California Public Utilities Commission

February 26, 2021

Addendum to Staff Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009

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I. Summary of Addendum

A. Background

On December 18, 2020, Energy Division staff issued an addendum to its initial August 7, 2020 issue paper and straw proposal. The addendum included a revised proposal, authored by Professor Frank Wolak, entitled "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California: The Standardized Fixed-Price Forward Contract (SFPFC) Approach." Following this issuance, staff held a workshop on January 8, 2021 that focused on providing parties with a better understanding of the SFPFC framework. A second meeting was held by Professor Wolak on January 14, 2021 to answer further questions regarding the proposal.

In early February Energy Division staff held three days of workshops focused on Track 3B2 proposals. These workshops were held on February 8th, 9th, and 10th, 2021. Professor Wolak presented on the SFPFC framework on February 10th. Prior to the workshop, a Question-and Answer document was circulated to the service list.

B. Summary of Revisions

In this addendum, staff provides further details regarding the SFPFC proposal (detailed in the II. Appendix A). This addendum builds off the Question-and-Answer document circulated to parties prior to the February 10th workshop. The addendum includes discussion of the following:

- The compliance period and SFPFC products,
- SFPFC compliance and true-up auction frequency,
- Details regarding how the SFPFC product could be traded bilaterally,
- Interactions with the Renewable Portfolio Standard (RPS),
- Interactions with the Integrated Resource Planning (IRP) process,
- Preliminary versus final clearing of the SFPFC products,
- Methods for determining firm energy values ,
- Addressing concerns regarding FERC jurisdiction over mechanism, and
- Development of further implementation details.

II. Appendix A – Addendum to Revised Proposal issued on December 18, 2020 - "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California: The Standardized Fixed-Price Forward Contract Approach"

Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California: The Standardized Fixed-Price Forward Contract Approach

by

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This document presents numerical examples that illustrate several details of the Standardized Fixed-Price Forward Contract (SFPFC) approach to long-term resource adequacy based on questions received following the January and February 2021 workshops. The documented should be considered an addendum to the previous version of the proposal submitted on December 18, 2021.

The addendum provides further clarifications regarding:

- The compliance period and SFPFC products
- SFPFC compliance and true-up auction frequency
- Details how the SFPFC product could be traded bilaterally
- Interactions with the Renewable Portfolio Standard (RPS)
- Interaction with the Integrated Resource Planning (IRP) process,
- Preliminary versus final clearing of the SFPFC products
- Methods for determining firm energy values
- Addressing concerns regarding FERC jurisdiction over mechanism
- Development of further implementation details

A. Compliance Period of SFPFC Products

The compliance period is the length of time covered by the SFPFC contract, for example, January 1, 2021- December 31, 2021 for an annual compliance period or January 1, 2021 to March 31, 2021, May 1, 2021 to June 30, 2021, July 1, 2021 to September 30, 2021, and October 1, 2021 to December 31, 2021 for quarterly compliance periods. The compliance period of the SFPFCs can be calendar years, quarters or even months. Regardless of the compliance period, a SFPFC is a financial swap contract for a fixed amount of energy, where this total quantity of energy is allocated to hours within the compliance period using the hourly shares of energy consumed during that compliance period using *realized hourly system demands* during the compliance period. This means that final settlement of the SFPFC contracts cannot occur until realized demand for all hours in the compliance period is known. Consequently, there is a need for preliminary settlement during the compliance period. We outline a preliminary settlement mechanism below.

Because the firm energy value assigned by the CPUC and ISO to a generation unit is the maximum allowable amount of SFPFC energy the owner of the unit can sell during a compliance period, the choice of compliance period of the SFPFCs could be tailored to the ability of specific generation resources to deliver energy during that compliance period. For example, the fact that both wind and solar generation units in California produce more energy during the summer months than in other times of the year is an argument for quarterly compliance periods for SFPFC contracts so that amount of energy a resource can sell in a quarter under extreme system conditions, its quarterly firm energy value, can adjusted for this known seasonal variation. In addition, many thermal resources in California systematically take planned outages during certain times of the year. Their firm energy value for each quarter should account for that fact.

A shorter compliance period for the SFPFCs would also reduce the uncertainty in the values of the final hourly forward contract allocations during the compliance period to sellers of SFPFCs and electricity retailers, the counterparties to these SFPFCs. Preliminary settlement of these contracts during the compliance period would involve a smaller true-up settlement after the compliance period for monthly SFPFCs relative to quarterly SFPFCs and smaller true-up settlements for quarterly relative to annual SFPFCs. The major complication with shorter compliance periods for the SFPFCs is that it would requires more frequent procurement auctions and true-up auctions. Balancing these two concerns, argues in favor of compliance periods for SFPFC products that are no longer than quarters of the year.

B. Auction Frequency and Terms

If the compliance period for each SFPFC product is quarterly, then there must be at least one annual up-front compliance auction and at least one true-up auction each quarter following the first compliance quarter of the SFPFC mechanism. The compliance auctions should be run sufficiently far in advance of the delivery period to allow new entrants to compete with existing generation resource owners to provide the SFPFC product. For example, if the first SFPFC auction is run in December of 2021 it should be for the compliance period starting in Quarter 1 (Q1) of 2024. At this time auctions for the remaining three quarters of 2024 could be run, as well as auctions for all quarters of 2025 and 2026. This means that every year, twelve auctions for quarterly products would be run. However, this could be modified to include quarterly auctions for more quarters in the future, say Q1 to Q4 of 2027, depending on the desired amount of future revenue certainty for sellers of SFPFCs.

The amount of energy purchased in the Q1-2024 auction would be equal to the California Energy Commission (CEC) forecast of the total energy demand for the first quarter of 2024. Recall that this is a single number equal to the total amount of energy that the CEC estimates will be consumed in that quarter. The Q2, Q3, and Q4 auctions would purchase the CEC forecast of the demand for these quarters. For Q1 to Q4 of 2025, the demands purchased could be slightly less than the CEC's forecast for these quarters, say 95% of the forecast demand in each quarter. For Q1 to Q4 of 2026, the demands purchased could be equal to 90% of the CEC forecast for that quarter.

All these percentages could be adjusted upwards to the extent that there is concern that adequate energy will be able to meet demand during the compliance quarters for the SFPFC contracts. In addition, more than 100% of the CEC's load forecast could be purchased for each quarter of 2024 to ensure that the actual demand for energy is met along with the California ISO's desired operating reserve margin. For example, 1.06 times the CEC's load forecast could be purchased in these up-front compliance auctions.

As time progresses, additional auctions could be run for the next 12 quarters 3 years in advance to maintain these percentages at each future annual delivery horizon. For example, in Q4 of 2022, an additional SFPFC auctions would be run to obtain the 100% of the CEC forecast for Q1 to Q4 of 2025, 95% of the forecast for 2026 and 90% of the forecast for 2027. This process would continue until Q2 of 2024, immediately after the first compliance period. The first true-up auction would need to be run based on actual energy production during Q1 2024. Then in each subsequent quarter a true-up auction would need to be run for the previous quarter along with the 12 quarterly compliance auctions 3 years in advance of delivery. See Figure 10 a visual description of the timing of the sale of each SFPFC products in an up-front compliance auction and the timing of subsequent true-up auction for that product.

It is important emphasize that the true-up auctions are very unlikely to trade significant quantities of energy given the relatively small rate of growth of energy demand in California. Table 1, taken from the 2017 and 2019 versions of the California ISO's *Annual Report on Market Issues and Performance* shows the Average Load = (total annual energy demand divided by the number of hours in the year) and Annual Peak Load in the California ISO control area from 2013 to 2019.

Table 1: Annual System Load in California ISO Control Area 2013-2019

Year	Annual Total Energy (GWh	Average Load (MW)	% Change	Annual Peak Load (MW)	% Change
2013	231,800	26,461	-1.0%	45,097	-3.7%
2014	231,610	26,440	-0.1%	45,090	0.0%
2015	231,495	26,426	0.0%	46,519	3.2%
2016	228,794	26,047	-1.4%	46,232	-0.6%
2017	227,749	26,002	0.0%	50,116	8.4%
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%

The typical rate of growth of the annual demand for energy is substantially less volatile than the rate of growth in annual peak demand. Moreover, total annual energy demand growth is negative for 2018 and 2019 and very likely for 2020 because of COVID-19. The volatility of annual peak demand emphasizes the importance of allocating the SFPFC energy using to the *actual hourly* pattern of demand throughout the quarter rather than a forecast of these magnitudes. This mechanism provides strong incentives for the sellers of this energy to ensure that these demand peaks are met at least cost.

Although the most straightforward approach to running the quarterly SFPFC auctions would be to run them as twelve independent auctions, one for each future quarter. However, to facilitate a three-year future revenue stream that could finance investment in new generation capacity, the twelve quarterly auctions could be run simultaneous so that a potential new entrant could sell pre-specified quantities of SFPFC energy in all twelve auctions or nothing at all. For example, the new entrant could submit offers to sell the same amount of energy in all auctions.

C. True-Up Auctions

The vast majority of SFPFC contracts will be purchased in advance of delivery. However, because the mechanism requires that the total quantity of SFPFC energy sold during the compliance period must equal the realized demand during that same period, after each compliance period there needs to be true-up auctions to buy back unused SFPFC energy or purchase additional SFPFC energy. The following examples use the 4-period model in Figures 1 to 9.

A compliance auction would be run far in advance of the compliance period to purchase 1000 MWh of energy for the four time periods shown in Figure 1. Suppose this auction cleared at a price \$60/MWh. Figure 2 shows the quantities sold in the auction for the three suppliers and their hourly SFPFC obligations assuming the pattern of aggregate demand in Figure 1 is realized for the four time periods. Figure 3 shows the hourly SFPFC holdings of the four retailers for the four time periods. The total demand across the four periods for each retailer are shown at the top of Figure 3.

Now suppose that the realized demand for the compliance period turns out to be 10 percent higher in each of the four periods. This implies the need for an ex post true-up auction for 100 MWh. Because demand is 10 percent higher in each of the four periods, the shares that allocate this additional 100 MWh across four time periods to the four retailers are the same as those used to allocate the original 1000 MWh across the four time periods. The incremental allocations to each of the four retailers are shown in Figure 6 and the total realized demands for the four periods for each retailer are shown at the top of the graph. The period-level obligations for the incremental SFPFC energy purchased in the true-up auctions depend on which suppliers sell this energy. If each firm sells ten percent more SFPFC energy in the true-up auction and system demand increases by 10 percent in each of the four periods, the period level allocations of the additional SFPFC energy for each retailer are shown in Figure 5. In this example, we assume that the true-up auction cleared at $70/MWh and the demand-weighted average short-term price for the four periods is $55/MWh.

In addition to the variable profits they would earn from selling the energy they produce from their own generation units in the short-term market, the three suppliers would receive the following difference payments to settle their SFPFC contract positions:

Firm 1 = ($60 - $55)300 + ($70 - $55)30
Firm 2 = ($60 - $55)200 + ($70 - $55)20
Firm 3 = ($60 - $55)500 + ($70 - $55)50.

Besides the variable profits they would earn from purchasing energy from the short-term market and selling to their retail customers at the retail price the four retailers would pay the following difference payments:

Retailer 1 = ($60 - $55)1000(110/1100) + ($70 -$55)(110/1100)100
Retailer 2 = ($60 - $55)1000(220/1100) + ($70 -$55)(220/1100)100
Retailer 3 = ($60 - $55)1000(330/1100) + ($70 -$55)(330/1100)100
Retailer 4 = ($60 - $55)1000(440/1100) + ($70 -$55)(440/1100)100

Both the original and true-up aggregate SFPFC purchases are allocated to individual retailers based on their actual share of total demand served during the four demand periods.

If this 100 MWh total demand increase is instead shared equally between periods 1 and 2, period 1 demand would now be 150 MWh and the period 2 demand would now be 250 MWh. Demand in periods 3 and 4 are unchanged from those in Figure 1. In the final settlement, 150 MWh of the SFPFCs would be allocated to retailers in period 1, 250 MWh percent in period 2, 400 MWh in period 3 and 300 MWh in period 4. Suppose that retailer 1 consumed the entire additional 100 MWh of energy during the compliance period. Retailer 1 would now be assigned 2/11 = (200/1100) of the above period level values of SFPFCs as opposed to the values shown in Figure 3. Retailer 2, 3 and 4 would be also be assigned 2/11, 3/11 and 4/11, respectively, because their demand totals for the four periods did not change.

Suppose that the entire 100 MWh true-up auction quantity was all sold by Firm 1 at a price of $65/MWh and as result of a different pattern of demands throughout the four periods, the demand-weighted average short-term price is $50/MWh. Now, in addition to the variable profits they would earn from selling energy in the short-term market produced by their generation units the three suppliers would receive the following difference payments to settle their SFPFC contract positions:

Firm 1 = ($60 - $50)300 + ($65 - $50)100
Firm 2 = ($60 - $50)200
Firm 3 = ($60 - $50)500

Besides the variable profits they would earn from purchasing energy from the short-term market to sell to their customers at the retail price, the four retailers would pay for the following difference payments:

Retailer 1 = (\$60 - \$50)(1000)(2/11) + (\$65 -\$50)100(2/11)
Retailer 2 = (\$60 - \$50)(1000)(2/11) + (\$65 -\$50)100(2/11)
Retailer 3 = (\$60 - \$50)(1000)(3/11) + (\$65 -\$50)100(3/11)
Retailer 4 = (\$60 - \$50)(1000)(4/11) + (\$65 -\$50)100(4/11)

Again, both the original and true-up aggregate SFPFC purchases are allocated to individual retailers based on their actual share of total demand served during the four demand periods.

What price clears the true-up auction depends on the extent of competition among suppliers to provide this additional energy. Clearly, suppliers are extremely unlikely to offer to supply this energy below the demand-weighted average short-term price over the compliance period because its overall profits would decline. However, if there are a substantial number of suppliers willing to sell this additional SFPFC energy, the price is unlikely to be significantly above the demand-weighted average short-term price.

It is important to note that the lower the demand-weighted average short-term price, the larger are the difference payments that suppliers receive. This is another way of demonstrating that all suppliers have an incentive to minimize the cost of meeting their SFPFC obligations by offering to supply this energy at their marginal cost of production in the short-term market.

The true-up auction for excess SFPFC energy operates in an analogous manner. Suppose that demand is 10 percent lower in every period as shown in Figure 7. Suppose each firm buys back 10 percent of its SFPFC quantity in the true-up auction. This yields the period-level SFPFC quantities for each supplier in Figure 8. If all retailers reduce their consumption in each of the four periods by 10 percent their hourly SFPFC allocations and their total demands for the four periods are those shown in Figure 8. Suppose that the demand-weighted average short-term price is \$45/MWh and true-up auction clears at \$40/MWh.

In addition to the variable profits they would earn from selling energy produced by their generation units in the short-term market, the three suppliers would now receive the following difference payments to settle their SFPFC contract positions:

Firm 1 = (\$60 - \$45)300 - (\$40 - \$45)30
Firm 2 = (\$60 - \$45)200 - (\$40 - \$45)20
Firm 3 = (\$60 - \$45)500 - (\$40 - \$45)50

Besides the variable profits they would earn from purchasing energy from the short-term market to sell to at the retail price to their customers, the four retailers would pay the following difference payments:

Retailer 1 = (\$60 - \$45)(90/900)1000 - (\$40 -\$45)(90/900)100
Retailer 2 = (\$60 - \$45)(180/900)1000 - (\$40 -\$45)(180/900)100
Retailer 3 = (\$60 - \$45)(270/900)1000 - (\$40 -\$45)(270/900)100
Retailer 4 = (\$60 - \$45)(360/900)1000 - (\$40 -\$45)(360/900)100

Once again, the price clears the true-up auction depends on the extent of competition among suppliers to purchase the excess energy. Clearly, suppliers are extremely unlikely to bid a price for this energy above the demand-weighted average short-term price over the compliance period. However, if there are a substantial number of suppliers willing to buy this excess SFPFC energy, the auction price is unlikely to be significantly below the demand-weighted average short-term price.

Now suppose that the entire 100 MWh true-up auction quantity was purchased by Firm 1 at a price \$35/MWh and this 100 MWh reduction in demand across the four periods came entirely from period 3 and only from retailer 3. Suppose that as result of a different pattern of demand throughout the day, the realized demand-weighted average short-term price is \$40/MWh. This implies the following realized system load shares for the four periods: 1/9, 2/9, 3/9, and 3/9. The total realized demands for each retailer are now 100, 200, 200, and 400, so portions of both aggregate SFPFC purchases are allocated to retailers using the following shares: 1/9, 2/9, 2/9, and 4/9.

Now, in addition to the variable profits they would earn from selling the energy produced by their generation units in the short-term market, the three suppliers would receive the following difference payments to settle their SFPFC contract positions
Firm 1 = (\$60 - \$40)300 - (\$35 - \$40)100
Firm 2 = (\$60 - \$40)200
Firm 3 = (\$60 - \$40)500
Besides the variable profits they would earn from purchasing energy from the short-term market to sell to their retail customers the four retailers would pay for the following difference payments

Retailer 1 = (\$60 - \$40)(1000)(100/900) - (\$35 -\$40)100(100/900)
Retailer 2 = (\$60 - \$40)(1000)(200/900) - (\$35 -\$40)100(200/900)
Retailer 3 = (\$60 - \$40)(1000)(200/900) - (\$35 -\$40)100(200/900)
Retailer 4 = (\$60 - \$40)(1000)(400/900) - (\$35 -\$40)100(400/900)

The original and true-up aggregate SFPFC purchases are allocated to individual retailers based on their actual share of total demand served during the four demand periods.

The SFPFC obligation of a supplier provides a strong financial incentive for a supplier to offer in at least as much energy at its marginal cost so it expects will be its final SFPFC allocation for that hour of the compliance period. Failure to do can result in the supplier purchasing energy from the short-term market at price that is substantially higher than the marginal cost of the generation capacity that the supplier does not offer into the short-term market. In this sense, the SFPFC obligation provides a supplier with a must offer obligation (MOO) for at least its realized allocation of the SFPFC energy for that hour of the compliance, because the SFPFC mechanism requires the supplier to replace any shortfall in output from its generation resources relative to this hourly SFPFC allocation through the short-term market at the hourly short-term price.

D. Interaction with Renewables Portfolio Standard Obligations

Retailers meeting their renewables portfolio standard obligations with unbundled renewable energy certificates (RECs) only need to purchase the mandated percentage of their realized demand in unbundled RECs. For example, if the unbundled REC obligation is 20 percent of realized demand, the realized total demands for the four periods of the four retailers in Figure 3 imply purchases of 20, 40, 60 and 80 RECs, respectively, at the prevailing price of RECs during this compliance period.

Bundled RECs can easily be integrated into this mechanism. Suppose that Retailer 3 has a bundled REC that produces a total 90 MWh in the four periods and the weighted average short-term price from selling the energy produced by this renewable resource in the short-term market is \$45/MWh and power purchase agreement price the retailer pays for this bundled REC is \$70/MWh. In this case, Retail 3's variable profits assuming no true-up auction and excluding the profits the retailer would earn from purchasing energy from the short-term market to sell at the retail price to its customers is:

Retailer 3 = (\$60 - \$55)300 + (\$70 -\$45)90.

Note that the second term in this payment stream clarifies that a bundled REC allows the retailer to avoid paying the weighted average price that the 90 MWh provided by the renewable resource owner providing the bundled REC could have been sold at in the short-term energy market. Thus, a bundled REC is the equivalent of a fixed-price forward contract with an hourly forward contract quantity equal to actual production of the renewable unit during that period that clears against the period-level short-term price.

If Retailer 3 also purchased 60 unbundled RECs at $20/MWh, this magnitude would become

Retailer 3 = ($60 - $55)300 + ($70 -$45)90 + $20(60),

and the Retailer 3 would have total renewable energy share of 50 percent. Because the retailer's total variable profits also includes its sales at the retail price and cost of purchasing this energy at the short-term price, the retailer may want to sign addition hedging arrangement to manage its aggregate short-term price risk.

The renewable resource owner could sell SFPFC energy up to the firm energy magnitude assigned to this renewable resource. Any net revenues the resource owner receives from the SFPFC settlement process would be offset against the amount the resource owner is due from the PPA with the retailer that purchased the bundled RECs from this resource owner. These revenues would be paid to the retailer to the offset the above market costs of the PPA to the retailer. Continuing the above example, suppose the renewable resource was assigned a firm energy value of the 30 MWh during the compliance period and it sold 30 MWh of SFPFC energy in the compliance auction at the $60/MWh price. The renewable resource would receive $150 = ($60 - $55)30 under the SFPFC settlement process. The retailer would then be only obligated to pay $6,150 = ($70/MWh x 90 MWh) - $150, the difference between the payments due under its PPA contract and the amount the resource received in SFPFC, for the 90 MWh is received in bundled renewable energy.

E. Interactions with California's Integrated Resource Planning Process

This mechanism places no requirements on the types of capacity that must be constructed to sell SFPFC energy. The joint CPUC and California ISO process that sets the firm energy value for an actual or proposed generation resource only limits the amount of annual SFPFC energy that generation resource can sell. In this sense the mechanism will not hinder the state's ability to meet it Integrated Resource Planning (IRP) goals. Whatever resources the state deems are necessary to meet its IRP goals can compete in the SFPFC auctions starting delivery three years in the future for at least twelve quarters. The seller of these SFPFC contracts will still be subject to the construction milestones necessary to be designated by the CPUC and ISO as actually capable of providing the firm energy sold in the SFPFC auction during the delivery horizon.

For example, suppose that the CPUC orders a large retailer to sign 10-year contract to construct resource to meets the state's IRP goals. This 10-year contract has a fixed revenue stream for the resource owner. The resource would be assigned firm energy values for each compliance period in this 10-year period and the full firm energy value of this resource for each compliance period would be entered into the SFPFC auction as a price-taker. Any SFPFC revenues earned by the resource during this 10-year period would be netted against the 10-year contract revenue stream. The retailer that signed this 10-year contract would have its payment obligations to this resource reduced by these realized SFPFC revenues.

F. Interactions with Electricity Retailing and Demand Response

This mechanism places all retailers on equal footing in terms of their long-term resource adequacy obligations. As the above compliance and true-up auction examples show, all retailers must hold SFPFC energy equal to their actual consumption of energy during the compliance period, which can be the month, quarter, or year. In the above examples, the total quantity of SFPFCs is equal the total energy consumed by the retailer during the four demand periods.

Under the SFPFC mechanism, there is no way for a small retailer to free-ride off the long-term resource adequacy purchases of large retailers, as can occur in capacity-based mechanisms. Under these mechanisms, the long-term resource adequacy capacity purchases by the large retailers typically produce short-term market outcomes that can allow smaller retailers to sell energy at retail prices indexed to a short-term wholesale market price that is lower and less volatile because of long-term RA purchases of the large retailers. However, as the recent events in Texas have shown, if system conditions arise that produce dramatically higher short-term prices, these retailers are likely to become financially insolvent.

The fixed quantity of energy SFPFC energy purchased in advance of delivery provides a strong incentive for individual retailers to reduce their demand during all hours of the delivery period, particularly those with high short-term prices. Consequently, those retailers that can reduce their hourly demands benefit two ways. First, they reduce their allocation of total SFPFC energy during the compliance period. Less energy consumed during the compliance period implies a one-for-one reduction in their SFPFC obligation for this compliance period. Second, they can reduce their short-term wholesale energy purchase costs associated with serving the customer’s demand because a lower real-time demand will lead to lower short-term market prices. Therefore, a major advantage of the SFPFC mechanism is that it rewards retailers that are able to find flexible demand and utilize this flexibility to reduce the cost of serving their consumers.

G. Converting SFPFC to a Purely Bilateral Trading

There are two possible approaches to converting the SFPFC to a bilateral trading mechanism. The first approach retains the centralized compliance auction but allows individual load serving entities (LSEs) to submit their demand for each quarterly SFPFC product into the auction for each quarterly SFPFC product. The second approach does not involve centralized compliance auctions, but simply requires individual retailers to make a showing to the CPUC that they have purchased sufficient quantities of each quarterly SFPFC product from a qualified supplier to meet their compliance obligations before the compliance deadline. Both mechanisms follow up each compliance showing with a centralized backstop procurement auction where the CPUC purchases the aggregate shortfall of each quarterly SFPFC product and allocates the purchases of each SFPFC product to each LSE with a compliance shortfall for that product and assesses a penalty on the LSE for each MWh of their shortfall for each product. Both mechanisms would also involve the creation of a compliance account for the SFPFC energy purchased by each LSE to ensure that at all times the required fractions of the CEC’s forecast of system demand for future years is covered by SFPFC energy held by all LSEs.

Under the first approach, the up-front auctions of SFPFC energy starting deliveries 3, 4, and 5 years in future as shown in Figure 10 would continue. However, in advance of each annual compliance auction all suppliers would be assigned obligations for purchasing SFPRC energy in these auctions based on the share of system demand they served in the previous year. For example, if in December 2021 an LSE was determined to have served 10% of system demand in 2021, it would be assigned an obligation to purchase 10% of the CEC's forecast of system demand for 2024, and 10% of 95% the CEC's forecast for 2025, and 10% of 90% of the CEC's forecast for 2026.

This auction could run as a simple one-sided auction, where all retailers submit their desired quantities into each quarterly auction and the sum of these purchase quantities across all retailers determines the market demand for each quarterly SFPFC product. With these aggregate demands for each quarterly SFPFC product, suppliers could submit offers to supply SFPFC energy up to their total firm energy quantities for that compliance period. Each quarterly auction could clear as a declining clock auction where suppliers submit the amount of SFPFCs they are willing to supply at each price level. The price declines until the amount of SFPFCs suppliers are willing to sell at that price is equal to the market demand for that product.

If an LSE fails to purchase the mandated quantity of energy in each of quarterly SFPFC compliance auction, a backstop auction could be run immediately following this auction, where the aggregate amount of the shortfall between the amount of SFPFC energy purchased in the initial auction and the aggregate SFPFC obligation is purchased and allocated to the retailers that under procured relative to their SFPFC obligation. These retailers would also be subject to an immediate $/MWh financial penalty for any shortfall in their quarterly SFPFC purchases. The price in this backstop auction would be set at the higher of the compliance auction price and the market clearing price in the backstop auction to provide a strong incentive for retailers to purchase their obligation in the initial compliance auction.

Under the second approach, each LSE would be required to submit proof to the CPUC that it had purchased quarterly SFPFC energy from a qualified supplier of SFPFC energy (a supplier that owned a generation resource with verified quarterly firm energy) at least equal to its compliance obligation for each future compliance period. The CPUC would set the parameters of the SFPFC product that all retailers must purchase to ensure uniformity of the product. Generation unit owners would only be able to sell as much SFPFC energy in a quarter as the amount of quarterly firm energy the supplier had to sell. Suppliers and LSEs would disclose their SFPFC holdings and the identity of counterparty to the CPUC, so that the CPUC would ensure that all retailers met their SFPFC obligations for each quarter and that no supplier has sold more SFPFCs in a compliance quarter than it has in firm energy for that compliance quarter.

If any LSE failed to purchase the mandated quantity of quarterly of SFPFC energy it was required to hold by the compliance deadline, a backstop auction as described above would be run for the aggregate shortfall across all LSEs and these contracts would be allocated to those LSEs with SFPFCs shortfalls for that compliance period. In this case, because all initial SFPFC contracts are negotiated bilaterally, the CPUC may not be able to collect information on the prices for each SFPFC contract between a supplier and retailer. Thus, the allocated contracts from the backstop auction would use the market-clearing price from the auction. Each LSE would also be subject to a $/MWh financial penalty for any shortfall relative its quarterly requirements for each compliance period.

Under both approaches, the quantities of SFPFC energy purchased by each LSE either in the initial compliance process or through the backstop auction process would be held in a compliance account and the LSE would be responsible for posting collateral for the quantity SFPFC contracts purchased for each future quarterly delivery period. Similarly, the sellers of these SFPFC contracts would be responsible for posting collateral for the quantity of SFPFC contracts they sold for each future delivery quarter. LSEs would only be able to sell SFPFC energy held in their compliance account to other LSEs. This would ensure that total volume of outstanding SFPFC energy was always equal to the current value of the CEC's forecast for the electricity demand during the future compliance quarter. The clearinghouse would monitor trades of SFPFC energy in the compliance account to ensure that the aggregate amount of this energy in steady state is 100% of the CEC's forecast of demand for current year and the following three years, 95% of the CEC's forecast four years in the future and 90% of the CEC's forecast five years in the future.

In December of 2022, updates of two determinants of the SFPFC purchase obligations for each retailer would take place. First, the share of annual demand served by each retailer would be updated to reflect 2022 data. Second, the CEC's demand forecasts for future years would also be updated based on new information. For example, if the LSE served 12% of system demand during 2022, it would be assigned an obligation to purchase 12% of the CEC's current (December 2022) forecast of system demand for 2024, and 12% of the CEC's current forecast for 2025, and 12% of 95% of the CEC's forecast of 2026, and 12% of 90% of the CEC's current forecast for 2026.

If the first approach was in place, a centralized compliance auction would be run for LSEs to make the necessary incremental procurement of SFPFCs for each compliance quarter. If the second approach was in place, a deadline would be set for LSEs to make bilateral purchases of SFPFCs to attain the desired quantities of energy. Any incremental SFPFCs sold would have to be backed by unused firm energy for that compliance quarter. The CPUC would again verify that each LSE has met it SFPFC obligation for each future compliance quarter and each supplier has not sold more total SFPFCs for any compliance quarter that exceeds its total firm energy for that compliance quarter.

The CPUC run would be another round of backstop auctions for LSEs that failed to purchase the required quantity of SFPFCs for any compliance quarter. These purchases would be assigned to the LSEs with shortfalls for the compliance periods that they are short relative to their SFPFC obligation. They would also be subject to a $/MWh penalty for any shortfall.

The mechanism would continue adjusting each LSE's obligation based on its share of annual consumption in the previous year and the changes in the CEC's forecast of future demand. Beginning in January of 2024 deliveries under the SFPFC contracts would begin. Preliminary clearing of the contracts would take place using the hourly shares of system load for the first quarter of 2023, as discussed below. After the quarter ended there would be a true-up auction where each LSE would have to purchase sufficient SFPFC energy to cover their actual demand for the quarter. LSEs can also sell excess SFPFC energy in this true-up auction. This true-up process could also be done through bilateral trading between LSEs and suppliers.

It is important to emphasize that at all times the aggregate amount of outstanding SFPFC energy for each future compliance quarter should be greater than or equal to the SFPFC holding requirements for that quarter based on the CEC demand forecasts described above. The major difference between this bilateral mechanism and the centralized allocation mechanism is the LSEs can find themselves in different financial positions because of when they purchase or sell SFPFC energy and the price at which these transactions occur. It is also important to set the penalty paid by LSEs that fail to meet their quarterly future SFPFC obligations sufficiently high to ensure that LSEs do not find it profit-maximizing to shirk these obligations.

H. Preliminary Clearing of SFPFC Contracts

As noted above, during the compliance period of each quarterly SFPFC product, the actual hourly system demand share of total system demand for the quarter is unknown. These hourly shares of total system demand for the quarter are only known after all hourly system loads for the quarter are known.

Therefore, the SFPFC product must initially be cleared against a proxy load share. Because there is sufficient persistence in the hourly load shares for the same quarter of the year across adjacent years, it is reasonable to base preliminary settlement during the quarter on the hourly load shares from the same quarter of the previous year. The analysis below reflects that the resulting weighted average prices used to settle the SFPFC product are not typically significantly different from those that use the actual hourly load shares within the quarter, except when high short-term prices are coincident with high hourly system demand levels.

Table 2: Quarterly System-Load-Weighted Average 2019 DAM and RTM Prices

Quarter	P(2019,DAM,2019)	P(2019,DAM,2018)	P(2019,RTM,2019)	P(2019,RTM,2018)
1	53.02	52.06	49.09	48.23
2	24.16	23.63	31.71	30.28
3	36.48	35.75	34.16	33.51
4	41.52	41.14	34.86	34.67

Table 2 computes the hourly load-share weighted average prices for 2019 using the quarterly actual hourly load shares for 2019 and the hourly load shares for the same quarter of 2018 for the both the hourly day-ahead market (DAM) and hourly real-time market (RTM) prices using the system marginal energy cost (SMEC). The notation P(2019,DAM,2018) is the hourly load share weighted average price using the 2019 day-ahead (DAM) prices and the hourly load shares for same quarter of 2018. For the same price series and quarter of the year, the difference between the hourly load share weighted average price using the 2018 weights typically differs by no more than 5% percent from the share weighted average price using the 2019 weights.

Table 3: Quarterly System-Load-Weighted Average 2019 DAM and RTM Prices

Quarter	P(2020,DAM,2020)	P(2020,DAM,2019)	P(2020,RTM,2020)	P(2020,RTM,2019)
1	29.76	29.53	26.08	25.70
2	22.65	21.77	22.80	21.50
3	55.13	51.11	37.88	36.13
4	43.53	42.47	33.67	33.02

Table 3 computes the hourly load-share weighted average prices for 2020 using the quarterly actual hourly load shares for 2020 and the hourly load shares for the same quarter of 2019 for the day-ahead and real-time prices. The third quarter of 2020 demonstrates the importance of eventually clearing the SFPFC energy against the actual hourly load shares because hourly day-ahead prices are highest when the realized hourly load shares were highest. This positive correlation between actual hourly prices and realized hourly load shares provides sellers of SFPFC energy with a strong economic incentive to supply energy during these high-priced periods or face substantial difference payment to counterparty to the contract.

To understand how preliminary versus final settlement would work, consider the following example for a compliance period of Q1 2020. Suppose that the real-time price is used for settlement and that the supplier sold 50,000 MWh of SFPFCs in quarter at a price of $35/MWh. The supplier would receive ($35 – $25.70)50,000 in the preliminary settlement during Q1 2020 SFPFCs. Then after the quarter is concluded and the actual hourly shares of total quarterly demand are known, the supplier would pay ($26.08 - $25.70)50,000 as part of the final settlement process. In this case, the settlement adjustment is 4 percent of the initial settlement amount.

I. Determining Quarterly Firm Energy Values

It will be necessary to develop firm energy methodologies for all resource types that can provide value in meeting the SFPFC requirements. These methodologies will take time to develop and will likely require several rounds of workshops. Below is some high-level thinking about how these methodologies could be determined for thermal generation, hydroelectric resources, and wind and solar generation.

Determining the quarterly firm energy value for dispatchable thermal generation units is relatively straightforward. The nameplate capacity of the generation unit multiplied by the average quarterly availability factor (percent of hours in the quarter the unit is available to operate) from the previous three years multiplied by the number of hours in the quarter is reasonable estimate of the amount of energy the unit can produce in the quarter. Defining firm energy values on a quarterly basis would account for the fact that all generation units require scheduled maintenance actions. Because scheduled maintenance actions are taken into account in determining availability factors, this information would in the process of determining the quarterly firm energy value of a thermal resource.

For hydroelectric resources, the quarterly firm energy value could be determined from historical quarter-of-year distributions of energy production from the generation unit. The lowest 710th percentile of the distribution of energy production from the generation unit during that quarter of the year would be a conservative estimate of the quarterly firm energy for hydroelectric resources. This means that there is a 90 percent probability (based on historical data) that amount of energy this resource can produce exceeds this value. Again, defining firm energy values on a quarterly basis would account for the substantial seasonality in hydroelectric energy availability. This would improve the credibility of the resulting firm energy values for determining precisely how much amount of energy the resource can provide under stressed system conditions during that quarter of the year.

For existing wind and solar resources, the quarterly firm energy could be determined from historical quarter-of-year of energy production from the generation unit. The lowest 10th percentile of the distribution of energy from the generation unit during that quarter of the year would again be a conservative estimate of the quarterly firm energy value for these resources.

If there is insufficient data available on the output of a solar or wind generation resources to compute this percentile, data on historical wind or solar conditions at the generation unit's location can be used to determine the quarterly firm energy value. The percentiles of the distribution wind or solar resource availability at the unit's location can be used. This percentile of resource availability distribution can be converted into an estimated percentile of the solar or wind energy production at that location.

These two methodologies—historical energy production data and historical renewable resource availability data—could even be combined to provide estimates of the percentile of the distribution of energy production from a wind or solar resource.

J. Concerns Regarding FERC Jurisdiction

One view of the SFPFC mechanism is that it is a state energy policy like the RPS or the market for GHG emissions allowances. The California Air Resources Board runs periodic centralized auctions for GHG emissions allowances that fossil fuel generation unit owners purchase. The revenues from the GHG emissions allowance sales to generation unit owners are allocated to California LSEs to offset partially the cost of the GHG allowances on the price LSEs pay for wholesale electricity.

Under the SFPFC mechanism electric suppliers sell SFPFCs and the obligations to make the payments due to suppliers under these SFPFCs are allocated to LSEs in California. No actual energy is sold under the SFPFCs. The payment flows between sellers of the SFPFCs and counterparty LSEs are determined based on the short-term price of electricity. There is no requirement that the seller of a SFPFC supply energy equal to its hourly allocation of the total SFPFC it has sold for the compliance period. However, as noted earlier, the financial incentives implicit in the SFPFC obligations provides strong incentives for suppliers to offer at least that much energy into the short-term market at their marginal cost.

In addition, the quarterly firm energy values assigned to each generation unit limit the amount of SFPFCs that supplier can sell within any compliance cycle. Similarly, the energy production of a renewable generation unit limits the amount of RECs that unit can sell within a compliance cycle and the amount energy a natural gas-fired generation unit produces is the minimum amount of GHG emissions allowances it must purchase.

K. Implementation Details and Transition Period to the SFPFC Framework

While the proposal is still very high level. If the Commission chooses to move forward with this approach, there are many details that will require further development and stakeholder input to implement the proposal. These implementation details will require the following key elements:

1.) Establishment of central clearing house and what elements would be needed under a centralized or bilateral approach.
2.) Development of firm SFPFC energy quantities by resource type
3.) Further development of the appropriate SFPFC quantities to be purchased in the quarterly compliance auctions
4.) LSE financial penalties for failing to meet compliance and true up obligations.
5.) Transitioning any existing resource adequacy contracts to the SFPFC framework

The transition to the SFPFC framework will likely involve the development of a calculation to convert current RA contracts to the SFPFC value stream. This will be needed because current RA contracts are based on capacity values (MW months) rather than firm energy values (MWhs for each quarter). These key elements could be further developed in future workshops and or working groups established to address each of the individual elements listed above.

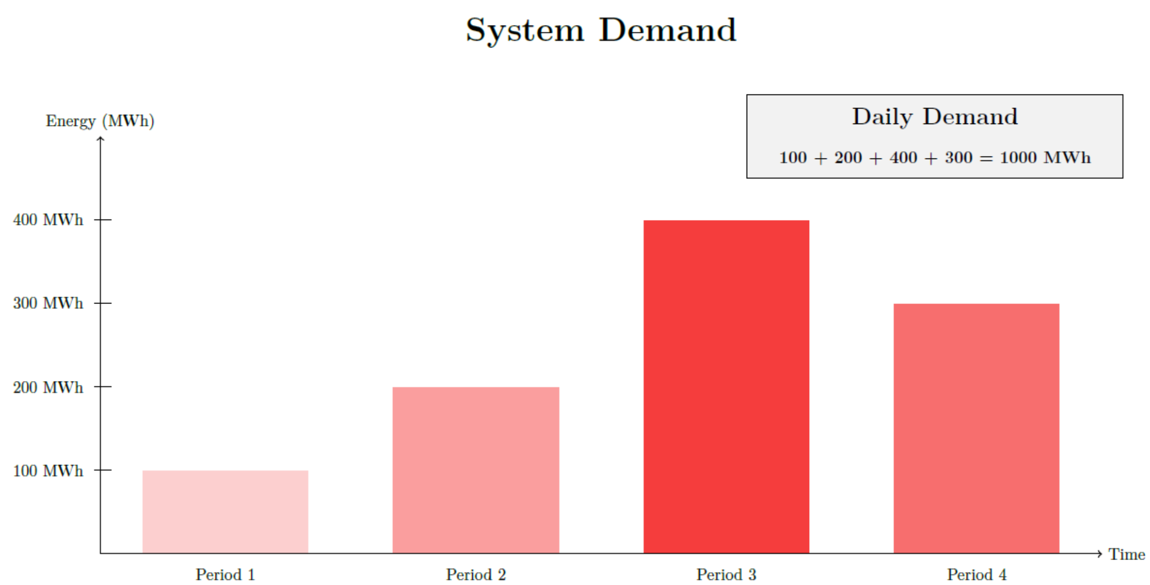

Figure 1: Hourly System Demands

Three Firms:

Firm 1 sells 300 MWh

Firm 2 sells 200 MWh

Firm 3 sells 500 MWh

Total Amount Sold by Three Firms = 1000 MWh

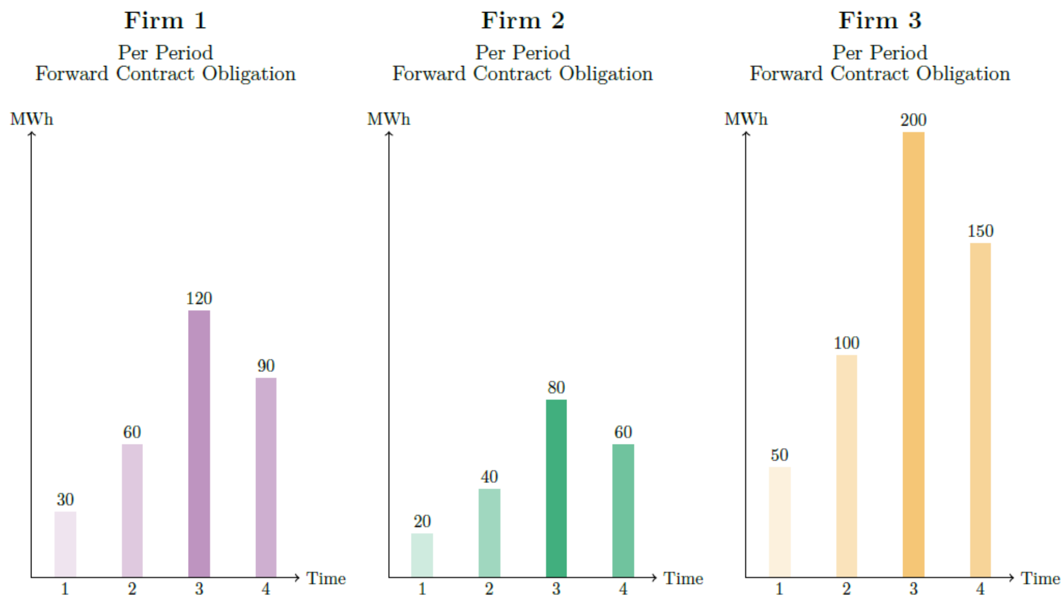

Figure 2: Hourly Forward Contract Quantities for Three Suppliers

Four Retailers:

Retailer 1 holds 100 MWh

Retailer 2 holds 200 MWh

Retailer 3 holds 300 MWh

Retailer 4 holds 400 MWh

Total Amount Held by Four Retailers = 1000 MWh

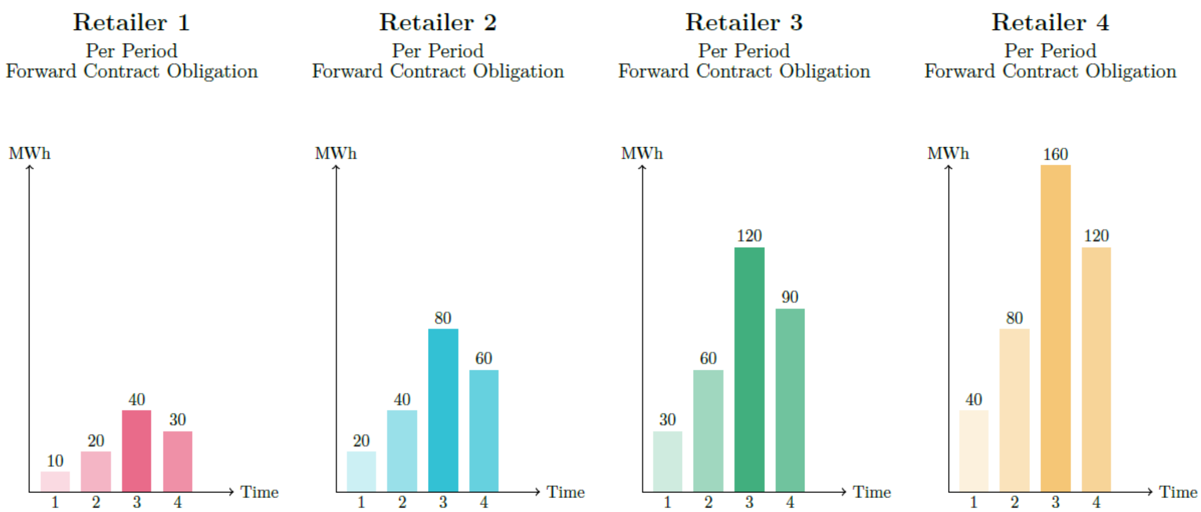

Figure 3: Hourly Forward Contract Quantities for Four Retailers

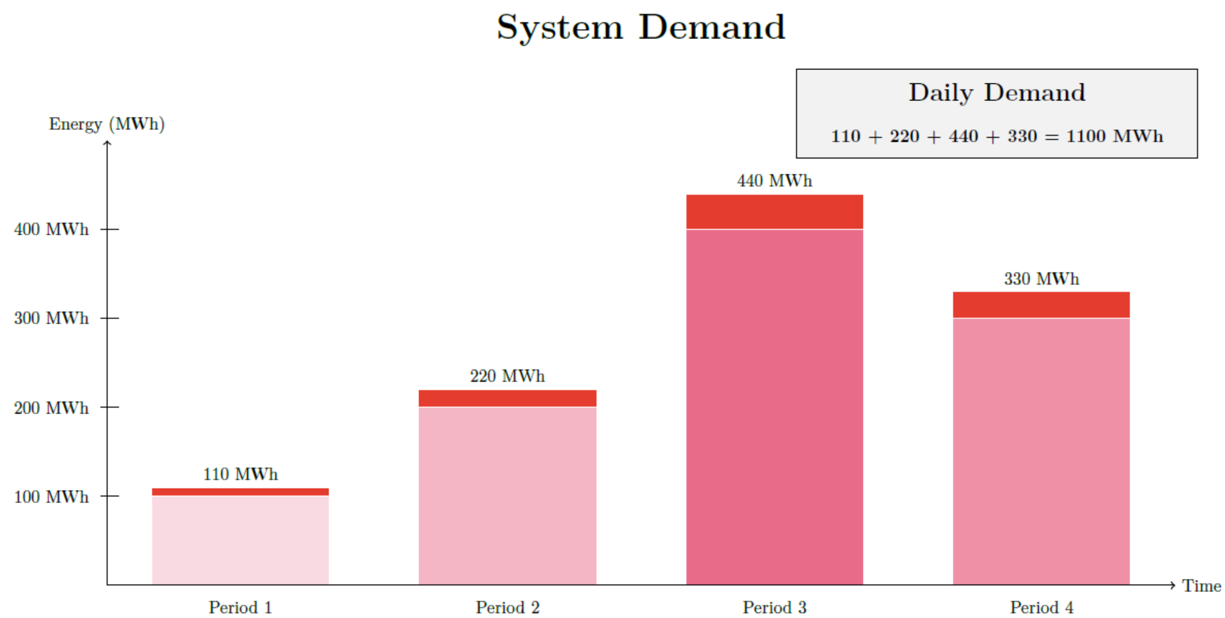

Figure 4: Hourly System Demands (10 Percent Higher)

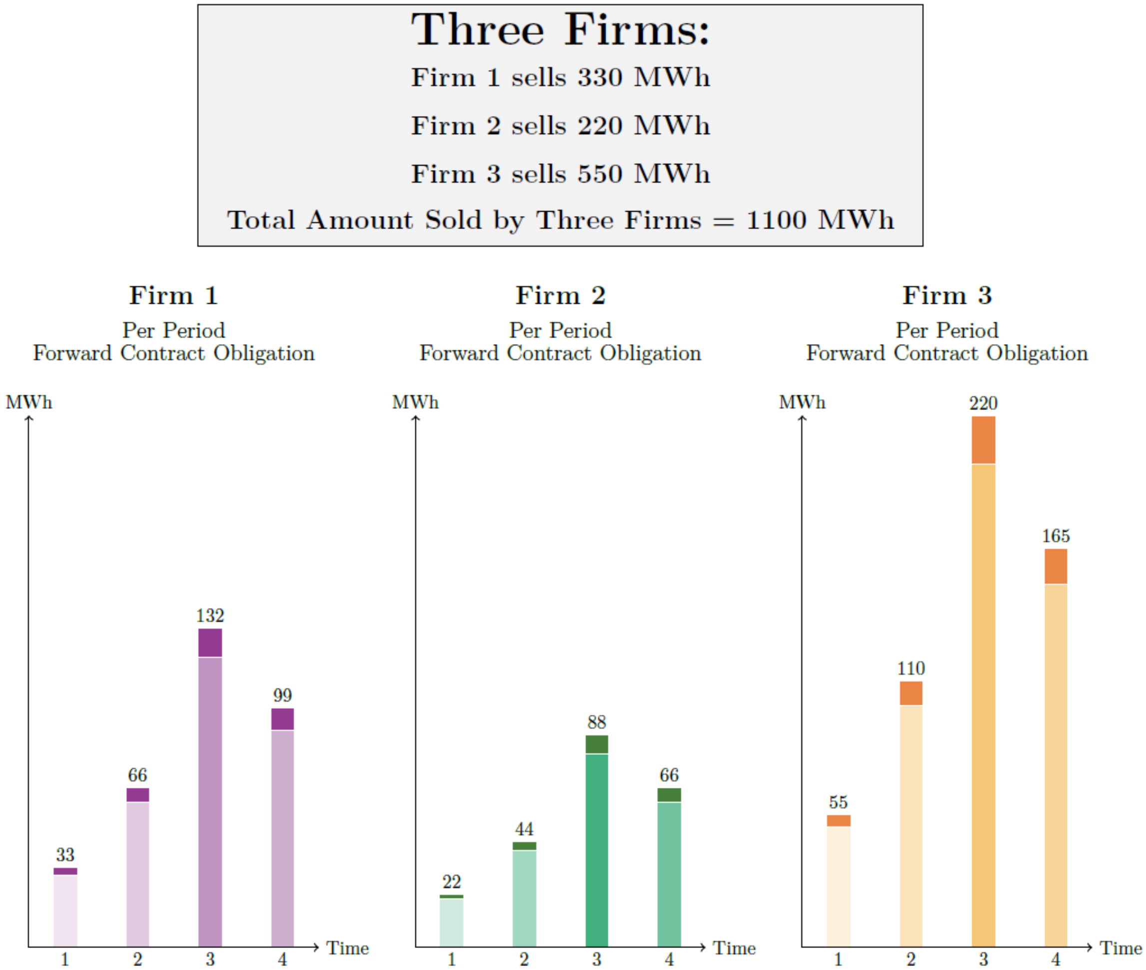

Figure 5: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

Four Retailers:

Retailer 1 holds 110 MWh

Retailer 2 holds 220 MWh

Retailer 3 holds 330 MWh

Retailer 4 holds 440 MWh

Total Amount Held by Four Retailers = 1100 MWh

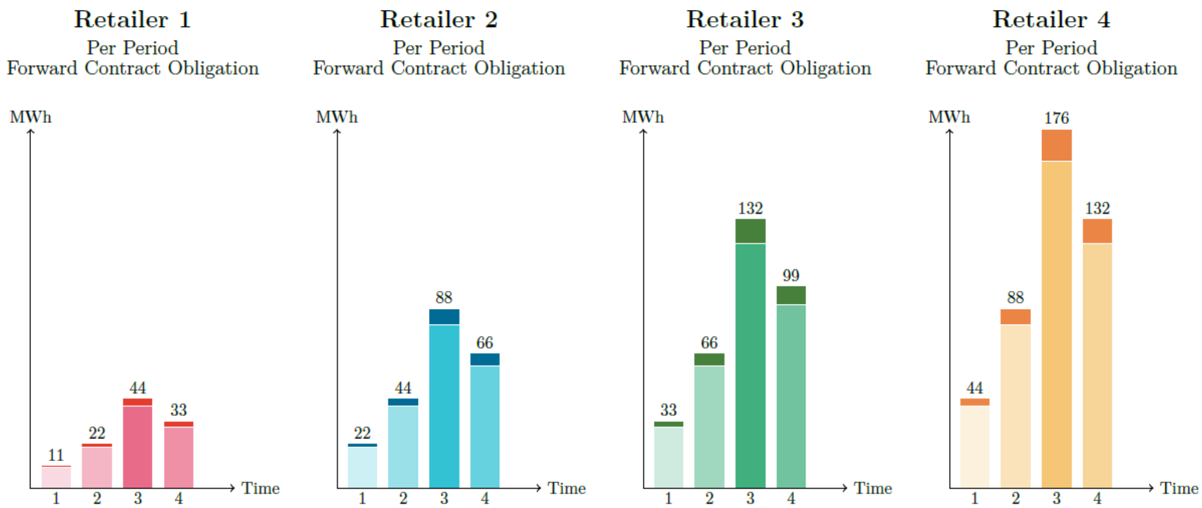

Figure 6: Hourly Forward Contract Quantities for Four Retailers (10 Percent Higher)

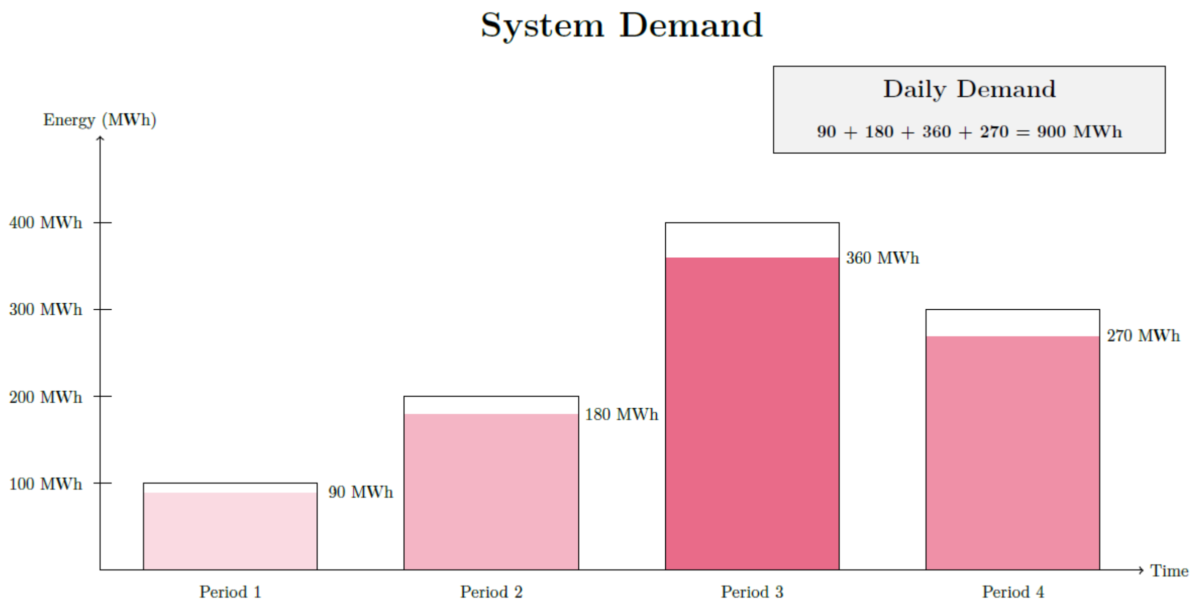

Figure 7: Hourly System Demands (10 Percent Lower)

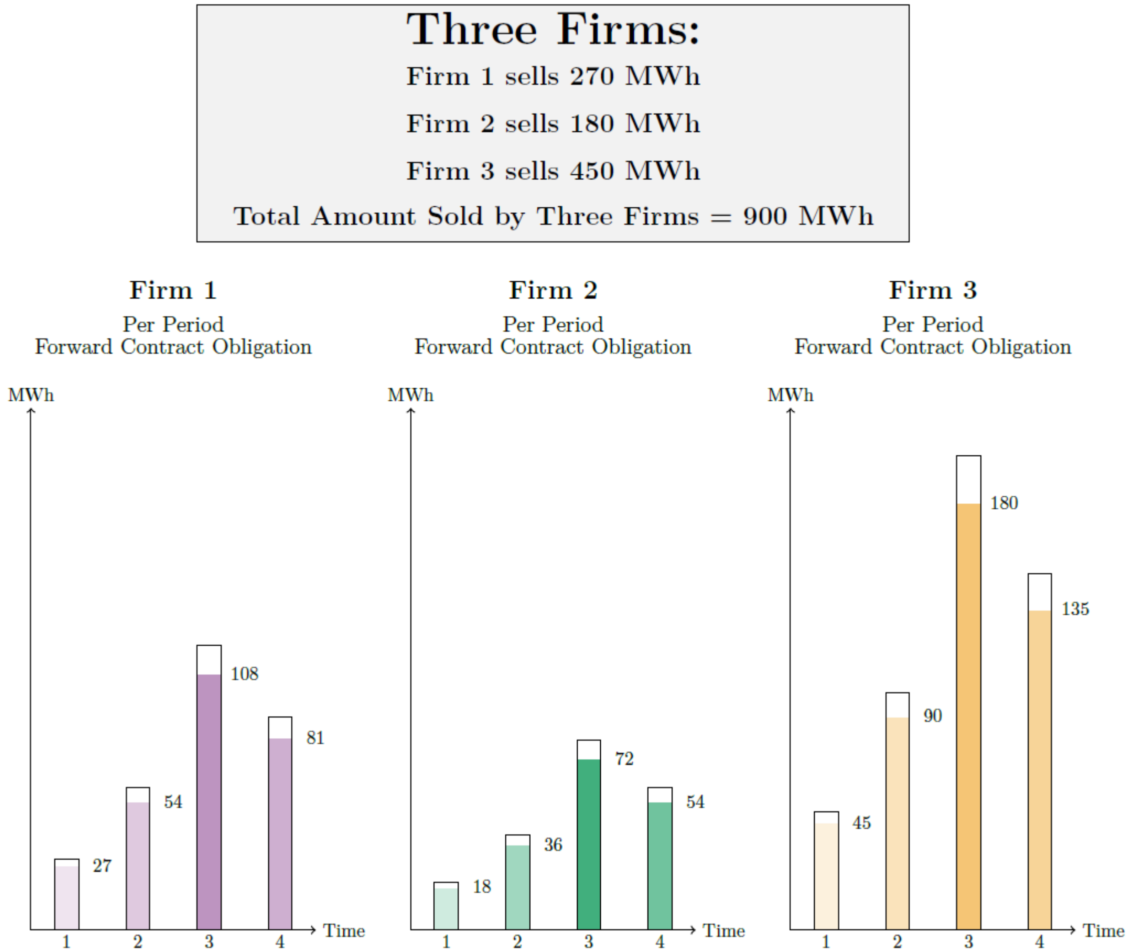

Figure 8: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

Four Retailers:

Retailer 1 holds 90 MWh

Retailer 2 holds 180 MWh

Retailer 3 holds 270 MWh

Retailer 4 holds 360 MWh

Total Amount Held by Four Retailers = 900 MWh

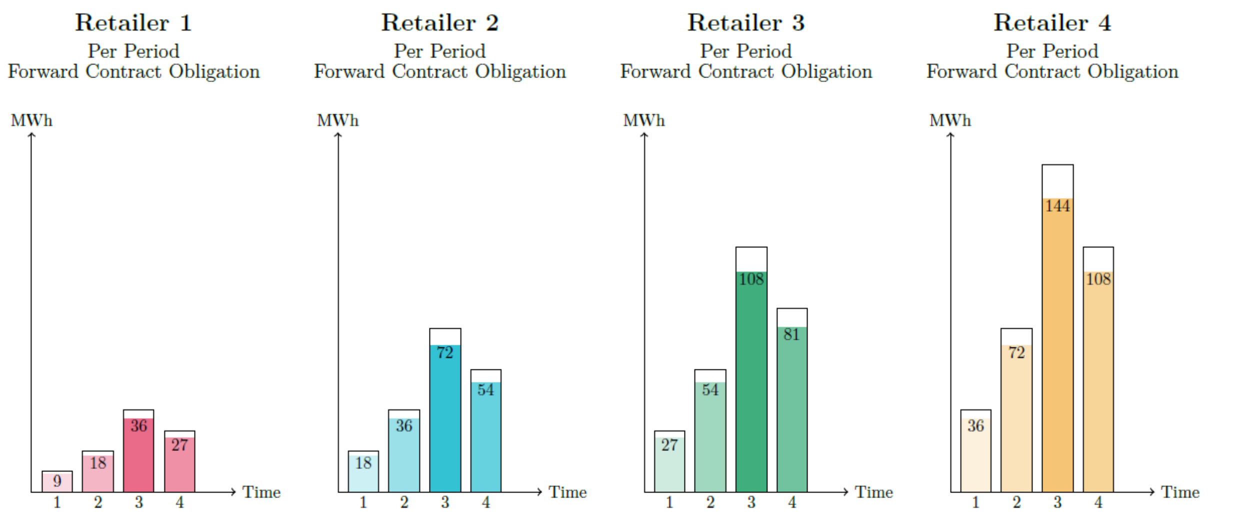

Figure 9: Hourly Forward Contract Quantities for Four Retailers (10 Percent Lower)

Figure 10: Sequencing of Compliance and True-Up Auctions

		Compliance Period Year						
Auction date	**Auction Type**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
December-21	Compliance	Q1-Q4: 100% requirement for all quarters	Q1-Q4: 95% requirement for all quarters	Q1-Q4: 90% requirement for all quarters				
March-22	Compliance							
June-22	Compliance							
September-22	Compliance							
December-22	Compliance		Q1-Q4: 100% (extra 5% for all quarters)	Q1-Q4: 95% (extra 5% for all 4 quarters)	Q1-Q4: 90% requirement for all quarters			
March-23	Compliance							
June-23	Compliance							
September-23	Compliance							
December-23	Compliance			Q1-Q4: 100% (extra 5% for all quarters)	Q1-Q4: 95% (extra 5% for all 4 quarters)	Q1-Q4: 90% requirement for all quarters		
March-24	Compliance and True-up	Q1 True-up						
June-24	Compliance and True-up	Q2 True-up						
September-24	Compliance and True-up	Q3 True-up						
December-24	Compliance and True-up	Q4 True-up			Q1-Q4: 100% (extra 5% for all quarters)	Q1-Q4: 95% (extra 5% for all 4 quarters)	Q1-Q4: 90% requirement for all quarters	
March-25	Compliance and True-up		Q1 True-up					
June-25	Compliance and True-up		Q2 True-up					
September-25	Compliance and True-up		Q3 True-up					
December-25	Compliance and True-up		Q4 True-up			Q1-Q4: 100% (extra 5% for all quarters)	Q1-Q4: 95% (extra 5% for all 4 quarters)	Q1-Q4: 90% requirement for all quarters

III. Appendix B – Revised Proposal issued on December 18, 2020 "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California: The Standardized Fixed-Price Forward Contract Approach"

Long-Term Resource Adequacy in an Intermittent Renewable

and Import Dependent Future in California

by

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1. Introduction

Why is a capacity-based long-term resource adequacy mechanism an increasingly expensive approach to ensuring that the instantaneous supply of electricity equals the instantaneous demand throughout the year in California? First, the state has ambitious renewable energy goals that it plans to meet primarily with intermittent wind and solar resources. Second, California depends on imports for between 25 to 30 percent of its electricity. Third, this import dependence is particularly acute during system conditions when instate wind and solar generation units produce little electricity, as was demonstrated during the second half of August and early in September of 2020. Fourth, defining the firm capacity value of an intermittent renewable wind or solar resource is a difficult, if not impossible, task that becomes increasingly so as the share of wind and solar resources increases.

These factors argue in favor of a long-term resource adequacy mechanism that focuses on achieving what consumers want—the instantaneous supply of electricity equals the instantaneous demand for electricity throughout the year. This document presents a mandated standardized long-term contract for energy approach to achieving this goal. This mechanism can include features of the existing capacity-based mechanism, support retail competition, and reward active participation of final consumers in the wholesale electricity market.

Table 1 presents the installed capacity of grid scale wind and solar generation units in California as of the start of the year and the annual mean, median and standard deviation of the hourly output of these generation units. From 2013 and 2019, the installed capacity of grid scale wind and solar units increased by 328%. The annual median of hourly wind and solar energy production only increased by 231%, while the standard deviation of hourly wind and solar energy production increased 430%. The table also presents the annual coefficient of variation of hourly output (the ratio of the annual standard deviation divided by the annual mean) and the standardized skewness (the ratio of the average value of the mean-centered third power of hourly output divided by the third power of the standard deviation of hourly output). The coefficient of variation increases by 28% from 2013 to 2019 and standardized skewness increased by 326%. These changes in the distribution of hourly wind and solar output imply an increasingly uncertain supply of electricity in California between 2013 and 2019.

The sustained periods of low intermittent renewable energy production implied by the figures in Table 1 and California's dependence on electricity imports creates both a medium and long-term energy supply risk that requires a new long-term resource adequacy mechanism. The traditional capacity-based approach to long-term resource adequacy is unlikely to be the least cost mechanism for ensuring that the demand for energy is met throughout the year.

In a zero marginal cost intermittent future, wind and solar resources must hedge their energy supply risk with controllable generation resources in order to maintain long-term resource adequacy. Cross hedging between these technologies accomplishes two goals. First, it can provide the revenue stream necessary for fixed cost recovery by controllable generation units. Second, it ensures that there is sufficient controllable generation to meet demand under all foreseeable future system states, with a high degree of confidence.

Table 1: Capacity in MW and Features of Distribution of

Hourly Wind and Solar Output in MWh by Year

Year	2013	2014	2015	2016	2017	2018	2019
Mean	1348	2132	2510	3115	3869	4520	4617
Standard Deviation	883	1461	1983	2427	3258	3606	3818
Median	1364	1971	2031	2386	2596	3256	3150
Coefficient of Variation	0.65	0.69	0.79	0.78	0.84	0.80	0.83
Standardized. Skew	0.19	0.45	0.63	0.55	0.60	0.55	0.62
Standardized. Kurtosis	2.32	2.50	2.95	2.07	1.97	1.96	2.03
Capacity in (MW)*	4873	7698	9652	11,850	14,224	15,113	15,992

*As of the beginning of the year.

This paper presents a long-term resource adequacy mechanism for designed for an electricity supply industry with a large share of zero marginal cost intermittent renewables and substantial import dependence. I first explain why a wholesale electricity market requires a long-term resource adequacy mechanism. I then describe a mandated standardized long-term contract approach to long-term resource adequacy that provides strong incentives for intermittent renewable resource owners to hedge their energy supply risk with controllable generation resource owners. This mechanism ensures long-term resource adequacy in markets with retail competition while also allowing the short-term wholesale price volatility that can finance investments in storage and other load-shifting technologies necessary to manage a large share of intermittent renewable resources. Finally, I outline a process for transitioning to the mandated standardized long-term contract for energy mechanism and describe how this transition can utilize features of the existing capacity-based mechanism.

2. Resource Adequacy with Significant Intermittent Renewables

Why do wholesale electricity markets require a regulatory mandate to ensure long-term resource adequacy? Electricity is essential to modern life, but so are many other goods and services. Consumers want cars, but there is no regulatory mandate that ensures enough automobile assembly plants to produce these cars. They want point-to-point air travel, but there is no regulatory mandate to ensure enough airplanes to accomplish this. Many goods are produced using high fixed cost, low marginal cost technologies, similar to electricity supply. Nevertheless, these firms recover their cost of production, including a return on the capital invested, by selling their output at a market-determined price.

So, what is different about electricity that requires a long-term resource adequacy mechanism? The regulatory history of the electricity supply industry and the legacy technology for metering electricity consumption results in what I call a *reliability externality.*

2.1. The Reliability Externality

Different from the case of wholesale electricity, in the market for automobiles and air travel there is no regulatory prohibition on the short-term price rising to the level necessary to clear the market. Airlines adjust the prices for seats on a flight over time in an attempt to ensure that the number of customers traveling on that flight equals the number of seats flying. This ability to use price to allocate the available seats is also what allows the airline to recover its total production costs.

Using the short-term price to manage the real-time supply and demand balance in a wholesale electricity market is limited by a finite upper bound on a supplier's offer price and/or a price cap that limits the maximum market-clearing price. Although offer caps and price caps can limit the ability of suppliers to exercise unilateral market power in the short-term energy market, they also reduce the revenues suppliers can receive during scarcity conditions. This is often referred to as the *missing money* problem for generation unit owners. However, this missing money problem is only a symptom of the existence of the "reliability externality."

This externality exists because offer caps limit the cost to electricity retailers of failing to hedge their purchases from the short-term market. Specifically, if the retailer or large consumer knows the price cap on the short-term market is $250/MWh, then it is unlikely to be willing to pay more than that for electricity in any earlier forward market. This creates the possibility that real-time system conditions can occur where the amount of electricity demanded at or below the offer cap is less than the amount suppliers are willing to offer at or below the offer cap. This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail load until the available supply offered at or below the offer cap equals the reduced level of demand, as occurred a number of times in California between January 2001 and April 2001, and most recently on August 14 and 15, 2020.

Because random curtailments of supply—also known as rolling blackouts—are used to make demand equal to the available supply at or below the offer cap under these system conditions, this mechanism creates a "reliability externality" because no retailer bears the full cost of failing to procure adequate amounts of energy in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its actual demand is equally likely to be randomly curtailed as another retailer of the same size that has not procured adequate energy in the forward market. For this reason, all retailers have an incentive to under-procure their expected energy needs in the forward market.

The lower the offer cap, the greater is the likelihood that the retailer will delay their electricity purchases to the short-term market. Delaying more purchases to the short-term market increases the likelihood of insufficient supply in the short-term market at or below the offer cap. Because retailers do not bear the full cost of failing to procure sufficient energy in the forward market, there is a missing market for long-term contracts for energy with long enough delivery horizons into the future to allow new generation units to be financed and constructed to serve demand under all future conditions in the short-term market. Therefore, a regulator-mandated long-term resource adequacy mechanism is necessary to replace this missing market.

Some form of regulatory intervention is necessary to internalize the resulting reliability externality, unless the regulator is willing to eliminate or substantially increase the offer cap so that the short-term price can be used to equate available supply to demand under all possible future system conditions. This approach is taken by the Electricity Reliability Council of Texas (ERCOT), which has a $9,000/MWh offer cap, and National Electricity Market in Australia, which has a 15,000 Australia Dollars per MWh offer cap. However, raising the offer cap on the short-term market does not eliminate the reliability externality; it just reduces the set of future system conditions when random curtailments will be needed to balance real-time supply and demand. In addition, if customers do not have interval meters that can record their consumption on an hourly basis, then they have a very limited ability to benefit from shifting their consumption away from high-priced hours. All that can recorded for these customers is their total consumption between two successive meter readings so they can only be billed based on an average wholesale price during the billing cycle. Therefore, raising or having no offer cap on the short-term market would not be advisable in a region where few customers have interval meters. Even in regions with interval meters, there would be substantial political backlash from charging hourly wholesale prices that cause real-time demand to equal available supply under all possible future system conditions.

Currently, the most popular approach to addressing this reliability externality is a capacity procurement mechanism that assigns a firm capacity value to each generation unit based on the amount of energy it can provide under stressed system conditions. Under the current long-term resource adequacy mechanism in California, sufficient firm capacity procurement obligations are then assigned to retailers to ensure that annual system demand peaks can be met.

Capacity-based approaches to long-term resource adequacy rely on the credibility of the firm capacity measures assigned to generation units. This is a relatively straightforward process for thermal units. The nameplate capacity of the generation unit times its annual availability factor is a reasonable estimate of the amount of energy the unit can provide under stressed system conditions. For the case of hydroelectric facilities, this process is less straightforward. The typical approach uses percentiles of the distribution of past hydrological conditions for that generation unit to determine its firm capacity value.

Assigning a firm capacity value to a wind or solar generation unit is extremely challenging for several reasons. First, these units only produce when the underlying resource is available. If stressed system conditions occur when the sun is not shining or the wind is not blowing, these units should be credited with little, if any, firm capacity value. Second, because there is a high degree of contemporaneous correlation between the energy produced by solar and wind facilities within the same region, the usual approach to determining the firm capacity of a wind or solar unit assigns a smaller value to that unit as the total MWs of wind or solar capacity in the region increases. For example, on

August 14, 2020 the amount of wind energy produced from the almost 6,000 MW of wind capacity in California during the late evening when the rolling blackouts occurred was less than 700 MWh. In contrast, the effective load carrying capacity (ELCC) for wind units during August 2020 was set at 21 percent, which implies a firm capacity value of the 6,000 MW of wind capacity of more than 1200 MW. The trends in the annual distributions of hourly wind and solar output shown in Table 1 imply that these types of outcomes are increasingly likely in a capacity-based long-term resource adequacy mechanism as the share of intermittent wind and solar resources in California increases.

According to the California Energy Commission, the amount of natural gas-fired generation capacity in the state has declined by more than 8,500 MW between 2013 and 2019. This implies that when there are low levels of renewable energy production in California, the state must rely on electricity imports to serve demand. The out-of-state generation unit assumed to provide an electricity import is largely a purely financial construct because energy flows into the California because more energy is produced in the rest of Western Electricity Coordinating Council (WECC) than is being consumed there and less energy is being produced in California than is consumed in the state. Unless California builds additional controllable generation resources or makes substantial investments in energy storage, the state will be increasingly reliant on energy imports (that occur because more energy is produced outside of California that is being consumed outside of the state and not because a specific out-of-state generation unit is producing energy) particularly when instate renewable energy production is low. These trends provide further evidence against California continuing to rely on a capacity-based long-term resource adequacy mechanism.

2.2. Supplier Incentives with Fixed-Price Forward Contract Obligations for Energy

The standardized fixed-price forward contract (SFPFC) approach to long-term resource adequacy recognizes that a supplier with the ability to serve demand at a reasonable price may not do so if it has the ability to exercise unilateral market power in the short-term energy market. A supplier with the ability to exercise unilateral market power with a fixed-price forward contract obligation finds it expected profit maximizing to minimize the cost of supplying this forward contract quantity of energy. The SFPFC long-term resource adequacy mechanism takes advantage of this incentive by requiring retailers to hold hourly fixed-price forward contract obligations for energy that sum to the hourly value of system demand. This implies that all suppliers find it expected profit maximizing to minimize the cost of meeting their hourly fixed-price forward contract obligations, the sum of which equals the hourly system demand for all hours of the year.

To understand the logic behind the SFPFC mechanism, consider the example of a supplier that owns 150 MWs generation capacity that has sold 100 MWh in a fixed-forward contract at a price of $25/MWh for a certain hour of the day. This supplier has two options for fulfilling this forward contract: (1) produce the 100 MWh energy from its own units at their marginal cost of $20/MWh or (2) buy this energy from the short-term market at the prevailing market-clearing price. The supplier will receive $2,500 from the buyer of the contract for the 100 MWh sold, regardless of how it is supplied. This means that the supplier maximizes the profits it earns from this fixed-price forward contract sale by minimizing the cost of supplying the 100 MWh of energy.

To ensure that the least-cost "make versus buy" decision for this 100 MWh is made, the supplier should offer 100 MWh in the short-term market at its marginal cost of $20/MWh. This offer price for 100 MWh ensures that if it is cheaper to produce the energy from its generation units—the market price is at or above $20/MWh—the supplier's offer to produce the energy will be accepted in the short-term market. If it is cheaper to purchase the energy from the short-term market—the market price is below $20/MW—the supplier's offer will not be accepted and the supplier will purchase the 100 MWh from the short-term market at a price below $20/MWh.

This example demonstrates that the SFPFC approach to long-term resource adequacy makes it expected profit maximizing for each seller to minimize the cost supplying the quantity of energy sold in this forward contract each hour of the delivery period. By the logic of the above example, each supplier will find it in its unilateral interest to submit an offer price into the short-term market equal to its marginal cost for its hourly SFPFC quantity of energy, in order to make the efficient "make versus buy" decision for fulfilling this obligation.

If each supplier knows that the sum of the values of the hourly SFPFC obligations across all suppliers is equal the system demand, each firm knows that its competitors have substantial fixed-price forward contract obligations for that hour. This implies that all suppliers know that they have limited opportunities to raise the price they receive for short-term market sales beyond their hourly SFPFC quantity. For the above example, the supplier that owns 150 MWs of generation capacity has a strong incentive to submit an offer price close to its marginal cost to supply any energy beyond the 100 MWh of SFPFC energy it is capable of producing. Therefore, attempts by any supplier to raise prices in the short-term market by withholding output beyond their SFPFC quantity are likely to be unsuccessful because of the aggressiveness of the offers into the short-term market by its competitors with hourly SFPFC obligations.

2.3. SFPFC Approach to Resource Adequacy

This long-term resource adequacy mechanism requires all electricity retailers to hold SFPFCs for energy for fractions of realized system demand at various horizons to delivery. For example, retailers in total must hold SFPFCs that cover 100 percent of realized system demand in the current year, 95 percent of realized system demand one year in advance of delivery, 90 percent two-years in advance of delivery, 87 percent three years in advance of delivery, and 85 percent four years in advance of delivery. The fractions of system demand and number of years in advance that the SFPFCs must be purchased are parameters set by the regulator to ensure long-term resource adequacy. In the case of a multi-settlement LMP market, the SFPFCs would clear against the quantity-weighted average of the hourly locational prices at all load withdrawal nodes.

SFPFCs are shaped to the hourly system demand within the delivery period of the contract. Figure 1 contains a sample pattern of system demand for a four-hour delivery horizon. The total demand for the four hours is 1000 MWh, and the four hourly demands are 100 MWh, 200 MWh, 400 MWh and 300 MWh. Therefore, a supplier that sells 300 MWh of SFPFC energy has the hourly system demand-shaped forward contract obligations of 30 MWh in hour 1, 60 MWh in hour 2, 120 MWh in hour 3 and 90 MWh in hour 4 for Firm 1 in Figure 2. The hourly forward contract obligations for Firm 2 that sold 200 MWh SFPFC energy and Firm 3 that sold 500 MWh of SFPFC energy are also shown in Figure 2.

These SFPFC obligations are also allocated across the four hours according to the same four hourly shares of total system demand. This ensures that the sum of the hourly values of the forward contract obligations for the three suppliers is equal to the hourly value of system demand. Taking the example of hour 3, Firm 1's obligation is 120 MWh, Firm 2's is 80 MWh and Firm 3's is 200 MWh. These three values sum to 400 MWh, which is equal to the value of system demand in hour 3 shown in Figure 1.

These standardized fixed-price forward contracts are allocated to retailers based on their share of system demand during the month. Suppose that the four retailers in Figure 3 consume 1/10, 2/10, 3/10, and 4/10, respectively, of the total energy consumed during the month. This means that Retailer 1 is allocated 100 MWh of the 1000 MWh SFPFC obligations for the four hours, Retailer 2 is allocated 200 MWh, Retailer 3 is allocated 300 MWh, and Retailer 4 is allocated 400 MWh. The obligations of each retailer are then allocated to the individual hours using the same hourly system demand shares used to allocate the SFPFC energy sales of suppliers to the four hours. This allocation process implies Retailer 1 holds 10 MWh in hour 1, 20 MWh in hours 2, 40 MWh in hour 3 and 30 MWh in hour 4. Repeating this same allocation process for the other three retailers yields the remaining three hourly allocations shown in Figure 3. Similar to the case of the suppliers, the sum of allocations across the four retailers for each hour equals the total hourly system demand. For period 3, Retailer 1's holding is 40 MWh, Retailer 2's is 80 MWh, Retailer 3's is 120 MWh, and Retailer 4's is 160 MWh. The sum of these four magnitudes is equal to 400 MWh, which is the system demand in hour 3.

2.4. Mechanics of Standardized Forward Contract Procurement Process

The SFPFCs would be purchased through auctions several years in advance of delivery in order to allow new entrants to compete to supply this energy. Because the aggregate hourly values of these SFPFC obligations are allocated to retailers based on their actual share of system demand during the month, this mechanism can easily accommodate retail competition. If one retailer loses load and another gains it during the month, the share of the aggregate hourly value of SFPFCs allocated to the first retailer falls and the share allocated to the second retailer rises.

The wholesale market operator would run the auctions with oversight by the regulator. One advantage of the design of the SFPFC products is that a simple auction mechanism can be used to purchase each annual product. A multi-round auction could be run where suppliers submit the total amount of annual SFPFC energy they would like to sell for a given delivery period at the price for the current round. Each round of the auction the price would decrease until the amount suppliers are willing to sell at that price is less than or equal to the aggregate amount of SFPFC energy demanded.

The wholesale market operator would also run a clearinghouse to manage the counterparty risk associated with these contracts. All US wholesale market operators currently do this for all participants in their energy and ancillary services markets. In several US markets, the market operator also provides counterparty risk management services for long-term financial transmission rights, which is not significantly different from performing this function for SFPFCs.

SFPFCs auctions would be run on an annual basis for deliveries starting two, three, and four years in the future. In steady state, auctions for incremental amounts of each annual contract would also be needed so that the aggregate share of demand covered by each annual SFPFC could increase over time. The eventual 100 percent coverage of demand occurs through a final true-up auction that takes place after the realized values for hourly demand for the delivery period are known.

The following two examples illustrate how the true-up auctions would work. Assume for simplicity, the monthly load shares of the four retailers remain unchanged. Suppose that the initial 1000 MWh SFPFC in the above example sold at $50/MWh. However, suppose that actual demand turned out to be 10 percent higher in every period as shown Figure 4 and the additional 100 MWh purchased in the true-up auction sold at $80/MWh. If each firm sold 10 percent more SFPFC energy in the true-up auction this would yield the hourly obligations for each supplier shown in Figure 5. The hourly obligations for the four retailers are shown in Figure 6. These would clear against the average cost of purchases from the original auction and true-up auction of $52.73.

If the realized hourly demands are ten percent lower as shown in Figure 7, the true-up auction would buy back 100 MWh of SFPFC energy. If all suppliers bought back 10 percent of their initial sales at $20/MWh, the resulting hourly obligations would be those shown in Figure 8. The 10 percent smaller hourly obligations of the four retailers are shown in Figure 9 and these would clear against the average cost of the initial auction purchase less the revenues from the true-up auction sales for the required 900 MWh of obligations of $53.33.

As shown in Figures 6 and 9, each purchase or sale of the same annual SFPFC product is allocated to retailers according to their load shares during the delivery month. If three different size purchases are made for the same annual SFPFC product at different prices, then each retailer is allocated its load share for the month of these three purchases. This ensures a level playing field for retailers with respect to their long-term resource adequacy obligation. All retailers face the same average price for the long-term resource adequacy obligation associated with their realized demand for the month.

The advance purchase fractions of the final demand are the regulator's security blanket to ensure that system demands can be met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual SFPFC auction. As shown above, if too much SFPFC energy is purchased in an annual auction, it can be sold back to generation unit owners in a later auction or the final true-up auction.

2.5. Incentives for Behavior by Intermittent Renewable and Controllable Resources

Because all suppliers know that all energy consumed every hour of the year is covered by a SFPFC in the current year and into the future, there is a strong incentive for suppliers to find the least cost mix intermittent and controllable resources to serve these hourly demands. To the extent that there is concern that the generation resources available or likely to be available in the future to meet demand are insufficient, features of the existing capacity-based resource adequacy mechanism can be retained until system operators have sufficient confidence in this mechanism leading to a reliable supply of energy. The firm capacity values from the existing capacity-based long-term resource adequacy approach can be used to limit the amount of SFPFC energy a supplier can sell.

The firm capacity value multiplied by number of hours in the year would be the maximum amount of SFPFC energy that the unit owner could sell in any given year. Therefore, a controllable thermal generation unit owner could sell significantly more SFPFC energy than it expects to produce annually and an intermittent renewable resource owner could sell significantly less SFPFC energy than it expects to produce annually. This upper bound on the amount of SFPFC energy any in-state generation unit could sell enforces cross hedging between controllable in-state generation units and intermittent renewable resources.

The current capacity-based requirements on out-of-state suppliers could put limitations on the maximum amount of SFPFC energy they could sell in a year. For example, if an out-of-state supplier has 10 MWs of firm capacity not committed to provide energy to consumers in its home state, then it could sell at most 87,600 MWh of SFPFC on an annual basis.

This mechanism uses the firm capacity construct to limit forward market sales of energy by individual resource owners to ensure that it is physically feasible to serve demand throughout California during all hours of the year, but only purchases the commodity that consumers want energy. Because all suppliers know that system demand each hour of the year is covered by a SFPFC purchased in advance of delivery (except for the true-up quantities discussed earlier), collectively suppliers have a strong financial incentive to find the least cost way to serve this demand, regardless of real-time system conditions.

In most years, a controllable resource owner would be producing energy in a small number of hours of the year, but earning the difference between the price at which they sold the energy in the SFPFC auction and the hourly short-term market price times the hourly value of its SFPFC energy obligation for all the hours that it does not produce energy. Intermittent renewables owners would typically produce more than their SFPFC obligation in energy and sell the additional energy at the short-term price. In years with low renewable output near their SFPRC obligations, controllable resource owners would produce close to the hourly value of their SFPFC energy obligation, thus making average short-term prices significantly higher. However, aggregate retail demand would be shielded from these high short-term prices because of their SFPC holdings.

2.4. Advantages of SFPFC Approach to Long-Term Resource Adequacy

This mechanism has a number of advantages relative to a capacity-based approach. There is no regulator-mandated aggregate capacity requirement. Generation unit owners are allowed to decide both the total MWs and the mix of technologies to meet their SFPFC energy obligations. There is also no prohibition on generation unit owners or retailers engaging in other hedging arrangements outside of this mechanism. Specifically, a retailer could enter into a bilateral contract for energy with a generation unit owner or other retailer to manage the short-term price and quantity risk associated with the difference between their actual hourly load shape and the hourly values of their retail load obligation.

This mechanism provides a nudge to market participants to develop a liquid market for these bilateral contract arrangements at horizons to delivery similar to the SFPFC products. Instead of starting from the baseline of no fixed-price forward contract coverage of system demand by retailers, this mechanism starts with 100 percent coverage of system demand, which retailers can unwind at their own risk.

This baseline level of SFPFC coverage of final demand is a more prudent approach to long-term resource adequacy in a region such as California where the vast majority of customers purchase their electricity according to a fixed retail price or price schedule that does not vary with real-time system conditions. A baseline 100 percent SFPFC coverage of final demand provides the retailer with wholesale price certainty for virtually all of its wholesale energy purchases (except for the small true-up uncertainty described above), that significantly limits the financial risk retailers faces from selling retail electricity at a fixed price and purchasing this energy from a wholesale market with increasingly volatile wholesale prices.

An additional benefit of this mechanism is that the retail market regulator, this case the California Public Utilities Commission (CPUC), can use the purchase prices of SFPFCs to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. This would provide retailers with a strong incentive to reduce their average wholesale energy procurement costs below this price through bilateral hedging arrangements, storage investments, or demand response efforts.

There are several reasons why this mechanism should be a more cost-effective approach to long-term resource adequacy than a capacity-based mechanism in a zero marginal cost intermittent future. First, the sale of SFPFC energy starting delivery two or more years in the future provides a revenue stream that will significantly increase investor confidence in recovering the cost of any investment in new generation capacity.

Second, because retailers are protected from high short-term prices by total hourly SFPFC holdings equal to system demand, the offer cap on the short-term market can be raised in order to increase the incentive for all suppliers to produce as much energy as possible during stressed system conditions. Third, the possibility of higher short-term price spikes can finance investments in storage and load-shifting technologies and encourage active participation of final demand in the wholesale market, further enhancing system reliability in a market with significant intermittent renewable resources.

If SFPFC energy is sold for delivery in four years based on a proposed generation unit, the regulator should require construction of the new unit to begin within a pre-specified number of months after the signing date of the contract or require posting of a substantially larger amount of collateral in the clearinghouse with the market operator. Otherwise, the amount of SFPFC energy that this proposed unit sold would be automatically liquidated in a subsequent SFPFC auction and a financial penalty would be imposed on the developer. Other completion milestones would have to be met at future dates to ensure the unit is able to provide the amount of firm energy that it committed to provide in the SFPFC contract sold. If any of these milestones were not met, the contract would be liquidated.

3. Transition to SFPFC Mechanism in California

With sufficient advance notice, transitioning to the SFPFC approach to long-term resource adequacy in California would be relatively straightforward because, as noted above, this mechanism makes use of features of the existing capacity-based mechanism. The first step in the transition would be a plan for phasing out the existing capacity-based mechanism in four years. SFPFC auctions for delivery in four years would then be run. This would provide sufficient advance notice for market participants to adapt the mix of supply resources to the new long-term resource adequacy mechanism.

All SFPFCs would clear against the quantity-weighted average of real-time locational marginal prices (LMPs) at all load-withdrawal nodes in California. By the logic described above, this would ensure that all sellers of SFPFCs collectively have a strong incentive to ensure that real-time demands, not the day-ahead demands, at all locations in California are met at least cost. Retailers would face some locational short-term price risk because of differences between this price and the load aggregation point (LAP) price they are charged for purchases of energy from the short-term market. Financial transmission rights could be allocated to loads to hedge a significant fraction of this residual locational price risk.

Each subsequent year in the transition, another SFPFC auction for energy to be delivered in four years would be run. Incremental SFPFC auctions for deliveries in three, two and one year would also be run to achieve aggregate SFPFC quantities that satisfy the increasing advance purchase percentages of realized system demand described earlier. The clearinghouse would adjust collateral requirements of the sellers and buyers of these SFPFCs throughout the year to ensure that each side of the transaction will fulfill their obligation when these contracts clear. Once the first year that the SFPFC obligations clear, there would also be a true-up auction to ensure 100% coverage of realized demand.

It is important to emphasize how this mechanism provides financial incentives to serve the demand at all locations in California at least cost. Because all SFPFCs clear against the quantity-weighted average of the hourly real-time LMPs, sellers of SFPFCs collectively have a financial incentive to ensure that nodal price spikes do not occur because of a local scarcity condition or other local reliability event.

The following example illustrates this incentive. Suppose a supplier that owns a 150 MWh unit located in a generation pocket has sold 100 MWh of SFPFC energy for $50/MWh, but only small fraction of this energy is consumed at nearby nodes. Suppose that the price spikes at a one or more load nodes and this leads to a quantity-weighted average LMP of $500/MWh. Suppose this supplier was able to sell 100 MWh in the short-term market in this generation pocket for $40/MWh. In this case, the supplier's variable profit is ($40/MWh - $30/MWh)*100 MWh – ($500/MWh - $50/MWh)*100 MWh, assuming its marginal cost is $30/MWh. Consequently, even if the supplier is able to sell its SFPFC quantity of energy in the short-term market, the second term in the supplier's variable profits that results from clearing of the its SFPFC obligations provides a strong incentive for it to take actions to ensure that price spikes at load withdrawal nodes do not occur. Transmission constraints out of the generation pocket that limit the amount of energy the supplier can sell in the short-term market further reduce the supplier's variable profits. This fact implies an additional incentive for sellers of SFPFCs to serve system demand at least cost.

To the extent that there is concern that these financial incentives are insufficient for generation unit owners to address all local reliability issues, separate SFPFC products could be created for regions of the state. For example, there could separate SFPFCs for the demand nodes in Northern California and the demand nodes in Southern California. Only suppliers with the ability to deliver energy from their capacity to demand in Northern California could sell in the Northern California SFPFC auction. A similar requirement would apply for sellers in the Southern California SFPFC auction. The Northern California SFPFC obligations would be assigned to Northern California retailers and the Southern California SFPFC obligation would be assigned to Southern California retailers. By having fewer load nodes included in the clearing prices for Northern and Southern California SFPFCs, price spikes at individual nodes in these regions would have a greater impact of the clearing price and therefore provide stronger incentives for suppliers to minimize the cost serving demand in both Northern and Southern California.

4. Final Comments

Wholesale market design is a process of continuous learning, adaption, and hopefully, improvement. The transition of the California electricity supply industry from a system based on controllable natural gas-fired generation units to a system based on intermittent wind and solar resources and controllable energy from electricity imports requires a change in the market design. The standardized energy contracting approach to long-term resource adequacy described in this paper is designed to achieve a reliable supply energy under all possible future system conditions for this new industry structure.

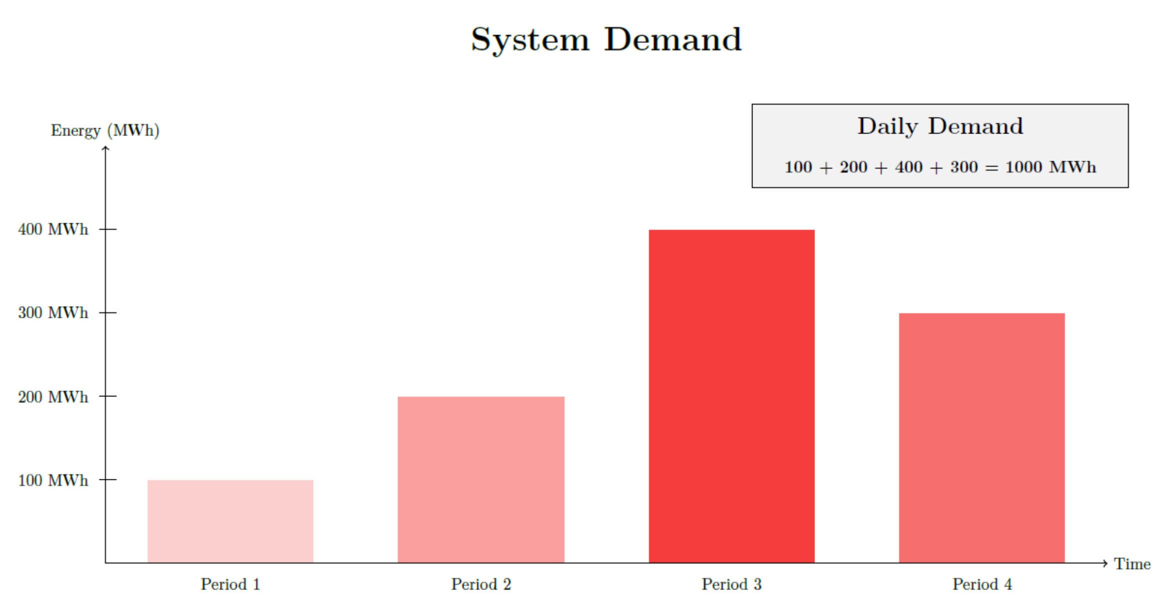

Figure 1: Hourly System Demands

Three Firms:

Firm 1 sells 300 MWh

Firm 2 sells 200 MWh

Firm 3 sells 500 MWh

Total Amount Sold by Three Firms = 1000 MWh

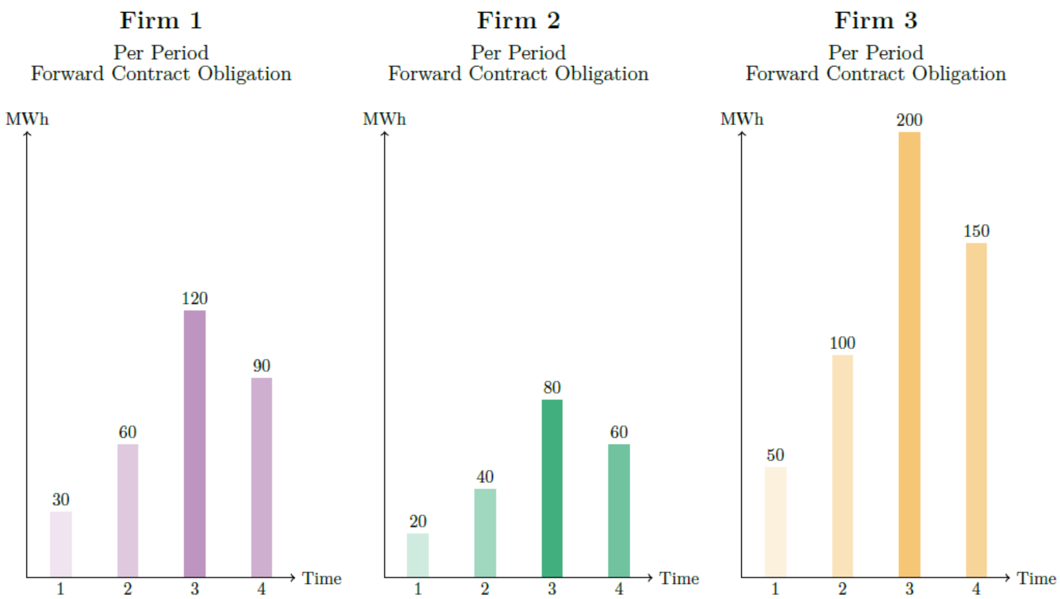

Figure 2: Hourly Forward Contract Quantities for Three Suppliers

Four Retailers:

Retailer 1 holds 100 MWh

Retailer 2 holds 200 MWh

Retailer 3 holds 300 MWh

Retailer 4 holds 400 MWh

Total Amount Held by Four Retailers = 1000 MWh

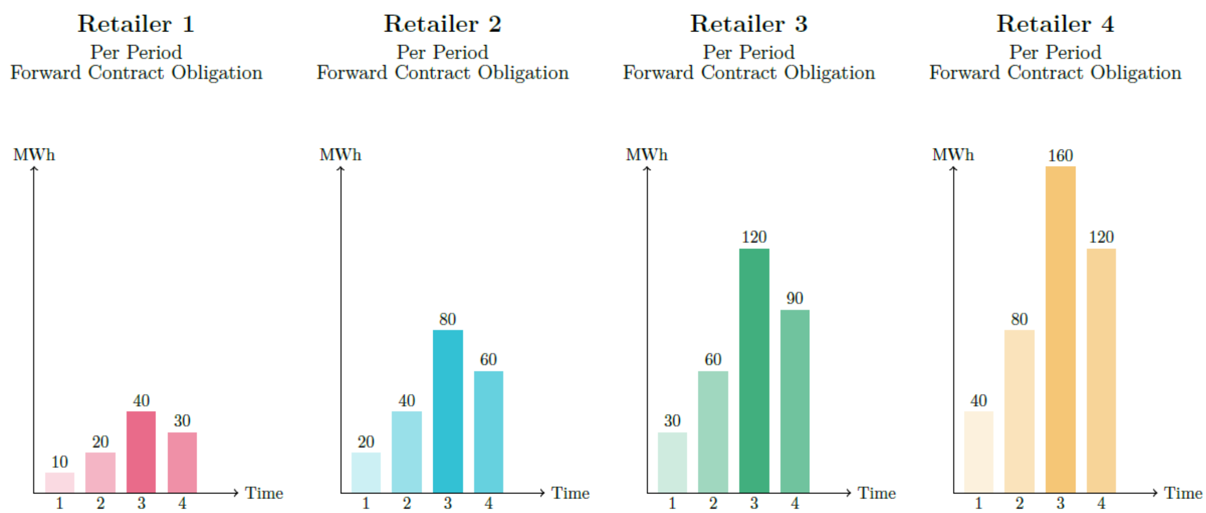

Figure 3: Hourly Forward Contract Quantities for Four Retailers

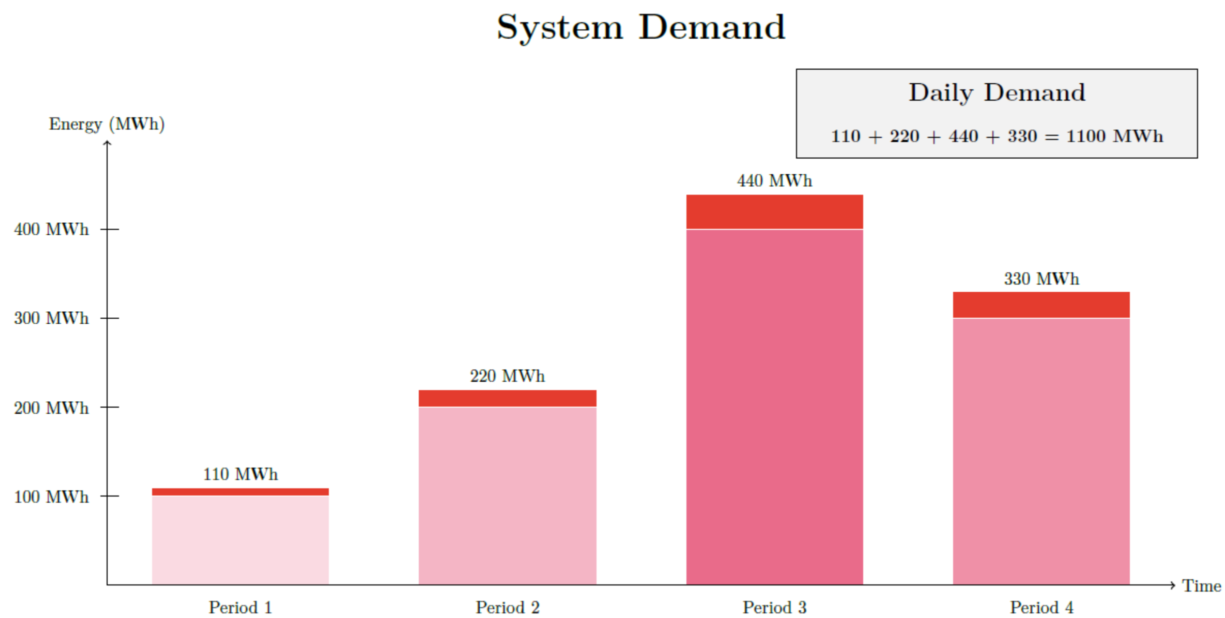

Figure 4: Hourly System Demands (10 Percent Higher)

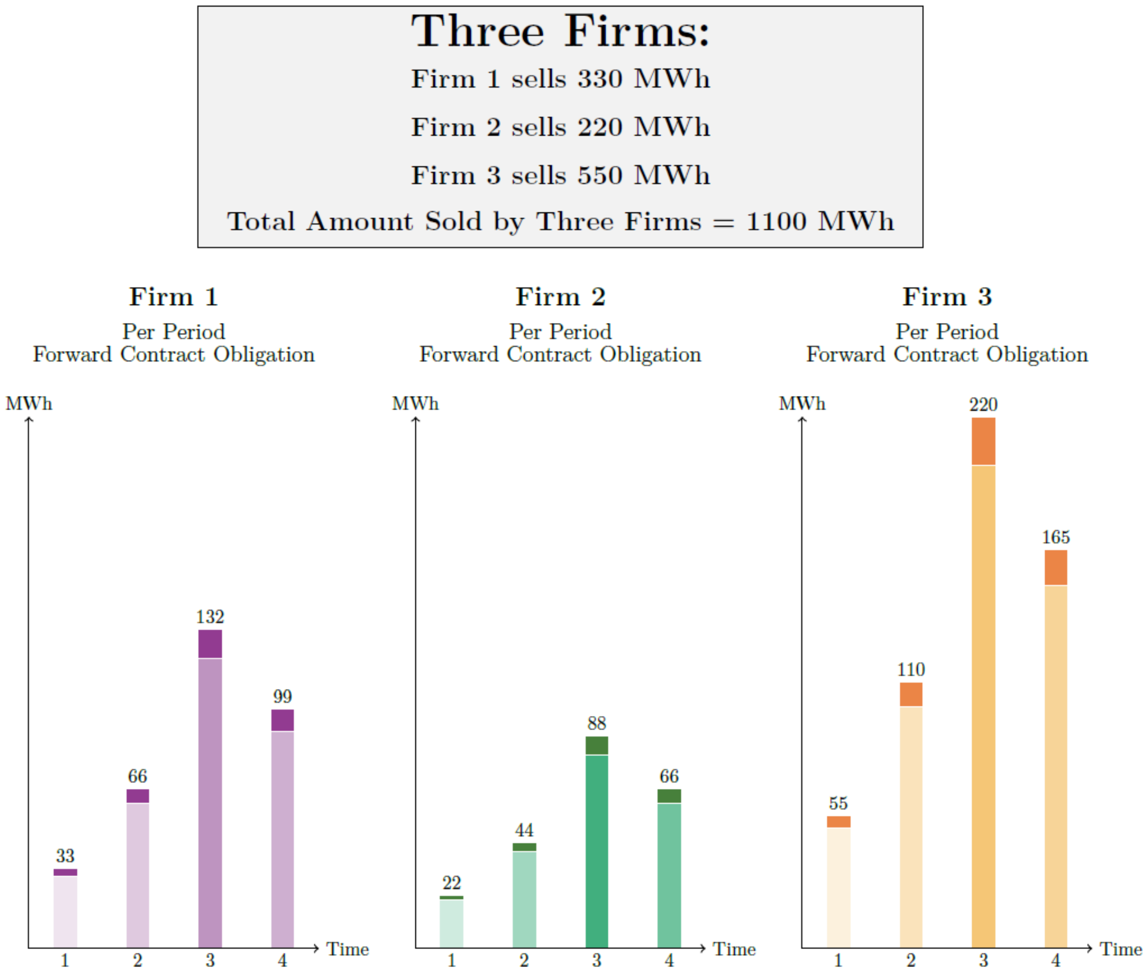

Figure 5: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

Four Retailers:

Retailer 1 holds 110 MWh

Retailer 2 holds 220 MWh

Retailer 3 holds 330 MWh

Retailer 4 holds 440 MWh

Total Amount Held by Four Retailers = 1100 MWh

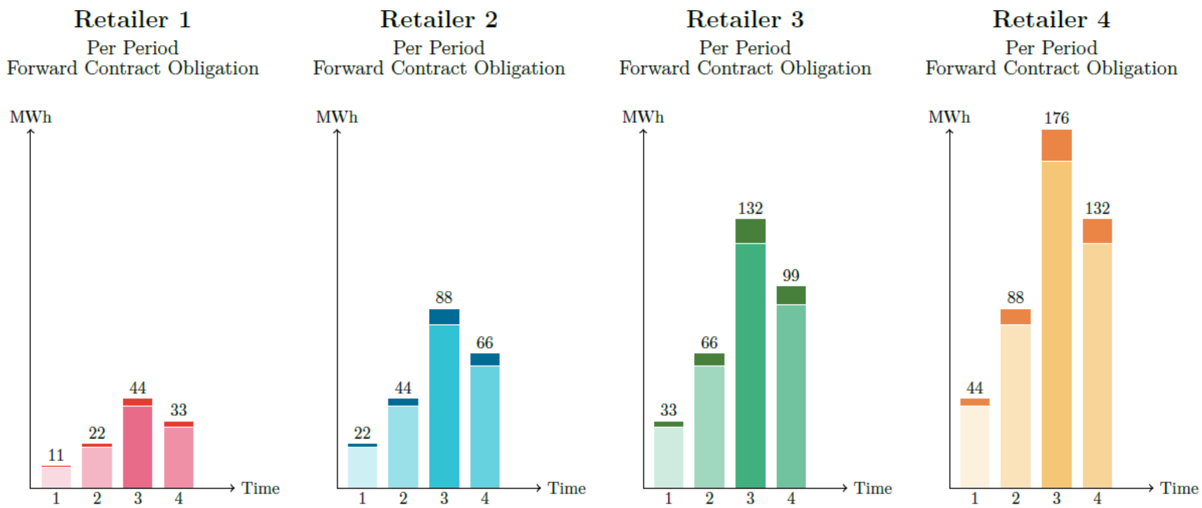

Figure 6: Hourly Forward Contract Quantities for Four Retailers (10 Percent Higher)

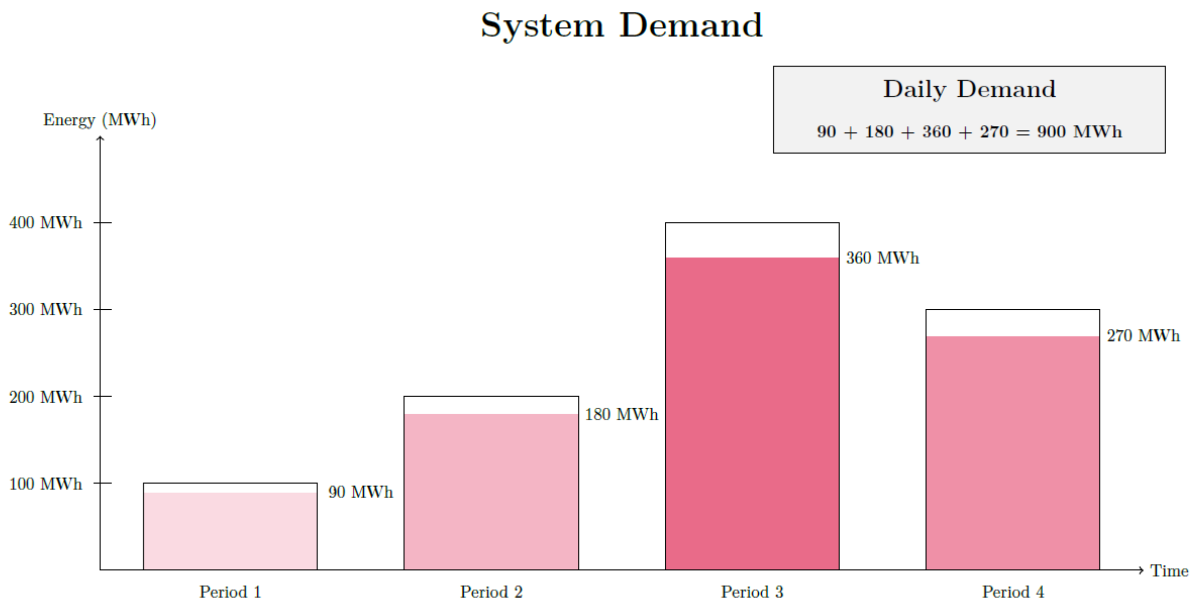

Figure 7: Hourly System Demands (10 Percent Lower)

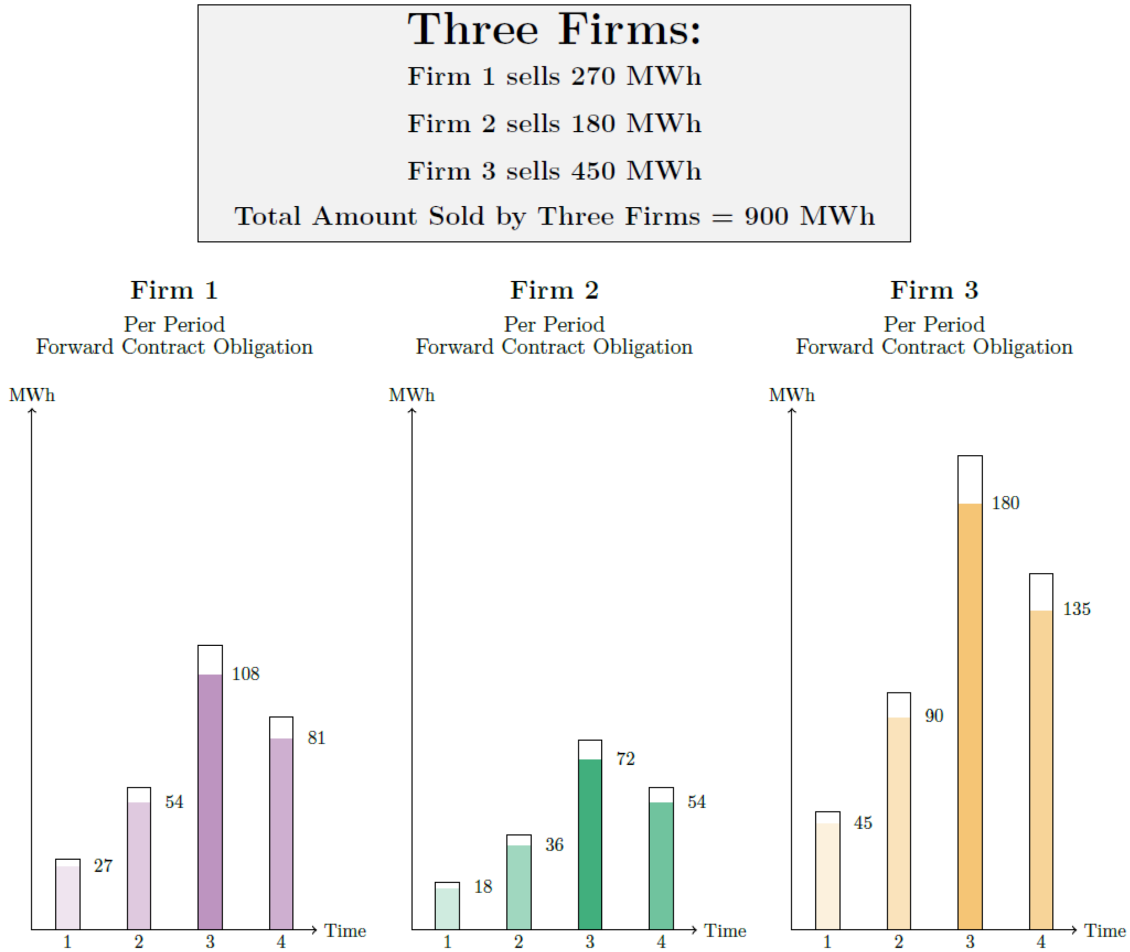

Figure 8: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

Four Retailers:

Retailer 1 holds 90 MWh

Retailer 2 holds 180 MWh

Retailer 3 holds 270 MWh

Retailer 4 holds 360 MWh

Total Amount Held by Four Retailers = 900 MWh

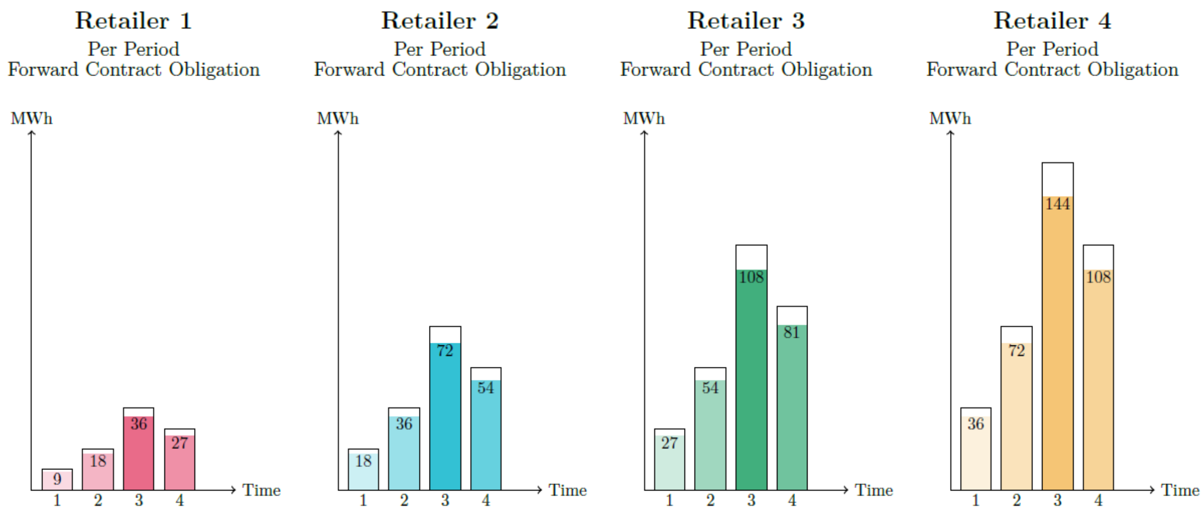

Figure 9: Hourly Forward Contract Quantities for Four Retailers (10 Percent Lower)