for a single solar unit was 1500 MWh during the day (10 am and 4 pm), with guaranteed zero output at night. Game players had no knowledge of wind and solar realizations when they were constructing their generating portfolios for a given year, but they did receive a perfect forecast of wind and solar output for Day 1 of each year immediately before they placed their electricity market bids for that day, and then again before they placed their bids for Day 2.

The stylized years in the game were not intended to represent realworld years per se, but rather steps along the path from a modest (~20%) share of renewable generation to a level that would meet (or exceed) California's 2030 renewable energy target. Renewables penetration in the game was driven by a renewable portfolio standard (RPS), which required each retailer to purchase sufficient renewable energy certificates (RECs) to cover 20%, 40%, and 60% of their electricity sales in Years 1, 2, and 3, respectively. (A genco received one REC for each megawatt-hour it produced with renewable sources; these RECs could be traded among gencos and retailers at any point during the simulation.) A steadily increasing carbon tax ( $0/tonne of CO_2$  in Year 1, 60/tonne in Year 2, and 120/tonne in Year 3) levied on gencos provided an additional incentive for carbon emissions reductions.

For simplicity, the operation of the SFPFC mechanism was selfcontained within each simulated year, rather than taking place on a rolling basis as it would in a real-world context. There were four main phases in the SFPFC process:

1) "Commit" phase: A quantity of SFPFCs equal to expected market demand in the year was auctioned off via a uniform-price auction in which gencos submitted four price-quantity pairs expressing the quantity of SFPFCs they were willing to sell at each price.

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#### Table 1

Cost and emissions characteristics of generating/storage units in the game. (Note that these stylized values are not necessarily reflective of real generating units.)

Unit Type	Capacity [MW] (for dispatchable units) or Expected Hourly Output [MWh/h] (for wind / solar)	Fixed Cost [\$/hr]	Variable Cost [\$/MWh] at a Zero Carbon Price	Emissions Rate [tonnes CO <sub>2</sub> / MWh]	Assigned "Firm Capacity" Factor
Wind	750	30,000	0	0	0.5
Solar	750	45,000	0	0	0.5
Base	1000	25,000	20	1.0	1
Intermediate	1000	10,000	45	0.5	1
Peak	1000	3,000	90	1.0	1
Battery	1000	20,000	0	0	0.5



Fig. 4. Spot price (purple), demand-weighted average spot price (red), SFPFC price in initial auction (turquoise), and final SFPFC price after both initial and true-up auctions (green) in games. (Negative prices occurred when renewable output exceeded demand.)

2) "Prepare" phase: The four gencos in each market reconfigured their portfolios of wind, solar, storage, and dispatchable generators (Base, Intermediate, or Peak) to cover their SFPFC commitments and attempt to maximize future profits. In any given year, gencos could buy and decommission an unlimited number of dispatchable generators and/or battery storage units<sup>6</sup> (see unit properties in Table 1), and they could buy up to three new renewable units.<sup>7</sup> To simulate a backstop policy that regulators might impose during a transition to SFPFC-based resource adequacy, gencos were also required to hold

"firm capacity" equal to their largest expected SFPFC quantity commitment in any period, with wind and solar receiving firm capacity credit of 50% of their expected output in high-demand periods,<sup>8</sup> and batteries receiving firm capacity credit of 50% of their maximum possible output in a given period.

- 3) "Deliver" phase: Wholesale electricity markets were run for each of the eight periods, one day at a time, with gencos placing offers for Base, Intermediate, Peak, and storage units in advance of each day.
- 4) "Settle" phase: SFPFC load shapes were adjusted based on the actual shares of total demand contributed by each of the eight periods. A true-up auction was also conducted in which gencos could sell or buy back SFPFCs depending on the difference between total realized and expected demand for the year.

<sup>&</sup>lt;sup>6</sup> Batteries submitted two bids into the market instead of the single bid that a dispatchable generator would submit. Their "sell" bid was similar to that of a dispatchable generator. If the market price cleared at or above the level of this "sell" bid, then the battery would discharge any stored energy. If the market price cleared at or below the level of this "buy" bid, then the battery would charge up to its available storage capacity. If the market price cleared above the "buy" bid and below the "sell" bid, the battery would maintain its current state of charge.

<sup>&</sup>lt;sup>7</sup> The goal of the limit on renewable energy units purchased per year was to achieve a progression in renewable energy output over the three stylized years.

<sup>&</sup>lt;sup>8</sup> Just as in a real market, this assignment of "firm capacity" credit to a resource that is not controllable is inherently somewhat arbitrary.



Fig. 5. Aggregate expected generation and storage capacity by type in each year of each game (colored columns), with expected demand at each time of day (black line). (The colored columns indicate capacity for dispatchable units and expected output for wind and solar units.)

#### 5. Insights from the SFPFC games

#### 5.1. Insights from genco performance and strategy

The SFPFC mechanism incentivizes gencos to manage the risk of supply shortfalls and high prices, starting several years ahead. One way they do this is by analyzing expected future market conditions and bidding into the initial SFPFC auction accordingly. Gencos in our game used spreadsheet analysis and other methods to estimate SFPFC prices that would be profitable in each year based on the known renewables targets and carbon prices. The gencos' collective offers at auction produced SFPFC clearing prices that generally provided a sufficient "reliability premium" to make gencos profitable where spot prices alone would not have. This reliability premium is illustrated by Fig. 4, which shows spot prices by period across the games as well as the demandweighted average spot price and the SPFPC price (both initial auction price and final composite price including the additional quantities bought or sold in the true-up auction) by year. In all cases except Year 3 of Game B, the SFPFC price provided gencos with a positive reliability premium—i.e. the SFPFC price exceeded the demand-weighted average spot price.

The predictability of returns from the SFPFC mechanism is an important advantage as spot prices become more volatile with increasing renewable energy penetration. As seen in Fig. 4, spot prices in higher renewable years (as in Years 2 and 3 of our game) swung between low levels when net demand was low (realized wind and solar output covered most or all of demand) and high levels when net demand was high (realized wind and solar output covered only a small share of demand). The increasing carbon price further increased volatility by driving up the marginal cost of the carbon-emitting units that needed to run when renewable output was low, increasing the market-clearing price in these low-renewable periods. As shown in Fig. 5, gencos acquired significant battery storage capacity in Year 3 to take advantage of the electricity price volatility they expected in this high-renewables/high-carbon-price condition.

Gencos appeared to account for the risk of higher-than-expected net demand when they reconfigured their generation portfolios in the "Prepare" phase. As shown in Fig. 5, total dispatchable capacity alone ended up being greater than—or, in one case, approximately equal to—expected market demand in every period. Gencos presumably understood the financial risk of being short of their SFPFC commitments if wind and solar output ended up substantially below expectations and/or demand ended up substantially above expectations.

Gencos shifted away from high-fixed-cost Base units as renewable targets increased. Higher renewable shares meant lower capacity factors for dispatchable capacity, which made it more difficult for these units to recover high fixed costs. This strategic shift to dispatchable units with lower fixed costs is likely to be observed in the real world as renewable energy shares increase. The SFPFC mechanism is consistent with a new paradigm in which dispatchable units are increasingly compensated for providing reliability services rather than bulk megawatt-hours of electricity, which will be obtained principally from zero-carbon sources.

Genco bidding behavior in the wholesale electricity market demonstrated the strong disincentives to the exercise of unilateral market power that are created by the SFPFC mechanism. Gencos in our games bid marginal cost on all their units even in market hours that would have been ripe for the exercise of unilateral market power in the absence of SFPFC commitments. Fig. 6 shows an extreme example of this. Genco4 won 78% of the initial SFPFCs in this year, and it built significant quantities of Intermediate and Peak units to physically hedge its contract obligations. All gencos received a forecast of expected renewable output immediately before they placed electricity market bids, so they were aware that solar output would be low and wind output would be very low, increasing net demand. They were not given a forecast of total demand, which in this case was 8000 MWh higher than expected. (This particular market period was a stylized representation of a late summer heat wave in California, where wind output is typically very low, solar output is somewhat low because high temperatures reduce conversion efficiency, and total demand is high due to heavy use of air conditioning.) In the absence of forward contract obligations, Genco4 could have benefitted from exercising unilateral market power through its bids to push prices to the \$500/MWh offer cap, yielding it a profit in this hour of more than \$3,000,000. Forward contract commitments changed this incentive, and the use of the SFPFC mechanism in particular meant that:



Fig. 6. Market results for Day 1, 4 pm hour in Year 3 of SFPFC Game B. The horizontal black line across the bid for each generating unit (and battery) shows the marginal cost of that unit, including the \$120/tonne carbon fee in Year 3.<sup>101</sup>

Table 2
Ratio of SFPFC true-up auction difference payments to initial auction difference
payments

Year 1 Year 2	Year 3
Game A 0.2% 49.0%	0.1%
Game B 0.7% 4.1%	1.7%

1) higher-than-expected demand in a given hour would translate into a higher contract quantity, so gencos were incentivized to bid marginal cost on their units even beyond the demand forecast, and 2) total market demand in each period was expected to be covered, so there would not be "extra" demand in the market for gencos to capture at high prices after they had hedged their contract obligations. For these reasons, Genco4 was rational to bid marginal cost on all of its Intermediate and Peak generating units as it did (see Fig. 6); its profits in this period were lower than if there had been no forward contracts, but vastly higher than if it had bid the price cap and had to buy the shortfall relative to its forward contract quantity from the spot market at \$500/MWh.<sup>9</sup> Across all 24 market periods of each of the two games we played, the wholesale electricity price never cleared above the marginal cost of the highestmarginal-cost generating unit. This was a testament to the effectiveness of the SFPFC mechanism in discouraging the exercise of unilateral market power.

At the end of each year ("Settle" phase), the true-up auction allowed gencos to sell additional SFPFCs if total demand over the year exceeded forecast demand and buy back SFPFCs if total demand over the year fell short of forecast demand. SFPFC difference payments to gencos from the true-up auction had a relatively modest effect on overall genco profits compared with difference payments from the SFPFCs sold in the initial auction (see Table 2), for two reasons. First, the SFPFC quantities available to be sold or bought in the true-up auction were significantly smaller than the quantities sold in the initial auction—a reflection of the fact that forecasts for overall yearly demand were reasonably good. (The

largest deviation from forecast demand in our game occurred in Year 2, where actual demand for the year was 177,000 MWh, versus a forecast demand of 192,000 MWh, meaning that the true-up auction required gencos to buy back a total of 15,000 SFPFCs—a less than 10% error in the demand forecast.) Second, clearing prices in the SFPFC auction typically differed from the demand-weighted spot price by only several dollars per MWh, providing only modest positive difference payments to the gencos. This likely reflected the fact that gencos were bidding, with no transaction costs, for a contract of known value, producing a relatively competitive market.

The one outlier case where true-up auction payments were comparatively significant-at 49% of the magnitude of the initial auction payments (see Table 2)-may potentially have resulted from an attempt by gencos to exercise market power in the true-up auction. Fig. 7, which shows the combined genco offer curve in the true-up auctions for Years 1 and 2, provides at least speculative support for this possibility. In the Year 1 auctions in both games, gencos offered in at relatively competitive prices, resulting in market-clearing true-up prices that let them buy back the roughly 3500 SFPFCs on offer at only slightly below the demand-weighted average spot price that represented the known value of each SFPFC. In Year 2 of Game A, by contrast, all of the gencos bid in much less competitive prices, with no single genco willing to buy back the entire stock of 15,000 SFPFCs on offer for more than \$0 per SFPFC. The clearing price of \$0 and the relatively high quantity of SFPFCs on offer vielded appreciable profits for the gencos who bought them back. We cannot definitively determine from this data whether the gencos intentionally exercised unilateral market power (or even colluded) to lower the price, but it's a possibility that would merit further investigation.

These results suggest that a real-world SFPFC implementation might benefit from omitting the true-up auction. SFPFCs' main effect on genco bidding incentives comes from the knowledge that contract quantities will adjust to load shape; based on our conversations with participants, the existence of the true-up auction did not materially change genco incentives beyond this. The true-up auction ended up being a relatively minor contributor to genco financial outcomes in most cases. In the one case where the true-up auction *was* materially significant, there is reason to believe gencos may have exercised market power in the true-up auction. The true-up auction also introduced significant conceptual complexity, with many game participants understandably struggling to grasp how they should bid in the true-up auction, given that energy

<sup>&</sup>lt;sup>9</sup> Genco4 suffered a loss in this period of around \$360,000; had it bid \$500/ MWh on all its units, this loss would have ballooned to almost \$13,000,000 due to the genco's larger quantity shortfall with respect to its SFPFC commitments and the higher price (\$500/MWh) at which it would have had to procure this shortfall on the spot market.



Fig. 7. Combined genco offer curves for buying back SFPFCs in Years 1 and 2 true-up auctions. The vertical red lines represent the total quantity of SFPFCs to be bought back in each case.

markets had already run and the additional SFPFCs bought or sold were therefore of known value.

#### 5.2. Insights from retailer performance and strategy

By design, retailers are passive participants in the SFPFC contract mechanism, with the logic that generators have more tools with which to manage electricity quantity risk several years into the future. The retailers are assigned the "buy" side of the SFPFC product after both initial and true-up auctions are complete. If the SFPFC price exceeds the demand-weighted spot price over the year, as it did in almost all cases in our games, retailers make difference payments to gencos proportional to their share of total demand for the compliance period (one "year" in our game or one month in the real-world implementation proposed by Wolak, 2022).<sup>11</sup>

The most important differentiator of profits between retailers in our game was their trading behavior in the market for Renewable Energy Certificates (RECs). As shown in Fig. 8, traded REC prices in Game A approached the ceiling price of \$400 after it became clear that total renewable output in Year 1 would fall short of the RPS target in that year of 20% of electricity sales coming from renewable energy—and that some retailers would therefore be forced to pay the penalty of \$400 for each REC they were short of their compliance obligation. Retailer1

ended up absorbing a massive penalty of \$3.15M for Year 1 noncompliance, while Retailer4 faced a more modest penalty of \$170k. (The flip side of the equation was that gencos who built significant wind and solar in Year 1 were able to benefit from selling RECs at high prices.) The Game A retailers that hedged the risk of high prices by buying RECs early in the year at prices near \$200 had the best financial results in this year. Years 2 and 3 were much more favorable for retailers in both games due to significant wind and solar overbuilds that caused total renewable output to significantly exceed RPS targets (see Table 3). (Game A renewable output in Year 3 was under the renewables target for that year, but the gap was more than filled with excess RECs carried over from Year 2.) This excess of renewables relative to the RPS targets caused REC prices to plummet and retailer finances to improve.

As shown in Fig. 9, cost to load can be divided into three categories: procurement of electricity on the spot market, the additional SFPFC reliability premium (i.e. the difference between what retailers would have paid for electricity on the spot market alone and what they paid with the SFPFC mechanism in place), and REC purchases. Electricity spot procurement costs include the effect of the carbon tax that gencos incorporate into their bids, raising the wholesale electricity price, which is the main reason these costs are significantly higher in Year 3. In our games, the SFPFC reliability premium was a relatively modest contributor to overall costs to consumers.

#### 6. Conclusions

The energy market games illustrated the benefits of standardized forward contracting for long-term resource adequacy in general—and of forward contracts covering realized load shape in particular. The fixedquantity forward contracts tested in the Boise and Brasília games were effective at maintaining sufficient dispatchable capacity to back up renewables, and they avoided the severe problems with unilateral market power that were observed in the capacity market scenarios. The full SFPFC game showed the additional advantages of forward contracts where contracted quantities are retroactively adjusted to match realized load shape over the compliance period. Even with very strict environmental rules, including a carbon price of \$120/tonne and a renewable target of 60% of demand in the final year of the game, the SFPFC

<sup>&</sup>lt;sup>10</sup> Because this market had batteries, the market results chart shows a dotted demand line (final consumer demand) as well as a solid demand line (final consumer demand plus maximum possible demand from charging batteries); batteries that offer in to charge are shown on the offer curve as "negawatt demand." (If the price clears below their "buy" offer for charging, they do not charge and function as "negawatts.")

<sup>&</sup>lt;sup>11</sup> We believe there is a good argument for letting supply-side participants in the market (i.e., gencos) play the leading role in managing quantity risk, as they have many tools with which to do this. However, it is worth noting that making retailers passive recipients of the hedge provided by the SFPFC instrument might make them somewhat less aggressive in trying to hedge against high prices by deploying demand management tools. We recommend further investigation of how to balance incentives for the use of supply-side vs. demand-side tools for ensuring system reliability.



Fig. 8. All Renewable Energy Certificate (REC) trades in both games. Each gray circle represents one trade, chronologically ordered, with circle diameter representing REC quantity. Vertical lines indicate clock time remaining until the close of trading in a given year.

#### Table 3

Actual renewable energy shares of demand versus RPS targets.

		Year 1	Year 2	Year 3
Renewable Portfolio Standard (%)		20.0	40.0	60.0
Renewable Energy as Share of Demand (%)	Game A	18.9	74.4	47.1
	Game B	25.8	79.0	78.2



Fig. 9. Cost to load in our games from spot procurement of electricity (light blue), the SFPFC "reliability premium" (dark blue), and purchases of Renewable Energy Certificates (RECs) (or payment of RPS non-compliance penalties).

mechanism yielded an electricity market with moderate prices and ample reserve capacity even in low-renewables periods (see Fig. 10). The SFPFC mechanism provided gencos with enough of a reliability premium to make them financially viable without raising costs to consumers to an excessive degree. The mechanism was fully compatible with a Renewable Portfolio Standard, as it would be with other renewable energy incentives.

Game-based training proved to be an effective way to train regulators, regulatory staff, and students in the functioning and value of standardized forward contracting. Prior to the game-based training, the operation of forward contracts was not intuitive to most participants. Capacity payments for "steel in the ground" to back up renewables seem very tangible; forward contracts that penalize gencos for failing to back up renewables seem less so. Game-based training helped overcome this bias, showing participants in a hands-on way that forward contracts actually have sharper teeth than capacity markets.

The SFPFC approach can present even more of a conceptual hurdle than fixed-quantity forward contracts that do not adjust based on load



Fig. 10. Total dispatchable capacity available (including charged batteries) in red versus net demand (total demand minus renewable output) in blue for each period. (Note how gencos' acquisition and operation of batteries made more energy capacity available in high-price periods in Year 3 of Game B.)

shape. The key to the SFPFC mechanism lies in each genco's knowledge that their contract quantities in each hour will adjust after the fact, making it highly inadvisable to bid under the assumption that realized demand will never exceed forecasts. After playing the SFPFC games, students in our Stanford course seemed able to grasp the load shape adjustment mechanism without significant difficulty.

One component of the SFPFC implementation we tested, the true-up auction, was particularly confusing for participants. In fact, our experience with the games led us to conclude that the true-up auction is more trouble that it's worth. Eliminating the true-up auction means it is not possible to cover exactly 100% of realized demand in a compliance period due to demand forecasting errors. However, the difference is likely to be small, and the fact that the SFPFCs sold in the initial auction retroactively adjust to actual load shape over the compliance period means that gencos still have the desired incentive to manage the risk of higher-than-expected demand in any particular hour. If the regulator wants to further hedge against the risk of higher-than-expected demand over the entire compliance period, they can simply require that more than 100% of forecast demand be purchased through the SFPFC auction. The key functional elements of the SFPFC mechanism-a standardized product, centralized years-ahead procurement, and retroactive load shape adjustment—do not require the use of the true-up auction, and the game-based policy prototyping described here suggests real-world implementations may be better off without it.

#### **Declaration of Competing Interest**

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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#### Conflict of Interest

The authors declare that they have no competing interests.

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