Day Ahead Market Enhancements: Updates to Revised Straw Proposal

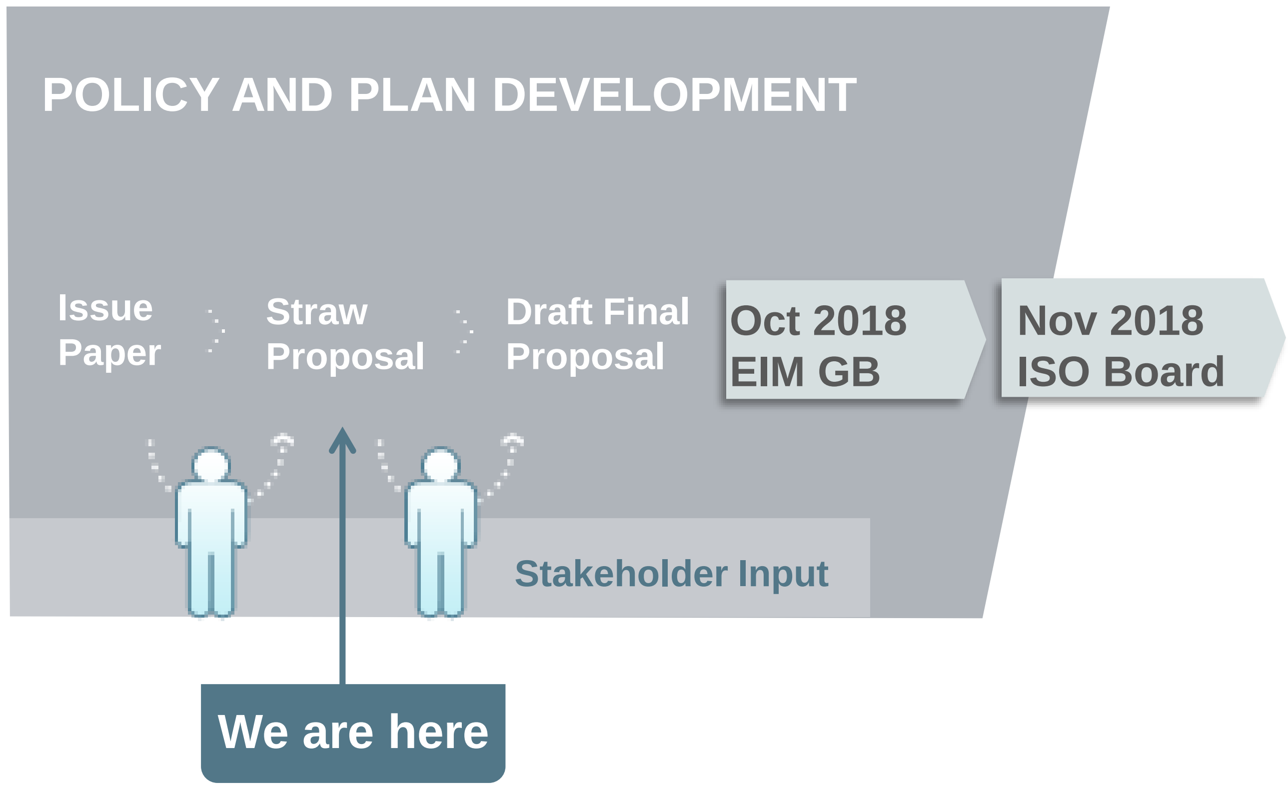
Workshop

June 19, 2018

Agenda

Time	Topic	Presenter
10:00 – 10:15	Welcome and Introductions	Kristina Osborne
10:15 – 10:30	Overview	Megan Poage
10:30 - 11:30	Market Formulation	George Angelidis
11:30 – 12:00	Settlement	Don Tretheway
12:00 – 1:00	LUNCH	
1:00 – 2:30	Other Design Elements	Don Tretheway
2:30 – 3:30	FRP Requirement	Hong Zhou
3:30 – 3:45	Comparison of DA Physical Supply	Danielle Tavel
3:45 – 4:00	Next Steps	Kristina Osborne

ISO Policy Initiative Stakeholder Process



Day-Ahead Market Enhancements

OVERVIEW

Megan Poage
Sr Market Design Policy Developer

California ISO

Materials provided for this workshop

- Presentation
- Updated Appendix C – Market Formulation
- Solver Model Excel Spreadsheet
- Settlements Excel Spreadsheet
- Response to Stakeholder Comment Matrix
- Draft Impact Assessment

What is changing?

- Current DAM
  - MPM pass
  - IFM pass
  - RUC pass
  - D+2 run
  - D+3 run
- Hourly intervals
- RUC Capacity
  - Up

- New DAM
  - MPM pass
  - IFM/RUC pass
  - D+2 run
  - D+3 run
- 15min intervals
- DA FRP
  - Up/Down

Imbalance Reserves are now Day-Ahead Flexible Ramping Products (FRP)

- RT FRP currently settles Forecasted Movement and Uncertainty Awards

- To align with DA FRP, all resources will be settled for Scheduled Energy and Uncertainty Awards
  - Energy Schedule + Up Uncertainty Award = FRP Up
  - Energy Schedule – Down Uncertainty Award = FRP Down

Day-Ahead Market Enhancements

MARKET FORMULATIONS

George Angelidis, Ph.D.
Principal
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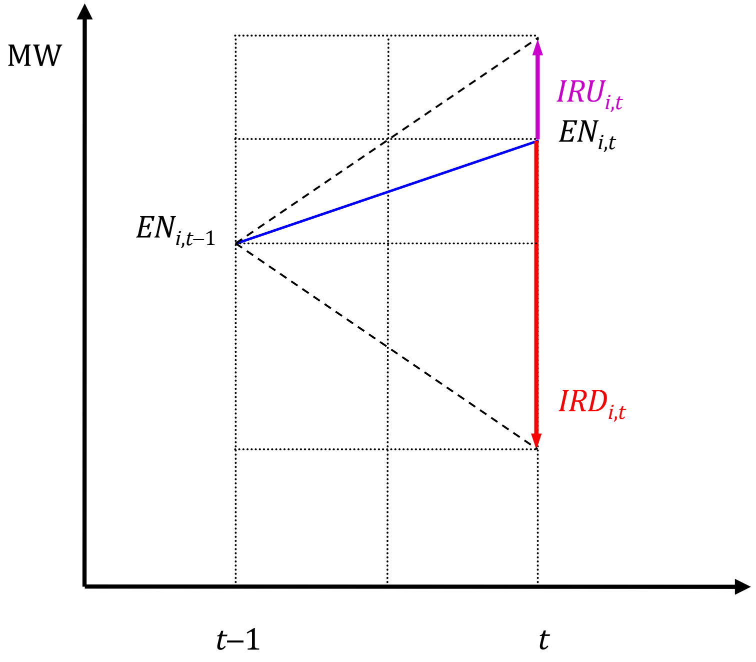
California ISO

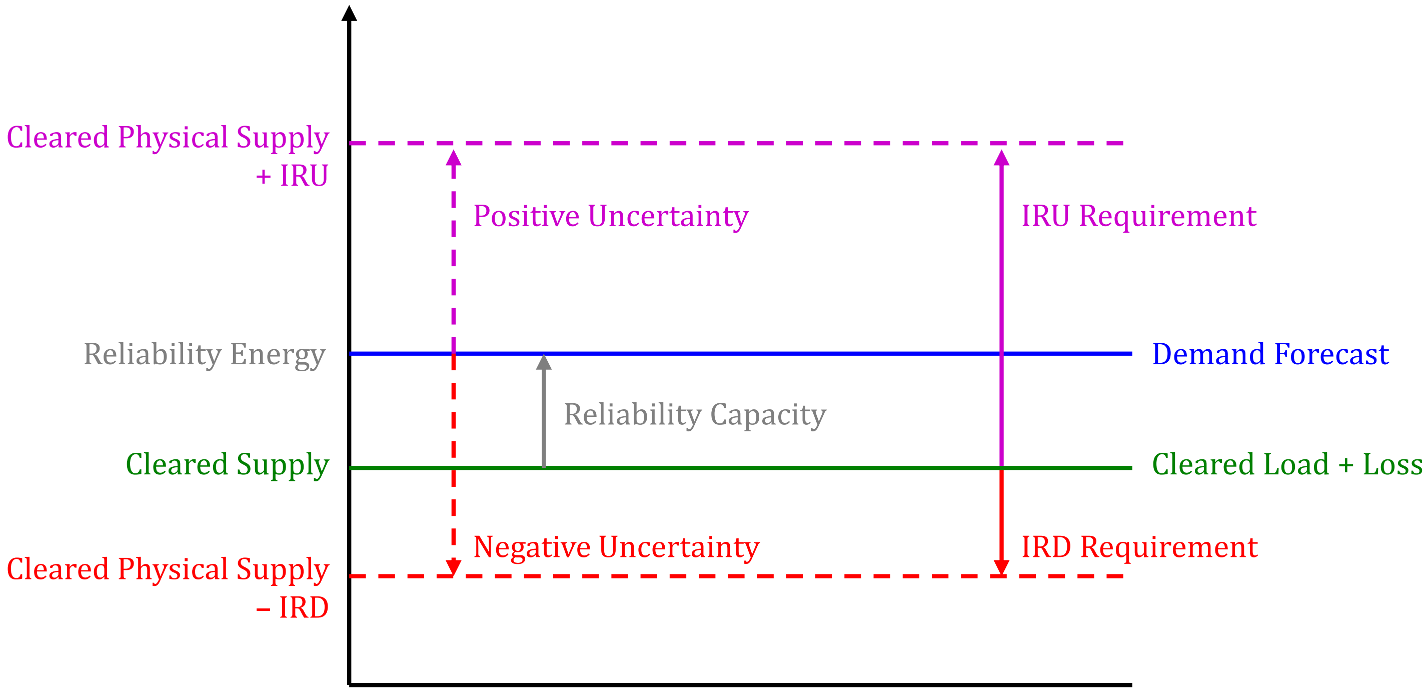
What is Imbalance Reserve?

- Reserved upward and downward ramping capacity procured at t–1 to be delivered if needed at t to meet the demand forecast plus upward and downward uncertainty



DA FRP

Day-Ahead Market targets



Power balance and Imbalance Reserve procurement constraints

$$\sum_i EN_{i,t} + \sum_j EN_{j,t} = \sum_i L_{i,t} + \sum_j L_{j,t} + Loss_t \qquad \lambda$$

$$\sum_i EN_{i,t} + \sum_i IRU_{i,t} \geq D_t + IRUR_t \qquad \rho$$

$$\sum_i EN_{i,t} - \sum_i IRD_{i,t} \leq D_t - IRDR_t \qquad \sigma$$

i: physical resource index

j: Virtual resource index

Locational Marginal Price

- Physical Supply:
  - $LMP_i = \lambda + \rho + \sigma$
- Non-Participating Load and Virtual Supply/Demand
  - $LMP_j = \lambda$
- Imbalance Reserve Up capacity
  - $LMP_{IRU} = \rho$
- Imbalance Reserve Down capacity
  - $LMP_{IRD} = -\sigma$

Price simplification by bundling Energy in the IRU/IRD awards

- Physical Supply, Non-Participating Load, and Virtual Supply/Demand:
  - EN_i, EN_j, L_i, L_j ◆ $LMP_i = LMP_j = \lambda$
- Imbalance Reserve Up award
  - $EN_i + IRU_i$ ◆ $LMP_{IRU} = \rho$
- Imbalance Reserve Down award
  - $EN_i - IRD_i$ ◆ $LMP_{IRD} = \sigma$

Deviation settlement between IRU/IRD and FRP

- IRU/IRD re-procured as Energy/FRU/FRD in RTM
- Bundle Energy in FRU/FRD awards internalizing Forecasted Movement
  - Deviation settlement of movement/uncertainty across markets:
    - $EN_i^{(DAM)} + IRU_i \rightarrow EN_i^{(FMM)} + FRU_i^{(FMM)} \rightarrow EN_i^{(RTD)} + FRU_i^{(RTD)}$
    - $EN_i^{(DAM)} - IRD_i \rightarrow EN_i^{(FMM)} - FRD_i^{(FMM)} \rightarrow EN_i^{(RTD)} - FRD_i^{(RTD)}$
- Comprehensive cost allocation across markets

Cost allocation

- Reliability cost
  - $RC = D - \sum_i EN_i$
  - $\max(0, RC)\ \rho$
    - Allocated to net negative demand deviation plus net virtual supply up to a user rate of ρ (existing tier-1 RUC cost allocation)
  - $-\min(0, RC)\ \sigma$
    - Allocated to net positive demand deviation plus net virtual demand up to a user rate of $-\sigma$ (tier-1)
  - Remaining cost is allocated to metered demand (tier-2)

Cost allocation

- Upward Uncertainty cost
  - $[\sum_i IRU_i - \max(0, RC)]\, \rho^{(DAM)} + \sum_i \Delta FRU_i\ \rho^{(FMM)} + \sum_i \Delta FRU_i\ \rho^{(RTD)}$
  - Allocated to upward uncertainty movement using existing FRU cost allocation
- Downward Uncertainty cost
  - $-[\sum_i IRD_i + \min(0, RC)]\, \sigma^{(DAM)} - \Delta FRD\ \sigma^{(FMM)} - \Delta FRD\ \sigma^{(RTD)}$
  - Allocated to downward uncertainty movement using existing FRD cost allocation

Cost allocation

- Scheduled Energy cost
  - $\sum_i EN_i^{(DAM)}\ \rho^{(DAM)} + \sum_i \Delta EN_i^{(FMM)}\ \rho^{(FMM)} + \sum_i \Delta EN_i^{(RTD)}\ \rho^{(RTD)} + \sum_i EN_i^{(DAM)}\ \sigma^{(DAM)} + \sum_i \Delta EN_i^{(FMM)}\ \sigma^{(FMM)} + \Delta EN_i^{(RTD)}\ \sigma^{(RTD)}$
  - Allocated to metered demand

California ISO

DA FRP

Excel Solver Example

California ISO	LOL (MW)	UOL (MW)	Ramp Rate (MW/min)	Energy Bid ($/MWh)	IRU Bid ($/MW)	IRD Bid ($/MW)	Energy Schedule (MW)					IRU Award (MW)					IRD Award (MW)				
Interval							0	1	2	3	4	0	1	2	3	4	0	1	2	3	4
G1	0	100	10	$10	$1	$1	50	100	100	100	100	0	0	0	0	0	0	60	40	20	30
G2	0	100	10	$20	$2	$2	50	100	100	100	100	0	0	0	0	0	0	0	0	0	0
G3	0	100	10	$30	$3	$3	50	100	100	100	100	0	0	0	0	0	0	0	0	0	0
G4	0	100	10	$40	$4	$4	50	0	0	0	0	0	50	70	90	80	0	0	0	0	0
VG5	0	100		$35				70	70	70	70										
L1	0	140		$60				140	140	140	140										
L2	0	230		$50				230	230	230	230										
VL3	0	50		$25				0	0	0	0										
Demand								340	360	380	370										
IRU Requirement													10	10	10	10					
IRD Requirement																		100	100	100	100
Constraints																					
Objective Function	-$44,490							-$11,450	-$11,450	-$11,450	-$11,450		$200	$280	$360	$320		$60	$40	$20	$30
Power Balance								0	0	0	0										
IRU Procurement													0	0	0	0					
IRD Procurement																		0	0	0	0
Shadow Prices																					
Power Balance								$35	$35	$35	$35										
IRU Procurement													$4	$4	$4	$4					
IRD Procurement																		-$1	-$1	-$1	-$1
Settlement																					
G1								$3,500	$3,500	$3,500	$3,500		$400	$400	$400	$400		-$40	-$60	-$80	-$70
G2								$3,500	$3,500	$3,500	$3,500		$400	$400	$400	$400		-$100	-$100	-$100	-$100
G3								$3,500	$3,500	$3,500	$3,500		$400	$400	$400	$400		-$100	-$100	-$100	-$100
G4								$0	$0	$0	$0		$200	$280	$360	$320		$0	$0	$0	$0
VG5								$2,450	$2,450	$2,450	$2,450										
L1								-$4,900	-$4,900	-$4,900	-$4,900										
L2								-$8,050	-$8,050	-$8,050	-$8,050										
VL3								$0	$0	$0	$0										
Total								$0	$0	$0	$0		$1,400	$1,480	$1,560	$1,520		-$240	-$260	-$280	-$270
Grand Total								$0					$5,960					-$1,050			

Day-Ahead Market Enhancements

SETTLEMENT

Don Tretheway
Sr. Advisor, Market Design Policy

California ISO

Settlement of FRP for physical resources, imports and exports

- Settle FRP deviations between markets
  - DA FRP at the DA FRP price
  - FMM deviations at the FMM FRP price
  - RTD deviations at the RTD FRP price

- If UIE/OA, clawback payment to energy schedule

- Follow FRP no-pay provisions for uncertainty awards

- No need for disqualification/penalty because deviations between markets are settled

DA FRP

FRP settlement when uninstructed imbalance energy

FRU	Scheduled Movement	Uncertainty Award
Positive UIE	No settlement	No Pay
Negative UIE	Deviation charge	N/A

FRD	Scheduled Movement	Uncertainty Award
Positive UIE	Deviation charge	N/A
Negative UIE	No settlement	No Pay

DA FRP

Cost allocation of DA and RT flexible ramping product

- Upward Reliability Capacity cost allocation (existing)
  - (1) Net virtual supply + net negative metered demand, (2) metered demand
- Downward Reliability Capacity cost allocation (new)
  - (1) Net virtual demand + net positive metered demand, (2) metered demand
- FRP Up Uncertainty cost allocation (existing)
  - Monthly allocation by category
- FRP Down Uncertainty cost allocation (existing)
  - Monthly allocation by category
- FRP Scheduled Energy cost allocation (modification)
  - Previously only allocated for FRP forecasted movement
  - Metered demand

DA FRP

Excel Settlement Spreadsheet

Awards / Schedule	IFM Energy	IFM DA Flexible Ramping Product Up Uncertainty	IFM DA Flexible Ramping Product Down Uncertainty	FMM Energy	FMM Flexible Ramping Product Up Uncertainty	FMM Flexible Ramping Product Down Uncertainty	RTD Energy	RTD Flexible Ramping Product Up Uncertainty	RTD Flexible Ramping Product Down Uncertainty	Meter Energy
Bid In Non-Participating Load	-1000	N/A	N/A	-1400	N/A	N/A	-1450	N/A	N/A	-1445
Virtual Demand	-100	N/A	N/A	0	N/A	N/A	0	N/A	N/A	N/A
Generator 1	200	400	0	600	100	0	650	80	0	655
Generator 2	200	0	400	400	0	100	400	0	80	390
Variable Energy Forecast	400	0	0	400	0	0	400	0	0	400
Virtual Supply	300	N/A	N/A	0	N/A	N/A	0	N/A	N/A	N/A
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
Clearing Price	$ 30.00	$ 4.00	$ (2.00)	$ 35.00	$ 2.00	$ (1.00)	$ 40.00	$ 1.00	$ (0.50)	
Convert to MWh Pricing for Interval	$ 7.50	$ 1.00	$ (0.50)	$ 8.75	$ 0.50	$ (0.25)	$ 10.00	$ 0.25	$ (0.13)	
ISO Reliability Forecast	1115									
Cleared Physical Supply	800									
Reliability Forecast to FMM Uncertainty		300	300		N/A	N/A		N/A	N/A	
FMM FRP Requirement		100	100		100	100		N/A	N/A	
RTD FRP Requirement		N/A	N/A		N/A	N/A		80	80	

Settlement	IFM Energy	IFM Imbalance Reserve Up Energy Schedule	IFM Imblance Reserve Down Energy Schedule	IFM Imbalance Reserve Up Uncertainty	IFM Imbalance Reserve Down Uncertainty	FMM Energy	FMM Flexible Ramping Product Up Energy Schedule	FMM Flexible Ramping Product Down Energy Schedule	FMM Flexible Ramping Product Up Uncertainty	FMM Flexible Ramping Product Down Uncertainty
Bid In Non-Participating Load	$ 7,500	N/A	N/A	N/A	N/A	$ 3,500	N/A	N/A	N/A	N/A
Virtual Demand	$ 750	N/A	N/A	N/A	N/A	$ (875)	N/A	N/A	N/A	N/A
Generator 1	$ (1,500)	$ (200)	$ 100	$ (400)	$ -	$ (3,500)	$ (200)	$ 100	$ 150	$ -
Generator 2	$ (1,500)	$ (200)	$ 100	$ -	$ (200)	$ (1,750)	$ (100)	$ -	$ -	$ 75
Variable Energy Forecast	$ (3,000)	$ (400)	$ 200	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Virtual Supply	$ (2,250)	N/A	N/A	N/A	N/A	$ 2,625	N/A	N/A	N/A	N/A

Settlement	RTD Energy	RTD Flexible Ramping Product Up Energy Schedule	RTD Flexible Ramping Product Down Energy Schedule	RTD Flexible Ramping Product Up	RTD Flexible Ramping Product Down	Uninstructed Imbalance Settlement Energy	Uninstructed Imbalance Settlement Flexible Ramping Product Up Energy Schedule	Uninstructed Imbalance Settlement Flexible Ramping Product Down Energy Schedule	Uninstructed Imbalance Settlement Flexible Ramping Product Up No Pay	Uninstructed Imbalance Settlement Flexible Ramping Product Down No Pay
Bid In Non-Participating Load	$ 500	N/A	N/A	N/A	N/A	$ (50)	N/A	N/A	N/A	N/A
Virtual Demand	$ -	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Generator 1	$ (500)	$ (13)	$ 6	$ 5	$ -	$ (50)	$ -	$ 3	$ 1	$ -
Generator 2	$ -	$ -	$ -	$ -	$ -	$ 100	$ 10	$ -	$ -	$ 1
Variable Energy Forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Virtual Supply	$ -	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Cost Allocation RUC Up (existing)	$ 315	(1) Net virtual supply + net negative metered demand, (2) metered demand
Cost Allocation RUC Down (new)	$ -	(1) Net virtual demand + net positive metered demand, (2) metered demand
Cost Allocation Uncertainty Up (existing)	$ 244	FRP Monthly allocation by category
Cost Allocation Uncertainty Down (existing)	$ 124	FRP Monthly allocation by category
Cost Allocation Scheduled Movement (modifie	$ 279	Allocated to Metered Demand
Total Cost Allocation	$ 961	

Yellow cells are input data

California ISO

For illustrative purposes only
(Paid) Charged

DA FRP

Bid cost recovery for FRP is split between day-ahead and real-time

- DA BCR
  - Cost = Bid * DA Award
  - Revenue = Award * DA Price

- RT BCR
  - Cost = $0
  - FMM Revenue = Deviation * FMM Price
  - RTD Revenue = Deviation * RTD Price

DA FRP

Day-Ahead Market Enhancements

OTHER DESIGN ELEMENTS

Don Tretheway
Sr. Advisor, Market Design Policy

California ISO

ISO proposes to procure DA FRP using a demand curve

- Consistent with current RT FRP procurement
  - If expected avoidance of PBC > FRP cost then procure

- Modified proposal to require RA resources to still submit bids into real-time market even if no DA FRP award

- Non-RA resources that have a DA FRP award have a real-time must offer obligation
  - Generate bid similar to RUC awards today

DA FRP

Implementing sub-regional constraints will address deliverability concerns (1 of 2)

- ISO system (5 Min) and ISO extended (15 Min)

- Sub-regions established at the TAC level

- Enforce constraint that up (down) awards in sub-region cannot exceed sub-region up (down) requirement and transfer level out (in)

DA FRP

Implementing sub-regional constraints will address deliverability concerns (2 of 2)

- Requires implementing a power balance constraint for each sub-region
  - Include shadow price in Marginal Cost of Congestion (MCC) to maintain single SMEC at all nodes.
  - Since FRP in not modeled in CRR model exclude MCC from CRR settlement, as done with CME

- Lastly, operators can block resources from receiving awards if located in congested area within sub-region
  - Similar process used for ancillary services today

DA FRP

Propose that market services grid management charge applied to AS, CME, & FRP uncertainty awards

- Currently AS is charged the Market Services rate for all awards and deviations
- Currently CME/FRP is not charge the Market Services rate because this would create a marginal cost and bidding is not allowed
- In day-ahead cost can be included in capacity bid.
- In real-time, the capacity bid will set equal to market services charge

DA FRP

Re-optimization of Ancillary Services in the FMM: Design Impacts (1 of 2)

- Propose no bidding in RTM for spin and non-spin
  - By submitting bids to RTM, there is no marginal cost for making resource available to RTM. It is a sunk cost.
  - Energy opportunity cost will set the price
  - Bid cost will equal market services GMC charge

- Regulation up/down can continue to submit bids to RTM
  - Estimate of regulation energy settlement may need to be included in capacity bid
  - Mileage bids continue to be allowed in RTM

- Still support self-provision quantity just for AS

DA FRP

Re-optimization of Ancillary Services in the FMM: Design Impacts (2 of 2)

- Retire the flag to allow market participant to select contingency-only option
  - All awards will be contingency-only in RTD
- Operators can block a resource from being awarded AS
  - Current functionality
  - Ex: don't want resources behind a constraint awarded spin
- Operators can lock the DA AS award in RTM
  - After day-ahead markets, operators ensure AS is deliverable
  - Ex: concern that re-optimization would move AS from a deliverable resource to undeliverable resource
  - Log and report reason
- Similar to energy, must have a transmission profile that supports your AS bid to be awarded AS in FMM
  - If day-ahead AS award isn't tagged prior to T-40. It will result in a buy-back at the FMM price

DA FRP

Clarification to AS given 15-minute granularity in day-ahead market

- Appendix K requires spin/non-spin to sustain output for 30 minutes.
  - Applies even if no AS schedule in subsequent 15-minute interval
- AS on interties can only be procured from 15-minute dispatchable resources.
  - Hourly block require contingency dispatch to be held for remainder of the hour even if not needed
  - 15-minute dispatchable allow ISO to recover reserves after contingency event has been resolved

15-min

Additional AS clarifications to ensure accurate accounting of reserves

- Award AS using single dynamic ramp rate, limited by certified AS capacity

- Regulation ramp rate used in AGC can be lower than dynamic ramp rate

- If contingency event, spin/non-spin will be dispatched using dynamic ramp

- When in contingency, regulation resources use dynamic ramp rate

15-min

Resource Adequacy Availability Incentive Mechanism (RAAIM) will remain in effect

- This initiative is not changing the RT MOO of RA resources

- Using a demand curve to procure DA FRP does not ensure that 100% of imbalance met DA
  - Does ensure that DA FRP procured is ramp feasible

- Any changes to RAAIM will occur in FRACMOO2 or other initiative

N/A

RA Resource's DA FRP capacity bid is zero for interim period

- RA resources must bid $0.00 during transition period
  - Allows time for RA paradigm to recognize that marginal cost of real-time market availability will be compensated through day-ahead FRP
  - It is appropriate for the resource to be paid for any opportunity costs from not providing energy to meet DA FRP uncertainty requirement
  - Note: ISO will insert the market services cost as the bid cost

- Transition period is end of 2020 or EDAM implemented; whichever is sooner
  - EDAM will allow other BAAs to use ISO resources to meet DA FRP requirements. Marginal capacity costs should be recovered through market price.

DA FRP

ISO proposes Master File certification flag for certain resources to not be considered for DA FRP uncertainty awards

- RDRR/PDR can elect to bid as an hourly block and only be awarded energy
  - Block option chosen in DA, remain block in RT

- Hourly block interties can only bid and be awarded energy
  - Block option chosen in DA, remain block in RT

- 15-minute interties can register a system resource as select flag to be economically cleared in DA, but not considered for DA FRP because the system resource isn't 15-minute dispatchable in real-time m

DA FRP

Allow Contingency Modeling Enhancement (CME) to have a capacity bid in the day-ahead market

- CME and DA FRP have the same capacity cost to be available in RT with economic bids

- Propose CME will use the DA FRP bid price

- But for CME must test for market power
  - If the dynamic competitive path assessment (DCPA) is non-competitive, set CME bid price to historical DA FRP clearing bid cost
  - The historical average DA FRP clearing price would include opportunity costs which should not be reflected in CME bid
    - Seek stakeholder comment on how to determine default FRP bid

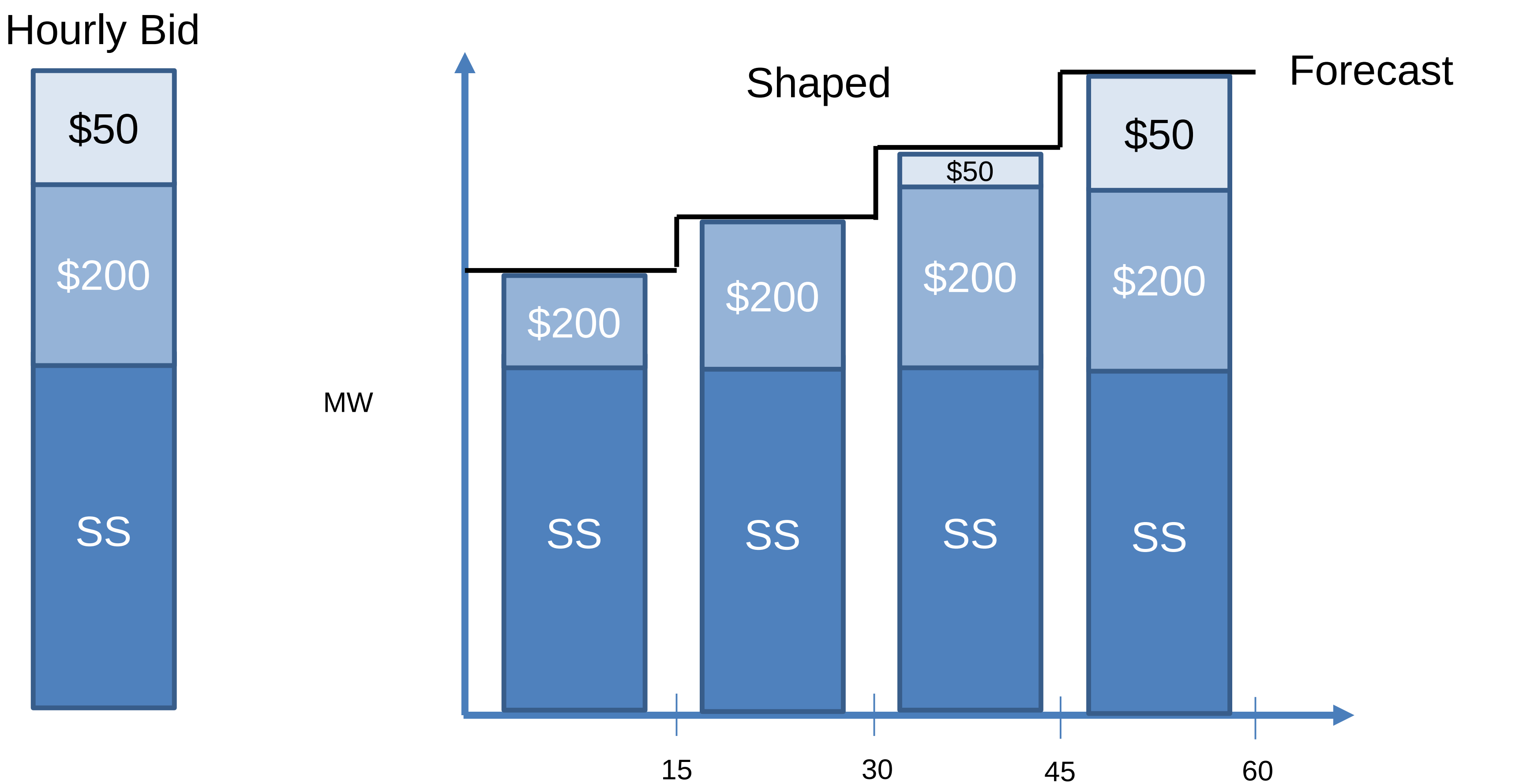
DA FRP

Allow bid-in load and VERs to shape their economic bids based upon relative forecast

- SCs provide 15-minute forecast for non-participating load
- SCs provide 15-minute upper economic limit for VER
  - IFM will use CAISO forecast or SC submitted (determined by SC)
  - If SC uses their own forecast in IFM, they can still use the ISO forecast in the RTM
  - RTM will use CAISO forecast to clear the market, but SC can submit own forecast for settlements
- Certain Proxy Demand Response resources output changes as underling load changes
  - Request stakeholder comment if PDR should use a DA forecast

15-min

Non-participating Load Shaping of Bid Curve



15-min

Interties can be scheduled with 15-minute granularity and be awarded DA FRP (1 of 2)

- Applies both to imports and exports.
- As with internal supply,
  - If DA 15-minute schedules are different can roll over as a RT self-schedule with different MW for each 15-minute interval
- External VERs can use forecast to schedule in day-ahead market

15-min

Interties can be scheduled with 15-minute granularity and be awarded DA FRP (2 of 2)

- DA FRP award will apply to energy schedule

DA FRP

Modeling of DA FRP sourced from a resource in an EIM BAA

- ISO system resource registered in Master File
- Auto-mirror resource used to balance ISO system resource
- RT bids submitted at ISO system resource.
- If DA FRP award, the resource sufficiency test for both BAAs will be adjusted
  - 50MW DA FRP Up award. ISO upward flex requirement reduced by 50MW. Source BAA upward flex requirement increased by 50MW
  - 40MW DA FRP Down award. ISO downward flex requirement reduced by 40MW. Source BAA downward flex requirement increased by 40MW

DA FRP

Modeling of RA sourced from a resource in an EIM BAA

- ISO system resource registered in Master File
- Auto-mirror resource used to balance ISO system resource
- RT bids submitted at ISO system resource.
- If RA capacity with RT MOO, the resource sufficiency test for both BAAs will be adjusted
  - 50MW DA FRP Up award. ISO upward flex requirement reduced by 50MW. Source BAA upward flex requirement increased by 50MW
  - 40MW DA FRP Down award. ISO downward flex requirement reduced by 40MW. Source BAA downward flex requirement increased by 40MW

15-min

Market Power Mitigation Changes

- Market power mitigation moves to 15-minute granularity in DAM
- For consistency, will evaluate in FMM for each 15-minute interval versus hourly
  - Currently, if mitigated in FMM run, then mitigated for balance of the hour
  - Proposal, if mitigated in FMM, mitigation of future interval will be determined in subsequent FMM
- If mitigated in FMM, then mitigated for the three relevant 5-minute intervals in RTD

15-min

Inter-SC trades for energy will be performed on a 15-minute interval basis

- Currently submit a single hourly interSC trade 45 min before the hour

- Proposal
  - Allow RT interSC trades to be submitted 45 minutes prior to each FMM interval
  - Will enable VERs to use a 15-minute forecast closer to actual flow to create interSC trade
  - AS should remain hourly because cost allocation is done hourly
  - InterSC GMC $1.00 charge divided by 4. New rate $0.25 per trade

CRR Clawback will move from hourly evaluation to 15-minute interval evaluation

- CRRs are settled for each 15-minute day-ahead interval
- Cleared convergence bids are awarded by 15-minute interval and settled at 15-minute LMP
- Convergence bids are automatically reversed at the FMM price for the corresponding real-time 15-minute interval

15-min

Modification to expected energy calculation to support 15-minute granularity

- Currently, standard ramping energy (SRE) and ramping energy deviation (RED) calculated for all resources to address hourly schedule changes

- Propose to only calculate SRE and RED for resources that self-schedule into the real-time market
  - Hourly block self-schedule will assume a 20 minute ramp
  - 15-minute self-schedule will assume a 10 minute ramp

15-min

Misc. Pricing Rule Clarifications

- Administrative pricing rules use the relevant day-ahead 15-minute interval if needed for FMM and RTD

- Make whole payments for price corrections only made to Load and Block Exports.
  - 15-minute bidding exports will get BCR.

15-min

Day-Ahead Market Enhancements

FRP REQUIREMENT

Hong Zhou
Market Development Analyst - Lead

California ISO

Summary

- Summary of Methodology Options Available
- Explore two approaches for Load, Wind, and Solar Requirement
  - Histogram (Similar to Current Flexible Ramp Requirement)
  - Quantile Regression

    Use historical data to determine parameters, with regressors being the DA forecasts
- Methodology Proposal for DA Uncertainty Requirement
- Graphically demonstrate the proposed methodology in the setup for finding requirement for each month and each hour

Note: Data range for this analysis is January through December of 2017

DA FRP

Methodology Options

1. Utilize a methodology (H: Histogram) that is similar to what is currently used for the Flexible Ramping Product (FRP) procurement. Requirement will be determined based on differences between the DAM and RTD.
2. Utilize a statistical regression technique (Q: Quantile) to estimate the variation for individual components of load, wind, and solar. Then combine the results into the total imbalance reserve requirement..
3. Incorporate probabilistic forecasting for weather information (E: Ensemble), combine with the statistical regression technique as in #2 to determine the total imbalance reserve requirement. -- Possible future enhancement.

DA FRP

Definition for Forecasts

- KEY: (Up – Up; Dn – Down; Var – Variation; Req – Requirement)

- Load Up Var = Hourly RTD Load Max – DA Load
- Wind Dn Var = Hourly RTD Win Min – DA Wind
- Solar Dn Var = Hourly RTD Solar Min – DA Solar

- Load Dn Var = Hourly RTD Load Min – DA Load
- Wind Up Var = Hourly RTD Win Max – DA Wind
- Solar Up Var = Hourly RTD Solar Max – DA Solar

- Net Load = Load – Wind – Solar
  - Net Load Up Var = Hourly RTD Net Load Max – DA Net Load
  - Net Load Dn Var = Hourly RTD Net Load Min – DA Net Load

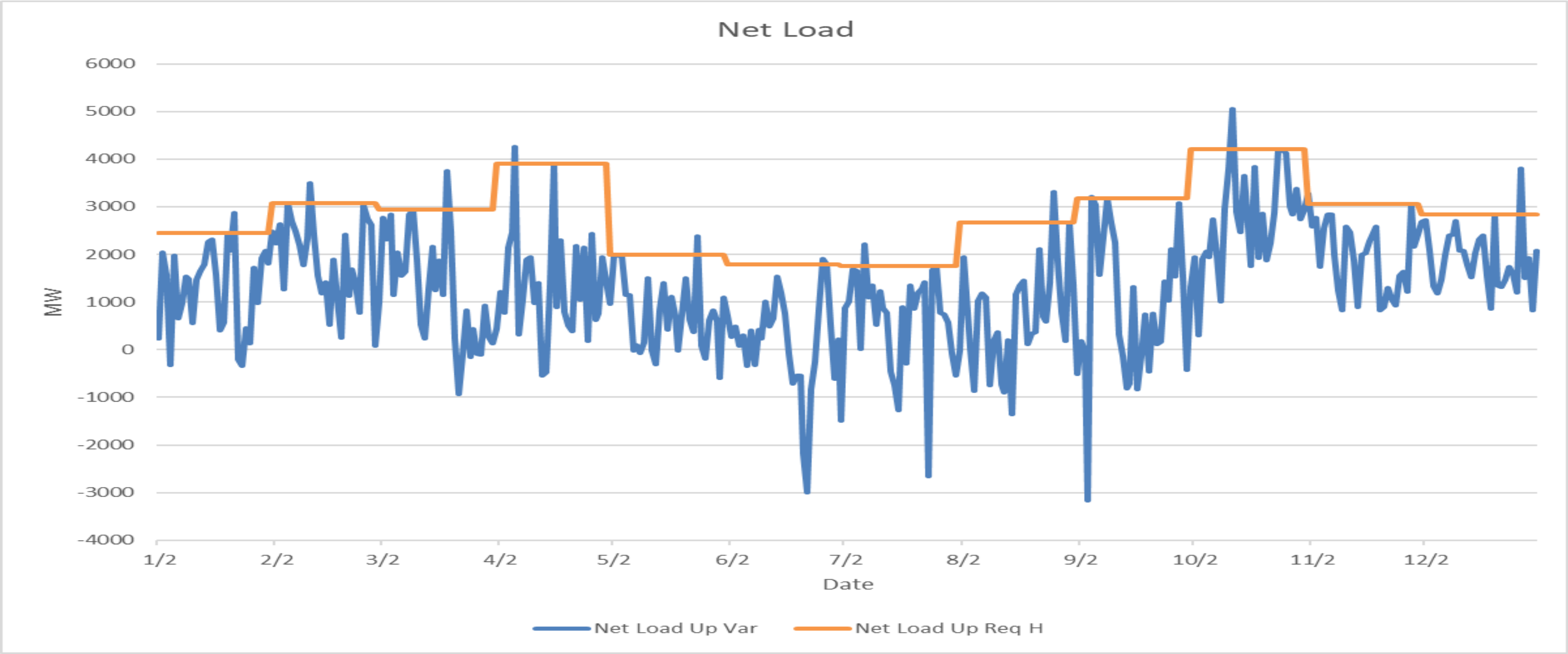
- Requirement is an estimated number based on observed Variation

DA FRP

Histogram Approach

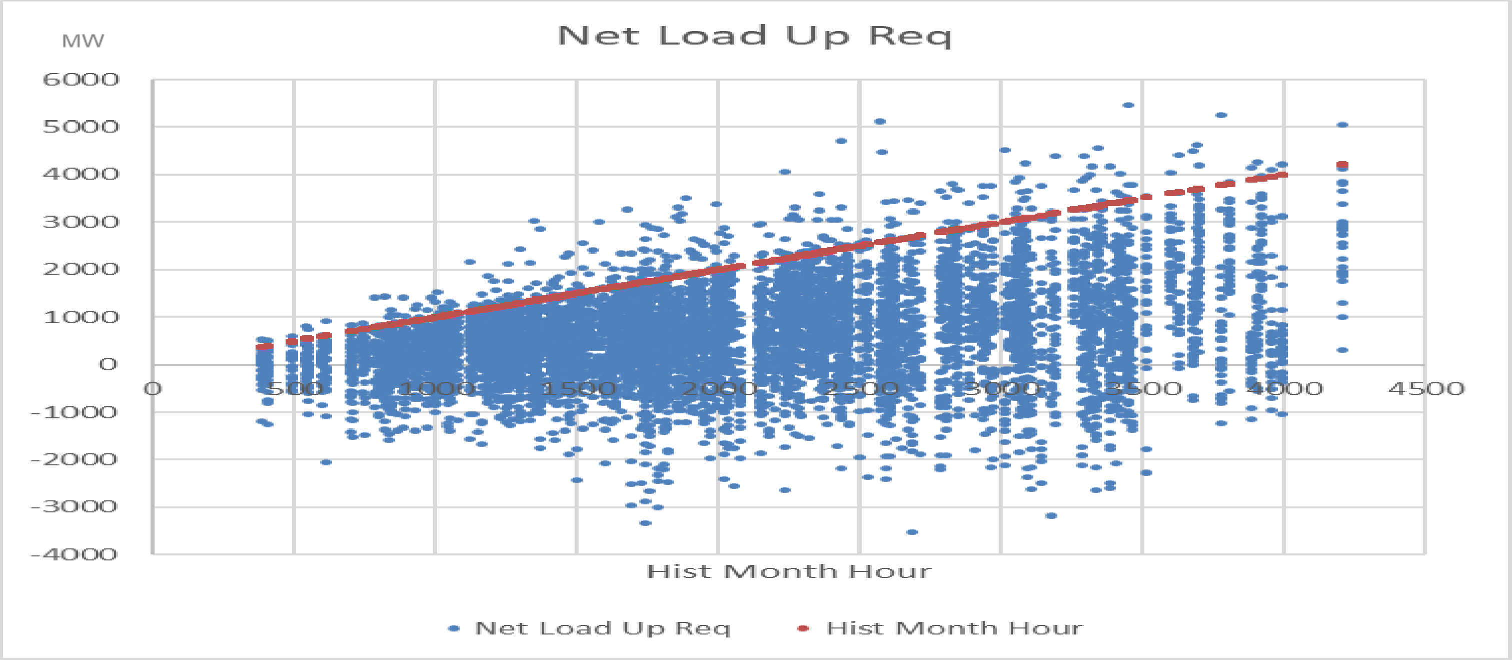
- Build a histogram of the Net load Up Variation for previous N (currently N=40 for real time) days for a given hour
- Use the 95 percentile of the histogram as Net load Up Requirement
- The calculated Net load Up Requirement carries no other inputs such as weather info and DA forecasts.
- That is, when using the regression model to find the 95 percentile, with no regressors, simply put, just Y = a in traditional model Y = a + b X
- Use HE 17 as example

Net Load Up Req H



DA FRP

Histogram: All the Hours



DA FRP

Histogram: Regression Perspective

- Histogram (H) approach can be viewed as the simplest quantile regression, as later we will build a more reasonable quantile regression model
- We can get 95 percentiles by using Y = a quantile regression model for

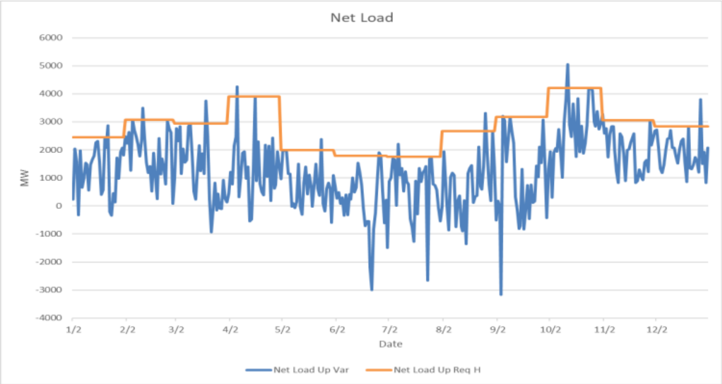
  Load_Up_Req, Wind_Dn_Req, Solar_Dn_Req, and Net_Load_Up_Req, respectively. Hour is treated as a dummy variable
- H: Wind_Dn_Var_H = a;

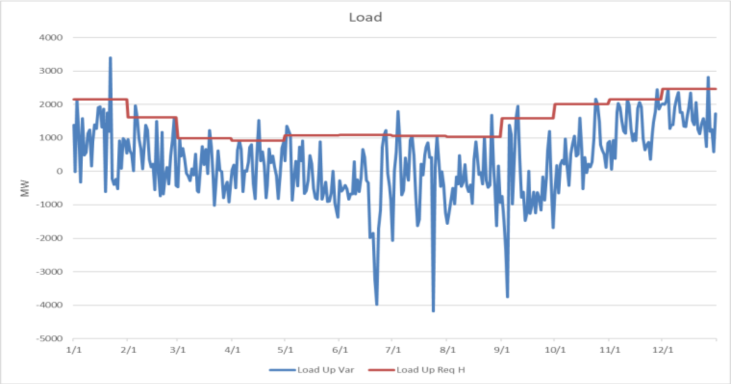
  Solar_Dn Var_H = a;

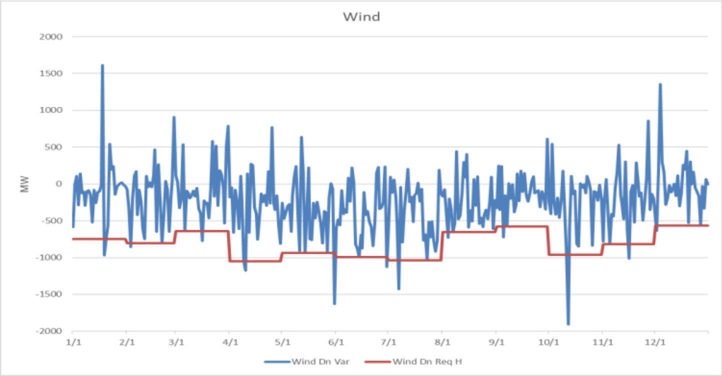
  Load_Up Var_H = a;

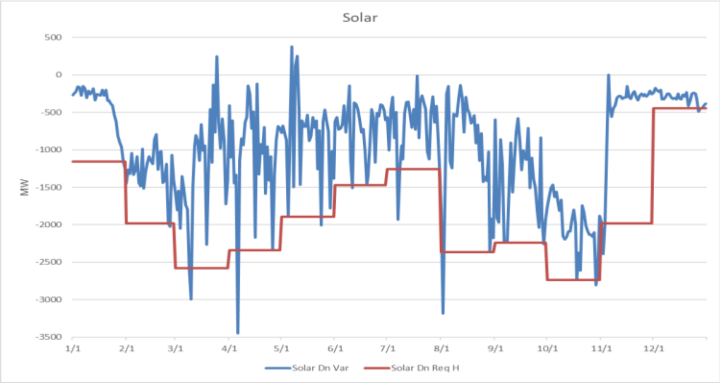
  Net_Load Up Var_H = a;
- The use of the requirements for the components (Load, Wind and Solar) as well as the coincidence requirement for Net_Load will be explained later.

Histogram Approach

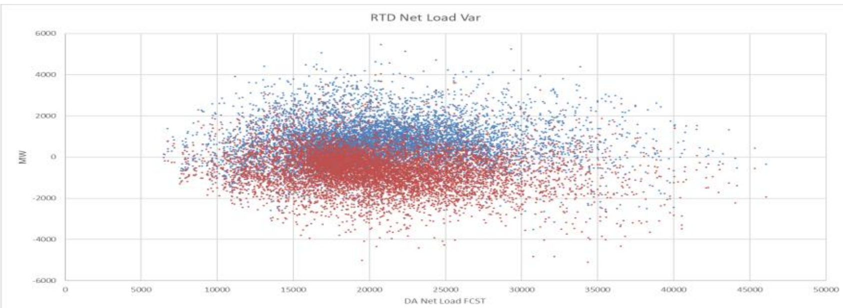


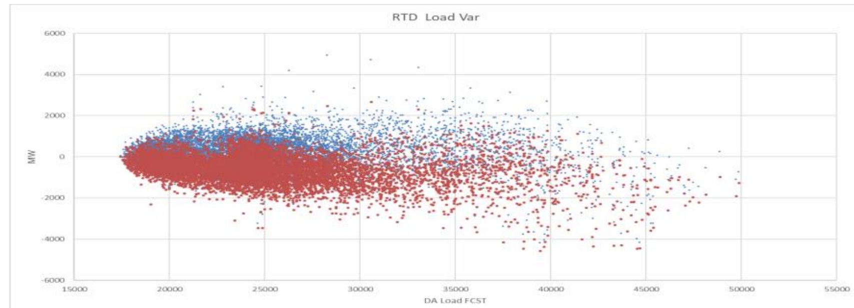


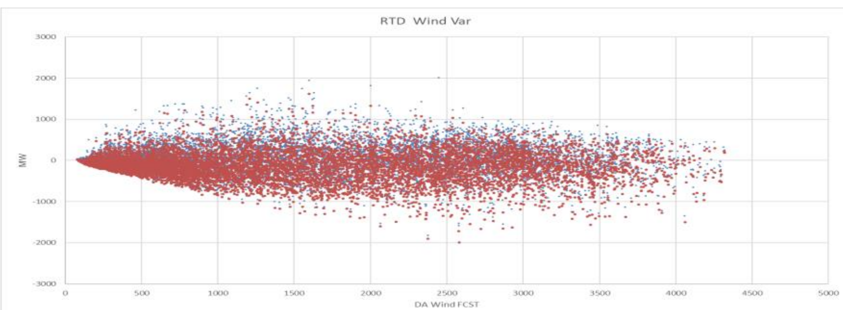


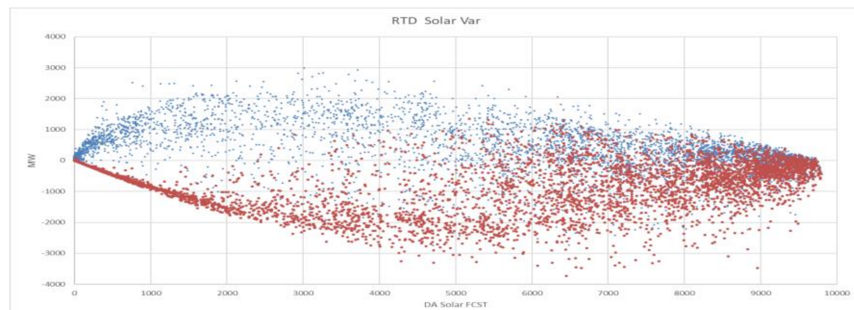


Quantile Regression: Variation







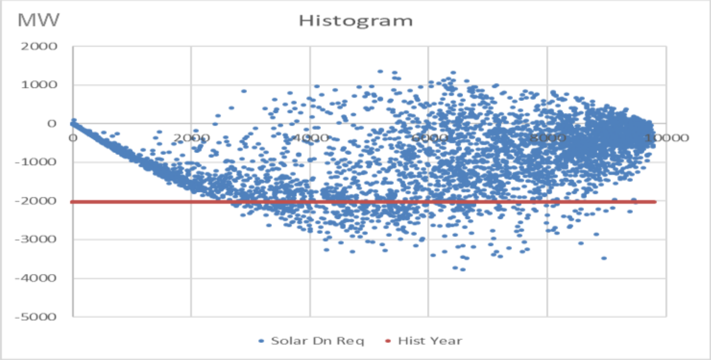


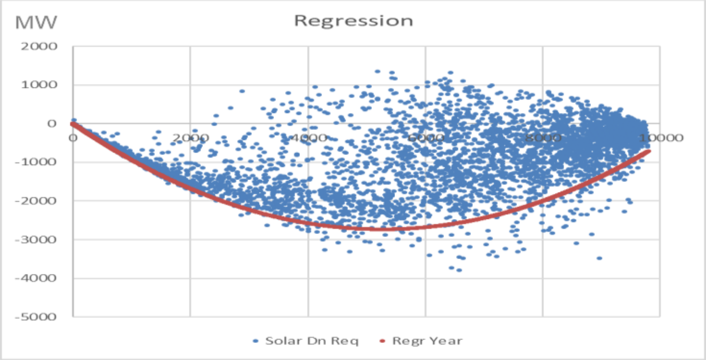
Color Key: Up Var (blue), Dn Var (red)

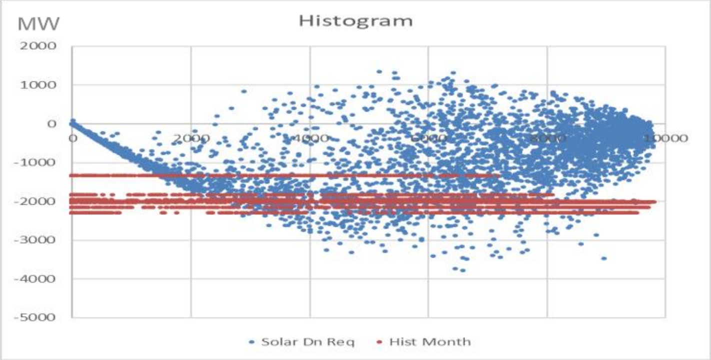
Quantile Regression: Model

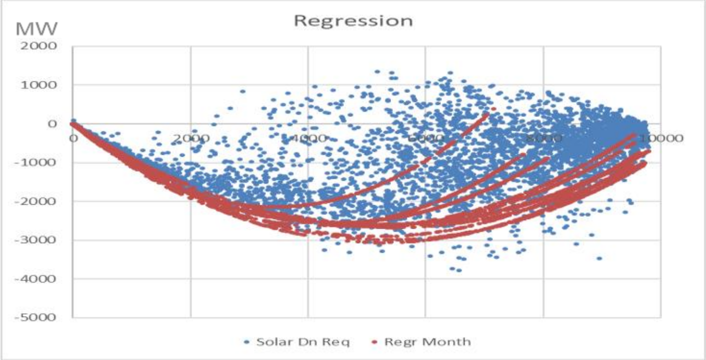
- Relationships are definitely not linear, more like quadratic
- Run quadratic quantile regression (Q) model to get 95 percentiles, i.e.,
  Y = a + b x + c x**2
- Q: Wind: Y = Wind_Dn Var, X = DA_Wind_Fcst;
  Solar: Y = Solar_Dn Var, X = DA_Solar_Fcst ;
  Load: Y = Load_Up_Var, X1 = DA_Load_Fcst,
  X2 = DA_Solar_Fcst,
  X3 =DA_Wind_Fcst
  Net_Load_Up_Req = ?
- The reason cannot do straight quantile regression for Net_Load_Up_Var is that no meaningful correlation/causation between RTD Wind and Solar to DA Load

Regression: Benefit









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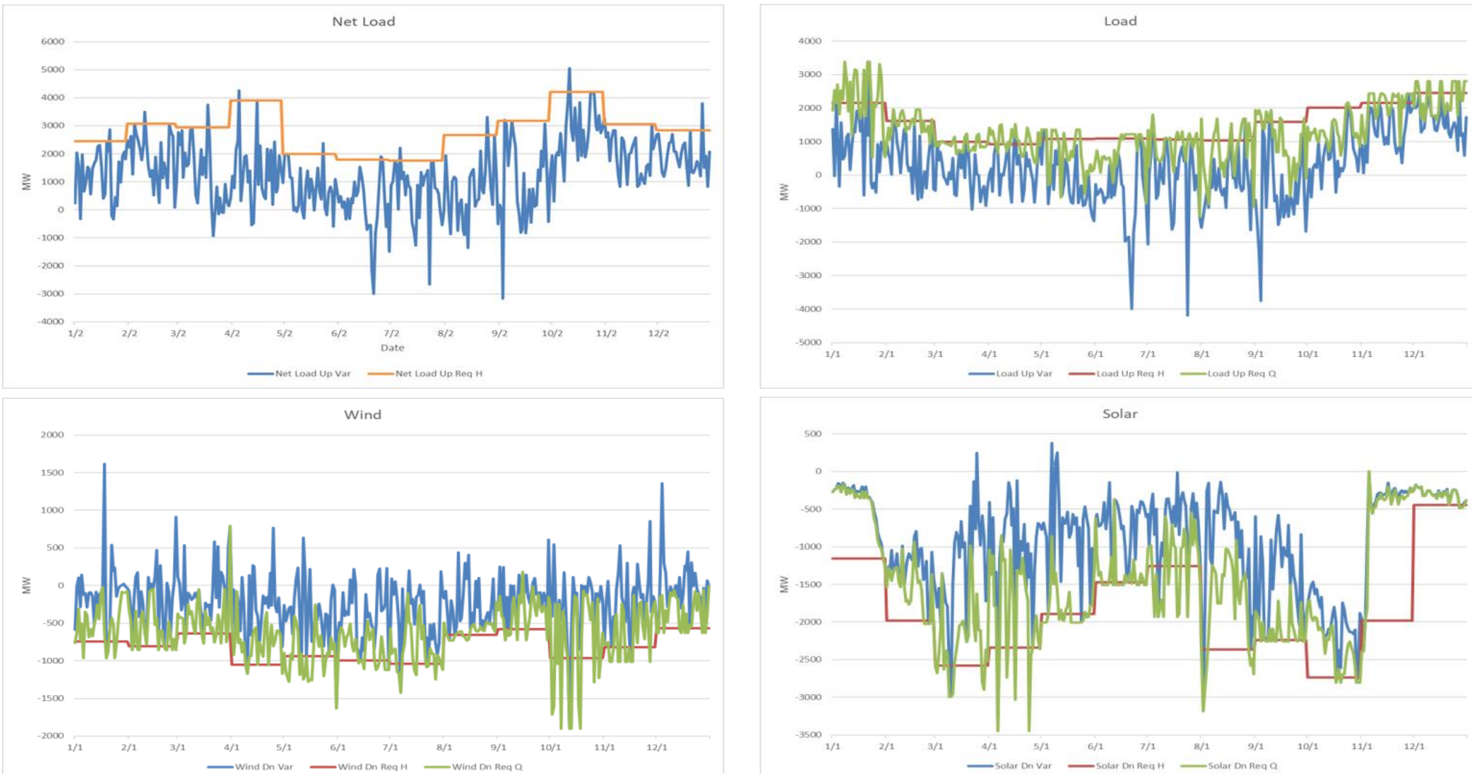
DA FRP

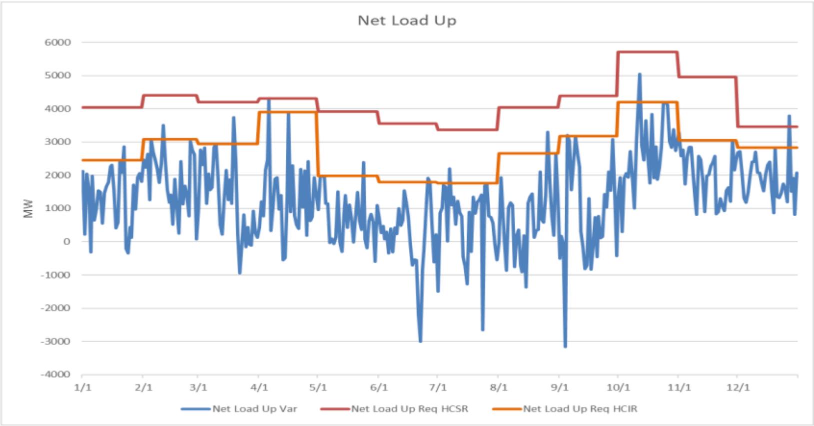
Quantile Regression: (H-red, Q-green)

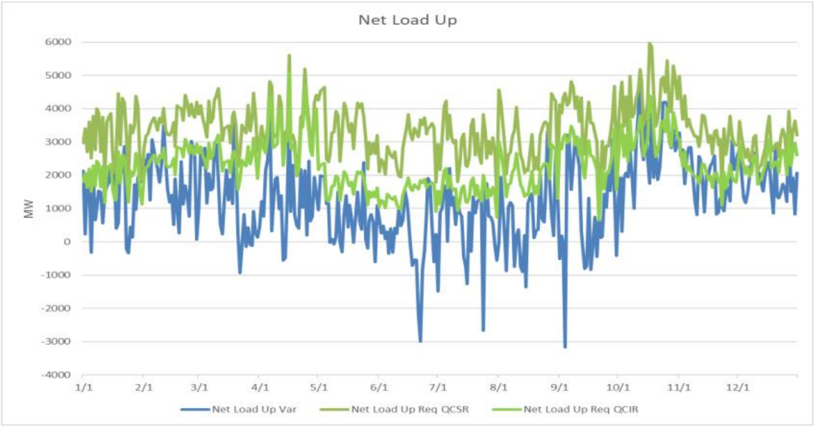


DA FRP

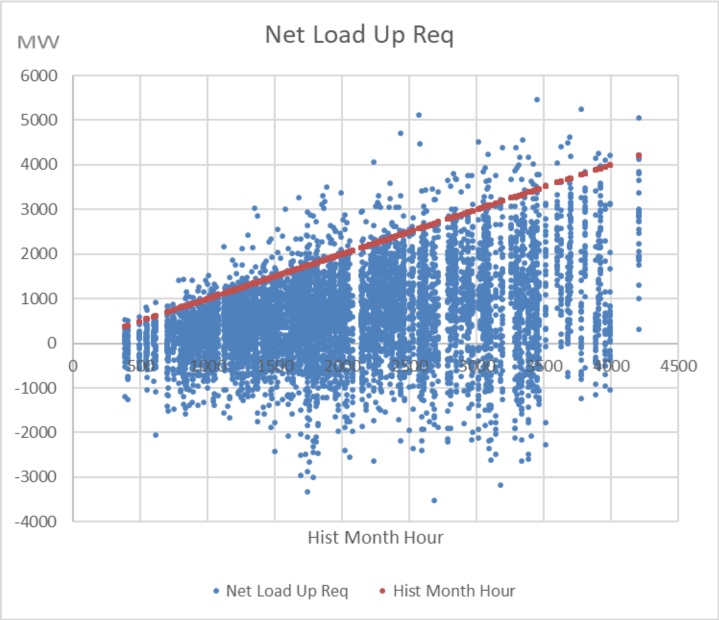
Histogram: Net Load Up Req

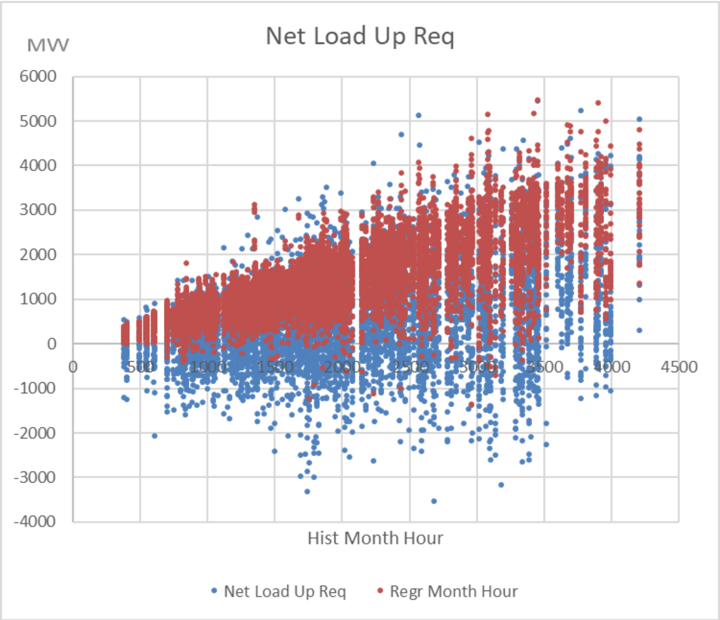
- Histogram based Coincidence Requirement(HCIR): Net Load Up Req H (orange)
- Histogram bsed Component Substitution Requirement(HCSR): Net_Load Up Req (red)
  = Load Up Req H – Wind Dn Req H – Solar Req Dn H
- Adjustment Ratio = HCIR/HCSR
- Get QCSR for Net Load Up Q = Load Up Req Q – Wind Dn Req Q – Solar Req Dn Q
- Multiply the Adjustment Ratio to Net Load Up Q to get final estimation





Regression: Benefit

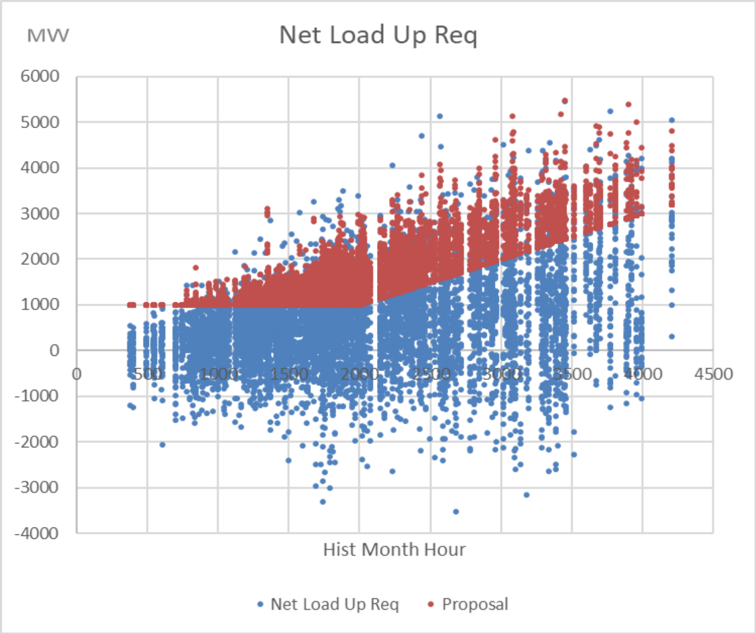




California ISO

DA FRP

Recommended Proposal



- Run rolling quantile regressions for previous N days (e.g., N = 40)
- Net Load Up Req Proposal

= max(X, max(Hist – Y, Regr), where X and Y are positive adjustable parameters.

- In the graph on the left,
  X = Y = 1000

DA FRP

Review: Steps Needed to Implement Regression Technique

- Goal: Obtain Net Load uncertainty requirement for DA to RTD
- Steps:
  1. Get Histogram based Coincidence Requirement (HCIR) for Net Load
  2. Get Histogram based Requirement for Load, Wind, and Solar
  3. Construct Histogram based Component Substitution Requirement HCSR for Net Load
  4. Get the ratio of HCIR to HCSR
  5. Get quantile regression based requirement for Load, Wind, and Solar
  6. Construct Quantile Regression base QCSR for Net Load
  7. The QCIR is estimated as QCIR = QCSR * HCIR/HCSR
  8. Ensure adequate reserves by creating a minimum requirement that must be honored to ensure reliability.

Future Steps and Development

- Future Improvement: Methodology #3

  Utilize probabilistic forecasting in combination with a statistical regression technique (methodology #2) to estimate the variation for individual components of load, wind, and solar.

- Continue to analyze regressors used in quantile regression technique for Load, Wind, and Solar.

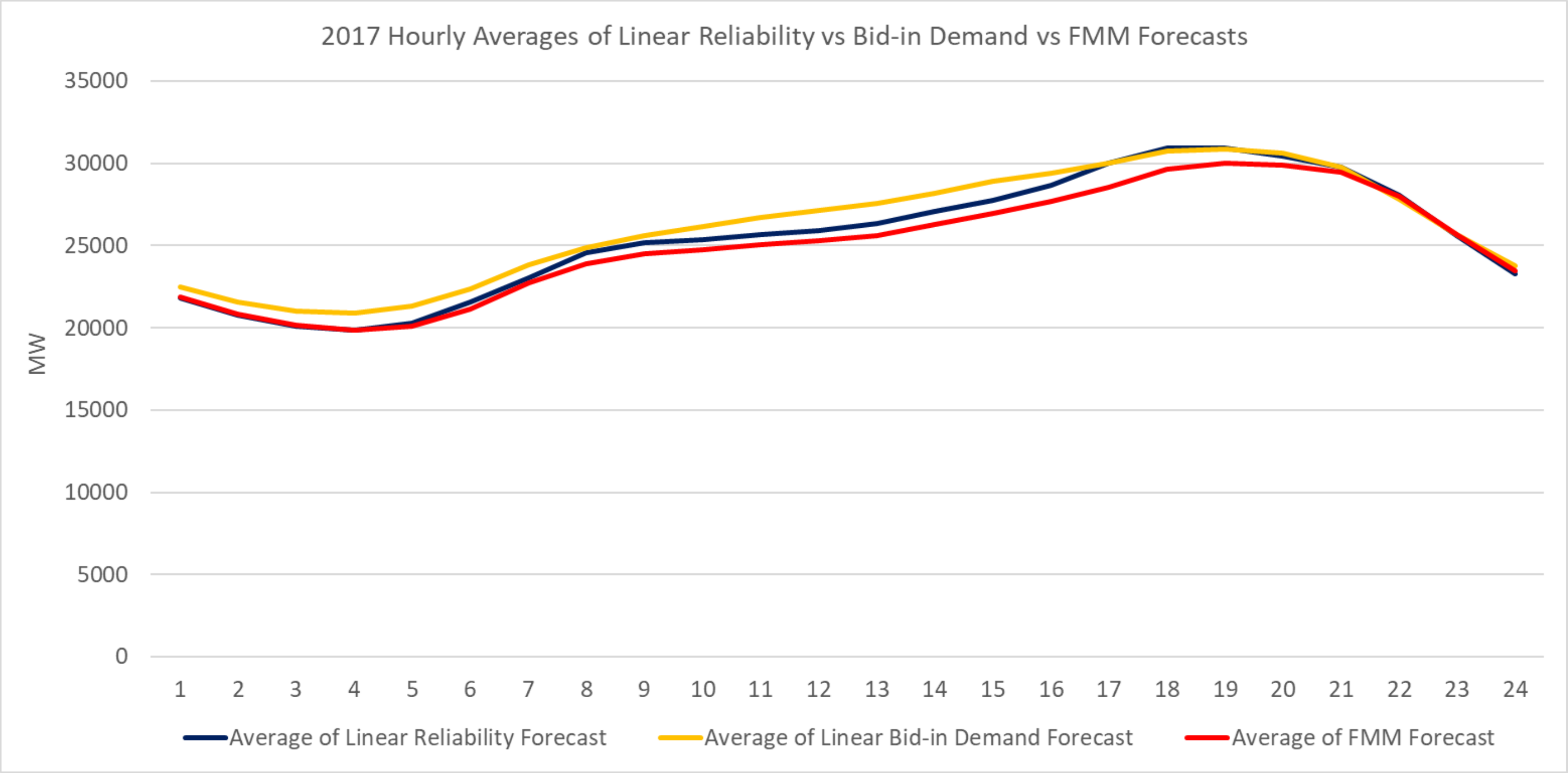
- Continue to analyze methodology to get from Load, Wind, and Solar to a Net Load Requirement.

Day-Ahead Market Enhancements

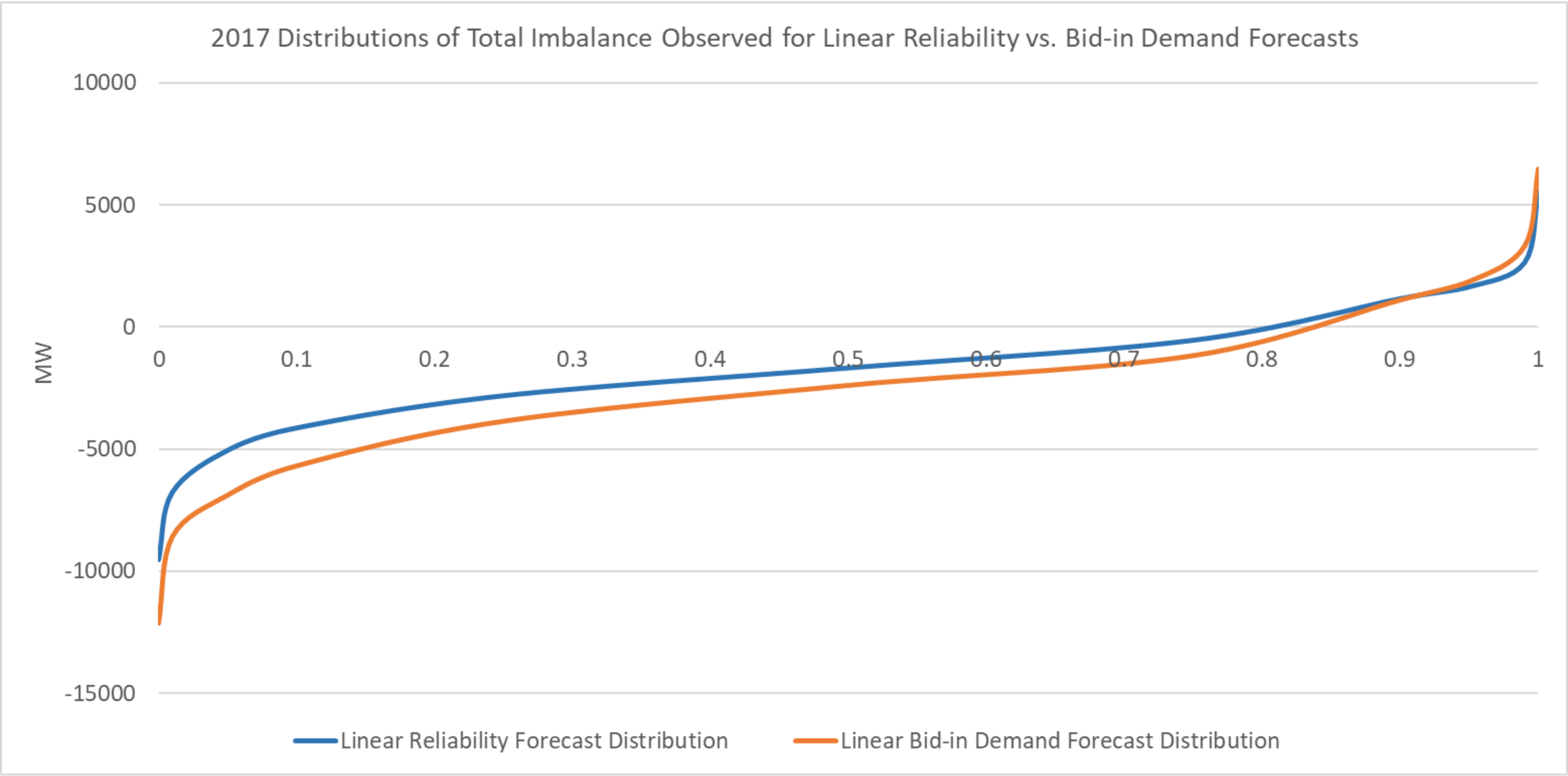
CLEARED PHYSICAL SUPPLY COMPARISON

Danielle Tavel
Policy Development Data Analyst

Forecast comparison of ISO reliability forecast accuracy and cleared bid in demand



Distributions of total imbalance observed needs



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Day-Ahead Market Enhancements

EIM CATEGORIZATION & NEXT STEPS

Kristina Osborne
Sr. Stakeholder Engagement Specialist
Stakeholder Affairs

California ISO

Proposed EIM Governing Body Classification

- The CAISO proposes the EIM Governing Body has a **hybrid** approval role for this initiative

- Stakeholders can include response to the EIM categorization in their comments

Updated schedule

	Date
Stakeholder Workshop / Meeting	June 19
Stakeholder Comments Due	July 10
Post Draft Final Proposal	September 5
Stakeholder Conference Call	September 12
Stakeholder Comments Due	September 26
EIM Governing Body Meeting (hybrid non-EIM specific)	October 31, 2018
CAISO Board of Governors Meeting	November 14-15, 2018

Appendix

Day-Ahead Market Enhancements

ELEMENTS THAT HAVE NOT CHANGED FROM 4/11 REVISED STRAW PROPOSAL

Additional design considerations:

- **15 Minute Load Aggregation Point (LAP)** – Currently, this is an hourly calculated value. Move to a 15-min LAP based on weighted average of the FMM and the three relevant RTD prices.

15-min

Eliminate the ancillary services self-provision qualification process

- Currently, pre-process before the DA market optimization

- Maintain scheduling priority, but allow co-optimization with other products

15-min

EIM changes need to align with ISO day-ahead market

- EIM base schedules are currently hourly consistent with ISO's current day-ahead scheduling granularity

- With DAM enhancements implementation, base schedules will now be submitted with 15-minute granularity

- 15-minute base schedules results in changes to:
  - Resources sufficiency evaluation
  - Over/under scheduling penalties

15-min

Resource sufficiency evaluation ensures EIM entities don't lean on others capacity, flexibility or transmission

- Currently, performed hourly if any test is failed, EIM transfers cannot exceed prior hour's level.

- Propose to consider each 15-minute interval individually
  - Still perform prior to operating hour to identify which intervals will be frozen

- Only freeze by 15-minute interval not entire hour

Over / under scheduling penalty will align with 15-minute base schedules

- Determine if penalty should apply each 15-minute interval
- Penalty only applies for 15-minute interval not entire hour
- Under extended DAM, this penalty is no longer applicable because EIM participants can’t determine how much imbalance is settled in EIM

15-min

During SMUD implementation identified need to add regulation up and regulation down energy settlement (1 of 2)

- Currently, an EIM entity use a manual dispatch after the operating hour to identify energy that resulted from following AGC

- Manual dispatch changes the classification of the regulation energy from uninstructed imbalance energy to instructed imbalance

- This is important because uninstructed imbalance energy determines the amount of uplift costs that can be shifted between BAAs.

15-min

During SMUD implementation identified need to add regulation up and regulation down energy settlement (2 of 2)

- Add regulation up and regulation down to hourly resource plan
- ISO will then settle regulation energy for the resource
- This eliminates the need for a manual dispatch to have the energy deviations classified as instructed

15-min