Day 3 of Track 3.B.2 Workshops

Wednesday, February 10, 2021

9:30 a.m. – 2 p.m.

California Public Utilities Commission

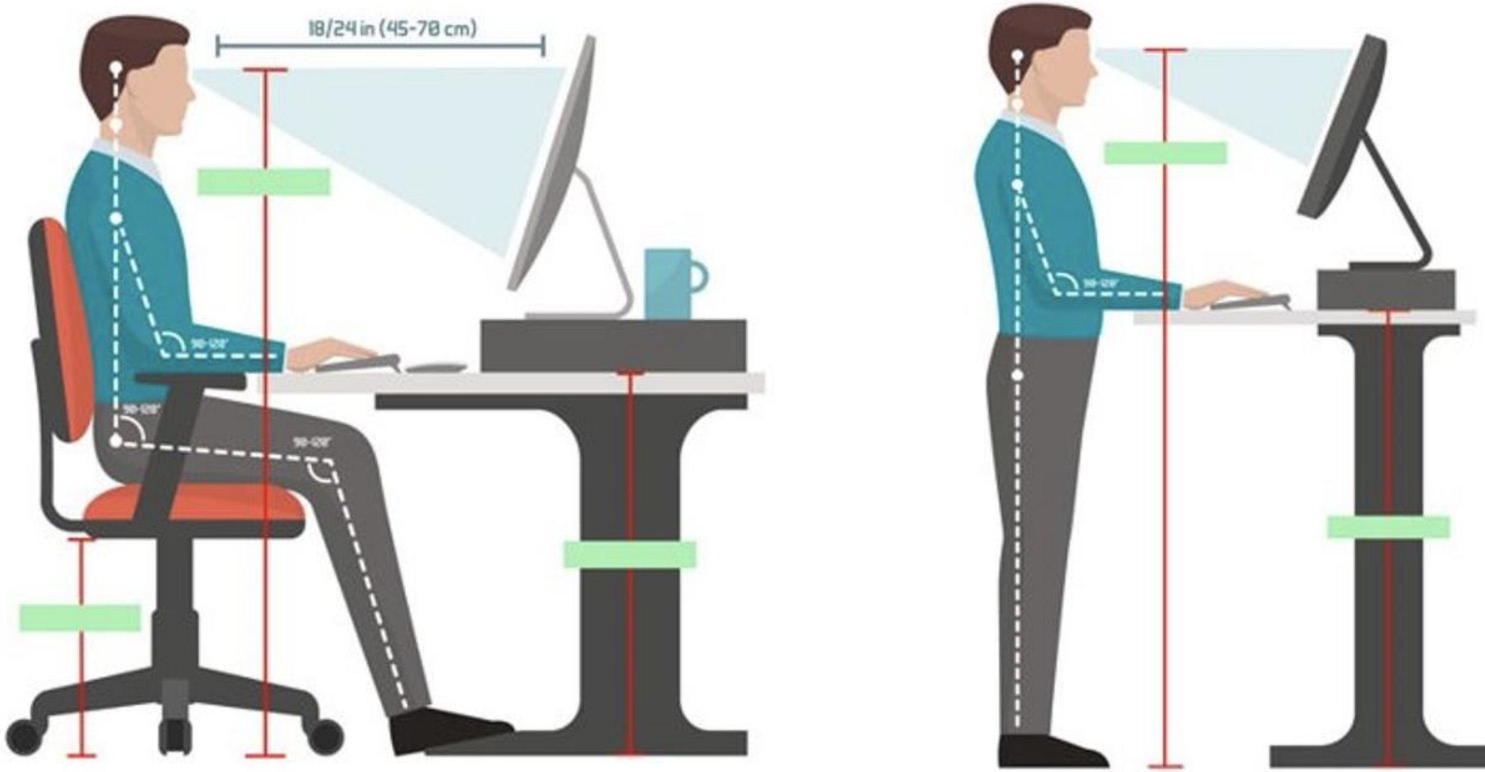
Logistics

- Online and will be recorded

- Today's presentation & recording will be uploaded onto RA history website
  - https://www.cpuc.ca.gov/General.aspx?id=6316

- Hosts (Energy Division Staff)
  - Jaime Rose Gannon
  - Linnan Cao

- Safety
  - Note surroundings and emergency exits
  - Ergonomic check



Logistics

- All attendees have been muted
- Presenters for each topic will be identified as panelists only when their topic is being addressed
- To ask questions, please use the "Q&A" function (send "To All Panelists") or raise your hand
- Questions will be read aloud by staff; attendees may be unmuted to respond to the answer. (Reminder: Mute back!)

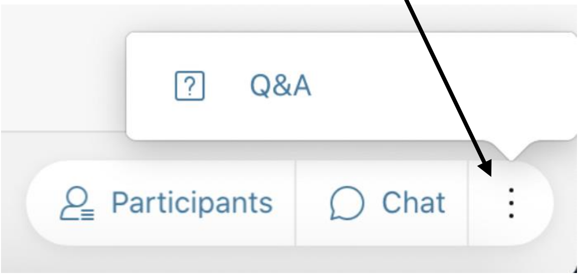
Mute/ Unmute

Participant List

Chat

Audio Options

"Q&A": on the bottom right of screen, click "3 dots"



Ground Rules

- Workshop is structured to stimulate an honest dialogue and engage different perspectives.
- Keep comments friendly and respectful.
- Please use Q&A feature only for questions, or technical issues.
- Do NOT start or respond to sidebar conversations in the Chat.

Agenda Day 3

Time	Day 3 - Wednesday Workshop Topics	Presenters/Time Duration
9:30-9:40 a.m.	Introduction & Safety	Energy Division, 10 min
9:40-11:20	Frank Wolak Presentation on Q&A Document	Frank Wolak, 1 hour 40 min
11:20-11:30	Stretch Break	
11:30-12 p.m.	Energy Division Bid Cap Proposal	Michele Kito, 30 min
12-1	Lunch	
1-2	CAISO UCAP Proposal	CAISO, 60 min

Track 3B.2 - December 11, 2020 revised Scoping Memo

- The scope of Track 3B.2 includes the following issues:

1. Examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements, given the increasing penetration of use limited resources, greater reliance on preferred resources, rolling off of a significant amount of long-term tolling contracts held by utilities, and material increases in energy and capacity prices experienced in California over the past years.
   a) <u>Specifically, address the direction the Commission intends to move in with respect to larger structural changes (e.g., capacity construct addressing energy attributes and reliance on resource use-limitations forward energy requirement construct). Set forth the necessary milestones and additional details that must be determined in order to implement the adopted direction for a compliance year no earlier than 2023.</u>

Track 3B.2 Calendar

TRACK 3B.2 CALENDAR	
Event	**Date**
Revised Track 3B.2 proposals due*	December 18, 2020
Comments on Track 3B.2 proposals	January 15, 2021
Workshop on revised Track 3B.2 proposals	Early - mid February 2021
Second revised Track 3B.2 proposals due	February 26, 2021
Comments on Track 3B.2 proposals	March 12, 2021
Reply comments on Track 3B.2 proposals	March 23, 2021
Proposed Decision on Track 3B.2	May 2021

Frank Wolak Presentation on Q&A Document

9:40 - 11:20 a.m.

Frank Wolak, Director, Program on Energy and Sustainable Development, Department of Economics, Stanford University

PESD STANFORD | PROGRAM ON ENERGY AND SUSTAINABLE DEVELOPMENT

Standardized Fixed-Price Forward Contract Approach to Long-Term Resource Adequacy

Frank A. Wolak

Director, Program on Energy and Sustainable Development

Professor, Department of Economics

Stanford University

February 10, 2021

CPUC RA Workshop

California’s Future Electricity Industry

Two factors make a capacity-based approach to long-term resource adequacy (RA) problematic

- California has ambitious renewable energy and climate goals
  - Renewable energy share of 60 percent by 2030 most likely to met from intermittent solar and wind resources
  - Reduce greenhouse gas (GHG) emissions to 40 percent below 1990 levels by 2030
- California obtains between 25 and 30 percent of its annual electricity consumption from imports
  - Imports to California occur because more energy is produced outside of state than is consumed outside of state in Western Interconnection (and the opposite is true for California)

California's Future Electricity Industry

Volatility in annual peak loads is significantly larger than volatility in annual energy demand

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%

Implication: Long-term RA mechanism should provide strong incentives for suppliers ensure that demand for energy is met every hour of the year

- Annual or monthly demand peaks are only known after the fact
- SFPFC energy sold for a compliance period that "delivers" according to actual system load shape provides strong incentive to meet demand peaks

Large intermittent renewables share implies increasing uncertainty in net demand (ND)

- ND = System demand – renewables output

Table 1: Annual Moments of Hourly Wind, Solar, and Wind and Solar Output (MWh)

	2013	2014	2015	2016	2017	2018	2019
	Hourly Wind Output (MWh)						
Mean	1033.54	1131.32	999.26	1204.73	1235.28	1597.35	1581.63
Median	973.79	1035.19	860.06	1092.49	1074.29	1496.55	1439.55
Standard Deviation	843.79	881.27	822.59	918.41	957.56	1161.22	1148.88
Coefficient of Variation	0.82	0.78	0.82	0.76	0.78	0.73	0.73
Standard Skewness	0.39	0.49	0.53	0.41	0.47	0.34	0.42
Standard Kurtosis	2.03	2.29	2.18	2.05	2.08	1.92	2.07
	Hourly Solar (MWh)						
Mean	315.39	1000.38	1510.80	1910.23	2633.99	2923.06	3035.64
Median	11.98	55.50	90.08	101.91	150.53	174.16	209.95
Standard Deviation	435.64	1290.47	1906.14	2391.94	3257.65	3587.68	3761.14
Coefficient of Variation	1.38	1.29	1.26	1.25	1.24	1.23	1.24
Standard Skewness	1.22	0.84	0.83	0.73	0.69	0.67	0.72
Standard Kurtosis	3.50	2.14	2.63	1.86	1.78	1.75	1.85
	Hourly Combined Wind and Solar Output (MWh)						
Mean	1348.93	2131.57	2510.06	3114.96	3869.27	4520.41	4617.28
Median	1364.04	1971.03	2030.58	2385.57	2595.63	3255.97	3150.32
Standard Deviation	883.40	1461.08	1983.06	2426.76	3258.25	3606.08	3818.19
Coefficient of Variation	0.65	0.69	0.79	0.78	0.84	0.80	0.83
Standard Skewness	0.19	0.45	0.63	0.55	0.60	0.55	0.62
Standard Kurtosis	2.32	2.50	2.95	2.07	1.97	1.96	2.03

Data Source: California ISO Oasis Web-Site.

California has more 18,000 MW of Wind and Solar Generation Capacity

CA’s Renewables Production

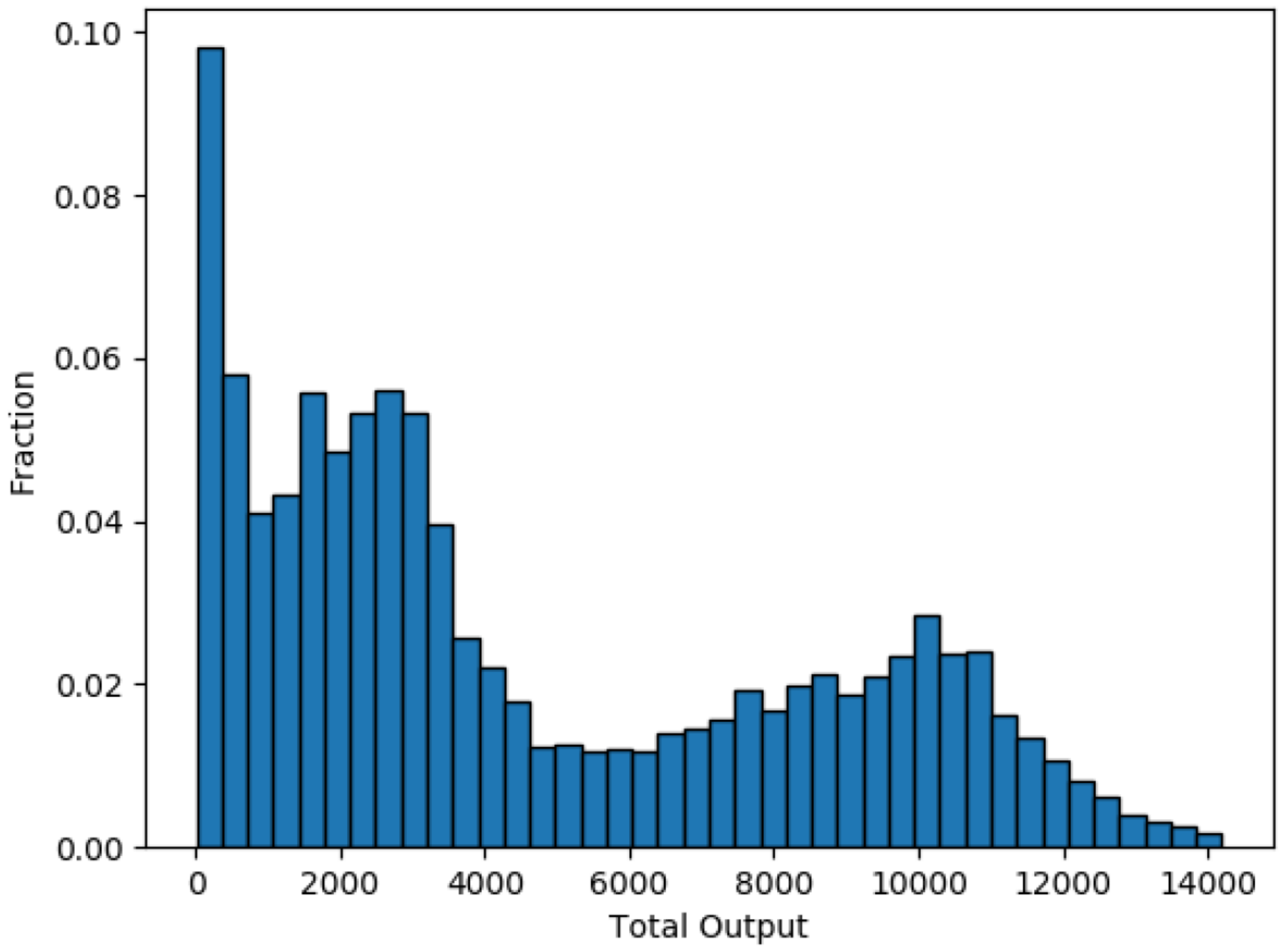


Figure 7: Histogram of Hourly Combined Wind and Solar Output in California ISO Control Area in 2019 (MWh).

California has more 18,000 MW of Wind and Solar Generation Capacity

Intermittency of CA's Renewables

Table 5: Combined Wind and Solar Output Shortfall Durations (Hours), Continue

	2013	2014	2015	2016	2017	2018	2019
Threshold Value				5000			
Number of durations	1	71	226	321	349	356	353
Mean	8758	119.20	32.84	19.84	16.31	15.33	15.50
Standard Deviation		260.95	65.10	21.56	8.19	6.32	7.21
Maximum	8758	1809	875	299	92	90	68
Threshold Value				6000			
Number of durations	1	15	96	258	333	343	339
Mean	8758	581.13	86.90	27.84	18.33	16.81	17.04
Standard Deviation		929.90	172.79	54.09	13.86	9.99	12.14
Maximum	8758	2938	1379	753	140	115	116
Threshold Value				7000			
Number of durations	1	1	19	131	284	318	318
Mean	8758	8759	457	61.89	23.36	19.38	19.16
Standard Deviation			800.28	155.67	36.90	22.03	20.62
Maximum	8758	8759	3177	1363	478	226	239
Threshold Value				8000			
Number of durations	1	1	3	45	227	280	283
Mean	8758	8759	2918	191.07	31.92	23.60	23.06
Standard Deviation			2794.44	437.76	71.69	46.05	43.96
Maximum	8758	8759	5583	2485	634	527	475

Data Source: California ISO Oasis Web-Site.

California has more 18,000 MW of Wind and Solar Generation Capacity

California's Future Electricity Industry

- Long durations of low renewable energy output requires in-state dispatchable resources or imports to meet net demand
  - Increasing uncertainty about when net demand is likely to peak
  - SFPFC energy sold for a compliance period that "delivers" according to actual system load shape provides strong incentive for this net demand to be met
- Large intermittent renewables share will require
  - Investments in both grid-scale and distributed storage
  - Active demand-side participation by customers with interval meters using dynamic retail electricity prices
  - Automated distribution network monitoring and on-site load-shifting technologies

California's Future Electricity Industry

Long-term resource adequacy mechanism should support business models that lead to efficient levels of investment in load flexibility

- Relatively constant hourly wholesale electricity prices under a capacity-based long-term resource adequacy mechanism unlikely to do this
- Short-term price volatility that reflects real-time system conditions supports investments in these technologies
  - Supports retail competition that benefits electricity consumers in the aggregate
  - Retailers that find flexible demand and take advantage of this flexibility can benefits themselves and their customers

SFPFC mechanism provides strong incentives for retailers to find and reward flexible demand

- Allows retailers determine on how much individual customers are exposed to short-term wholesale price volatility while still ensuring aggregate supply equals aggregate demand every hour of the year

Firm Capacity of Imports?

- Generation source of an electricity iimport is primarily a financial construct
  - Regulators in neighboring states are very unlikely to allow generation units owned by their utilities to sell capacity from specific units to California
- Importers can sell fixed quantity of energy to “delivered” to a location in California at a fixed price
  - 500 MWh of energy “delivered” to specific node in California
    - Delivered = Financially settled against price at that node
  - Provide price certainty to a retailer or load serving entity for a fixed quantity of energy
- The harsh reality of electricity imports
  - In real time imports goes to party willing to pay the highest price
  - SFPFC mechanism can allow short-term prices to rise to level needed to attract energy to California when needed, yet still protect consumers from these high price periods
    - Offer cap on short-term market can be increased because aggregate hourly demand is covered by SFPFC mechanism

Economic Logic Behind Design of SFPFC Mechanism

SFPFC Mechanism

Why are SFPFC energy deliveries shaped to actual pattern of system load during delivery horizon?

- Renewable energy shortfalls, not inadequate capacity, is fundamental reliability challenge in California
- Risk of supplying energy to meet actual hourly demands throughout year placed on entities best able to address it
  - Sellers of SFPFC energy and flexible demands
  - Cost of failing to meet SFPFC obligation during any hour of delivery period is actual cost to replace energy from short-term market

Why is SFPFC for a fixed number of MWhs of energy during delivery horizon?

- Resource owners, particularly those that own intermittent renewables, are better able to predict quantity of energy that can supplied during delivery horizon rather than during any given hour within delivery horizon
- Limits energy quantity risk that must be borne by both sellers of SFPFCs that own intermittent renewable and dispatchable resources
  - Product tailored to what resource is a capable of providing—Finite amount of energy during a given delivery horizon

SFPFC Mechanism

Why are there true-up auctions?

- True-up auction rewards suppliers for ensuring that supply equals realized (not forecasted) demand for every hour of delivery horizon
  - Sale of additional SFPFC energy in true-up auction rewards those suppliers that provided additional energy during compliance period
  - Purchase of unused SFPRC energy in true-up auction rewards suppliers for being available to produce that energy during compliance period
- True-up auction rewards for retailers and large consumers for reducing their consumption of energy, particularly during stressed system conditions
  - Provides strong incentives for retailers to invest in both grid-scale and distributed storage
  - Fosters active demand-side participation by flexible customers with interval meters using dynamic retail electricity prices
- Ensures that price paid for all demand within delivery horizon is hedged in SFPFC either ex ante or after the fact
  - Buying more than you need and selling back excess SFPFC energy likely to be a prudent procurement strategy for California given increasing uncertainty in hourly renewables output and net demand

SFPFC Mechanism

Frequency of compliance and true-up auctions

- Compliance auctions for quarterly products run 3 years in advance of delivery
  - In Q4 of 2021 run compliance auctions for deliveries beginning Q1-Q4 of 2024, 2025 and 2026
    - Twelve quarterly products auctioned
    - Purchase 100% of California Energy Commission (CEC) forecast of energy demand for Q1 to Q4 of 2024
    - Purchase 95% of CEC forecast of energy demand for Q1 to Q4 of 2025
    - Purchase 90% of CEC forecast of energy demand for Q1 to Q4 of 2026
  - In Q4 of 2022 run compliance auctions for deliveries beginning Q1-Q4 of 2025, 2026, 2027
    - Twelve quarterly products auctioned
    - Purchase ~5% of California Energy Commission (CEC) forecast of energy demand for Q1 to Q4 of 2025
    - Purchase ~10% of CEC forecast of energy demand for Q1 to Q4 of 2026
    - Purchase 90% of CEC forecast of energy demand for Q1 to Q4 of 2027

SFPFC Mechanism

Frequency of compliance and true-up auctions

- Process continues until Q2 of 2024 when first true-up auction is run for Q1 of 2024 based on actual energy supplied during compliance period
- Henceforth, each quarter has a true-up auction for the previous quarter and twelve compliance auctions at least 3 years in advance of delivery for 12 quarters into the future

Quarterly compliance auctions can be run independently or linked

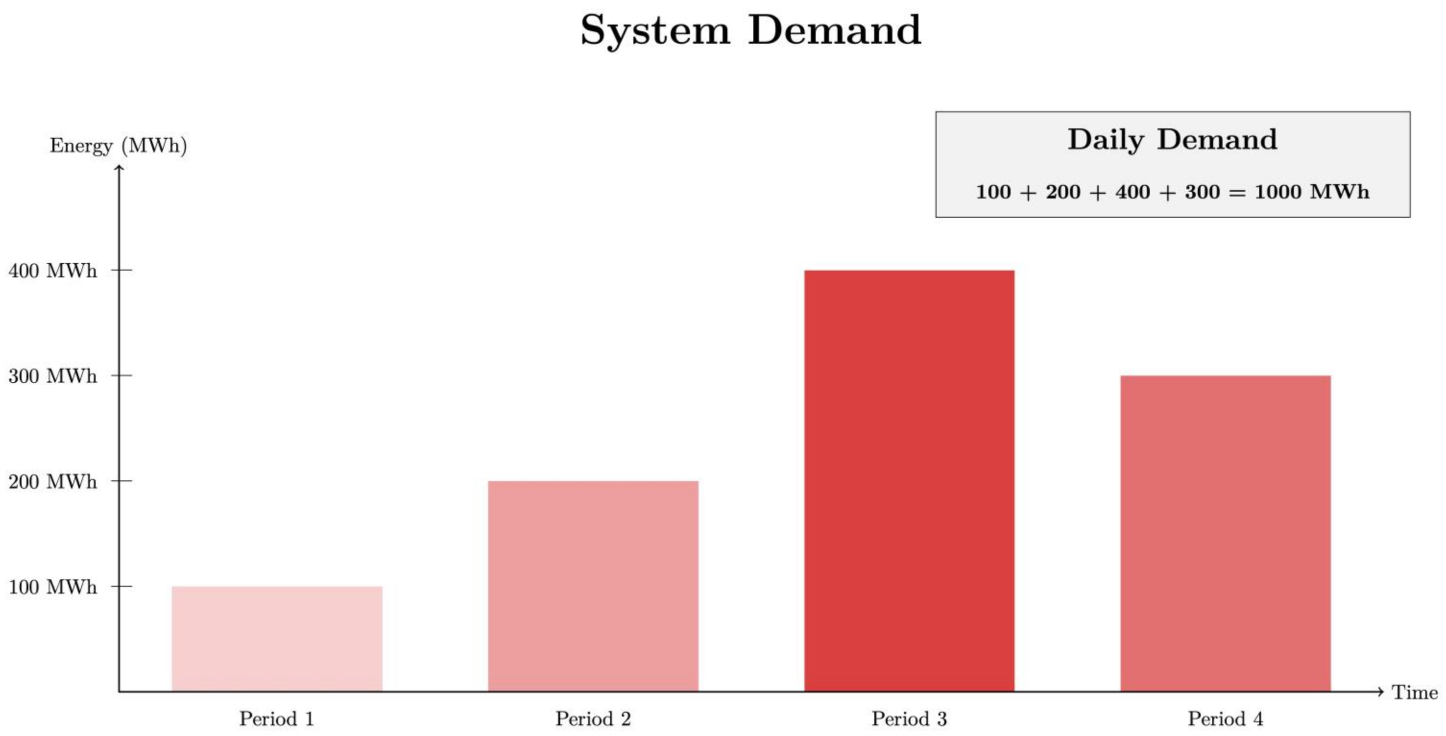
- Linked quarterly auctions can allow participants to sell linked quantities of energy in any combination of quarterly SFPFC auctions
- Provides up to a three-year (12 quarters) revenue stream to finance new entry of generation capacity
- More complex auction clearing mechanism required to clear linked auction than a simple declining clock auction

Design parameters associated with SFPFC auctions can be changed to meet CPUC and California ISO reliability goals

- How far in advance delivery SFPFC auction takes place determines what kinds of technologies can participate in auction
- Number of quarters in the future auctions are run for determines how much revenue certainty existing and new entrants have
- Advance purchase fractions and demand forecast determines confidence that reliability goals will be met

True-Up Auction Numerical Examples

SFPFC Resource Adequacy Process
(Four Period Compliance Process)



Realized Total System Demand ($\sum_{h=1}^{4} QD_h$) is equal 1,000 MWh and Has the Above Hourly Values, QD_h, h=1,2,3, and 4

SFPFC Resource Adequacy Process
(Four Period Compliance Process)

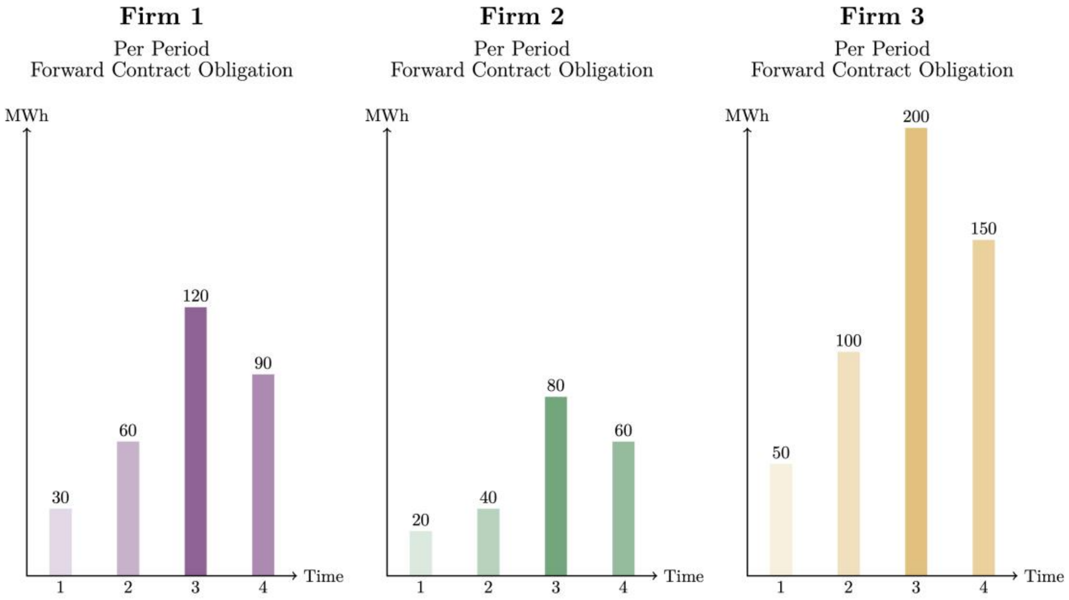
There are Three Firms:

Firm 1 sells 300 MWh

Firm 2 sells 200 MWh

Firm 3 sells 500 MWh

Total Amount Sold by Three Firms = 1000 MWh



Period-Level Values of QC_{hk} for Total Sales $Q_{total,k}$ of Each Firm k=1,2,3

$$\sum_{k=1}^{3} QC_{Total,k} = 1000 \text{ MWh} = \sum_{k=1}^{4} QD_h$$

SFPFC Resource Adequacy Process

(Four Period Compliance Process)

There are Four Retailers:

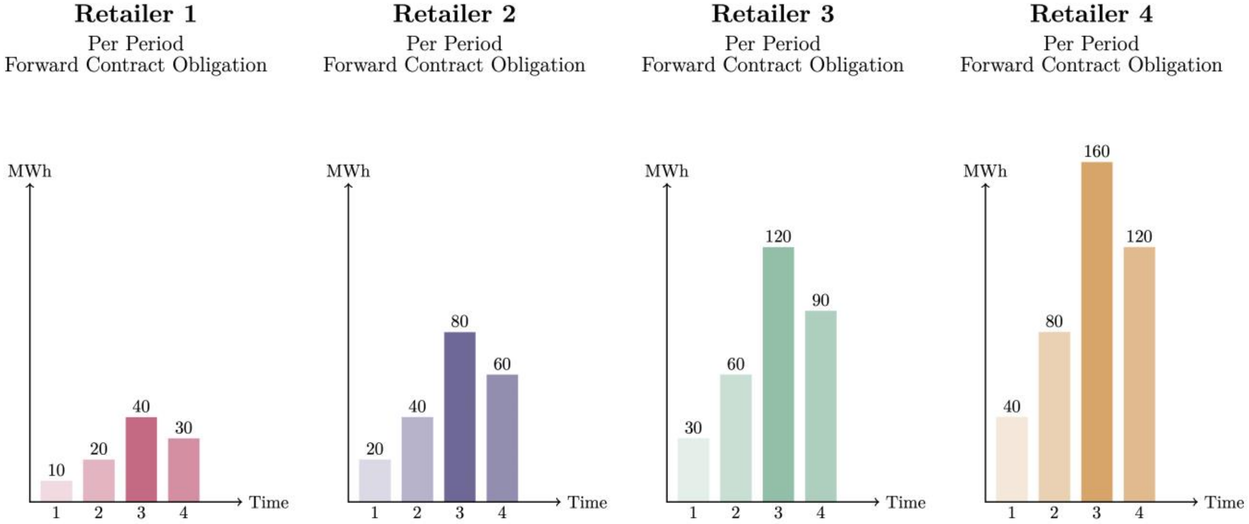
Retailer 1 sells 100 MWh

Retailer 2 sells 200 MWh

Retailer 3 sells 300 MWh

Retailer 4 sells 400 MWh

Total Amount Sold by Four Retailers = 1000 MWh



Sum of Hourly Forward Contract Obligations (QR_{hr}) Assigned to r=1,2,3,4 Retailers is equal to Hourly System Demand (QD_h) and Aggregate Forward Contract Obligations of Generation Unit Owners (QC_{hk})

$$\sum_{r=1}^{4} QR_{hr} = QD_h = \sum_{k=1}^{3} QC_{hk} \; for \; h = 1,2,3,4$$

10% Higher Demand All Periods and All Retailers

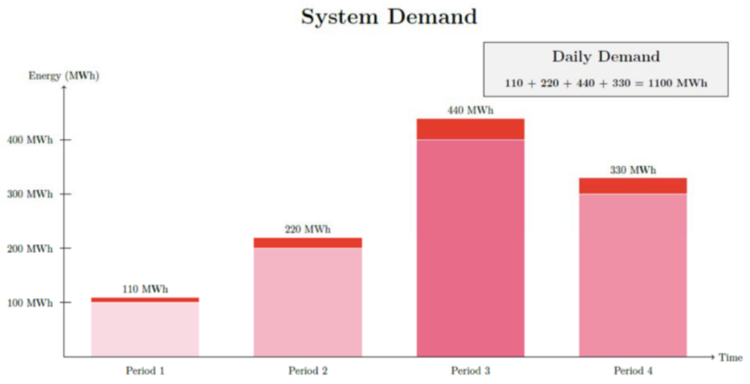


Figure 4: Hourly System Demands (10 Percent Higher)

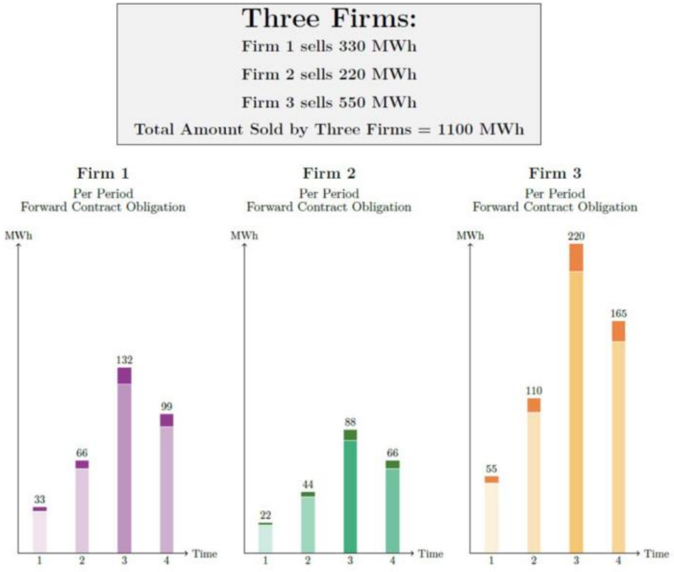


Figure 5: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

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

10% Higher Demand All Periods and All Retailers

Suppose that initial compliance auction cleared at $60/MWh for the original 1000 MWh for the four periods, but demand turned out to be 10% higher uniformly across all periods and retailers

Suppose that each firm sold 10% more SFPFC energy in true up auction for $70/MWh

- Given these assumptions, the load shape shares across the four periods are still 0.1, 0.2, 0.3 and 0.4
  - Load weighted average short-term price is $55/MWh
- Total load shares for four periods across retailers are 0.1, 0.2, 0.3 and 0.4

Long-term resource adequacy net payments to suppliers are:

Firm 1 = ($60 - $55)300 + ($70 - $55)30

Firm 2 = ($60 - $55)200 + ($70 - $55)20

Firm 3 = ($60 - $55)500 + ($70 - $55)50

Long-term resource adequacy net payments for four retailers are:

Retailer 1 = ($60 - $55)(1000)(110/1100) + ($70 -$55)100(110/1100)

Retailer 2 = ($60 - $55)(1000)(220/1100) + ($70 -$55)100(220/1100)

Retailer 3 = ($60 - $55)(1000)(330/1100) + ($70 -$55)100(330/1100)

Retailer 4 = ($60 - $55)(1000)(440/1100) + ($70 -$55)100(440/1100)

Note that 110/1100 = 0.1, 220/1100 = 0.2, 330/1100 = 0.3 and 440/1100 = 0.4

10% Higher Demand for Compliance Period

Suppose that 100 MWh demand increase is shared equally between periods 1 and 2 so period 1 demand is 150 MWh and period 2 demand is 250 MWh.

- 150 MWh of SFPFC energy would be allocated to period 1 and 250 MWh to period 2 in the final settlement.
- Suppose Retailer 1 consumed the entire additional 100 MWh during compliance period, which means is four-period demand is now 200 MWh
- Suppose entire 100 MWh purchased in the true-up auction was sold by Firm 1 at a price of \$65/MWh
- Given these assumptions, the load shape shares across four periods are 150/1100, 250/1100, 300/1100 and 400/1100
  - Load weighted average short-term price is now \$50/MWh
- Total load shares for four periods across retailers are 2/11, 2/11, 3/11 and 4/11

Long-term resource adequacy net payments to suppliers are:

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

Long-term resource adequacy net payment from four retailers are:

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)

Note that 2/11 = 200/1100, 2/11 = 200/1100, 3/11 = 300/1100, 4/11 = 400/1100

10% Lower Demand All Periods and All Retailers

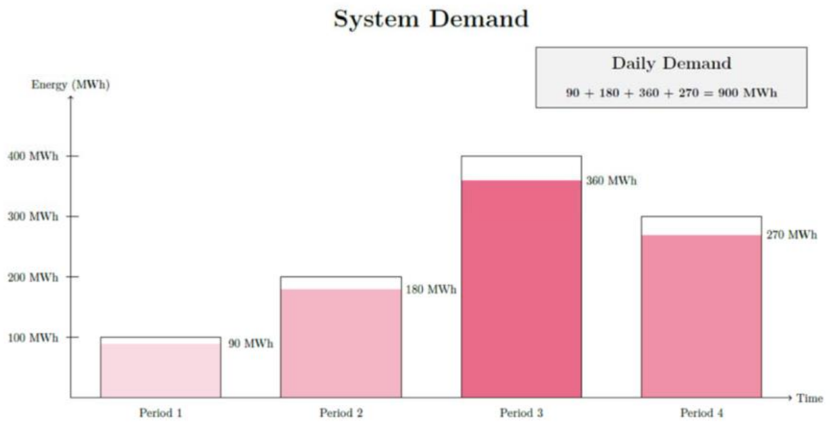


Figure 7: Hourly System Demands (10 Percent Lower)

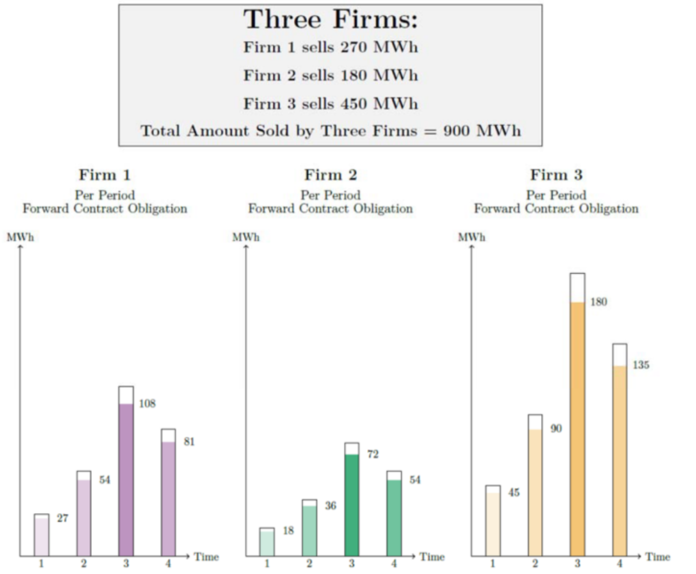


Figure 8: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

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

10% Lower Demand All Periods and All Retailers

Suppose that initial compliance auction cleared at $60/MWh for the original 1000 MWh for the four periods, but demand turned out to be 10 percent lower uniformly for all periods and retailers

- Given these assumptions, the load shape shares across the four periods are still 0.1, 0.2, 0.3 and 0.4
  - Load weighted average short-term price is $45/MWh because of lower demand
- Total load shares for four periods across retailers are 0.1, 0.2, 0.3 and 0.4
- Suppose that each firm bought 10% SFPFC energy they each initially sold in true up auction for $40/MWh
  - Note this is less than $45/MWh. Competition in auction determines how much less.

Long-term resource adequacy net payments to suppliers are:

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

Long-term resource adequacy net payments for four retailers are:

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

Note that 90/900 = 0.1, 180/900 = 0.2, 270/900 = 0.3 and 360/900 = 0.4

10% Lower Demand for Compliance Period

Suppose that 100 MWh demand decrease occurred in period 3 from Retailer 3

- Period 3 demand is now 200 MWh instead of 300 MWh
- Retailer 3's total consumption for the four periods is now 200 MWh instead of 300 MWh
- Suppose entire 100 MWh sold in the true-up auction was purchased by Firm 1 at a price of $35/MWh
- Given these assumptions, the load shape shares across four periods are 1/9, 2/9, 2/9 and 4/9
  - Load weighted average short-term price is now $40/MWh
  - Note that $35/MWh is less than $40/MWh

Long-term resource adequacy net payments to suppliers are:

Firm 1 = ($60 - $40)300 - ($35 - $40)100

Firm 2 = ($60 - $40)200

Firm 3 = ($60 - $40)500

Long-term resource adequacy net payment from four retailers are:

Retailer 1 = ($60 - $40)(1000)(1/9) - ($35 -$40)100(1/9)

Retailer 2 = ($60 - $40)(1000)(2/9) - ($35 -$40)100(2/9)

Retailer 3 = ($60 - $40)(1000)(2/9) - ($35 -$40)100(2/9)

Retailer 4 = ($60 - $40)(1000)(4/9) - ($35 -$40)100(4/9)

Note that 100/900 = 1/9, 200/900 = 2/9, 2/9 = 200/900, 4/900 = 4/9

Incorporating California's Environmental Policies into SFPFC Mechanism

Incorporating Renewable Energy Goals

Renewable energy goals can be met by retailers purchasing renewable energy certificates (RECs) equal to annual demand times required renewable energy share

- Retailer with 100 MWh demand purchases 40 RECs to meet 40 percent Renewables Portfolio Standard (RPS)

Different REC requirements can be met the same way

- Bucket 1, 2, and 3 REC requirements
- Purchase of Bucket 1 REC (energy+REC in same hour) simply implies a different hourly net load for retailer
  - Retailer's hourly net load is difference between actual hourly load and bundled RECs produced during that hour
  - Retailer can hedge difference between hourly net load and hourly standardized forward contract quantity in bilateral market

This logic is reinforces need to assign an Annual Firm Energy (AFE) value to intermittent renewable resources consistent with amount of energy these resources can provide under stressed (not typical) system conditions

- Significantly less than values assigned for wind and solar resources in August of 2020

Bundled RECs and the SFPFC Mechanism

Suppose Retailer 3 purchases a bundled REC that produces a total of 90 MWh in the four periods and the weighted average short-term price that would have been paid for this energy is $45/MWh

- $45/MWh = the sum of the hourly short-term price times the period-level production of renewable resource divided by 90 MWh

Assuming no true-up auction, Retailer 3's payment stream for its SFPFC obligations and bundled RECs, beyond the variable profits it earns from purchasing the energy needed to serve its demand at short-term market price and selling this energy at the retail price price 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 $45/MWh for the hourly stream of energy it receives from the renewable resource

- A bundled REC is equivalent to 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, its long-term RA and renewable energy net payment stream would be

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

and the Retailer 3 would have total renewable energy share of 50 percent.

Incorporating Renewable Energy Goals

California's Integrated Resource Plan (IRP) is compatible with SFPFC mechanism

Developer of a resource desired under IRP plan could sell SFPFC energy in compliance auction to obtain at least 3-year future revenue stream to finance investment

- Developer receives competitively supplied energy revenue stream from SFPFC auction for future energy sold

If project developer is unable to recover project costs from this revenue stream and expected future market and SFPFC revenues, it can apply to CPUC for additional financial support

Seller of this project would still be subject to CPUC/ISO construction milestones to provide Firm Energy that was sold in SFPFC compliance auctions or project developer is required to buy back SFPFC energy sold in future auction

Incorporating California's IRP Process

CPUC can have a backstop process to achieve integrated resource planning (IRP) process goals

- To the extent the CPUC believes additional resources are needed to meet goals, it can order resource to be constructed
- AFE associated with this resource and cost of energy provided allocated to all retailers according to same monthly load share served
- Excess infeasible annual energy must be refunded to retailers at actual price paid
  - Burden shared among sellers of standardized energy contracts based on sales shares of annual energy contracts
- Process should be run sufficiently far in advance to be credible
  - Waiting until last minute only increases costs to consumers
- Process can create strong incentives for suppliers to meet system demand with resource mix that avoids violating CPUC's IRP process

Financial Incentives Provided by SFPFC Contracts

Financial Incentives Created by SFPFCs

Hourly variable profits for generation unit owners

P(spot)Q(spot) + (P(contract) – P(spot))Q(contract) – C(Q(spot))

= P(contract)Q(contract) + P(spot)(Q(spot) – Q(Contract)) – C(Q(spot)

Note that generation unit owner has strong incentive to keep P(spot) as low as possible as long as Q(spot) < Q(contract)

- Lower offer price increases likelihood of larger Q(spot)

Least cost "make versus buy" decision to meet Q(contract) implies that thermal suppliers will submit offer to supply energy at marginal cost for this quantity of energy

- If Price > MC, supplying from unit is cheapest way to meet forward contract obligation
- If Price < MC, buying from short-term market is cheapest way to meet obligation

Generation unit owner that produces no energy during hour earns

(P(contract) – P(spot))Q(contract)

Retail Competition and SFPFC Mechanism

Retail Competition

SFPFC mechanism creates a level playing field for retail competition

- All retailers have SFPFC obligation based on the share of system load served in month
- Cost of monthly SFPFC obligation moves with energy sold by individual retailers
  - Those that serve more load pay for more of aggregate SFPFC cost
  - Those that serve less load pay for less of aggregate SFPFC cost

Eliminates potential for smaller retailers to free-ride off long-term RA purchases of larger retailers

- In capacity-based mechanism, smaller retailers can sell at retail prices indexed to hourly wholesale price that is lower because of long-term RA purchases of large firms

SFPFC mechanism allows retailers to expose their customers to hourly wholesale prices

- SFPFC mechanism starts from 100% fixed-price contracting of system demand, whereas existing long-term RA mechanism starts at 0% fixed-price contracting of system demand for energy
  - Where retailer ends up in percent coverage of its demand is its choice
  - Retailer can buy or sell bilateral contracts to achieve desired level of exposure to short-term prices
  - Retailer bears full cost and benefits of these actions

SFPFC mechanism rewards retailers that find flexible demands and makes the most lucrative use of these flexible demands

Physical Feasibility of Contracted Energy

Physical Feasibility of Contracted Energy

To make ISO comfortable with transition to SFPFC mechanism can define Annual Firm Energy (AFE) of resource which limits amount of energy it can sell in an SFPFC auction

- Seasonality in California's wind and solar production could be built in this mechanism
  - Firm energy of wind and solar capacity could vary by quarter of the year

To meet physical feasibility requirement, place limitations amount of SFPFC energy a resource can sell, but avoid segmenting market for energy

- SFPFC energy is a homogenous product that ensures demand equals supply for 8760 hours of the year
- Procure this through an anonymous auction mechanism far enough in advance of delivery to allow new investment to participate in auction ensures a competitive price for SFPFC energy

Physical Feasibility of Contracted Energy

Ensuring cross-hedging between intermittent and dispatchable resources

- Allow existing resources only to sell up to their annual firm energy (AFE)
  - Firm capacity is amount of energy unit can produce under stressed system conditions (determined by California ISO and CPUC)
  - CPUC and ISO jointly determine this value as they do for existing capacity construct under current Resource Adequacy (RA) process
- Annual Firm energy (AFE) in MWh = Firm Capacity (in MW) x 8760

Each participant in standardized contract auction can only sell a total amount of annual energy than is less than or equal to annual firm energy value (AFE)

- AFE of thermal resources significantly larger than amount of energy typically produced annually
- AFE of intermittent resources significant small than amount of energy typically produced annual
- No requirement that resources sell entire AFE in SFPFC auction
  - May want to sell less to ensure that it can fulfill its obligations

Ensures that total SFPFC energy sold can actually be delivered under all possible future system conditions

- Under typical conditions, most energy produced by intermittent resources and dispatchable (thermal) resources purchase this energy to meet standardized energy contract obligations
- Under scarcity conditions, most energy produced by dispatchable (thermal) resources and intermittent resources only provide their firm energy

Meeting Local Energy Requirements

Two approaches to managing *local long-term resource adequacy*

- Allow suppliers to sort out least cost way to meet local reliability constraints
- Can run auctions for standardized contracts that clear against different pricing hubs
  - Different spatial aggregated prices for each retailer
  - Need to determine service territory-level demands that sum to total system demand

Suppliers with fixed-price forward contract obligations that clear against geographically aggregated prices have a strong incentive to limit difference between price at their location and geographically aggregated price

- Buying energy at injection point and selling at geographically aggregated price
- Suppliers jointly have strong incentive to sort out least cost way to meet local reliability constraints

CPUC and ISO can decide to make backstop resource procurement as described earlier to the extent local resource adequacy is not met

- Refunds of excess annual forward contract energy equal to energy that backstop resource provides

Meeting Local Energy Requirements

This logic reinforces need to purchase standardized energy contract far enough in advance of delivery to allow new entrants to compete to supply products

- Suppliers with local market power can be disciplined by actions of suppliers that have sold forward standardized forward contracts
- Backstop process should operate far enough in advance to make it is a credible source of energy in future
  - Reduces regulatory burden of managing local market power
- Important goal of standardized contract-based resource adequacy approach is to allow entities best able to manage supply risk, manage this risk
  - Avoid costly legal process at FERC and CPUC to obtain necessary generation capacity to meet demand under all possible future system conditions

Transition to Energy-Contracting RA Process

Transitioning to this approach to long-term resource adequacy requires significant advance notice

- First procurement of contracts should start delivery at least three years in advance

Retailers and generation owners need sufficient time to adapt to an energy-contracting resource adequacy process

Significantly more cross-hedging between resources to ensure system demand is met under all possible future system conditions

- Intermittent resources re-insurance with dispatchable resources
- Dispatchable resources earn premium for providing this insurance

Mechanism values a firm MWh more than a non-firm MWh

Concluding Thought

There is nothing more difficult to take in hand, more perilous to conduct, or more uncertain in its success, than to take the lead in the introduction of a new order of things. Because the innovator has for enemies all those who have done well under the old conditions, and lukewarm defenders in those who may do well under the new."

– Niccolo Machiavelli (The Prince)

Q&A/Discussion

Stretch Break :)

Please be back at 11:30 a.m.

Image Source: iamthinks.blogspot.com

https://www.showeet.com/19/06/2016/templates/title-slide-templates-for-powerpoint-and-keynote/

Energy Division Bid Cap Proposal

11:30 a.m. - Noon

Michele Kito, Supervisor, Resource Adequacy and Procurement, Energy Division

Further Detail Regarding a Proposed Bid Cap to be Incorporated into the RA Construct

Energy Division -Michele Kito

California Public
Utilities Commission

Proposed Bid Cap for RA Product - Background

- In its August 7, 2020 proposal, Energy Division proposed three potential paths to address concerns identified with the current RA framework. Path 1 would make fundamental modifications to the existing capacity construct to include:
    1) Revising the exsisting MCC buckets that would make the buckets binding to address issues associated with use-limited resources
    2) Revising the RA product to include a least-cost dispatch requirement or a bid cap
- In its December 18, 2020 revised proposal, Energy Division provided more specifics regarding the addition of a bid cap. Staff notes that:
    - A bid cap does not ensure that RA resources will bid into the market at their marginal costs (similar to least cost dispatch requirements currently applicable to the IOUs under CPUC's jurisdiction).
    - However, it does ensure that RA resources would be subject to a price cap on their bids which would be significantly lower than the current $1000/MWh (rising to $2000/MWh) FERC hourly bid cap.

Further Details Provided - The Level of the Price Cap and Enforcement

- Level of the Price Cap-
  - Energy Division staff propose that the price cap be set at the higher of $300/MWh or the resource- specific default energy bid, excluding non-resource-specific default energy bids, such as those tied to indices.
    - By setting it to the "higher of" $300MWh or the resources default energy bid, it should capture potential gas anomalies that may arise.
    - Bid Curve during price spikes in July 2020 shows that vast majority of bids be less than $300/MWh (Available at ReportonMarketCompetitivenessJul30-312020.pdf (caiso.com))
- Verification and Enforcement
  - Energy Division staff propose a two-pronged enforcement mechanism

    1) Review that RA contracts have bid-cap provisions.

    2) Review bidding by market participants and refer load serving entities for non-RA compliance if the resources do not comply with the resource adequacy requirements per contractual provisions.

Further Details Provided - The Level of the Price Cap and Enforcement

- Existing contracts and timing
  - Energy Division staff propose that this proposed change be implemented for resource adequacy compliance year 2023. This would allow market participants to revise contracts, to the extent necessary.
- Legal obstacles
  - A bid cap on RA resources would not preclude non-RA capacity from bidding at any level.
  - A bid cap would be equally applicable to all RA resource types.
  - Energy Division staff propose that the requirements be implemented in 2023, any legal issues that may arise could be addressed before implementation in 2023.

Concerns Raised in Comments

- A bid cap of $300/MWh could limit the ability of California LSEs and grid operators to attract capacity from neighboring balancing authorities.
- A bid cap that is lower than caps in neighboring balancing authorities may disrupt the state's ability to rely on imports from neighboring balancing authorities, particularly during stressed conditions.
- A bid cap may not achieve Energy Division's goal of protecting customers from high energy prices if non-RA resources continue to set energy prices above the offer cap. To make the proposal more resilient to future changes in market conditions, the offer cap should be indexed to fuel prices and/or other market fundamentals that may raise or lower the overall level of electricity prices.
- Coordination with the CAISO will be necessary to ensure that there is no confusion regarding the application of various offer caps - It is unclear what impact this proposal would have on resources, like hydro or even storage, that may have opportunity costs (perhaps relying on price indices) that factor into their bid or DEB formulations.
- Imposition of a bid cap could be interpreted as interfering with the FERC jurisdictional wholesale market.
- The proposed enforcement is unfair and unworkable.
- Concerns regarding feasibility of a bid cap with regards to enforcement.
- Should consider a rebate mechanism as an alternative.

Is the Current Capacity Framework Providing Value to Ratepayers?

- RA resources have a must-offer obligation (MOO) into CAISO's energy markets that is meant to ensure they are available to meet the demand.
- A MOO does not dictate how a resource will bid into the markets. There is an expectation that resources will bid economically because they have incentives to earn energy rents, but generators, importers and third-party demand-response providers have been bidding seemingly above their marginal costs.
- Some have argued that RA is a call-option at the bid-cap, but this will not ensure reliability at least-cost, nor can you run an efficient market with many bidding uneconomically or at the cap.
- Further, there is no system-level market power mitigation in place in the CAISO market to address these issues.
- IOU resources (where they are the scheduling coordinator) are subject to least cost dispatch rules, which ensure the IOUs are bidding economically, but others are not.
- The RA construct is meant to ensure that the CAISO system has sufficient resources to meet demand, but an RA-only construct does not work if these RA resources flow to the highest bidder and out of the state during reliability events – it seems that only surplus should be exported, consistent with practices for other balancing authorities.

Q&A/Discussion

Lunch **Break**

Until 1 p.m.

https://www.slidecamp.io/home

CAISO UCAP Proposal

1- 2 p.m.

Bridget Sparks, Ph.D., Infrastructure and Regulatory Policy Developer, CAISO

Unforced Capacity Evaluation Proposal

Bridget Sparks, Ph.D.
Infrastructure and Regulatory Policy

CPUC Track 3.B2 Proceeding

February 10, 2021

Agenda

1. High-level overview of proposal
2. Discuss how UCAP could be adopted in conjunction with other proposals
   a. PG&E - Slice of Day
   b. Joint Parties - Net Qualifying Energy
   c. Energy Division - Forward Energy Contracts
3. Benefits of UCAP

Unforced Capacity Evaluation

- CAISO proposes to utilize a seasonal availability factor based approach to calculate unit specific availability factors during the tightest RA Supply Cushion hours
  - **RA Supply Cushion** = Daily Shown RA (excluding wind and solar) – Planned Outages – Opportunity Outages – Urgent Outages –Forced Outages – Net Load – Contingency Reserves
- Resource availability factors will incorporate historical forced and urgent derates and outages to determine the resource’s expected future availability and contributions to reliability
- Proposing to incorporate UCAP into the NQC value of resource to represent both deliverability and availability
- CAISO presented UCAP proposal in detail during the November 23rd workshop, and takes this opportunity to discuss how this proposal might fit with some of the other proposals submitted in this proceeding

PG&E's Slice of Day Proposal

- UCAP could be incorporated into this proposal by assessing resource's historic forced outage rates during the tightest RA Supply Cushion hours during each slices of day segment the resource wanted an NQC value, and the MOO would still be at the DQC so that each slice of day would provide substitute capacity for that portfolio of resources
- UCAP would be preferable to exceedance methodology
- For instance, a 24x7 gas generator could have 3 NQC values for the corresponding Slice of Day
  - Example: 500 MW Pmax resource with 100% deliverability, and a regulatory restriction that prevents its operation between 12am-6am

Slice of Day	Average Forced Outage Rate	Availability Factor	Final NQC	MOO
HE 23-7	75%	.286	143	500
HE 8-14	5%	.95	475	500
HE 15-22	10%	.9	450	500

SCE/CALCCA's Joint Proposal

- CAISO believes it's current seasonal average availability factor proposal could be incorporated into this proposal without significant re-design
  - With incorporation of UCAP into NQC this should also influence the NQE of the resource to better reflect the unit's energy availability taking into account average forced outages
  - Severability of NQE from NQC may increase difficulty of setting the appropriate MOO to provide the intended substitute capacity for expected forced outages of the portfolio and should be incorporated into these discussions

Energy Division's Standard Forward Energy Contact

- UCAP could be incorporated into Energy Division's proposal by using the UCAP value of the resource to set the limit on how much energy a resource could sell in the forward auctions
  - For instance a 100 MW gas unit with a 10% forced outage rate would be eligible to sell 788,400 MWh in annual firm energy (i.e. 90MW *8760)
- May want to tweak the UCAP formula to look at outages in all hours, or adjust seasons if we move away from a monthly construct
- The CAISO tariff would need a radical overhaul to align with this construct and creates conflicts with other LRA's who may maintain a capacity construct

Benefits of UCAP proposal

- Unforced capacity evaluations promote procurement of the most dependable and reliable resources up front by accounting for historical unavailability in their capacity value
  - Allows LSE's to take historic availability into consideration when making procurement decisions
  - Allows the CAISO to eliminate complicated and ineffective forced outage substitution rules, and promotes investment in maintenance to keep capacity values high
  - Removes incentives to withhold excess capacity from the market to cover substitutions
  - Improves capacity pricing transparency by removing replacement costs
- UCAP dynamically changes with the fleet's forced outage rate
  - Relying solely on the PRM, which is a static value, may lead to over/under procurement if future outage rates change
  - PRM would only need to cover 6% operating reserves plus forecast error based on load levels

Q&A/Discussion

California Public Utilities Commission

Thank you for attending today's Track 3.B.2 Workshop.
Feedback welcome.

Hosts contact:

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