PESD STANFORD | PROGRAM ON ENERGY AND SUSTAINABLE DEVELOPMENT

# Physically Feasible Short-Term and Long-Term Low Carbon Electricity Market


**Frank A. Wolak**

Director, Program on Energy and Sustainable Development

Professor, Department of Economics

Stanford University


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# The Energy Transition

- Growing share of intermittent renewables increases the number of constraints that must respected in system operation
- Dispatchable generation units must turn on and off in response intermittent renewables output
  - Annual capacity factors of dispatchable thermal units decline
- Patterns of transmission congestion are much less predictable because of increased uncertainty in the supply of intermittent renewables
- Operating reserves demand increases because of need to respond to sudden changes in intermittent renewables output
- Conclusion: If region wants to increase significantly the quantity of intermittent renewable energy, its short-term and long-term wholesale market design must address these challenges

# Outline of Presentation

- Principles guiding low carbon wholesale market design
  - Physically feasible short-term market
    - Match between market model and network model
    - Benefits of multi-settlement markets
      - Benefits of purely financial participants
      - Benefits of active demand-side participation
    - Local market power mitigation mechanism
    - Cost-based versus offer-based market
    - Co-optimized energy and ancillary services market
  - Physically feasible long-term market
    - Reliability externality and need for Long-Term Resource Adequacy (LT-RA) mechanism
      - Energy contract-based approach to LT-RA

# Market Design Principle #1:
# Match Financial Market and Physical Realities of Grid Operation

# Congestion Management

- **Market model must accurately capture reality of how transmission network and generation units operate**
- Differences between market model and operating reality requires re-dispatch of generation units
  - Generation unit owners require compensation to increase and decrease output relative to what cleared market model
- Payment for re-dispatch creates incentives for generation unit owners to take actions to cause it to occur
  - Unnecessarily increases cost of serving final demand
  - Creates incentive for suppliers to degrade, rather than improve system reliability

# Reality of Transmission Network Operation

- The “DEC game” in single zone or zonal market
  - Generation unit owner sold energy in zonal day-ahead market that could not be delivered because of intra-zonal constraints
    - Unit owner sells energy at market-clearing price in day-ahead market and buys it back at lower offer price
    - Make money by selling little or no actual energy
- The “INC game” in single zone or zonal market
  - Generation unit owner knows that energy will be required from unit in real-time because of intra-zonal constraints
    - Unit owner offers a high price day-ahead market, but sells no energy
    - Unit supplies necessary energy at offer price in real-time
- In real-time, physics always wins
  - Realities of how grid is actually operated must be respected
  - Market participants use this knowledge it to maximize profits
    - Graf, Quaglia, and Wolak (2020) “Simplified Electricity Market Models with Significant Intermittent Renewable Capacity: Evidence from Italy,” on web-site

# Congestion Management

- Many examples from around the world of market inefficiencies because of differences between market model and physical reality of grid operation
  - Colombia—Negative and positive reconciliations
  - Australia—Constrained on and constrained off generation
  - Intra-zonal congestion management in US zonal markets
- Increasing cost of making schedules that emerge from zonal markets in Europe physically feasible, in part because of increasing share of intermittent renewables
  - In 2017, Germany over 1 billion Euros to make final schedules physically feasible; Great Britain over 400 million Euros; Spain 80 million; Italy 50 million
- These costs are likely to increase as amount of intermittent renewables increases in these electricity supply industries

# US Solution

- All US markets have adopted locational marginal pricing (LMP) which explicitly prices all transmission constraints and generation unit operating constraints
  - Limits difference between market model used for pricing and actual operation of transmission network
  - *No infeasible schedules accepted in day-ahead market—eliminates possibility of INC/DEC game*
- LMPs are computed in day-ahead and real-time markets by minimizing the as-offered cost of meeting demand at all locations subject to configuration of transmission network and operating constraints on generation units
  - LMP at a location is increase in objective function value associated with a one unit increase in withdrawals at that location

# Market Design Principle #2:
# Multi-Settlement Market

# Multi-Settlement Market

- Advance planning should produce more efficient real-time dispatch of generation units
  - Particularly true for systems with thermal generation units that have significant start-up costs
  - Running only an hourly real-time market makes it more difficult for these units to operate in most efficient manner possible
- All US wholesale electricity markets operate a day-ahead forward market and real-time imbalance market
  - Suppliers submit multi-part offers to day-ahead market for all 24 hours of following day
    - Start-up and minimum load costs and energy offer curve for each hour of the day
  - ISO minimizes as-offered costs to meet demand at all locations in grid for all 24 hours of following day to compute market prices and day-ahead schedules for withdrawals and injections for all 24 hours of the day
    - Day-ahead schedules are firm financial commitments

# Multi-Settlement Market

- Firm-financial commitment means that a supplier receives revenue from day-ahead forward market sales *regardless of real-time output of its generation unit*.
  - Sell 40 MWh at a price of $25/MWh receive $1,000 for sales.
  - Any deviation from day-ahead generation or load schedule is cleared in real-time market.
  - If supplier only produces 30 MWh, it must purchase 10 MWh of day-ahead commitment from real-time market at real-time price
- Same logic applies to a load-serving entity. Buy 100 MWh in day-ahead market for $40/MWh and pay $4,000 *regardless of real-time consumption*
  - If load-serving entity consumes 110 MWh, must buy additional 10 MWh in real-time market at real-time price
  - If load-serving entity consumes 90 MWh, it sells 10 MWh not consumed in real-time market at real-time price

# Multi-Settlement Market

- Multi-settlement market rewards suppliers for reliability of supply, yet still pays same price to all resources in each market
  - Consider a market with significant intermittent resources
  - Supply of intermittent resources typically highly correlated
- Suppose that a dispatchable thermal unit sells 100 MWh at price of $50/MWh in day-ahead market and intermittent resource sells 80 MWh in day-ahead market at same price
- In real-time, *significantly less intermittent output is* produced than was scheduled
  - Unit produces 50 MWh, so must purchase 30 MWh from real-time market at $90/MWh
- Thermal unit must maintain supply and demand balance, which explains high real-time price
  - Sells 30 MWh at real-time of $90/MWh
- Average price paid to thermal and intermittent units
  - $59.23 = 100 MWh*$50/MWh + 30 MWh*$90/MWh)/130 MWh)
  - $26 = (80 MWh*$50/MWh – 30 MWh*$90/MWh)/50 MWh
- Dispatchable unit rewarded with higher average price than non-dispatchable intermittent unit, despite both units being paid same price in day-ahead and real-time markets

# Multi-Settlement Market

- Case of *unexpectedly high intermittent* output
  - Resource sells only 50/MWh in day-ahead market  and thermal unit sells 130 MWh, both at $50/MWh
  - Intermittent resource produces 80 MWh, which implies that it sells 30 MWh in real-time market at $20/MWh
    - Low real-time price because of unexpectedly large intermittent output
  - Thermal resource buys back 30 MWh in real-time at $20/MWh
- Average prices paid to thermal and wind units
  - $59 = (130 MWh*$50.MWh – 30 MWh*$20/MWh)/100/MWh
  - $38.75  = (50 MWh *$50/MWh + $30 MWh*$20/MWh) /80 MWh
- In this case, dispatchable unit is rewarded with higher average price than intermittent unit because it can reduce its output

# Multi-Settlement Market

- Facilitates active participation of final demand with interval meters in wholesale electricity market
- Avoids need to pay for demand reductions relative to administratively determined baseline MWh as is the case with traditional demand response products
  - Traditional demand response products have created significant regulatory controversy and reliability challenges in many markets
    - Bushnell, James, Benjamin F. Hobbs, and Frank A. Wolak. "When it comes to demand response, is FERC its own worst enemy?." The Electricity Journal 22, no. 8 (2009): 9-18, also on web-site
- In multi-settlement market, loads simply buy their baseline consumption in previous forward market
  - Day-ahead market purchase allows sale in real-time market
  - Important for developing active demand-side participation in wholesale market

# Wholesale Market Lessons from US

- For same level of output produced by thermal units in California, both total BTUs of fossil fuel energy used and total operating costs of thermal generation units fell after transition to multi-settlement LMP market from multi-settlement zonal market
  - Total fossil fuel energy used each hour to dispatch system fell by 2.5 %
  - Daily variable cost of operating system fell by 2.1%
    - Wolak, F.A. (2011) “Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets,” *American Economic Review, also on web-site.*
  - Estimated reduction in annual total cost of operating thermal units of more than $100 million from transition to multi-settlement LMP market
- Even larger costs savings from transition to multi-settlement LMP market design from multi-settlement zonal design in Electricity Reliability Council of Texas (ERCOT) market
  - Daily variable cost of operating system fell by 3.9%
    - Triolo, R. and Wolak, F.A. (2020) “Measuring the Market Efficiency Benefits of the Transition to a Multi-settlement LMP market in ERCOT,” available on web-site
  - Estimated reduction in annual total cost of operating thermal units of more than $300 million from transition to LMP market

# The Benefits of Purely Financial Participants in Multi-settlement LMP Markets

# Virtual or Convergence Bidding

- Virtual bids are identified as such and can be submitted at nodal level
  - Incremental (INC) virtual bid is a purely financial transaction that is treated just like an energy offer curve in the day-ahead market.
    - Amount sold in day-ahead market must be purchased in the real-time market as a price-taker
    - Profit from day-ahead sale of 1 MWh INC bid is $P_{DA} – P_{RT}$
  - Decremental (DEC) virtual bid is a purely financial transactions that is treated just like an demand bid curve in day-ahead market
    - Amount purchased in day-ahead market must be sold in real-time market as a price-taker.
    - Profit from accepted 1 MWh DEC bid is $P_{RT} - P_{DA}$
- All market participants can use virtual bidding to profit from expected nodal price differences.

# Virtual or Convergence Bidding

- Virtual bids converge day-ahead and real-time prices
  - Suppose virtual bidder sees $P_{DA} > P_{RT}$ systematically
  - Submit INC bids to sell energy at $P_{DA}$ which implies buying at $P_{RT}$
  - These actions can reduce $P_{DA}$ and increase $P_{RT}$, closing gap between two prices
- Closing gap between prices implies day-ahead schedules closer to real-time operating levels
- If virtual bidder figures out a lower cost solution to real-time operation and submits virtual bids to make it happen in real-time, this action reduces cost of serving demand

# Benefits of Financial Participants

- Jha and Wolak (2013) "Can Forward Commodity Markets Improve Spot Market Performance? Evidence from Wholesale Electricity," forthcoming, *American Economic Journal: Economic Policy*
  - Introduction of purely financial participants in California electricity market reduced mean and variance of differences between day-ahead and real-time prices and variance of real-time prices
  - Actions of purely financial participants reduced system-wide costs and input fossil fuel consumed to produce same amount of electrical energy during high demand periods when transmission and many operating constraints likely to be binding
- Wolak, F.A. (2019) "Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance: The Case of Singapore," *Oxford Review of Economic Policy*
  - Lowered barriers to purely financial retailers to enter market to compete with incumbent retailers
  - Introduction purely financial retailers in Singapore electricity market reduced contestable retail prices and short-term wholesale prices

# Market Design Principle #3:
# Local Market Power Mitigation

# Local Market Power Problem

- Transmission network built for former vertically integrated utility regime
  - Built to take advantage of fact that both transmission and local generation can each be used to meet an annual local energy need
    - Captures economies of scope between transmission and generation
  - Vertically-integrated utility considered local generation and transmission on equal basis to find *least-cost system-wide* solution to serve load
  - Transmission capacity across control areas of vertically-integrated monopolists built for engineering reliability
    - Sufficient transmission capacity so imports could be used to manage large temporary outages within control area
    - Few examples where transmission capacity was built to facilitate significant across-control-area electricity trade
      - Oregon to California flows on DC intertie

# Origins of Local Market Power

- Transmission network configuration, geographic distribution of wholesale electricity demand, concentration in local generation ownership, and production decisions of other generation units combine to create system conditions when a single firm may be only market participant able to meet a given local energy need
  - Firm is monopolist facing completely inelastic demand
  - No limit to price it can bid to supply this local energy
- Regulator must design local market power mitigation (LMPM) mechanism
  - Limits ability to supplier to exercise unilateral market power and distort market outcomes
  - Increasingly important to have LMPM mechanism as scale amount of intermittent renewable generation units

# Local Market Power Mitigation

- All US offer-based markets have automatic local market power mitigation (LMPM) mechanism
  - Automatically mitigates offers of any generation that is determined to possess a significant ability to exercise unilateral market power
  - Introducing an offer-based day-ahead and real-time LMP market without an effective local market power mitigation mechanism in place would be extremely risky for consumers
- Key Lesson: An effective automatic local market power mitigation mechanism must be in place when a two-settlement LMP market design is implemented
  - All wholesale markets require a local market power mitigation mechanism
  - Cost-based short-term market is a popular approach in Latin America for dealing with local market power issue

# Local Market Power Mitigation

- All US markets have form of *ex ante automatic mitigation procedure* (AMP) for local market power
  - Built into market software and runs each time actual market-clearing occurs
- All AMP procedures follow three-step process
    - Determine system conditions when supplier is worthy of mitigation
    - Mitigate offer of supplier to some reference level
    - Determine payment to mitigated and unmitigated suppliers
- Two classes of AMP procedures
  - Conduct and impact
    - NY-ISO, ISO-NE
  - Market Structure-Based
    - CAISO, PJM, ERCOT
- For discussion of the available options see
    - Graf, La Pera, Quaglia and Wolak (2021) "Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status Quo and Challenges," available on web-site

# Cost-Based Market

- Cost-based short-term market is an alternative approach to address local market power problem
  - Market operator computes costs of generation units from technical characteristics and input fuel price index using regulator-approved formulas
    - Start-up, minimum load, and energy offer costs
- Regulator-determined costs are "offers" in both day-ahead and real-time markets
- Resulting LMPs for energy are paid to generation unit owners and charged to load-serving entities
- Prudent approach to implementing an offer-based multi-settlement LMP market design
  - Run initial year of LMP market as a cost-based as opposed to offer-based market
  - In United States, PJM LMP market was operated as cost-based market for first year

# Market Design Principle #4: Co-Optimized Ancillary Services Market

# Operating Reserves Market

- Sequential energy and operating reserve markets are unnecessarily expensive procurement mechanism
  - Sequential market use a “stale” or “wrong” opportunity cost of energy when computing an operating reserve price
  - If day-ahead market for energy is not firm financial commitment, supplier could be taken for 10 MW of operating reserves at $4/MWh, because day-ahead price of energy was $23/MWh and its marginal cost is $20/MWh
  - In real-time, supplier could regret this decision because price of energy is $30/MWh

- Early in California, the ancillary services market cleared before real-time energy market and after day-ahead energy market (not co-optimized with day-ahead market)
  - During this time period ancillary services costs were 13% of annual energy costs in 1998, 5.7% in 1999 and 6.8% in 2000
  - During last three years of multi-settlement LMP market in California with approximately 30% renewables, ancillary services costs were 2% of annual energy costs in 2018 and 1.7% in 2019 and 2.2% in 2020

- Conclusion—Day-ahead and real-time markets that co-optimize energy and operating reserves can reduce consumer costs relative to sequential market clearing of energy and operating reserves

# Co-optimization of Energy and Operating Reserves Markets

- Co-optimization of energy and operating reserves ensures that generation unit owners never regret selling operating reserves versus energy in day-ahead market
  - If day-ahead price for energy is \$22/MWh and supplier has \$20/MWh energy offer for 10 MW and then opportunity cost of that unit supplying operating reserves with 10 MW is \$2/MW
  - If operating reserves price is \$4/MW, then supplier will be taken for 10 MW of operating reserves instead of energy if operating reserves is offer at \$1/MWh
  - Supplier does not regret this because supplier earns \$4/MW for ancillary service, but only \$2 MWh = \$22/MWh - \$20/MWh from selling energy
- Conversely, if day-ahead price for energy is \$25/MWh then 10 MW would used to produce energy at \$4/MW operating reserves price because \$5/MWh = \$25/MWh - \$20/MWh

# Day-Ahead Energy and Operating Reserves Markets

- System operator minimizes as-offered cost to meet demand for energy and all operating reserves in day-ahead market for all *24 hours of the day simultaneously*
  - Co-optimize procurement of energy and four ancillary services in day-ahead market
  - Can specify locational demands and prices for operating reserves, just like for energy
- Day-ahead market respects all transmission network and all relevant generation unit and transmission network operating constraints
  - Energy and operating reserves schedules that result from day-ahead market are physically feasible
  - Adequate transmission capacity for generation capacity providing SFU and SFD and SPIN and NSPIN

# Standard Initial Short-Term Market Design: Two-Settlement, Co-optimized Cost-Based LMP Market

# Two-Settlement Market

- Two-settlement LMP market that co-optimizes energy and operating reserves procurement using
  - Regulator-determined cost produce energy for each thermal and hydro generation unit
    - Start-up, minimum load, and energy offer curve for all units
  - Capped price offers and quantity offers to provide each operating reserve that a generation unit is qualified to provide because there is no verifiable variable cost for operating reserves
  - Large consumers and retailers submit locational demand bids in day-ahead market for all 24 hours of following day
    - Can start with inelastic demand bids
  - System operator determines demands for operating reserves for all 24 hours of following day
- Day-ahead market minimizes as-offered costs of meeting the bid-in demand for energy and system operator’s demands for operating reserves at all locations in subject to transmission network and all relevant operating constraints for all 24 hours of following day
  - Can account for ramp rates, start-up and minimum load costs, minimum uptime and downtime in day-ahead market solution
  - Day-ahead energy and operating reserves commitments are firm financial commitments

# Two-Settlement Market

- Real-time market minimizes as-offered cost of meeting actual real-time demands for energy and operating reserves at all locations in network subject to all relevant operating constraints
  - Deviations between real-time output levels and day-ahead schedules settled at real-time locational marginal prices as described previously
- Make-whole payments can be made to generation units that fail to recover costs from selling energy and operating reserves in day-ahead and real-time markets
  - Make-whole payment is the positive difference between short-term market revenues for day and costs of producing energy and operating reserves throughout day

# Managing Equity Concerns

- Objection to LMP often raised that it unfairly punishes customers that live in major load centers with higher prices
  - Grid would be planned differently if LMP pricing had been in place since start of electricity industry
    - In California, customers in San Francisco face higher LMPs than customers in Bakersfield (in Central Valley)
- Can manage political challenge of charging different prices to different locations in grid through load-aggregation point (LAP) pricing
  - Charge all loads quantity-weighted average LMP over all points of withdrawal in retailer's service territory

# A Physically Feasible Long-Term Market

# Need for LT-RA Mechanism

In former vertically-integrated geographic monopoly regime, utility is responsible for ensuring that demand is met under all possible future system conditions

- Regulator penalizes monopoly for supply shortfalls

In wholesale market regime no single entity is responsible for ensuring system demand is met under all possible system conditions

- Independent System Operator (ISO) can only operate market with resources offered into market
- Generation unit owners can only supply energy from the generation units they control
- Retailers can only purchase the energy that generation unit owners supply to wholesale market

Conclusion—Unless regulator treats electricity like any other product (see next slide), wholesale market regime requires a long-term resource adequacy mechanism

# Need for Resource Adequacy Mechanism

A long-term resource adequacy mechanism is necessary because of "reliability externality"

- Unwillingness of regulator to commit to using real-time price of energy to clear market under all possible future system conditions creates a "reliability externality"
  - Lack of interval meters often used to justify this unwillingness of regulator "to treat electricity like any other product"

All consumers know that random curtailment will occur if aggregate supply is less than aggregate demand

- This implies that no customer faces full expected cost of failing to procure adequate energy in forward market
- Cannot curtail individual customers that failed to procure adequate energy in forward market, only all customers in a specific region of grid

Because of existence of "reliability externality," in cost-based markets or those with a finite offer cap regulator must mandate a long-term resource adequacy mechanism

- *Ensure adequate supply to meet system demand under all future system conditions and allowed short-term prices*

# Historical Long-Term Resource Adequacy Challenge

- Initial Conditions: Electricity supply industry with dispatchable (typically, thermal) generation resources, mechanical meters, and offer cap on short-term wholesale market
- Major concern: Sufficient installed capacity to meet system demand peak
- Mechanical meters: Only allow measurement of total electricity consumption between consecutive meter reads
  - Typically done on monthly or bi-monthly basis
  - Precludes use of dynamic prices to reduce system peaks
- Offer cap on short-term market: Can prevent units that run infrequently to recover their total cost

# Capacity Payments: Historical Solution to Problem

- Assign all retailers firm capacity obligations equal to a multiple of their annual peak demand
  - Between 110 to 120 percent, depending on region
- All generation units assigned firm capacity quantity equal to amount of energy unit can produce under stressed system conditions
  - For thermal resource this is typically equal to nameplate capacity times the availability factor of the unit
  - For hydro units, typically based on historically worst hydrological conditions
    - For example from Colombia, see McRae and Wolak (2016) "Diagnosing the Causes of the Recent El Nino Event and Recommendations" available from web-site.
  - For solar and wind resources, it is extremely difficult to determine firm capacity of generation units
    - Firm capacity of a MW of wind or solar capacity declines with share of wind or solar energy in system demand because of high degree of correlation in output across locations
      - For case of California, "Wolak, Frank A. "Level versus Variability Trade-offs in Wind and Solar Generation Investments: The Case of California." *The Energy Journal* 37, (2016).

# Firm Capacity of Intermittent Resources

- Firm capacity of solar or wind resource typically determined by effective load carrying capacity (ELCC)
  - If stressed system conditions occur when it is dark, firm capacity of solar generation unit should be zero
  - If stressed system conditions occur when wind is not blowing, firm capacity of wind generation unit should be zero
- Assignment of firm capacity to intermittent renewable resources likely to be overly optimistic
  - Values used in CA for August 2020 were 27% of installed capacity for solar PV and solar thermal and 21% of installed capacity for wind
    - Rolling blackouts occurred in late evening on August 14 and 15 when hourly capacity factors were significantly less than less values
- Conclusion: Firm capacity approach to long-term resource adequacy poorly suited to regions with high shares of intermittent renewable energy
  - For examples from California and Texas see
    - Wolak F.A. “Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables, *Environmental and Energy Policy and the Economy*, volume 3, 2022.

# Long-Term Resource Adequacy for Markets Dominated by Intermittent Renewables

Question is not an energy-only market versus capacity market

- Key Point: A long-term resource adequacy mechanism is necessary in any energy market with a finite offer cap because of the reliability externality
- Higher offer caps on short-term market only reduce magnitude of reliability externality, but do not eliminate it

Consumers want system demand for electricity to be met under all possible future system conditions

- For environmental reasons, consumers would likely prefer to have fewer MWs of generation capacity

Long-term resource adequacy mechanism should focus on meeting system demand, not demand for each individual retailer

- Electricity supplied to a load comes from grid, not from specific generation units
- Recall that in wholesale market regime, no market participant is responsible for meeting system demand all hours of the year

# What is the Solution?

Long-term resource adequacy mechanism that

- Ensures that system demand is a met for all hours of the year under all possible future system conditions
- Meets region's renewable energy goals and greenhouse gas emissions goals
- Ensures long-term financial viability of the all resources necessary to meet these goals
- Minimizes annual cost of wholesale and ancillary services to consumers subject to meeting above goals
  - Allow maximum flexibility to suppliers and retailers to meet these goals

Important trade-off in design of long-term resource adequacy mechanism

- All revenues paid to generation unit owners come from electricity consumers
- Implication: For consumers to pay less, suppliers and retailers must find lower cost way to meet annual demand for energy and ancillary services

# Standardized Forward Energy Contract Long-Term RA Mechanism

- Purchase actual hourly system demands throughout the year in advance at a fixed price
  - Sellers of these contracts have strong financial incentive to meet system demand during all hours of the year under all possible future system conditions
  - All suppliers know that all load is covered by a standardized fixed-price forward contract
- Mechanism is consistent with meeting region's renewable energy goals and greenhouse gas emissions goals
- Physical feasibility of meeting system demand dealt with by assigning a maximum sales value for standardized energy contract quantity to each generation resource
  - System operator and regulator assign annual firm energy value to all in-region resources
- Fosters formation of liquid market for financial contracts between all market participants at delivery horizons that allow new generation resources to compete in this market

# Energy-Contracting Resource Adequacy Process

Mandate *standardized fixed-price forward contract holdings* by retailers for pre-specified fractions of realized system demand at various horizons to delivery

- 100% of demand one year in advance
- 97% of demand two years in advance
- 95% of demand three years in advance
- 92% of demand four years in advance

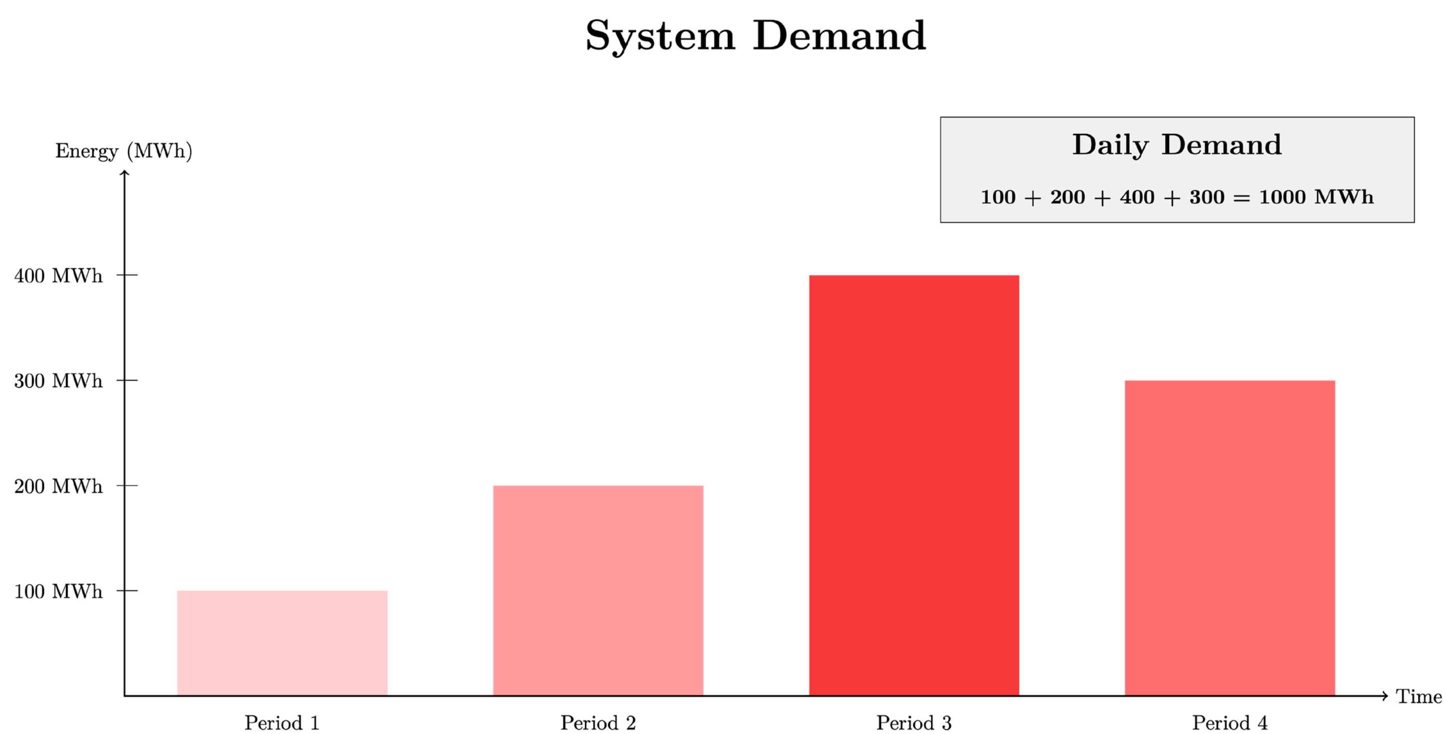
Above percentages are not set in stone, nor is years in advance contracts must be purchased

- Higher percentages provides greater confidence in resource adequacy
- Purchases more years in advance provides greater confidence in resource adequacy

Contracts are shaped to actual hourly system demand during “delivery” period

- Hourly standardized contract quantity, $QC_h$, varies with realized values of hourly system demand, $QD_h$
- Sellers of contracts have ability to manage this quantity risk through use of own generation units or through their own bilateral hedging arrangements
- Sellers can set price for standardized contract that incorporates cost of managing quantity risk associated with meeting actual system demand every hour of the year

# Energy-Contracting Resource Adequacy 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

# Energy-Contracting Resource Adequacy Process

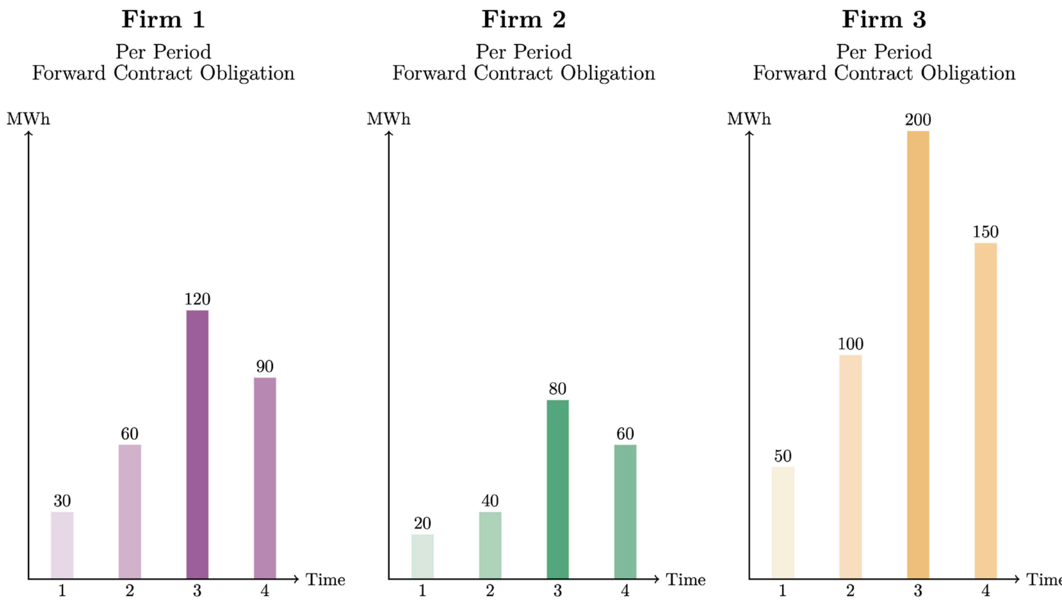
**There are Three Firms:**

**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

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

# Energy-Contracting Resource Adequacy Process

Delivery of initial annual contracts should begin far enough in advance of delivery that new sources of supply can compete to provide this energy

- At least three years between close of auction and delivery of energy
- Time horizon necessary for new entry to compete with existing generation unit owners to supply standardized forward contract

Contracts for annual energy are procured through centralized auction each year (or more frequently)

- Ex post true-up auctions (discussed below) needed to ensure total annual energy held by all loads equals actual annual demand

Simple auction mechanism can be used to procure energy because single product is being purchased

- Can run simple declining price auction to purchase standardized contract energy shaped hourly pattern of demand
- Each round of auction suppliers offer quantity of annual standardized contract energy they are willing to supply at prevailing price
  - Participants can only reduce quantity they are willing to supply each round
  - Price determined by first auction round that supply is less than or equal to demand

# Energy-Contracting Resource Adequacy Process

No capacity requirement

- Lets suppliers figure out least cost way to meet system demand for energy and ancillary services
    - Allocating quantity risk associated with meeting hourly variation in aggregate forward contract quantity among suppliers creates supply of operating reserves that can sell ancillary services
- Focuses on primary reliability problem in import-dependent market with significant amounts of intermittent renewables—adequate energy to serve demand
    - There has never been a shortage of generation capacity in California and other high renewables regions--New Zealand, Colombia, Brazil, and Chile--in wholesale market regime

Can increase offer cap on short-term market because all load is covered by standardized fixed-price forward energy contract

- Creates level playing field for demand-side and supply-side solutions

# Energy-Contracting Resource Adequacy Process

Periodic standardized auctions run by market operator overseen by regulator

- Purchases of standardized contracts are made and allocated to all loads based on their monthly (quarterly or annual) share of system load
- Clearinghouse manages counterparty risk between retailers and sellers of contracts
  - Counterparty risk assigned to retailers based on current share of system demand served and suppliers based on their contract sales

If allocation interval is a monthly, then retailers have hourly value of forward contract quantity, $QC_{ik}$, equal to their monthly share of system demand

- Can assign forward contract quantity to retailers at lower or higher degree of temporal aggregation than monthly
- Monthly allocation allows forward contract obligation to follow retail load as retailers lose and gain load across months
  - Retailer knows it will allocated monthly value of standard forward contract energy based on its share of monthly demand served

# Energy Contract Allocation Process

**There are Four Retailers:**

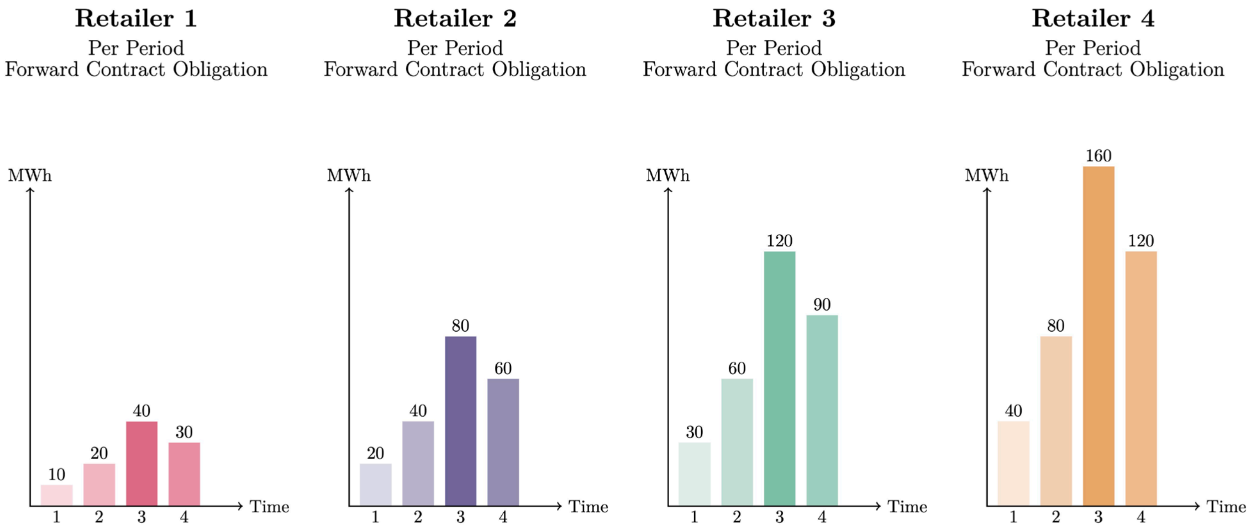
**Retailer 1 sells 100 MWh**

**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 ($QC_{hk}$)

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

# Energy-Contracting Resource Adequacy Process

All suppliers and load-serving entities know that actual system demand is fully hedged for all hours of the year

- Hourly output of individual suppliers is not fully hedged
- Hourly demand of individual load serving entities is not fully hedged

All suppliers and load serving entities are free to sign bilateral hedging arrangements to manage this residual short-term quantity and price risk

Wholesale energy markets typically start from zero hedging of system energy demand

- This typically leads to inadequate amounts of energy contracting because of reliability externality
  - In virtually all markets, participants complain about lack of liquidity in forward market for energy at delivery horizons needed to finance new investments

Standardized long-term contracting approach to resource adequacy starts from position that 100% of actual system load is hedged at delivery horizons necessary to financial new investment

- Suppliers and load-serving entities can expose themselves to more or less short-term price risk through additional forward market arrangements

# Incentives for Generation Unit Operation

There is no requirement that seller of contract must actually produce electricity sold in standardized forward contract

- Suppliers to have strong incentive to make least cost for consumers “make versus buy” decision to meet their hourly standardized fixed-price forward contract obligation

Behavior of dispatchable (thermal) generation unit owners with standardized forward energy contract obligations

- Owners will typically buy energy from short-term market instead of produce energy when there is a substantial amount of wind and solar energy produced

Encourages active demand-side participation in wholesale market (no need for low offers caps on short-term market)

- Consumers in aggregate protected from high wholesale prices by financial contract coverage of final demand
- Retailers that are willing to manage some short-term price risk can sell bilateral contract to expose themselves to this risk

# Incentives for Generation Unit Operation

To make efficient "make versus buy" decision to meet standardized forward contract obligation, thermal suppliers will submit offer to supply energy at marginal cost

- 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

Allocation of standardized contracts across dispatchable (thermal) suppliers ensures that all are committed to the short-term market at marginal cost for at least the hourly value of QC

Allocation of standardized contracts across intermittent suppliers ensures that they have strong incentive to make arrangements to supply or purchase at least hourly value of QC

- If system operator and regulator does not believe renewable resource can provide actual required energy to meet obligations under standardized forward contracts, they should reduce value of firm energy and therefore quantity that supplier can sell of standardized energy contract
  - This increases demand for standardized energy contracts from all dispatchable resources

# Physical Feasibility of Contracted Energy

Making ISO comfortable with transition to an standardized forward energy-contracts resource adequacy mechanism

- The firm capacity construct from capacity mechanism can be used to limit the quantity of standardized contract energy a unit owner can sell
- Do not want unit owners in the aggregate to sell more standardized energy than they are able to provide under all possible future system conditions

Dispatchable (typically thermal) resources will typically produce much less energy than they are capable of producing during extreme system conditions

Intermittent resources will typically produce much more energy than they are capable of producing during extreme system conditions

Mechanism encourages necessary cross-hedging between dispatchable resources and intermittent resources required to ensure demand is met under all possible future system conditions

- Intermittent units purchase quantity insurance from dispatchable resources for standardized energy contracts sold
- Intermittent unit owner can purchase cap contract with payment stream max(0,P(spot)-P(strike))Q(contract) for hours that renewable

# 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 energy is amount of energy unit can produce under stressed system conditions (determined by California ISO and CPUC)
  - Engineers 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

Ensures that total standardized contracts for 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

# 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)

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

Firm energy LT-RA does not interfere with ability of renewable resources to sell renewable energy certificates (RECs)

- LMP market design ensures least cost dispatch of available generation resources

# Concluding Comments

- Low cost, low carbon electricity supply industry requires short-term market that set efficient prices
  - Day-ahead and real-time locational marginal pricing market
    - This market design facilitates active demand side participation
  - Financial participants can increase competitiveness of wholesale and retail markets
  - Co-optimized energy and operating reserves market in day-ahead and real-time to procure increased amount of operating reserves required at least cost
  - Local market power mitigation mechanism must be in place because of increased opportunities to exercise unilateral market created by more intermittent resources
- Low cost, low carbon electricity supply industry requires long-term resource adequacy mechanism that address reliability externality
  - Mandate LT-RA mechanism necessary in all wholesale electricity markets with a finite offer cap on short-term market
    - Magnitude of cap only determines frequency of supply shortfalls
  - Assigns risk of energy shortfalls to entity best able to manage it
  - Encourages efficient short-term market outcomes
  - Supports development of a liquid forward market for energy

Thank you
Questions/Comments