Day-Ahead Market Overview

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The Purpose of Today's Session

To educate stakeholders on the features of the current day-ahead market, setting a foundation for the extended day-ahead market (EDAM) stakeholder process.

Agenda

- Kickoff
- Market Inputs
- Market Timeline
- Locational Marginal Pricing
- Congestion Revenue Rights
- Settlements
- Corresponding Initiatives
- Wrap-Up

The ISO is a nonprofit, public benefit corporation

Our responsibilities are to…

Drive innovation

Facilitate infrastructure planning

Provide market transparency

Maintain grid reliability

Run the Market

Support state and federal policy goals

Coordinate the bulk electric power system

Entities can participate through market products and reliability services in day-ahead

Energy

- Physical supply and demand
- Virtual supply and demand

Financial

- Congestion Revenue Rights
- Inter-SC trades

Reliability

- Ancillary services:
  - Instantaneous
  - Contingency reserve
- Residual unit commitment

A full day's operations are covered by two markets

Day-ahead market

Real-time market

Day-ahead markets procure resources to meet reliability needs

Assurance, a day in advance, that System Operators have adequate resources available in real-time

MARKET INPUTS

Section Objectives: Market Inputs

By the end of this section, you will be able to:

- Identify various data elements the market uses during optimization
- Describe how bids are structured and their impact on the day-ahead market

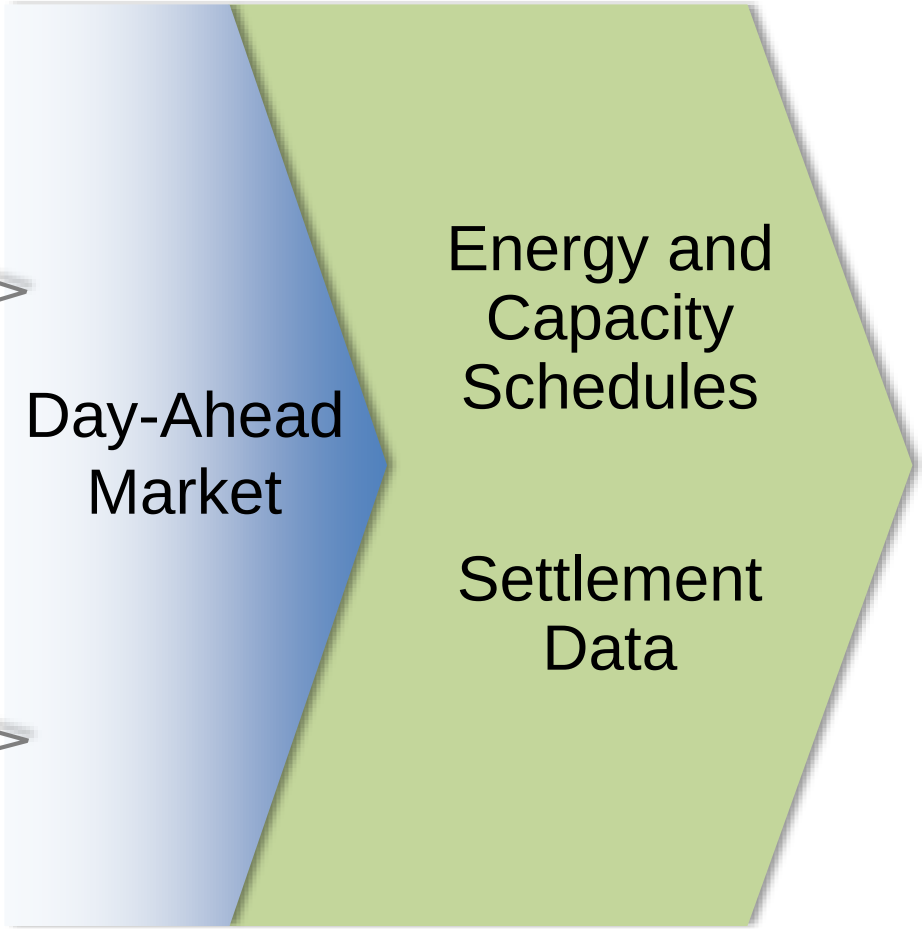
Inputs and outputs of the **day-ahead** market

Data:

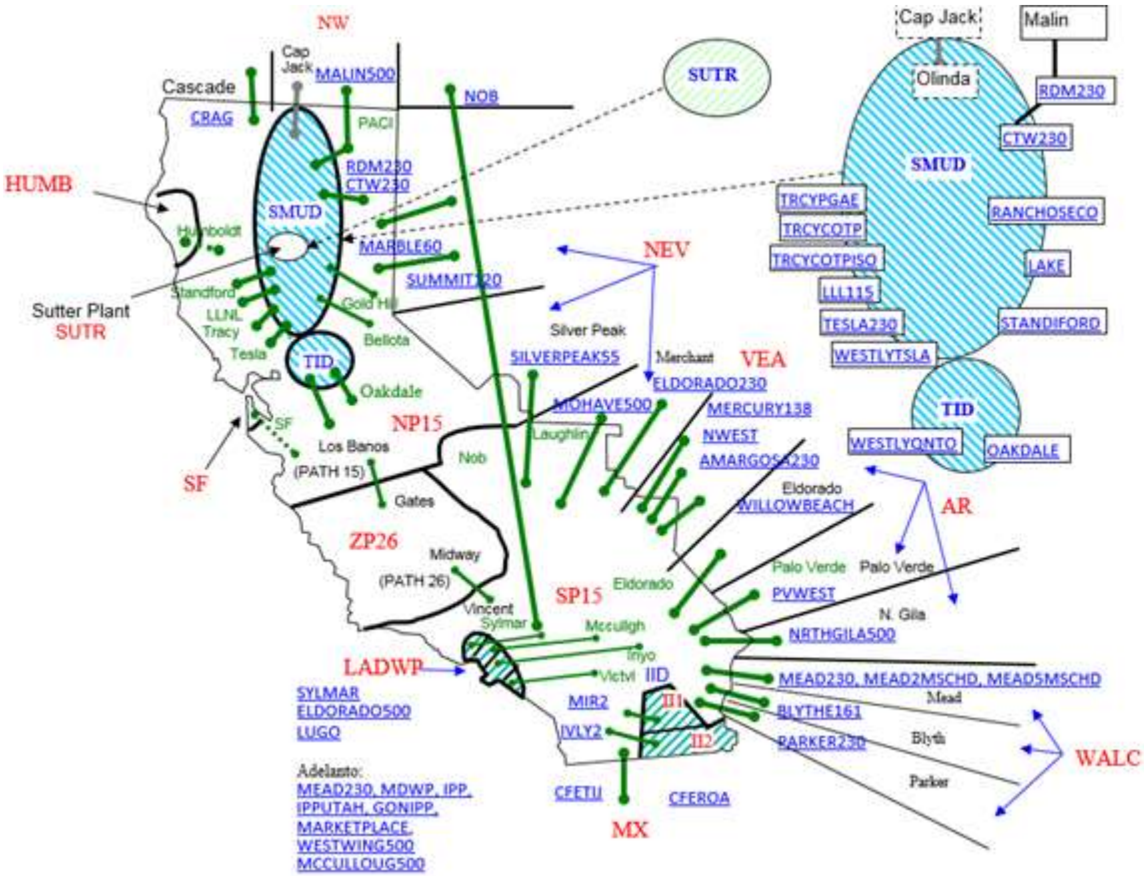
- System parameters
- Resource parameters
- Outage information
- Bid information
- ISO forecast of demand
- Transmission interface limits

Requirements:

- Reserves
- Residual unit commitment
- Energy to serve demand



Full Network Model



The Full Network Model contains information such as:

1. **ISO and aggregated Resource IDs**
2. **Default and custom LAP areas**
3. **Ancillary service and trade hub regions**
4. **Imports and exports are modeled as injections at intertie scheduling points**

Master File contains characteristics of each resource

- Resource ID
- Start up information
- Minimum on/off time
- Scheduling Coordinator ID
- Ramp rates/heat rates
- MSG configurations
- Plant type (gas, hydro, etc.)
- Greenhouse gas information
- Intertie resource information
- Fuel type
- PMin/PMax
- Variable energy resource indicator

Data inputs: Outage Information

Outage Data

Submitted to reflect physical restrictions for generation and transmission

Generation:

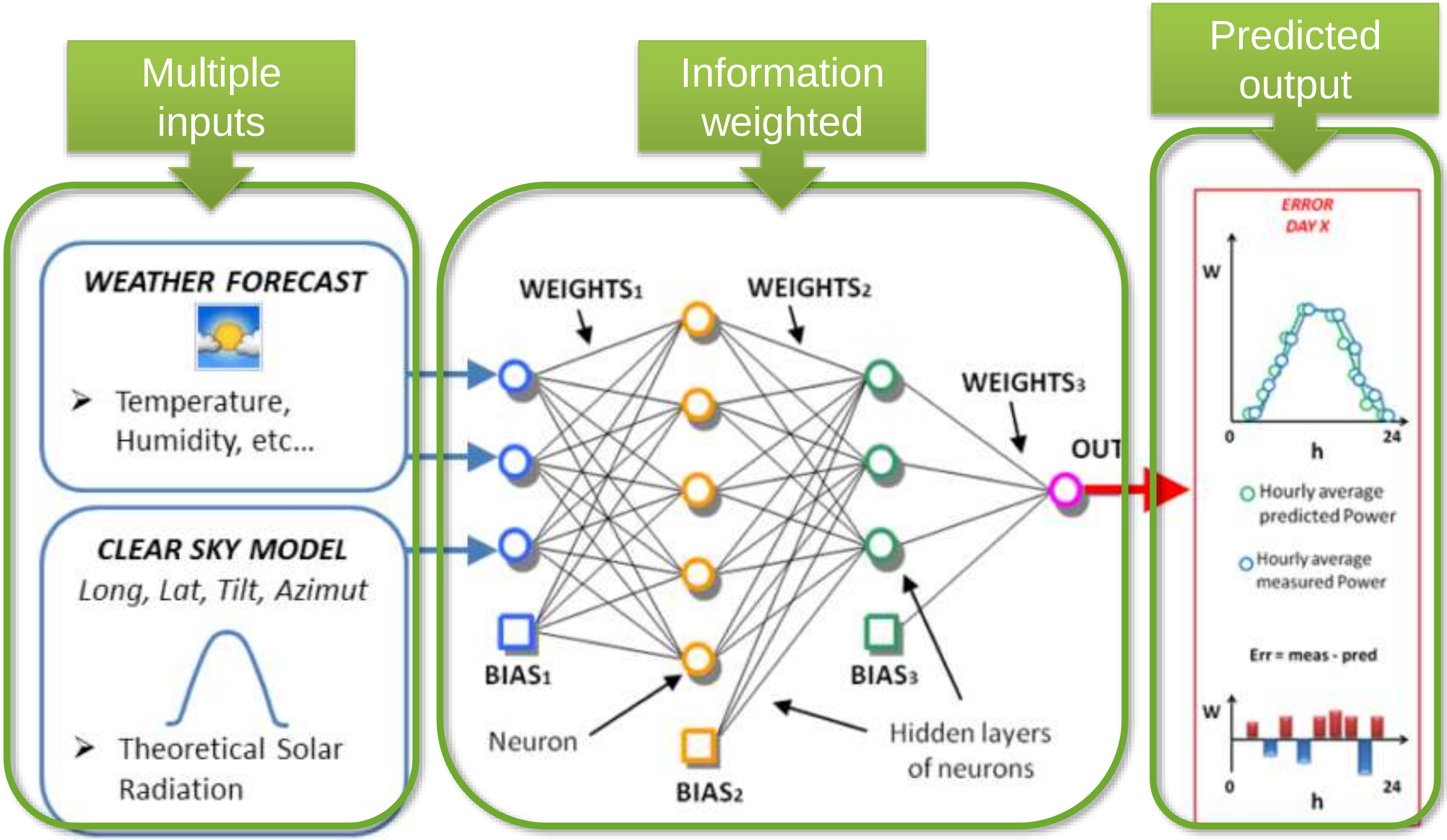
- Resource availability values used by market system to set forward schedule and real-time dispatch limits

Transmission:

- Market runs power flow calculation to take status of the bulk electric system into account

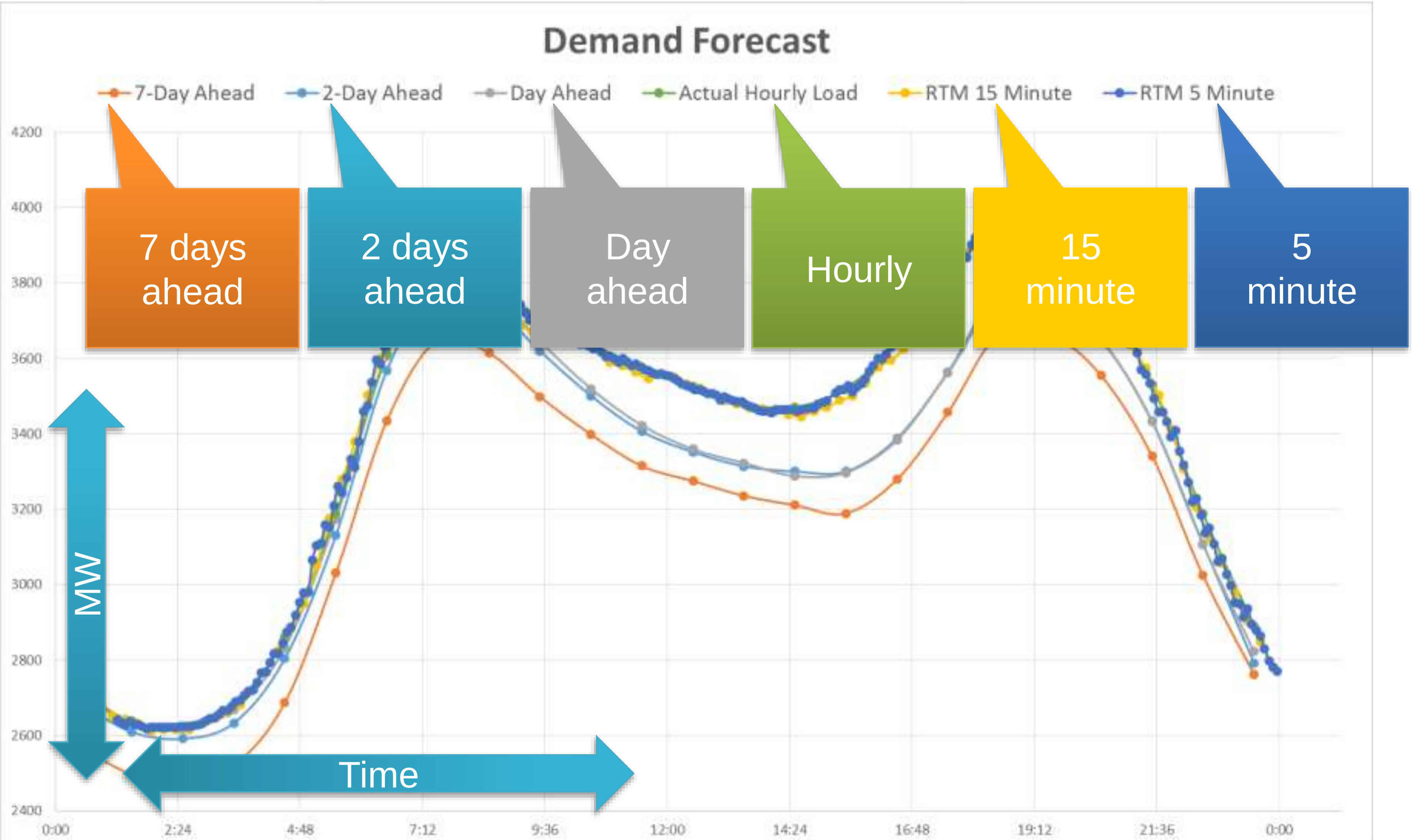
Not to be submitted for economic reasons

The ISO uses a neural network load forecasting model



Source: Energies 2015, 8(2), 1138-1153; doi:10.3390/en8021138

Forecasts updated to account for changes



Demand Bids

Supply Bids

Convergence (Virtual) Bids

BIDDING IN THE DAY-AHEAD MARKET

Section Objectives: Bidding

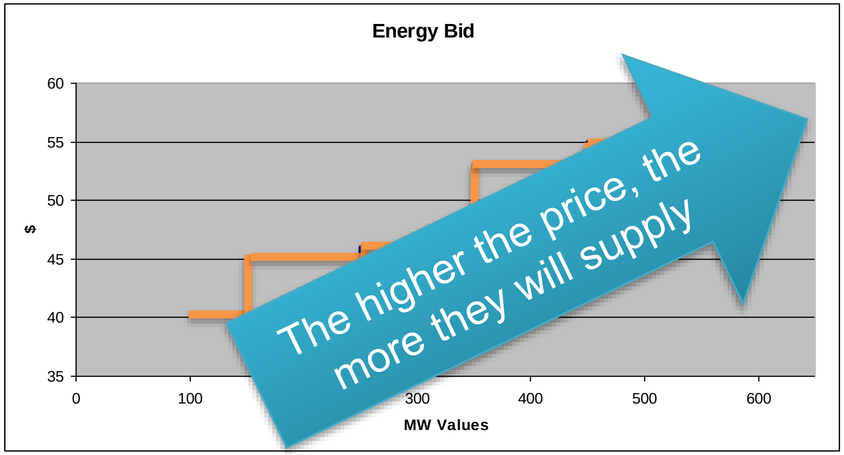
By the end of this section, you will be able to:

- Identify how economic bids are input into the market
- Identify the differences between physical and virtual bids

Energy bids provide an economic signal indicating a participant's willingness to supply or purchase energy

SUPPLY

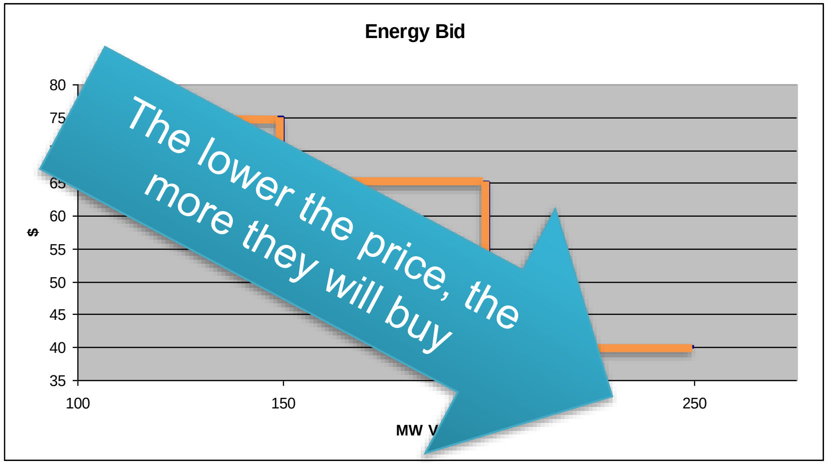
Up to 10 segments, monotonically non-decreasing



generators and imports

DEMAND

Up to 10 segments, monotonically decreasing

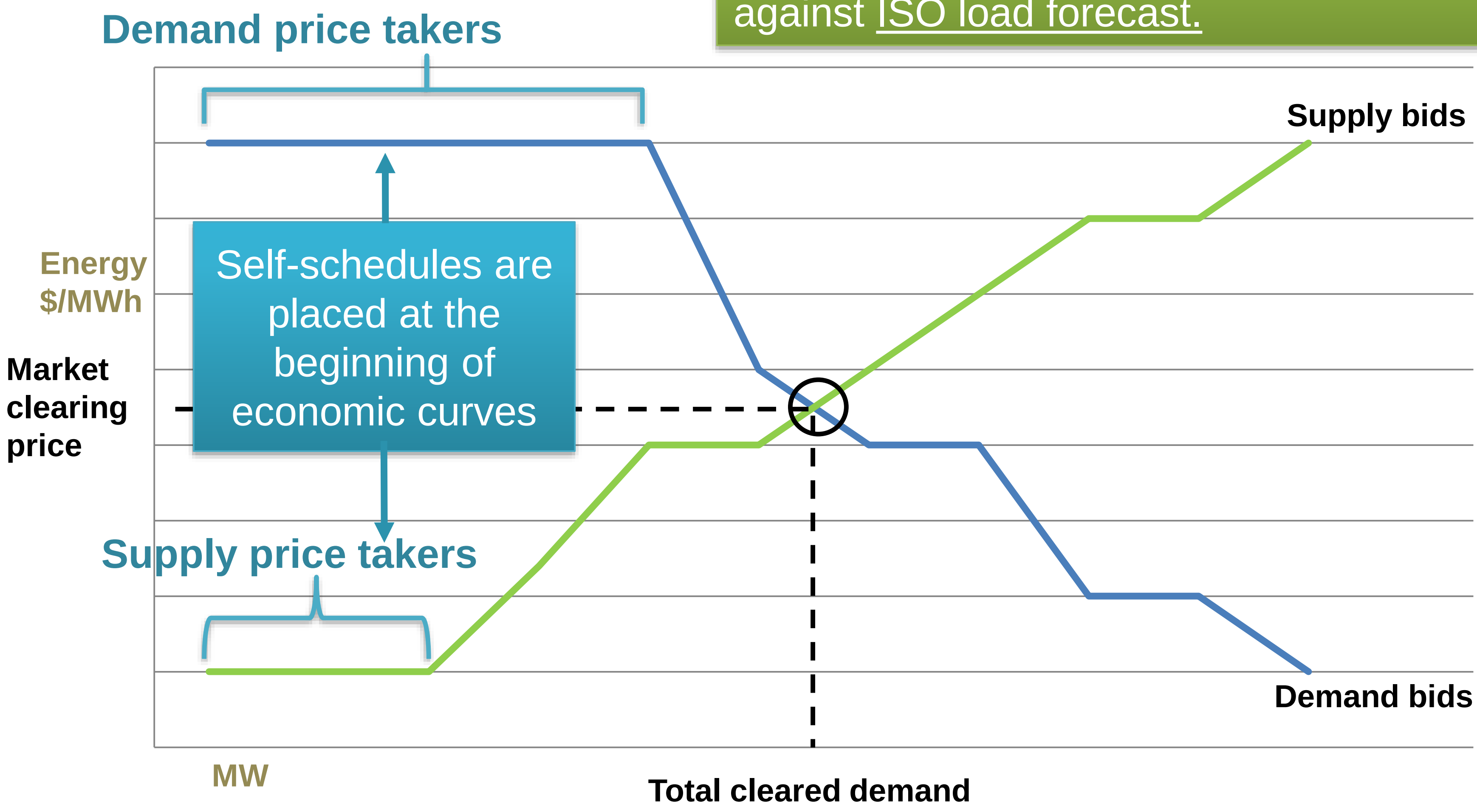


loads and exports

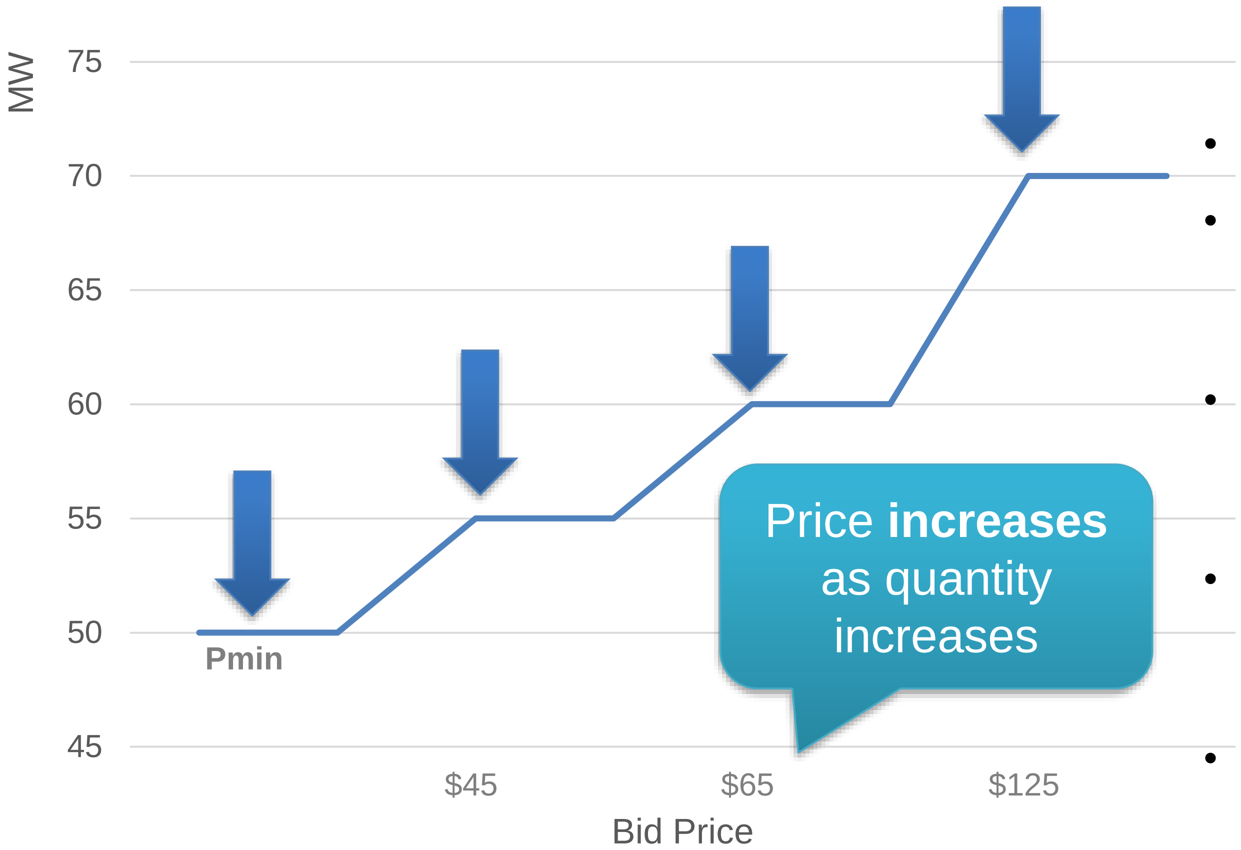
Self schedules (AKA price takers) submit bids for MW without prices

Self schedules and bids

Day-ahead clears supply bids against demand bids; **real-time** clears supply against ISO load forecast.

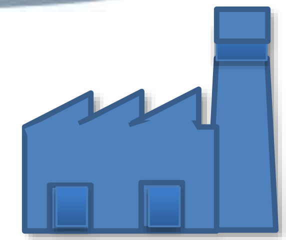


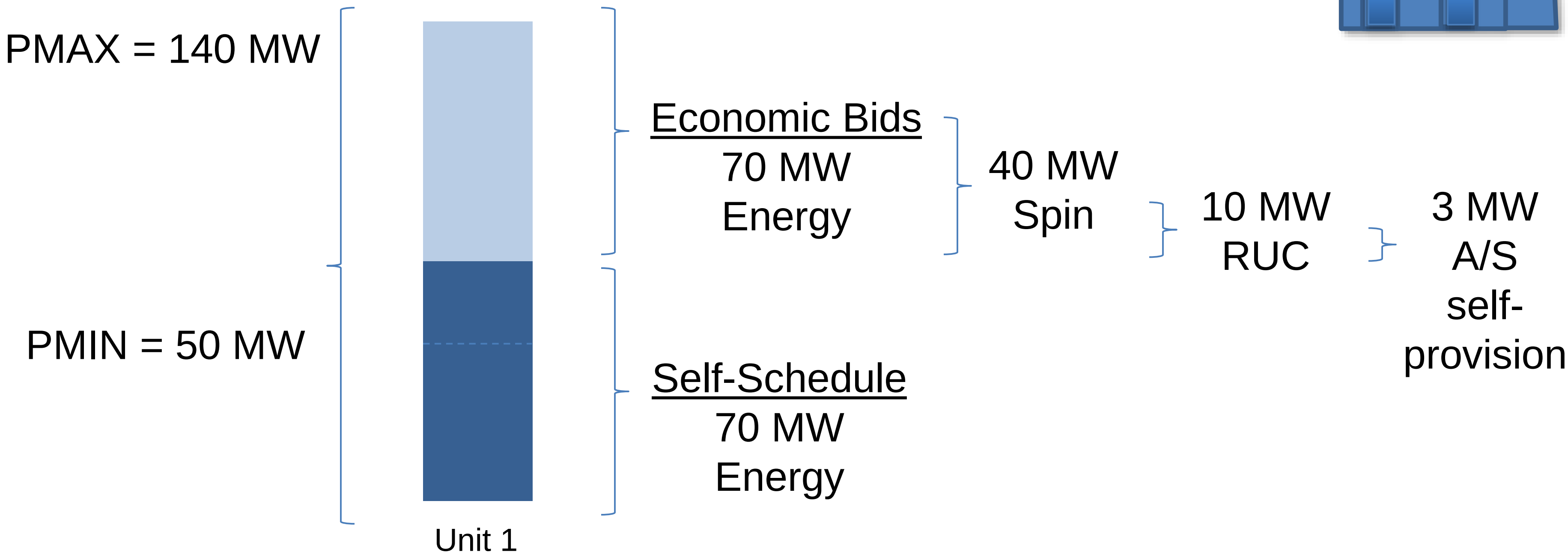
Supply Bid



- The Pmin is 50 MW
- If the price is least $45 I am willing to provide 5 more MWs (from 50 MW to 55 MW)
- If price is at least $65 I am willing to provide 5 more MW (55 MW to 60 MW)
- If the price is at least $125 I am willing to provide 10 more MW (60 MW to 70 MW)
- Import bids work the same way, however the bid begins at 0.

Day-Ahead Bidding for Supply





- The key point is that the same MWs are being offered to the market across a variety of products
- The market will co-optimize these offers for energy and ancillary services along with those from all of the other resources to determine the optimal solution across the entire day

Demand or Export Bid

- The self schedule is 11 MW
- If the price is $75 or less I am willing to purchase 4 more MWs (from 11 MW to 15 MW)
- If price is at least $65 I am willing to purchase 1 more MW (15 MW to 16 MW)
- If the price is at least $60 I am willing to purchase 1 more MW (16 MW to 17 MW)

Bidding Tools

Resource bidding: financial and physical participation in the market

Financial

- Supply: supply nodes, demand nodes, trading hubs
- Demand: supply nodes, demand nodes, trading hubs

Physical

- Supply: generators, imports
- Demand: load, exports

Convergence bidding: financial participation in the market

Virtual demand

- Bid to buy at day-ahead price & liquidate at 15-minute price
- Looks like price-sensitive demand
- Considered a “long” position

Virtual supply

- Bid to sell at day-ahead price & liquidate at 15-minute price
- Looks like a dispatchable supply resource
- Considered a “short” position

Some convergence bidders pair supply and demand bids to arbitrage the difference between day-ahead and real-time prices

Virtual Supply

Day-ahead Award		Real-time Liquidation		Result
Energy	$30	Energy	$29	
Congestion	$0	Congestion	$0	
Loss	-$1	Loss	-$1	
LMP (paid)	**$29**	**LMP (charged)**	**$28**	**$1**

Virtual Demand

Day-ahead Award		Real-time Liquidation		Result
Energy	$30	Energy	$29	
Congestion	-$5	Congestion	$-3	
Loss	-$1	Loss	-$1	
LMP (charged)	**$24**	**LMP (paid)**	**$25**	**$1**

Net $2

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Convergence Bidding: Dynamic Credit Check

- For virtual bidding, a **dynamic credit check** is performed at bid submission:

- Available credit limit =
  (aggregate credit limit) – (estimated aggregated liability)

Why does convergence bidding exist and what are the benefits to the market?

From the market perspective:

- Helps with market power mitigation
- Increases market liquidity
- Lower costs and improved grid operations due to more efficient day-ahead commitment
- Minimize differences between day-ahead & fifteen-minute prices

From the participant perspective:

- Mitigate the risk impact of an outage that happens after the close of the day-ahead market
- Hedge against exposure to fifteen-minute market pricing for load
- Earn revenues or risk losses between the day-ahead and fifteen-minute prices

Does convergence bidding affect the physical market?

- With virtual bids:
  - No physical energy is delivered or consumed
  - Not backed by physical assets

- For SCs who submit both virtual and physical bids, there is no link between the two types of bids

- Impacts
  - Pricing (can set the clearing price)
  - RUC procurement target
  - Congestion

Summary of bid features

Physical resource bid features

- Maximum of 10 segments
- Bids must be submitted by 10:00am on the day prior to the trade date
- Supply bids ($/MWh) have a monotonically <u>increasing</u> bid curve
- Demand bids ($/MWh) have a monotonically <u>decreasing</u> bid curve
- Subject to energy bid cap of $1000 and floor of $-150

See Tariff section 39.6 for more bidding rules

Features unique to virtual bids

- Only energy bids (no AS)
- No start up and minimum load
- Bid curve begins at zero (0)
- Minimum bid volume is 1 MW
- Must have price and quantity, no self schedules

Features unique to RUC and AS bids

- Bid cap of $250 and floor of $0

Questions?

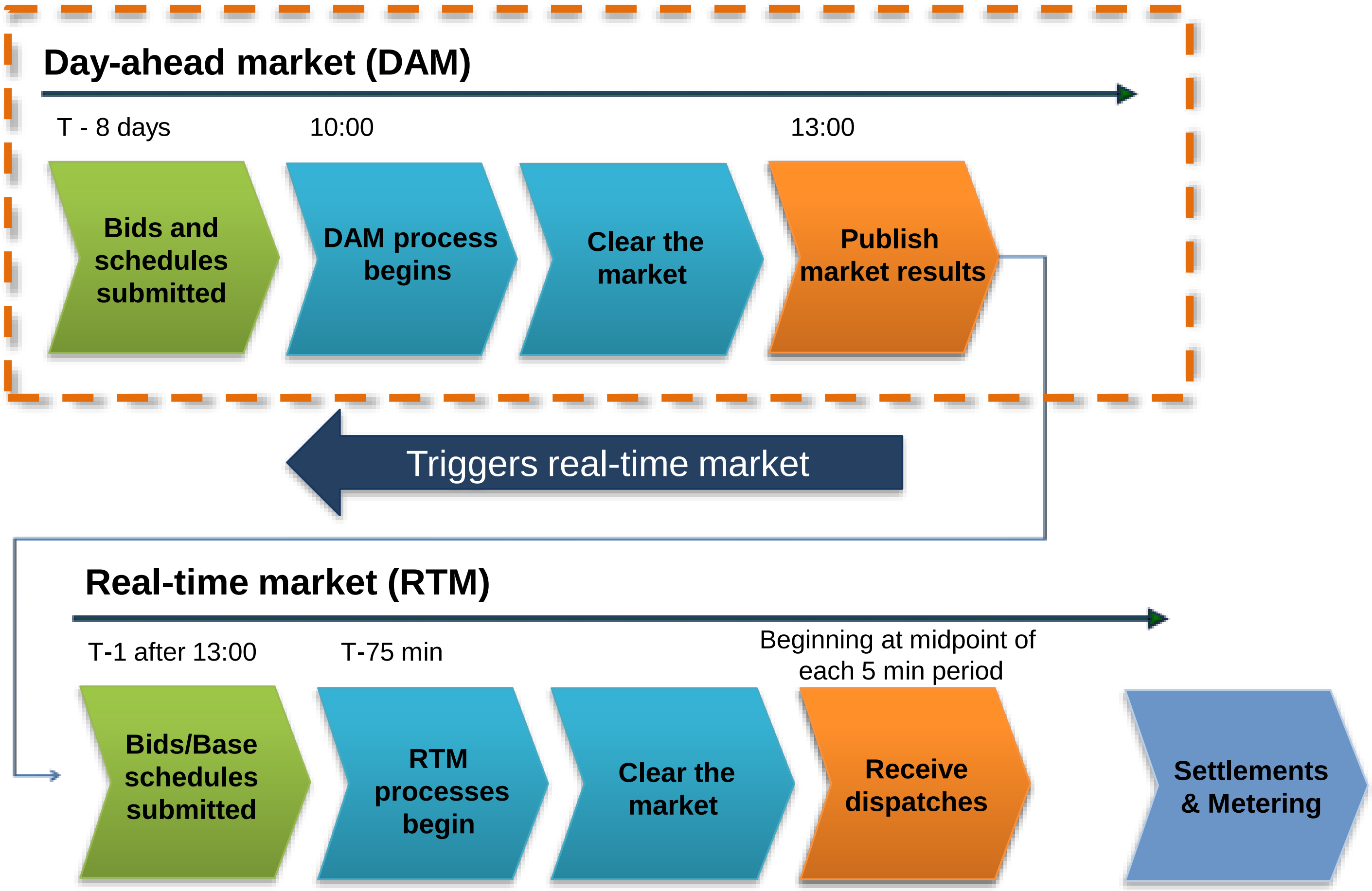
TIMELINE AND PROCESSES

Section Objectives: Timeline and Processes

By the end of this section, you will be able to:

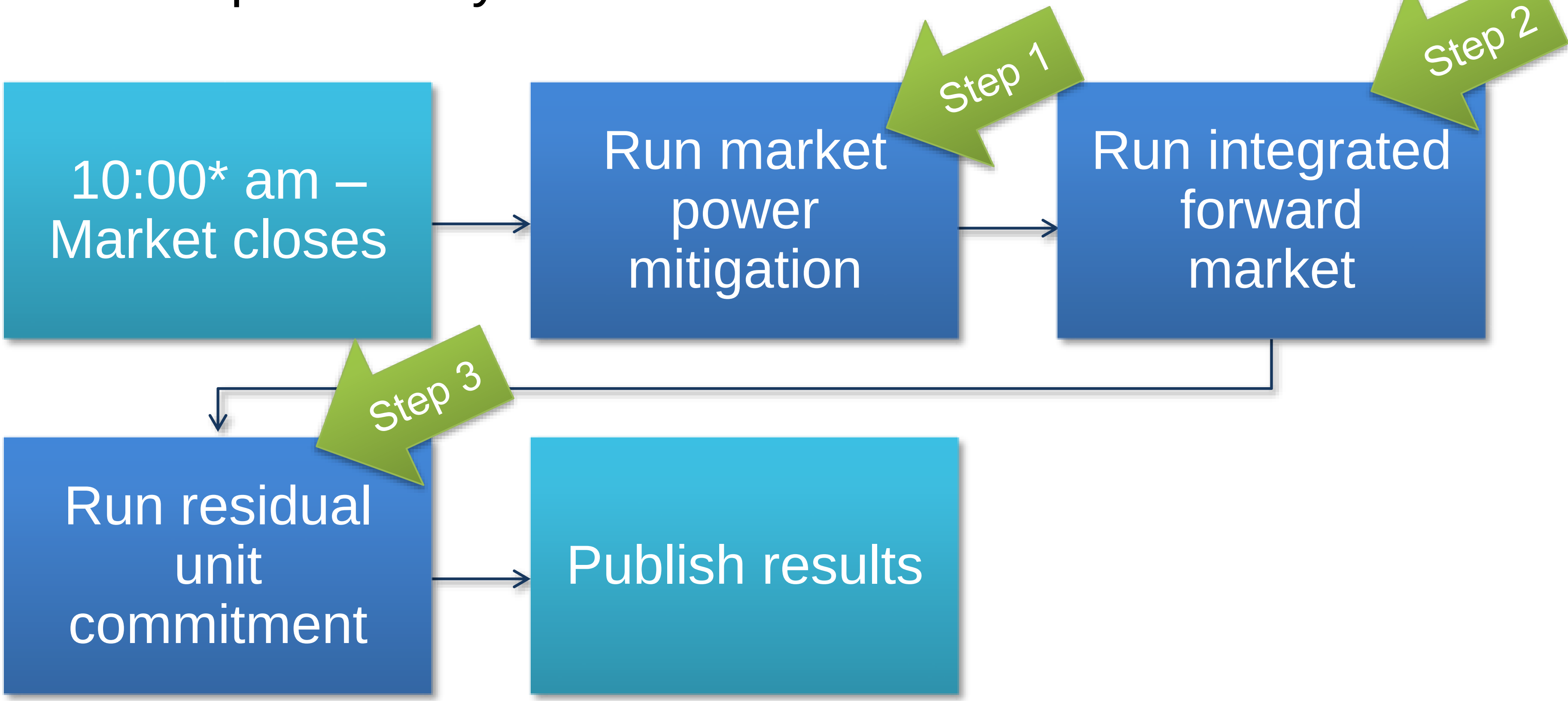
- Identify the basic parts of the day-ahead market process
- Explain the purpose, use in market operations and timelines of:
  - Market Power Mitigation
  - Integrated Forward Market
  - Residual Unit Commitment

Market process timelines



Day-ahead market process

Market opens 8 days before the trade date



* Pacific Prevailing Time

Step 1: Market power mitigation (MPM)

- Ensure units cannot exercise market power by nature of where they reside
- NOTHING is scheduled or dispatched as a result of this process
- May result in mitigated bids based on predetermined calculations

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If the potential for market power is determined

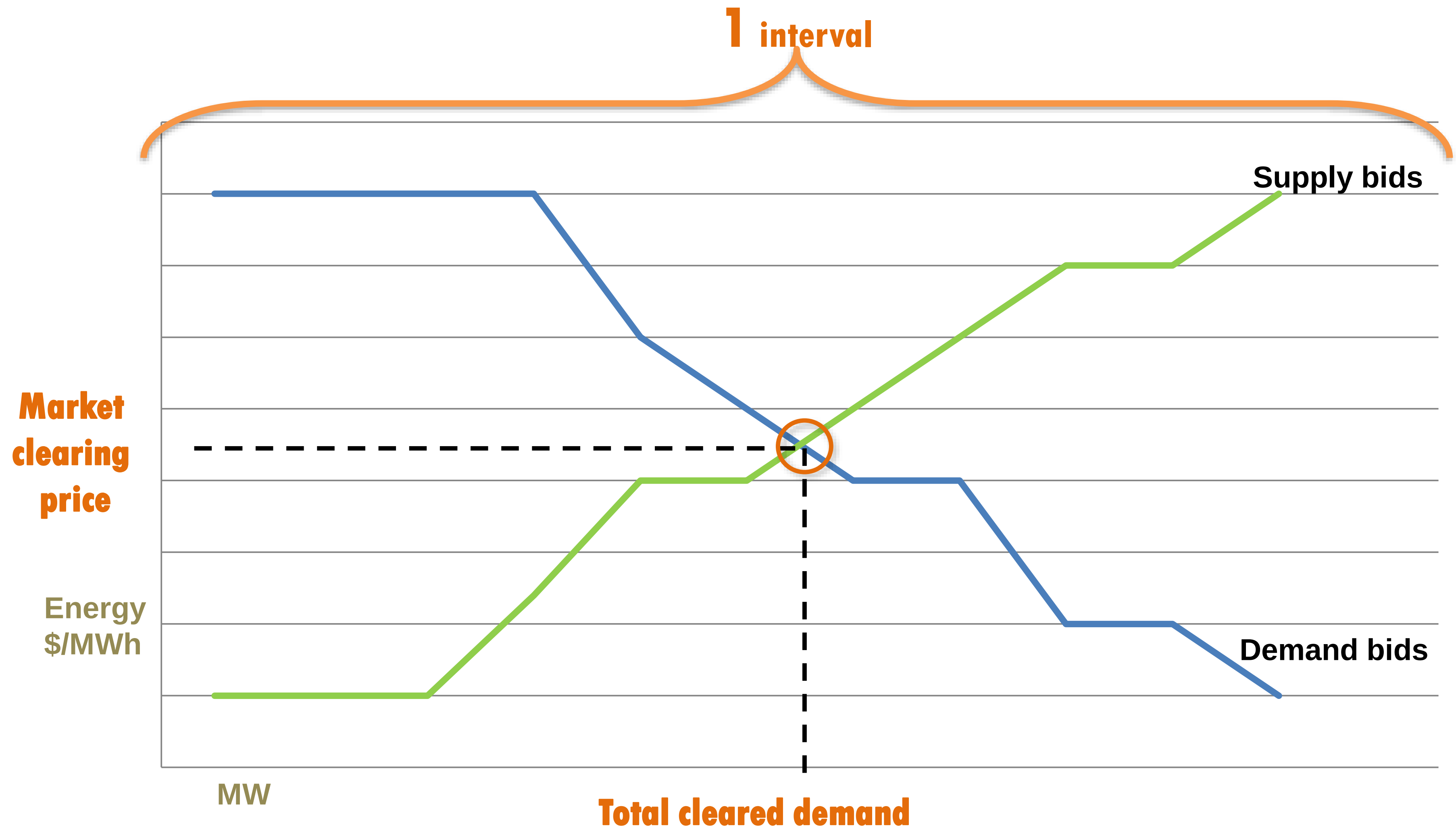
ISO replaces bid with the higher of their default energy bid or the competitive LMP

- For generating resources and participating loads
- Four methodologies for calculation
  - Variable Cost Option (ISO Tariff Section 39.7.1.1)
  - LMP Option (ISO Tariff Section 39.7.1.2)
  - Negotiated Rate Option (ISO Tariff Section 39.7.1.3)
  - Variable Cost Option plus Bid Adder (ISO Tariff Section 39.7.1.4)

Step 2: Integrated forward market

- Clears bid-in supply against bid-in demand
  - Day-ahead schedules
  - Virtual awards
- Procures 100% ancillary services
  - Ancillary service awards
- Commit resources

Step 2: What clears in the integrated forward market?



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Day-ahead market (**step 2**): Integrated forward market

- Clears bid-in supply against bid-in demand
  - Day-ahead schedules
  - Virtual awards
- Procures 100% ancillary services
  - Ancillary service awards
- Commit resources

Step 2: Ancillary services ensure reliability as electricity is moved from generating sources to customers

Regulation

- Regulation up
- Regulation down

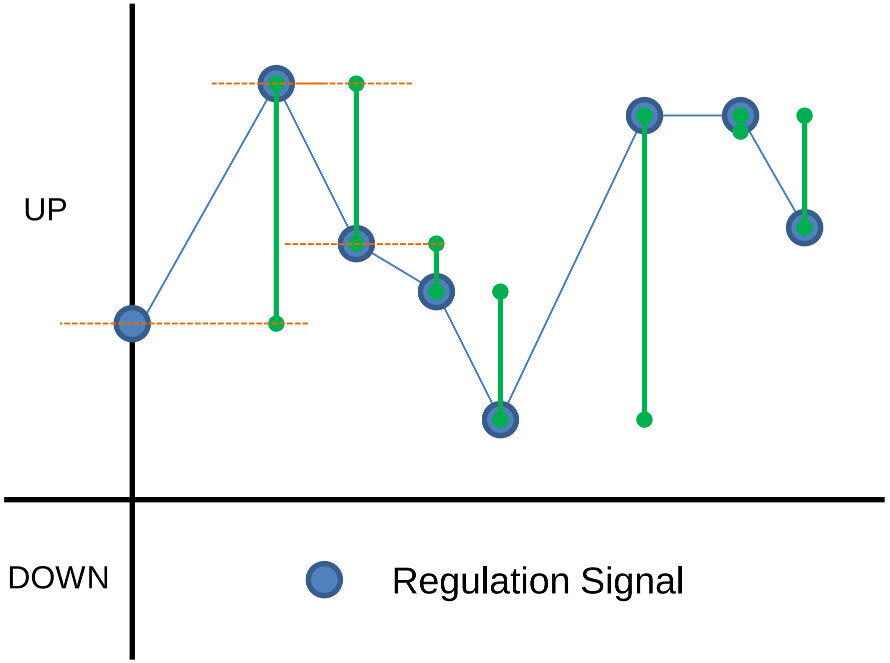
Constant adjustments under ISO control through automatic generation control (AGC)

Operating Reserves

- Spinning reserve
- Non-spinning reserve

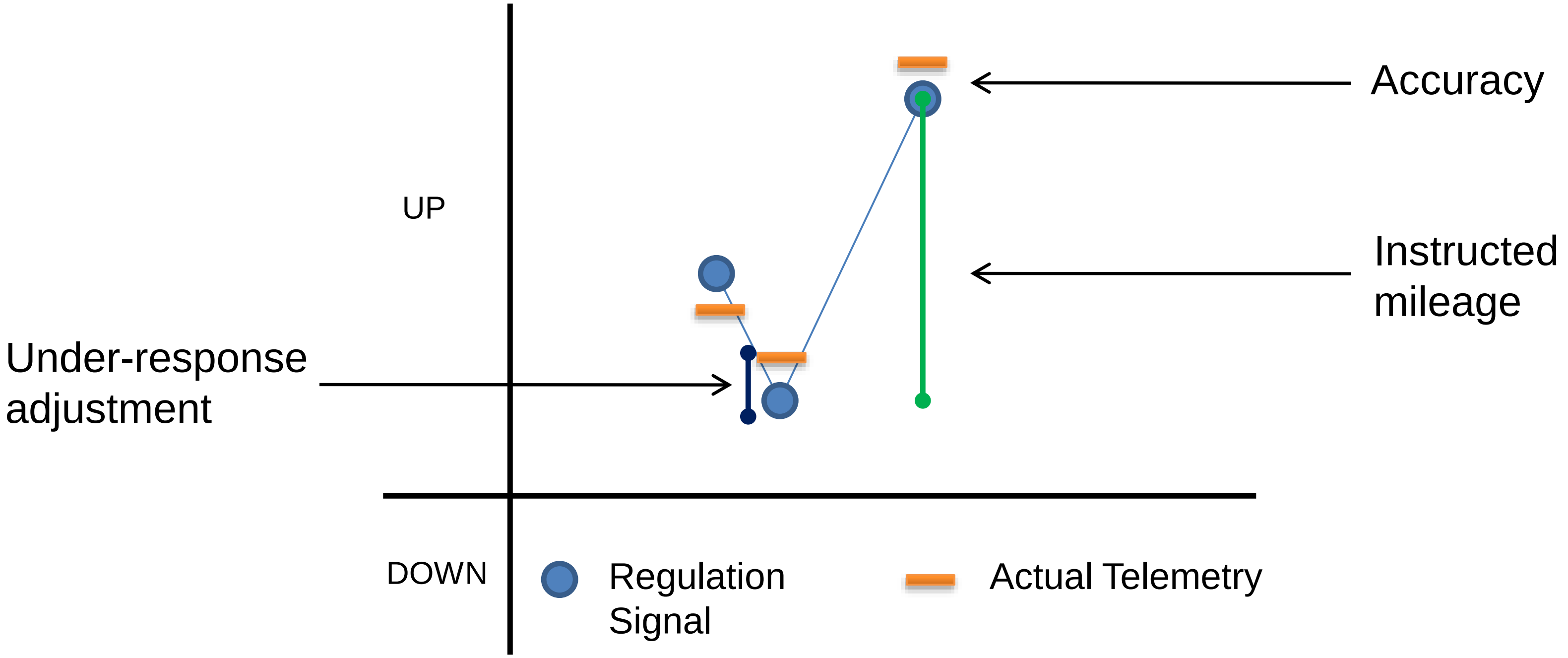
Supply that is either synchronized or not synchronized to the grid and can provide energy within 10 minutes

Instructed regulation movement or "mileage" is the sum of all green bars in a 15 minute interval



Resources receive a regulation signal of the MW output needed every four seconds.

Accuracy adjustments reduce mileage payment based upon performance



1. Under-response adjustment reduces mileage paid when a resource doesn’t provide actual movement
2. Accuracy measured by actual telemetry versus regulation signal

Regulation up and down – mileage bids

- SCs submit a bid for regulation mileage
  - Bid contains a price
  - No quantity is submitted. The award is constrained by a mileage multiplier and the regulation capacity award
- SCs that self-provide regulation do not submit mileage bids. The system inserts a $0 mileage bid
- Refer to the *BPM for Market Operations* for more information

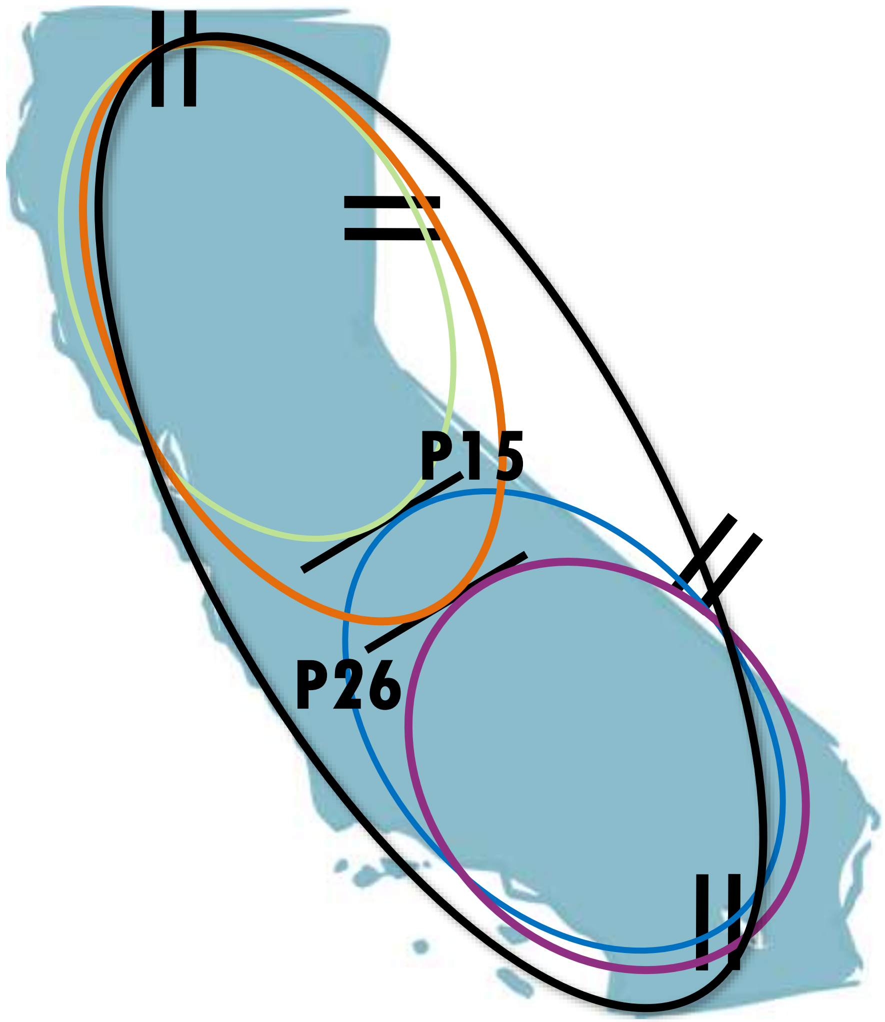
Step 2: Ancillary service procurement is regional

Two overlapping system regions to ensure reliability

- **ISO system region**
- **ISO expanded system region**

Eight sub regions

- **North of Path 15 & 26 + expanded northern region**
- **South of Path 15 & 26 + expanded southern region**



Capacity procurement target requirements

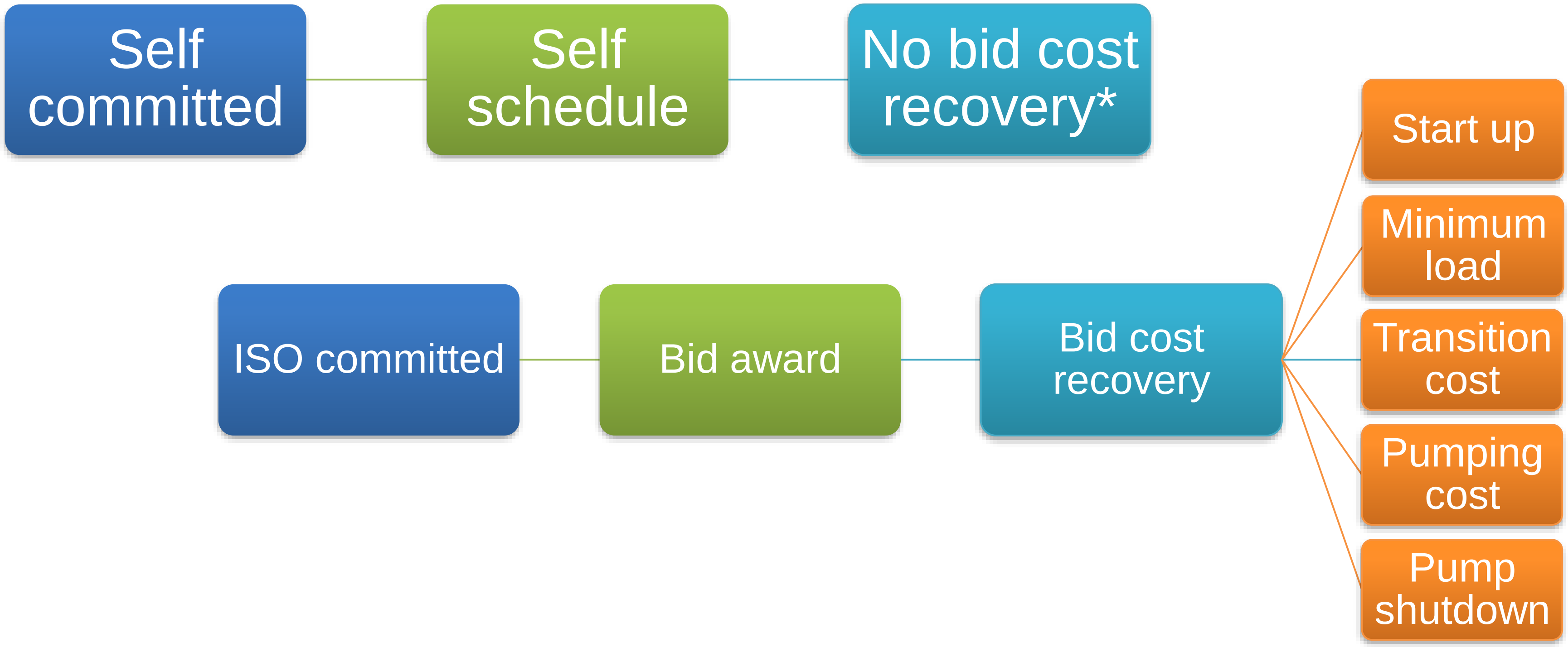
- Regulatory requirements ensure that adequate ancillary services are procured in the ISO BAA

- The ISO procures:
  – regulating reserves based on procurement targets set by ISO to meet WECC standards
  – contingency reserves based on procurement targets set by WECC
  – RUC based on forecasted demand for the entire system as well as for specific areas that may have local or regional requirements

Day-ahead market (**step 2**): Integrated forward market

- Clears bid-in supply against bid-in demand
  - Day-ahead schedules
  - Virtual awards
- Procures 100% ancillary services
  - Ancillary service awards
- Commit resources

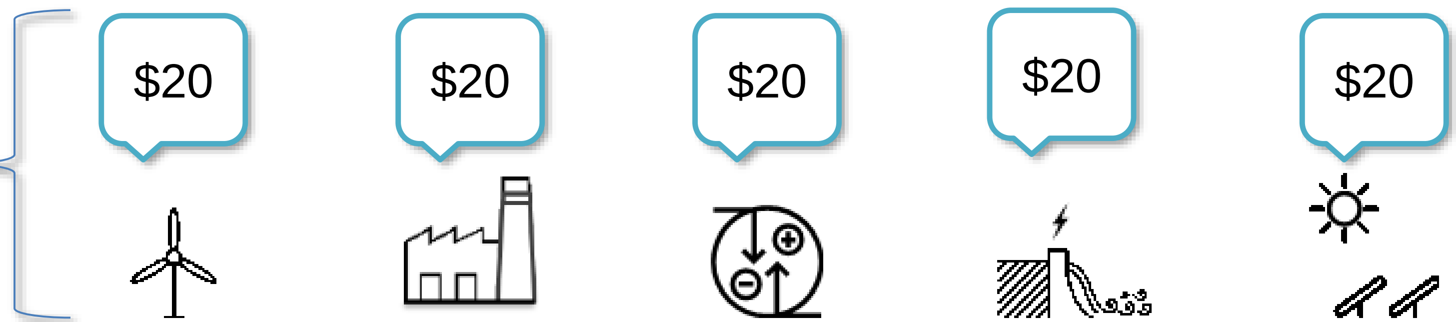
How the bid is submitted affects the resource commitment status



*** If resource bids above self schedule they could be eligible to recover energy bid amount, not start up and minimum load**

How does the market decide which resources to commit?

Bids



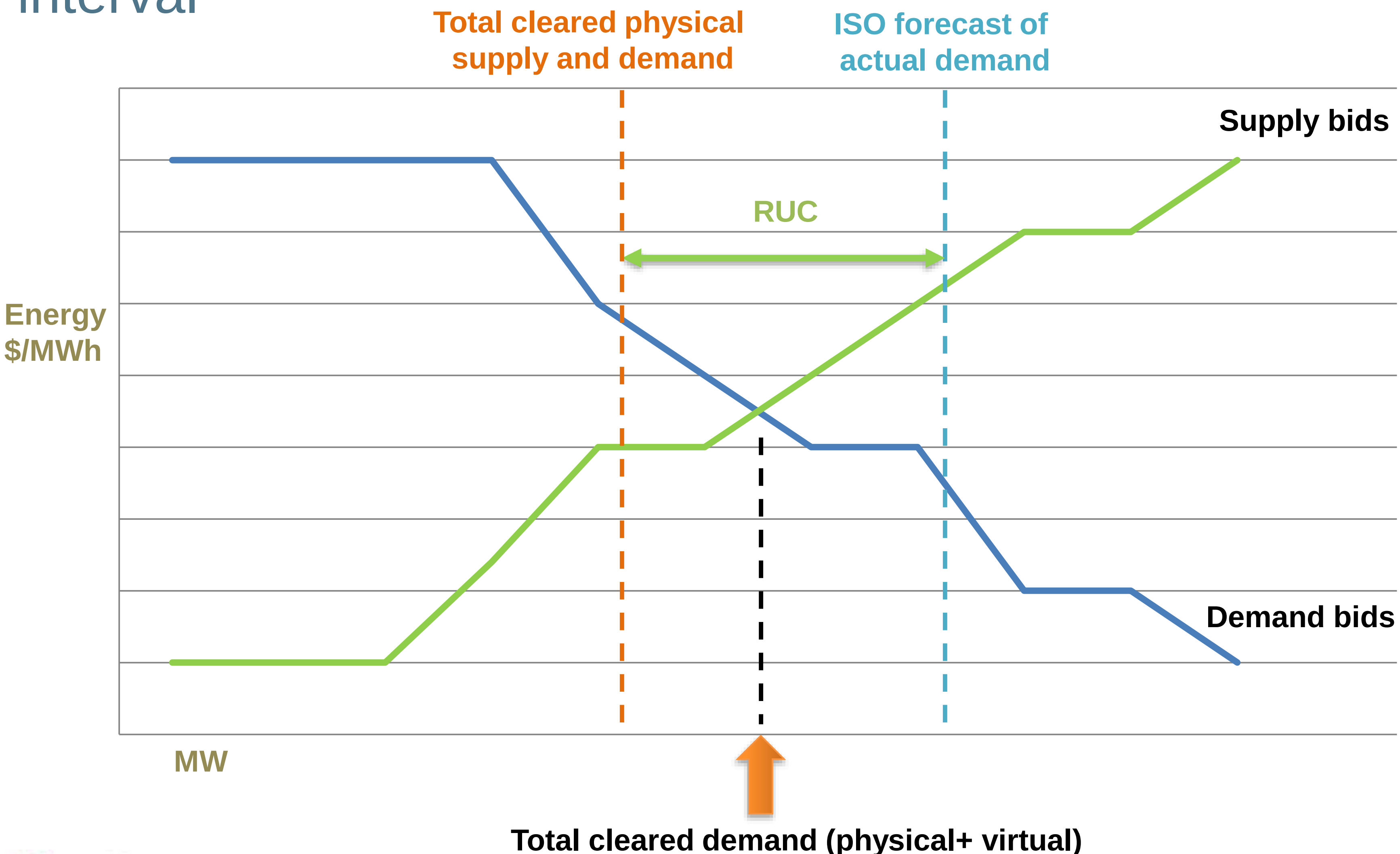
Three-part energy bid includes:

- Start-up cost (one time)
- minimum load cost (hourly)
- Energy bid curve above minimum load ($/MWh)

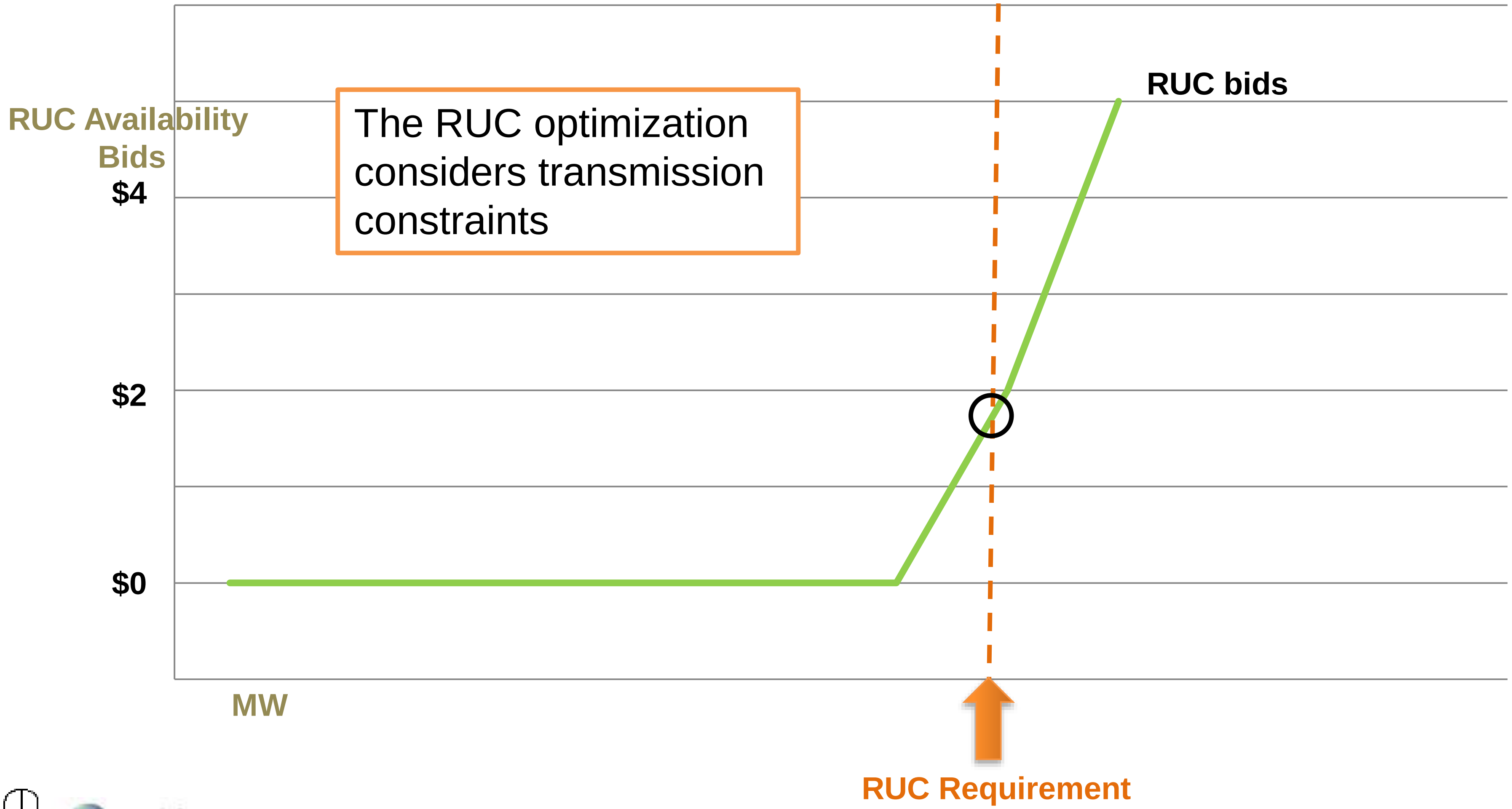
Step 3: Residual unit commitment

- A method of ensuring reliability of the grid
- Capacity procurement from additional day-ahead supply for real-time
- Selects from resource adequacy capacity and economic bids
- Awarded resources must submit an energy bid in the real-time markets

Residual unit commitment is determined for each interval



Residual unit commitment capacity bidding and procurement



RUC procured in zones

Regional requirements align with the following service territories:

- PG&E
- SCE
- SDG&E
- VEA

PTOs provide Demand Response spreadsheets that the ISO uses to lower RUC obligations

RUC looks out further than the next trade date

Extremely long-start commitment (ELC) process applies to:

- Resources with start times >18 hours
- Contractual intertie resources that must receive commitment instructions by 0600 hours one day ahead

Commitments are generated by RUC or manually notified by the ISO operator and the process considers bids in the day-ahead market up to two days out.

Day-ahead market results

When the Day-Ahead Market has completed its execution, a number of online reports are published and made available to Scheduling Coordinators, such as:

- Day-Ahead Generation Market Results
- Day-Ahead Load Market Results
- Convergence Bid Clearing Results
- Day-Ahead RUC Capacity

Questions?

LOCATIONAL MARGINAL PRICING

Section Objectives: Locational Marginal Pricing (LMP)

By the end of this section, you will be able to:

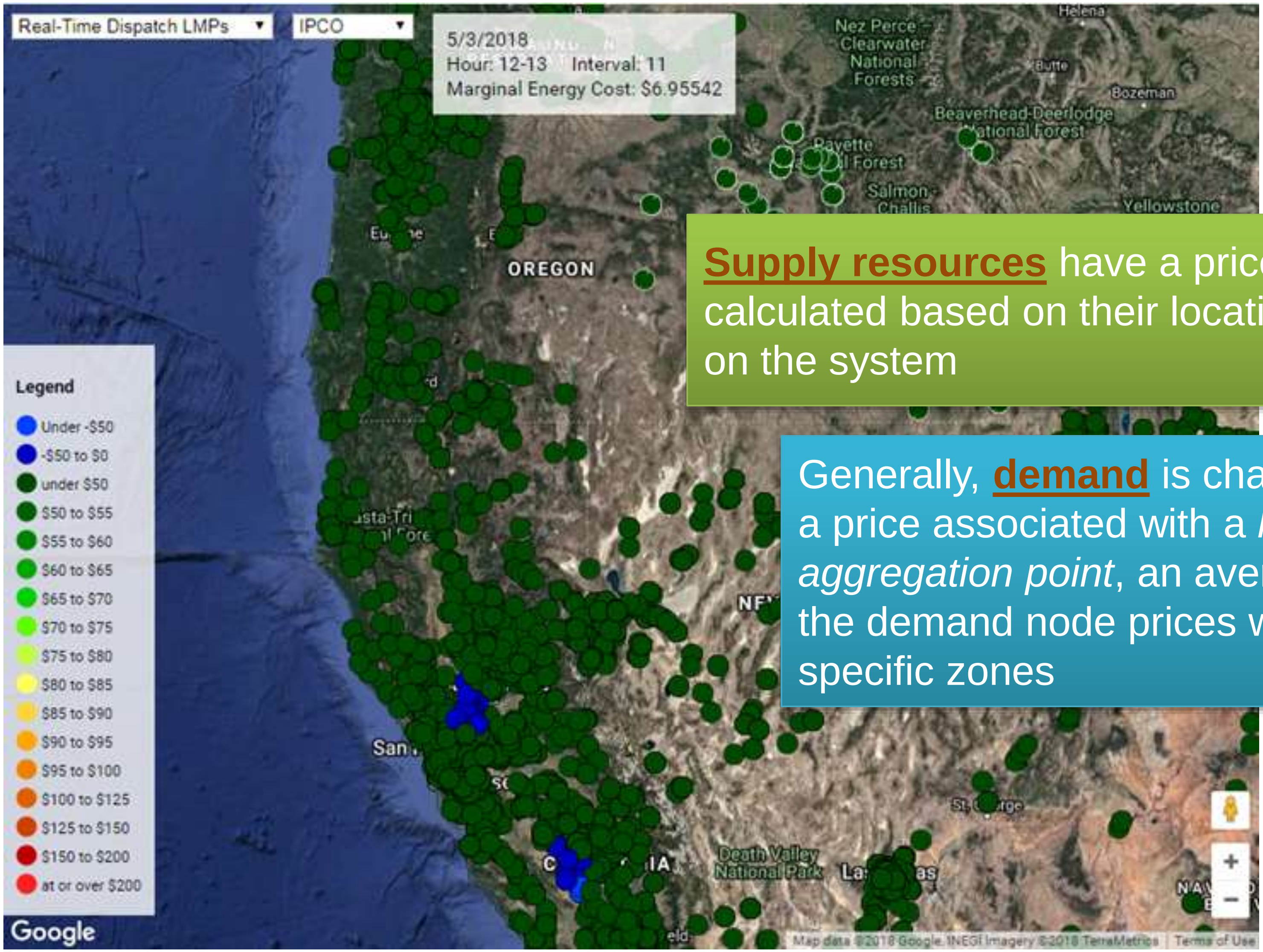
- Describe the components of the LMP
- Explain how the LMP is different for entities based on location
- Discuss why congestion revenue rights are part of the day-ahead market

Straight from the Tariff

California Independent System Operator Corporation
Fifth Replacement Tariff

Locational Marginal Price (LMP)
The marginal cost ($/MWh) of serving the next increment of Demand at that PNode consistent with existing Transmission Constraints and the performance characteristics of resources.

There are thousands of price nodes throughout the system



Supply resources have a price calculated based on their location on the system

Generally, **demand** is charged at a price associated with a *load aggregation point*, an average of the demand node prices within specific zones

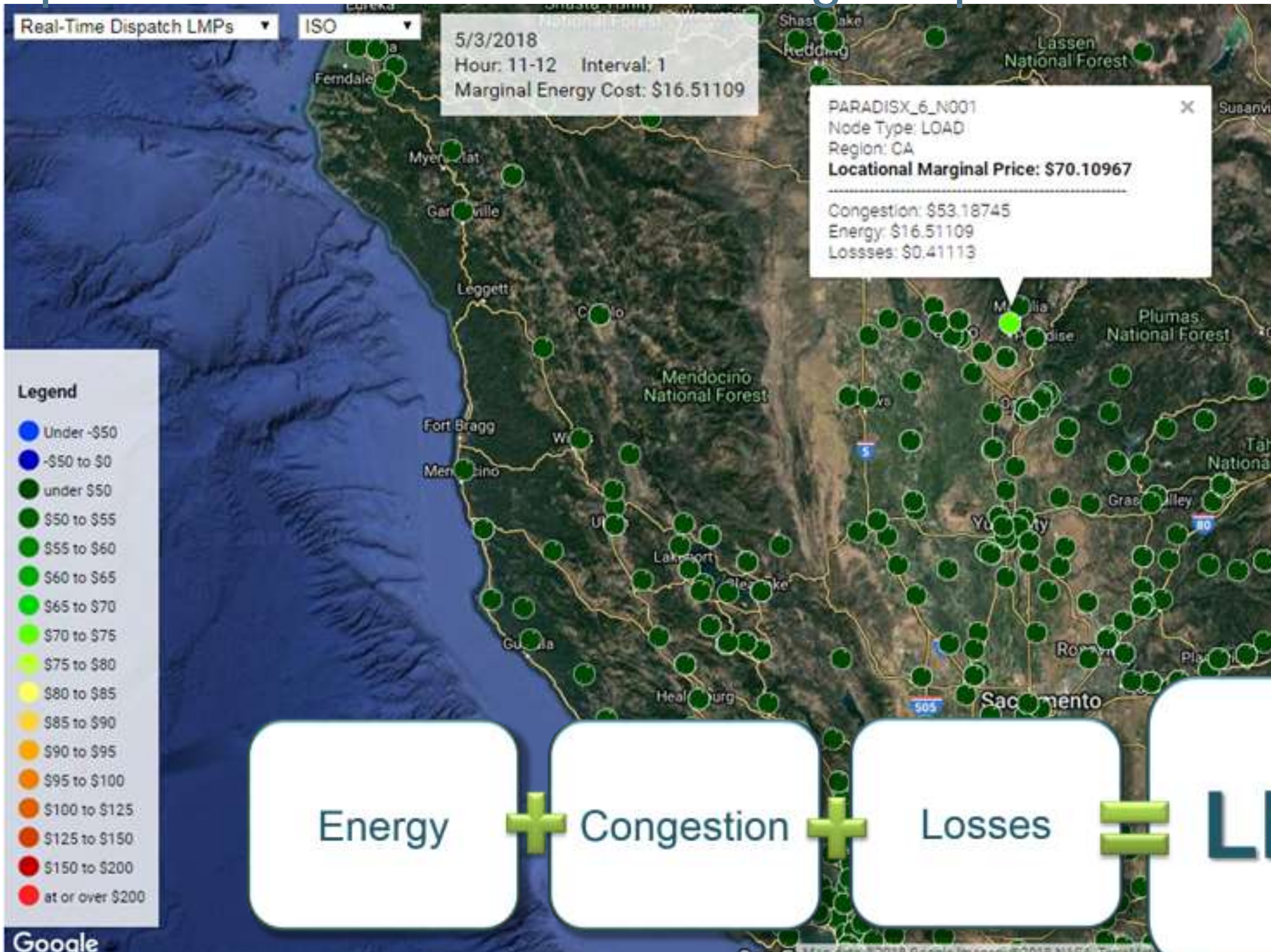
Nodal Pricing

Resources are paid the nodal price

Load pays the weighted average price of all load nodes in the service territory

Imports and exports are paid or pay the price at the scheduling point

Components of the locational marginal price



Energy + Congestion + Losses = LMP

Loss component

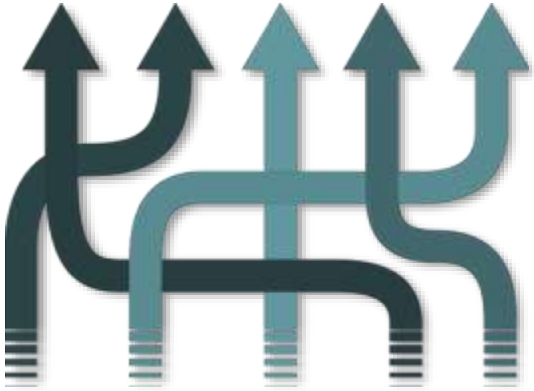
Actual losses use the full network model & the optimal power flow solution

The loss component of the LMP is based on marginal losses

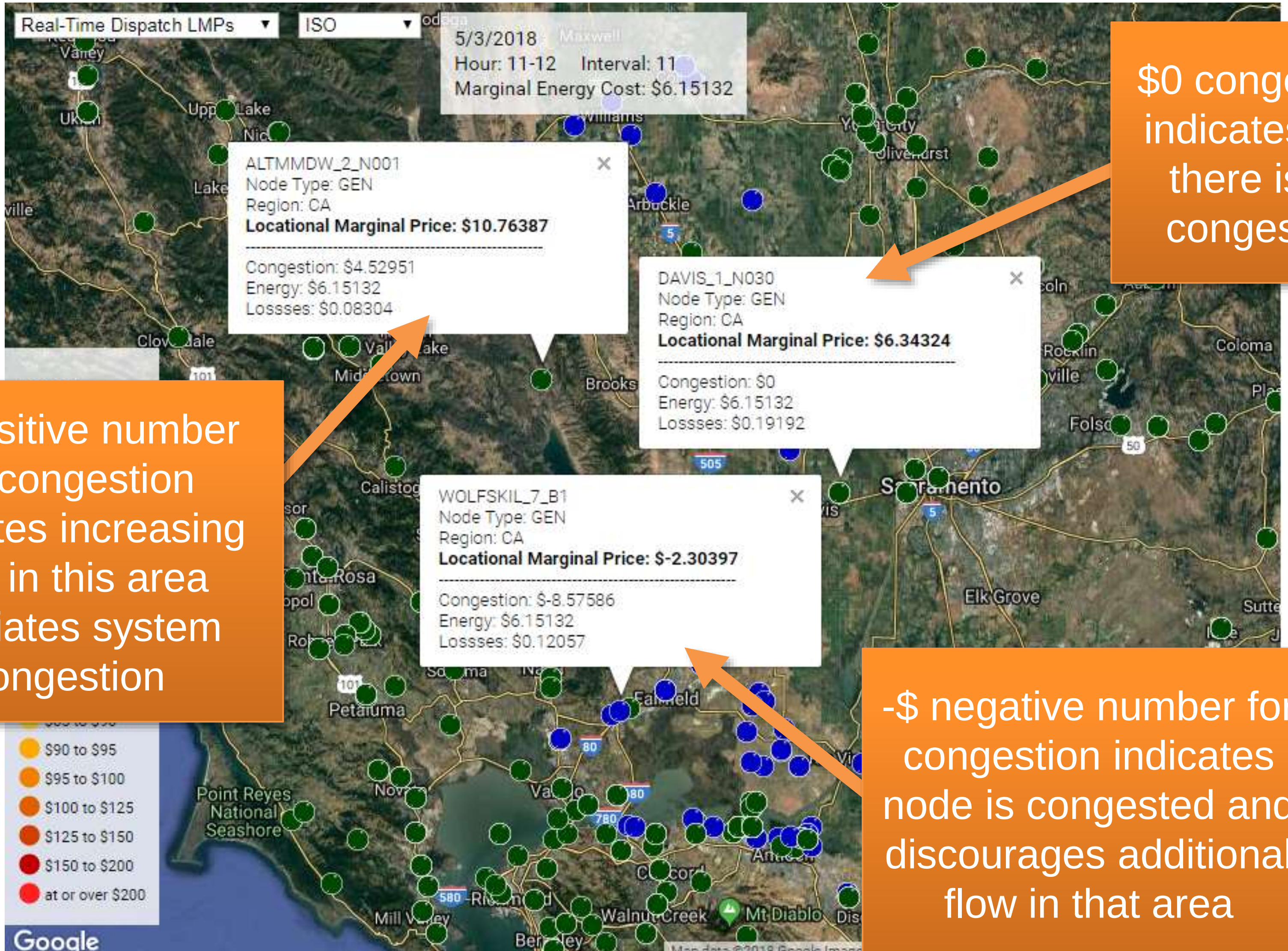
Marginal losses are based on loss sensitivity factors produced by the IFM program

Congestion

- A condition in which the lowest-priced electricity can't flow freely to a specific area due to heavy use of the transmission system
- Load pays more than generation gets paid resulting in congestion rents
- Potential causes:
  – Lack of transmission capacity
  – Outages



Congestion may result in higher or lower prices

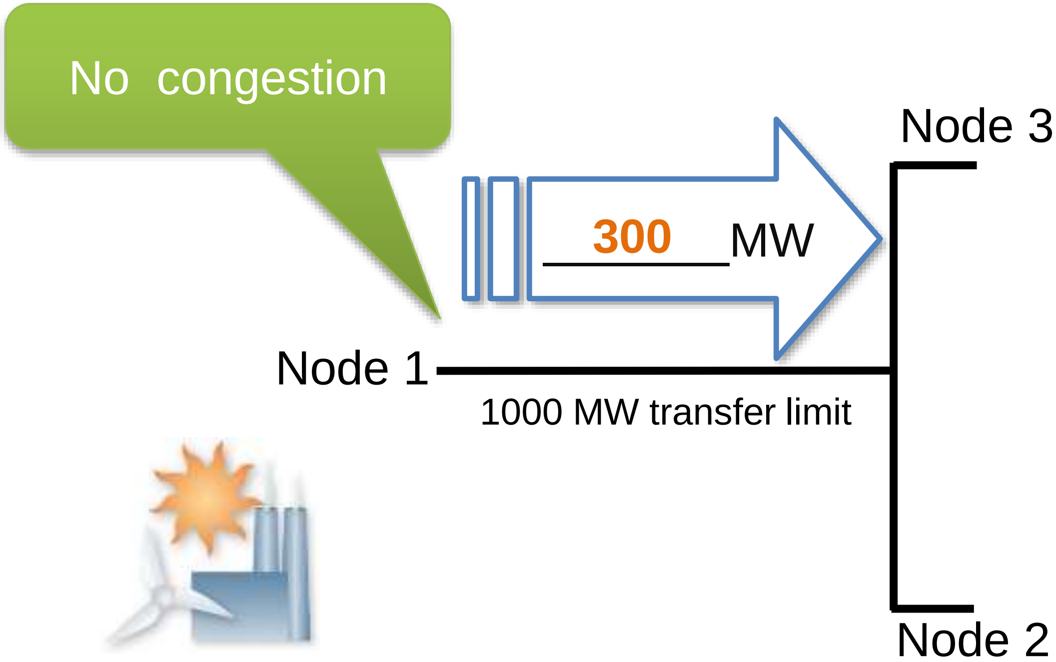


$0 congestion indicates that there is no congestion

+$ positive number for congestion indicates increasing flow in this area alleviates system congestion

-$ negative number for congestion indicates node is congested and discourages additional flow in that area

Example 1 – No congestion or losses



300 MW of load to be served

Energy	$40
Congestion	0
Loss	0
LMP	**$40**

Generator 1

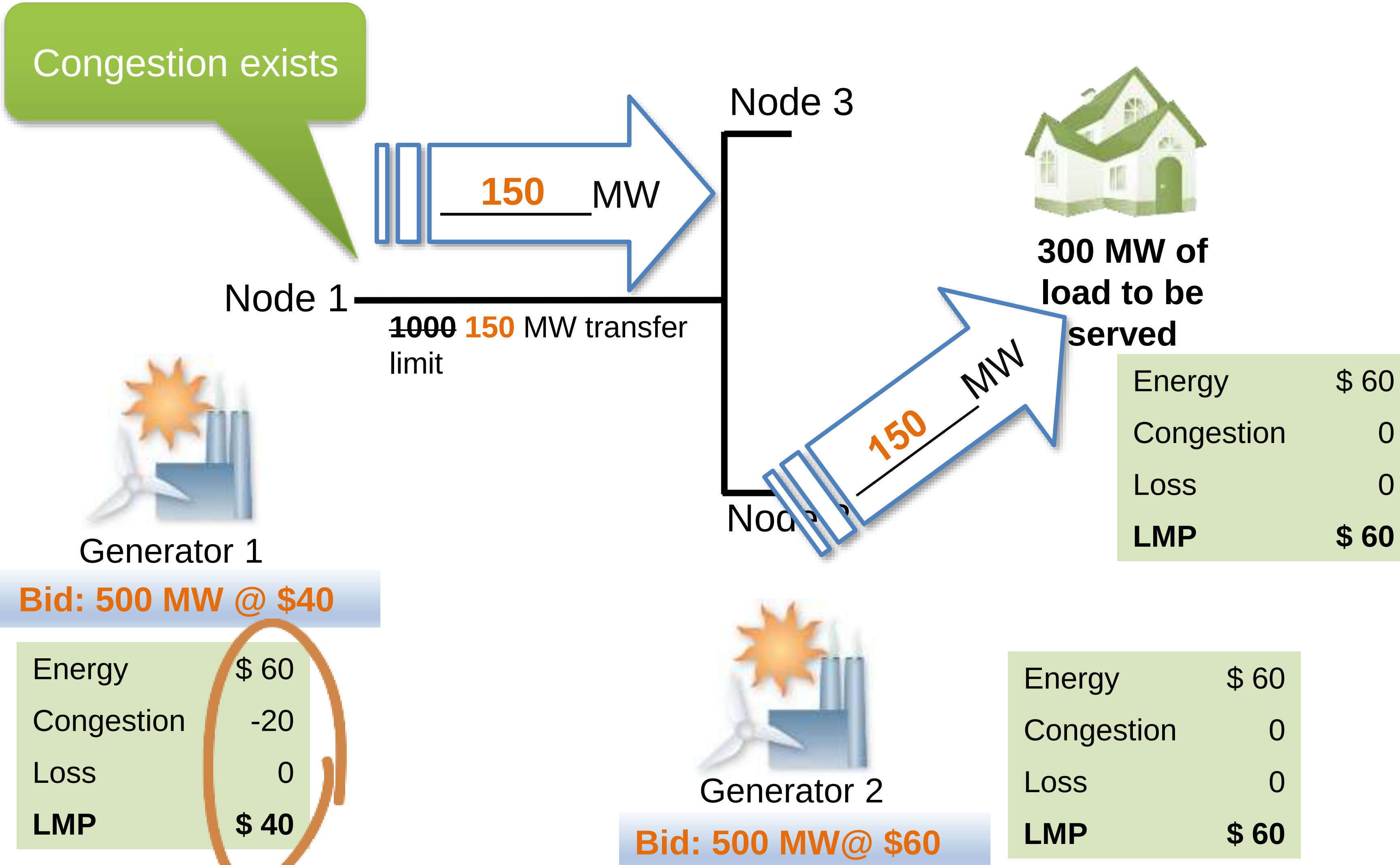
Bid: 500 MW @ $40

Energy	$40
Congestion	0
Loss	0
LMP	**$40**

Generator 2

Bid: 500 MW@ $60

Example 2 – Congestion, no losses



Generator 1 (Node 1):

Energy	$ 60
Congestion	-20
Loss	0
LMP	**$ 40**

Load (Node 3):

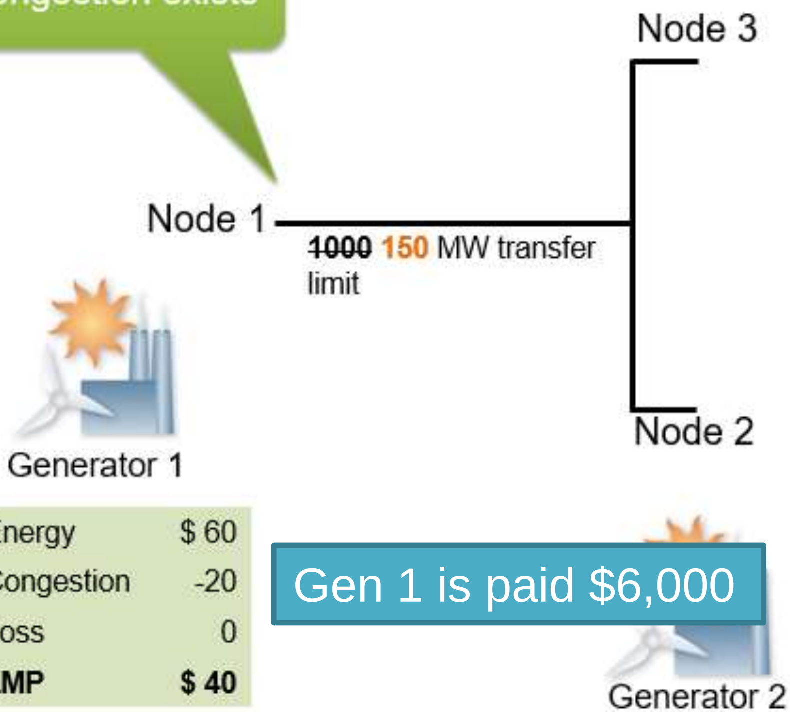
Energy	$ 60
Congestion	0
Loss	0
LMP	**$ 60**

Generator 2 (Node 2):

Energy	$ 60
Congestion	0
Loss	0
LMP	**$ 60**

Example 2 Recap

Congestion exists



Does the SC for the LSE have congestion revenue rights (CRRs)?

300 MW of load to be served

Energy	$ 60
Congestion	0
Loss	0
LMP	**$ 60**

Load pays $18,000

Generator 1

Energy	$ 60
Congestion	-20
Loss	0
LMP	**$ 40**

Gen 1 is paid $6,000

Generator 2

Energy	$ 60
Congestion	0
Loss	0
LMP	**$ 60**

Gen 2 is paid $9,000

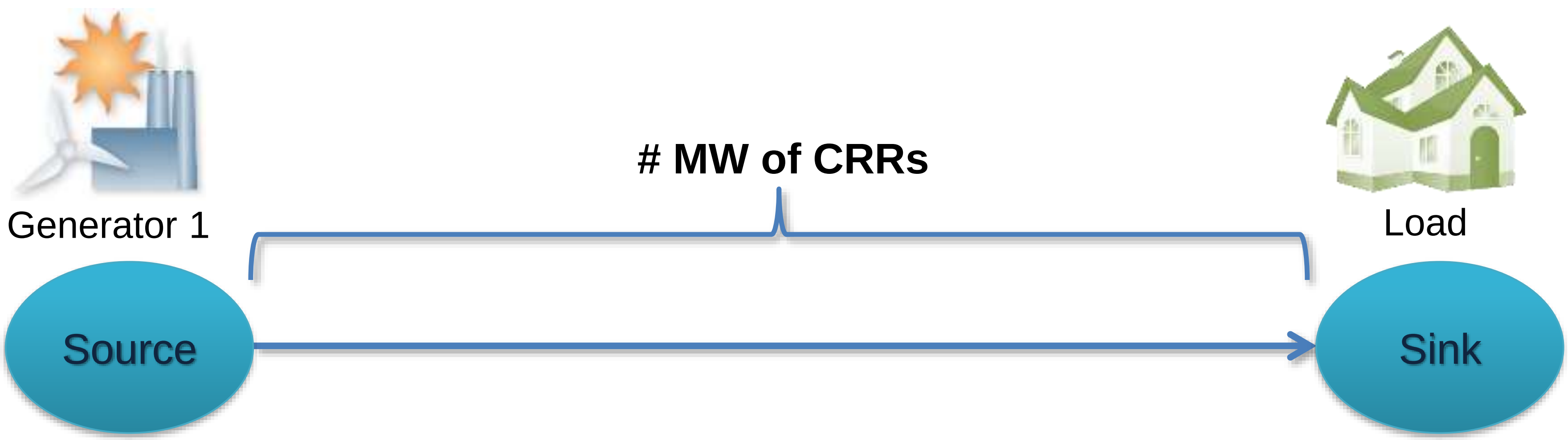
Due to congestion, the SC for the LSE paid $3,000 more than the generators were paid. This money is congestion revenue that will be allocated through Congestion Revenue Rights.

Questions?

CONGESTION REVENUE RIGHTS

Entities acquire Congestion Revenue Rights (CRRs) to offset day-ahead congestion costs

- Used to manage congestion cost variability based on LMPs
- Available through allocation and auction processes



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CRRs and the day-ahead market – key points

An SC is not required to own a CRR to bid into the day-ahead market

A CRR holder is not required to bid into the day-ahead market

An SC with a CRR is not required to bid consistent with the terms of their CRR (i.e. they do not need to bid at the source and sink of their CRR, or MW quantity)

An awarded day-ahead bid is settled at the LMP

A CRR is settled at the marginal cost of congestion (MCC) of the day-ahead locational marginal price (LMP)

Obtaining CRRs

Allocation	Auction
• For entities that provide for the upkeep of the transmission system including : • Internal load-serving entities (LSEs) • Out of balancing authority area LSEs • Project sponsors of merchant transmission facilities	• Open to entities that are registered as candidate CRR holders • Subject to creditworthiness requirements

Types of CRRs

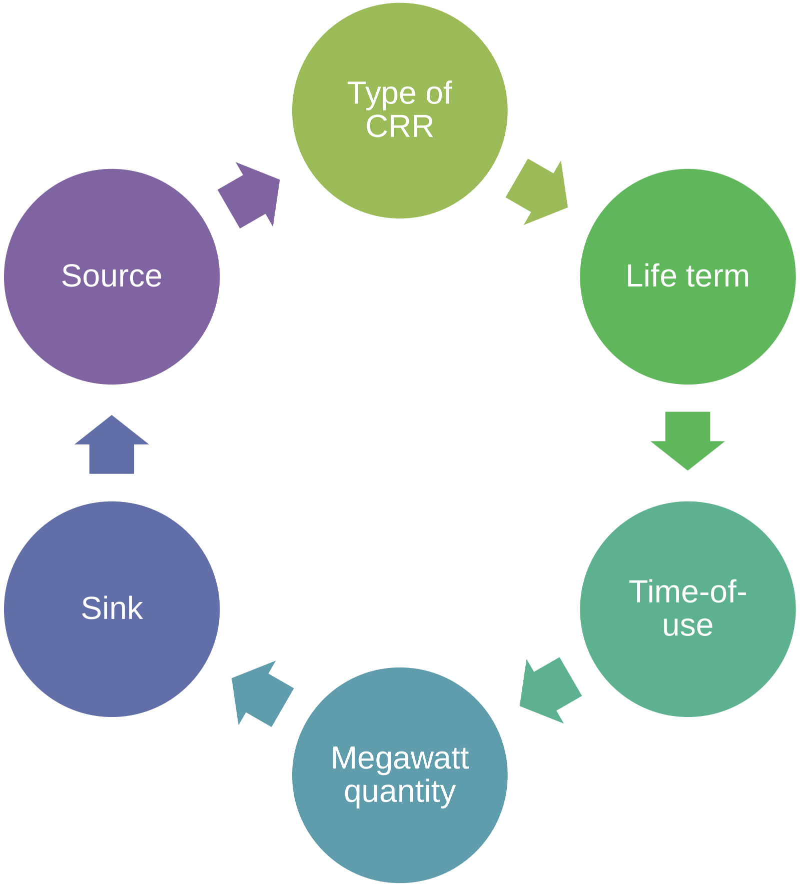
CRR Obligation

- Holder is paid if congestion is in the same direction of the CRR
- Holder is charged if congestion is in the opposite direction of the CRR
- Acquired via allocation or auction

CRR Option

- Holder is paid if congestion is in the same direction of the CRR
- No payment or charge if congestion is in the opposite direction of the CRR
- Available to project sponsors of a merchant transmission facility that do not elect some form of regulatory cost recovery, or converted merchant transmission facilities

CRRs are defined by these elements:



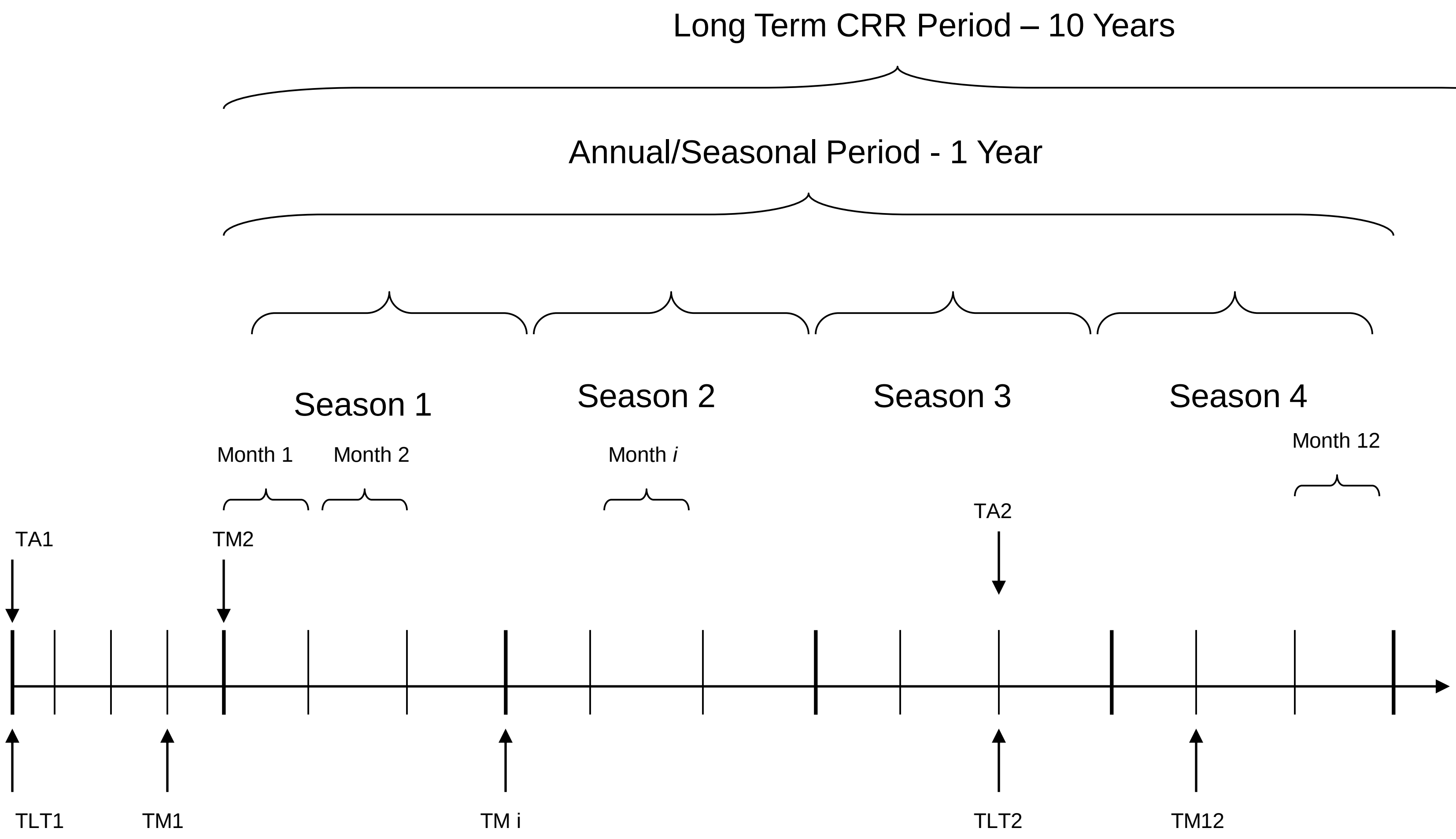
CRR terms

- Seasons are defined on a quarterly basis
  - Season 1 (Jan, Feb, Mar)
  - Season 2 (Apr, May, June)
  - Season 3 (Jul, Aug, Sep)
  - Season 4 (Oct, Nov, Dec)

- Long Term CRRs extend nine years after annual term for a total of ten years (allocation only)

- Months are calendar months (January, February, etc.)

CRR terms


Long Term CRR Period – 10 Years
Annual/Seasonal Period - 1 Year
Season 1
Season 2
Season 3
Season 4
Month 1
Month 2
Month *i*
Month 12
TA1
TM2
TA2
TLT1
TM1
TM i
TLT2
TM12

65% of the FNM capacity will be made available during the annual CRR process; 60% for Tier LT

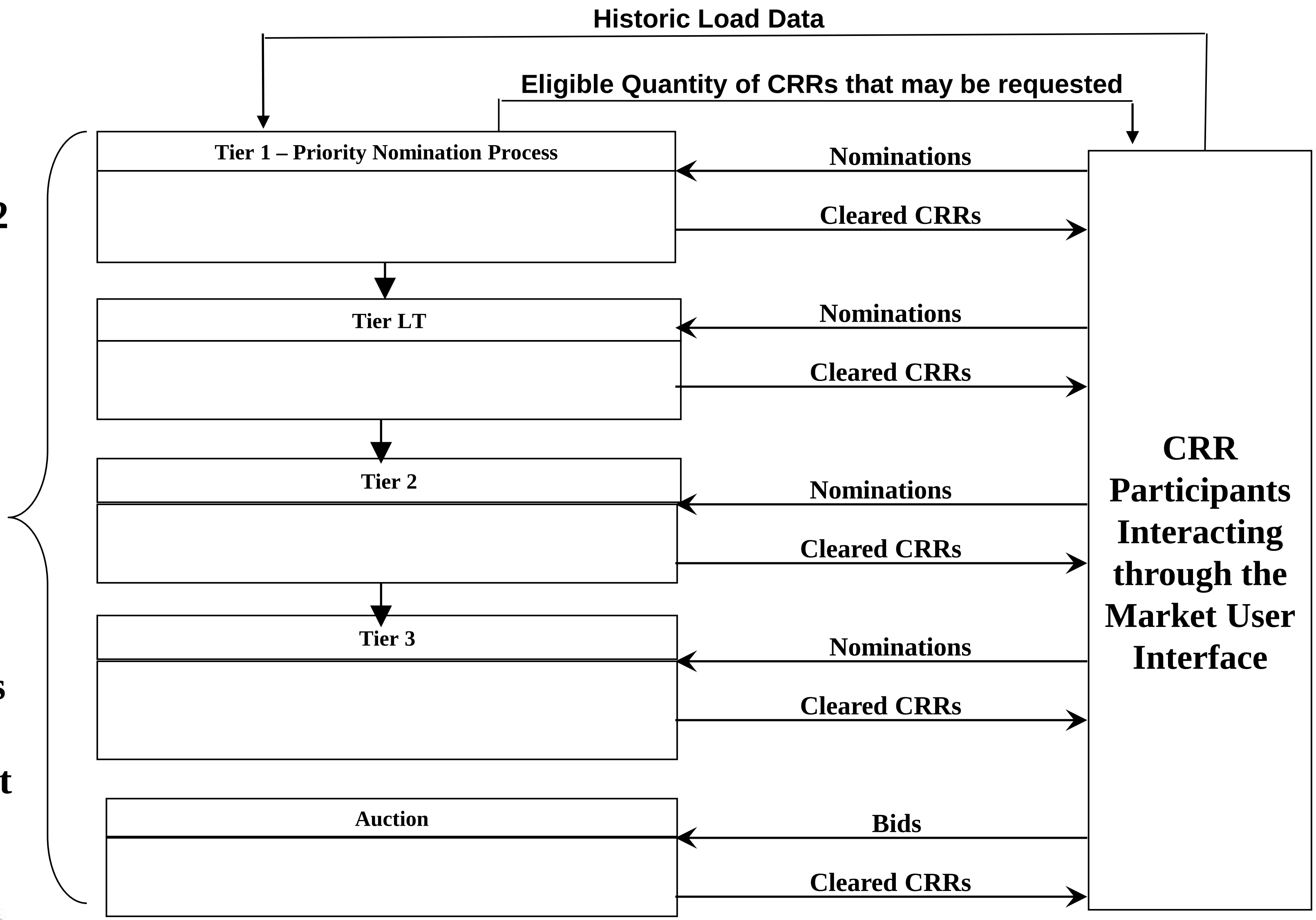
Term	Allocation/Auction Process
T_{A1} &T_{LT1}	Approximately 4 months before the start of the CRR year, the annual allocation/auction process will begin, which will produce seasonal/TOU CRRs for Seasons 1, 2, 3 and 4
Tier LT of the annual allocation process	Produces seasonal/TOU long term CRRs that will be allocated for the duration of 10 years (one year from the annual allocation and a nine-year extension through the long-term tier) using 60% of the FNM capacity
T_{A2} & T_{LT2}	Approximately 4 months before the start of the next year (year 2), the annual allocation/auction process will begin, which will produce seasonal/TOU CRRs for Seasons 1, 2, 3 and 4 and seasonal/TOU long term CRRs

CRR allocation and auction – annual process

A separate SFT will be run for each TOU

For T1,T2 T3, and the auction the FNM Capacity is scaled to 65 Percent

Tier LT is scaled to 60 Percent



CRR allocation and auction resource availability

- In the annual process all lines are assumed to be in-service unless a long-term outage is known prior to the running of the annual process
- In the monthly process outages are modeled
- After each allocation process there is an auction for the remaining capacity, subject to the simultaneous feasibility test

Annual | Monthly

Monthly CRR auction and allocation – tiered process

- Approximately 30 days before the start of the operational month the monthly allocation and auction process is run

- ISO releases 100% of system capacity less a global derate factor to account for unplanned outages and impacts of loop flow, this has historically been 17.5%

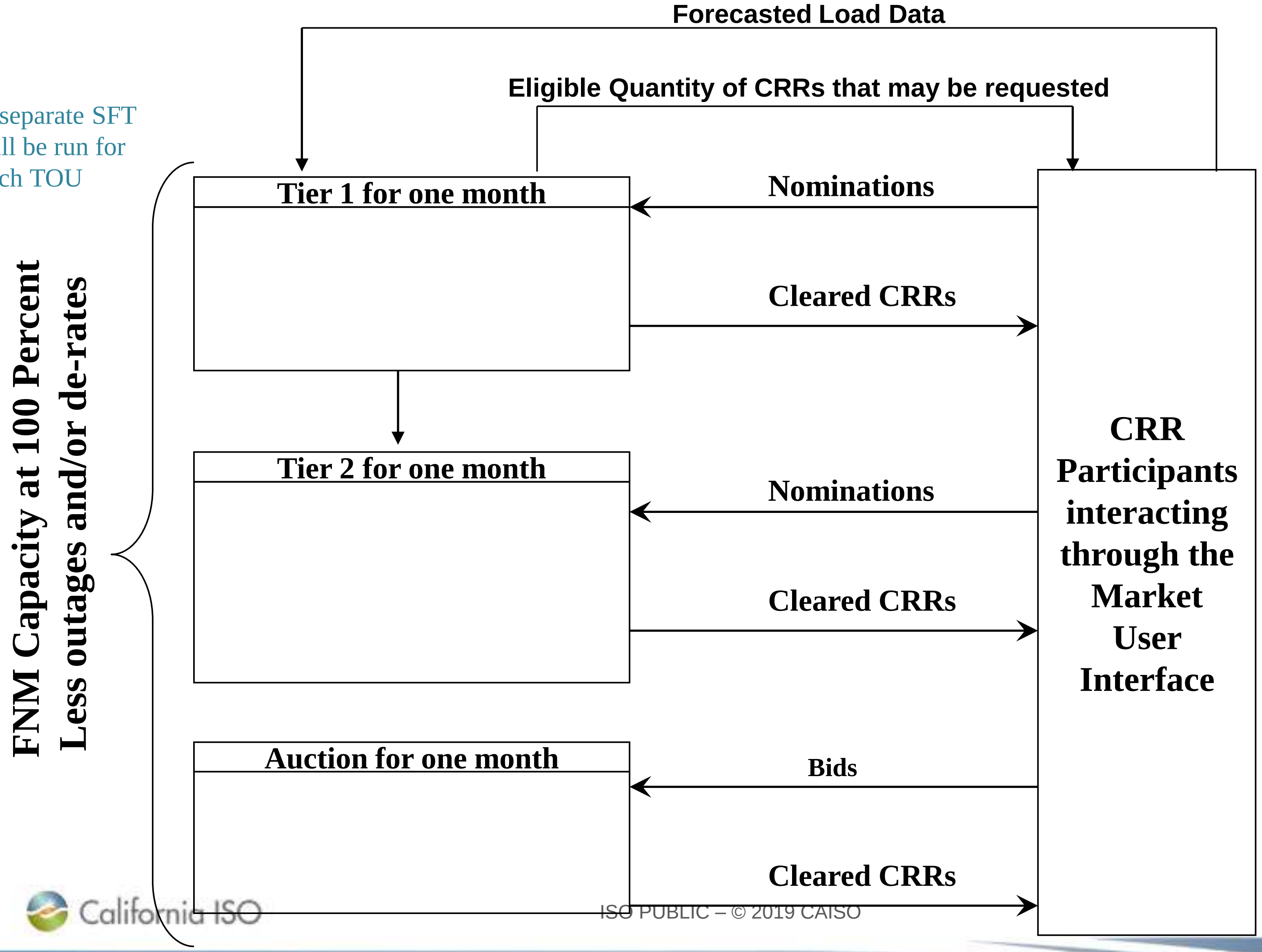
- Includes the modeling of outages

- Two allocation tiers and one auction

- LSEs can nominate up to 100% of the difference between its Monthly CRR Eligible Quantity and the total of any Seasonal CRRs allocated in the annual CRR Allocation and any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated

CRR allocation and auction – monthly process

A separate SFT will be run for each TOU



Simultaneous Feasibility Test

Purpose of the simultaneous feasibility test (SFT) is to award CRRs based on optimization formula and ensure revenue adequacy

The SFT takes the CRR source(s) location, the CRR sink(s) location and MW quantity(s) of the CRR nomination (allocation) or CRR bid (auction) and applies these to the FNM as if they were generator(s) and load(s)

The FNM used is similar to the model used in the day-ahead market including topology and constraints limits

Simultaneous feasibility test (SFT)

An optimization formula is used in both the CRR Allocation and CRR Auction process

- The topology and constraints are the same
- The objective function is slightly different in each

The CRR FNM is a DC model such that 1 MW of injection equates to 1 MW of withdrawal

CRR Allocation

- Objective function utilizes the weighted least squares (WLS)

CRR Auction

- Objective function is to maximize the bid-based value of the awarded CRRs

TOR and ETC modeling

- There are two basic types of transmission rights that the ISO models through the CRR process

Transmission ownership rights (TORs)	Existing transmission contracts (ETCs)

- These rights are defined through the transmission rights transmission curtailment (TRTC) procedures

TOR and ETC modeling (cont'd)

- When the ISO models these rights the intent is to remove capacity, which has a "perfect hedge", so that CRRs are not allocated or auctioned on this capacity
  - *Exempt from all ISO congestion charges if schedules are within rights (perfect hedge)*

- The ISO holds these CRRs not the rights holder

CRR Auction

CRR auction – auction eligibility

All entities can participate in the auction that have:

- Registered as a candidate CRR holder with the ISO
- Posted minimum required collateral for participation

Annual auction

$500,000

Monthly Auction

$100,000

CRR auction – auction overview

- All bids submitted into the auction process are subject to:
  - Initial validations of maximum portfolio credit exposure against aggregate credit limit
  - A simultaneous feasibility test with all previously allocated CRRs for the same period and TOU modeled as fixed injections and withdrawals

CRR auction – auction overview

Allowable CRR auction injections (sources) and withdrawals (sinks) combinations

		Sink				
Source		LAPs	GEN	PNODE	TIE	TH
	LAPs					
	GEN	**Y**			**Y**	**Y**
	PNODE					
	TIE	**Y**				**Y**
	TH	**Y**			**Y**	

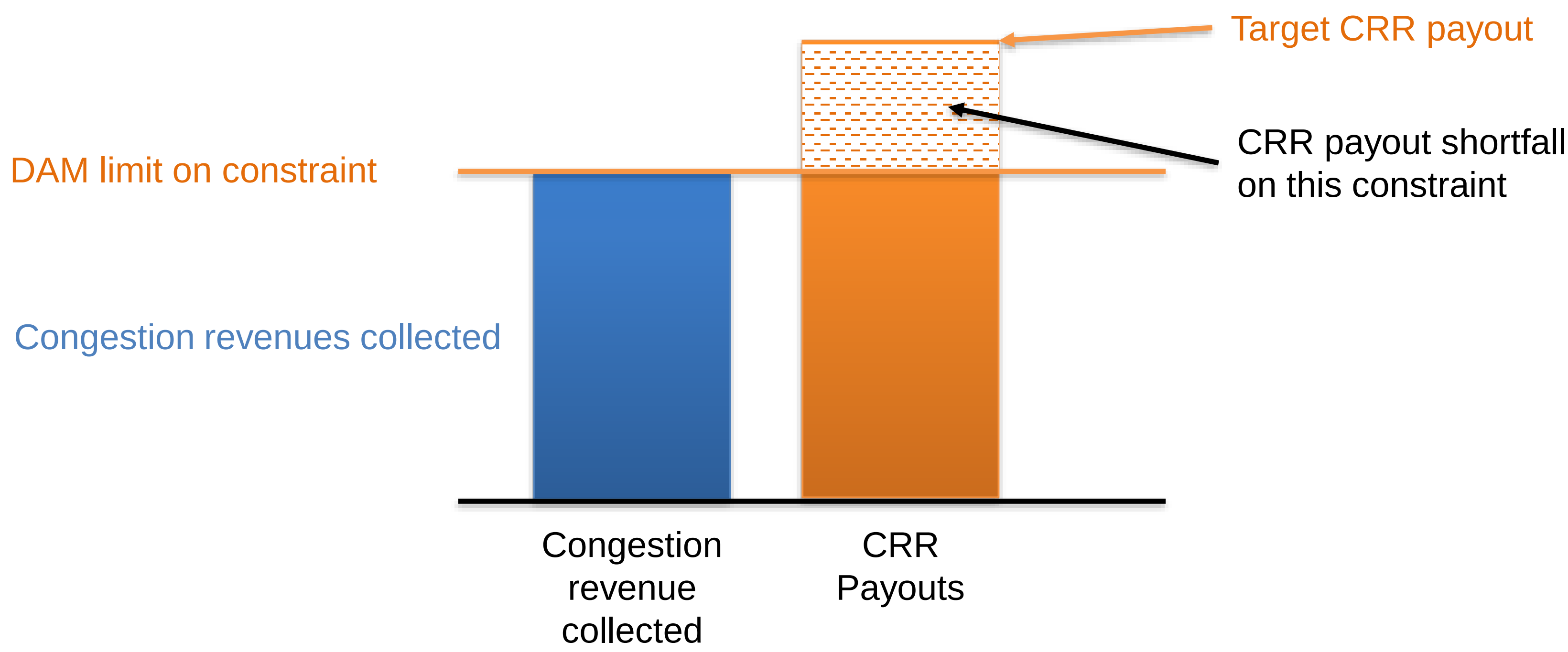
CRR auction – auction clearing prices

- All CRR APNode market clearing prices (MCPs) will be published after each market

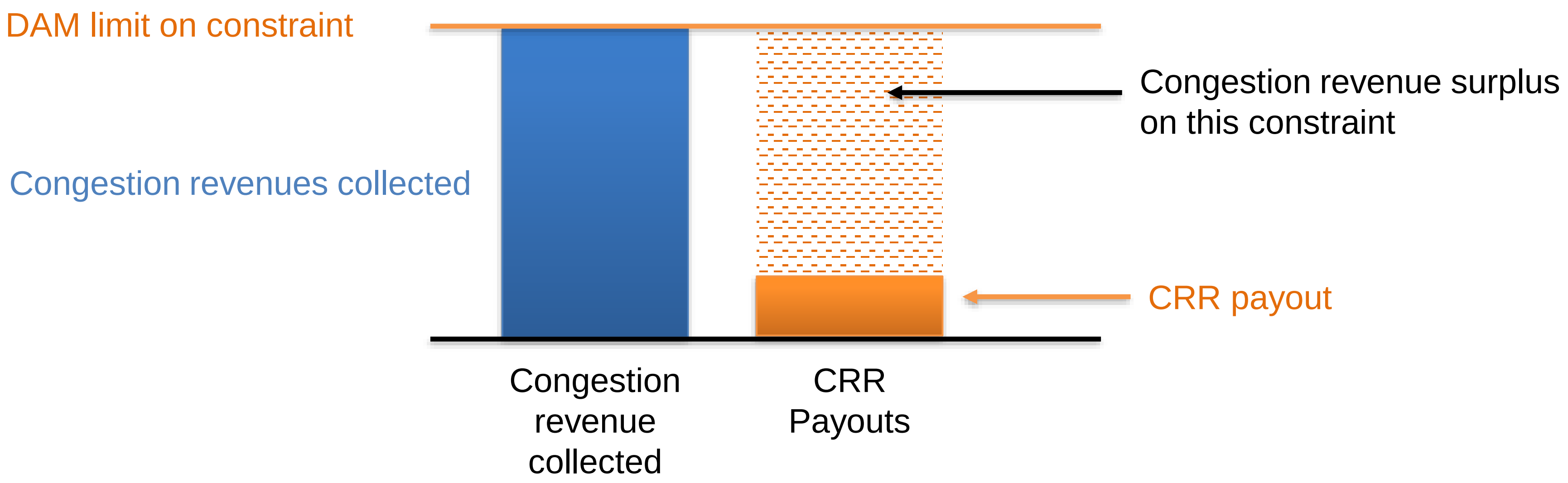
- In general, the clearing price of a CRR is the MCP at the source/injection minus the MCP at the sink/withdrawal
  - For **Buy Offers**
    - a <u>positive value</u> is a charge to the bidder
    - a <u>negative value</u> is a payment to the bidder

  - For a **Sell Offer**
    - a <u>positive value</u> is a payment to the seller
    - a <u>negative value</u> is a charge to the seller

CRRs are funded by collected revenue from the day-ahead market



Additional revenue could be applied to offset daily shortfall



Allows surpluses on one constraint in one hour to offset shortfalls on the same constraint in other hours

- For example:
  - Allocate $1,000 shortfall to CRR1 on a constraint in HE1
  - A $750 surplus associated with CRR1 is collected on the same constraint in HE18
  - The final settlement for CRR1 will be a shortfall allocation of $250
- Proposal does not mix surpluses across constraints
- Proposal returns remaining surpluses at the end of the month to measured demand

Convergence bids and congestion revenue rights

- Convergence bids can contribute to congestion
  - Increased (or decreased) congestion on the constraint could enhance entity's CRRs
- CRR Settlement Rule:
  - Recapture (where warranted) the increase in CRR revenues to CRR Holders that are attributable to that company's convergence bidding

Questions?

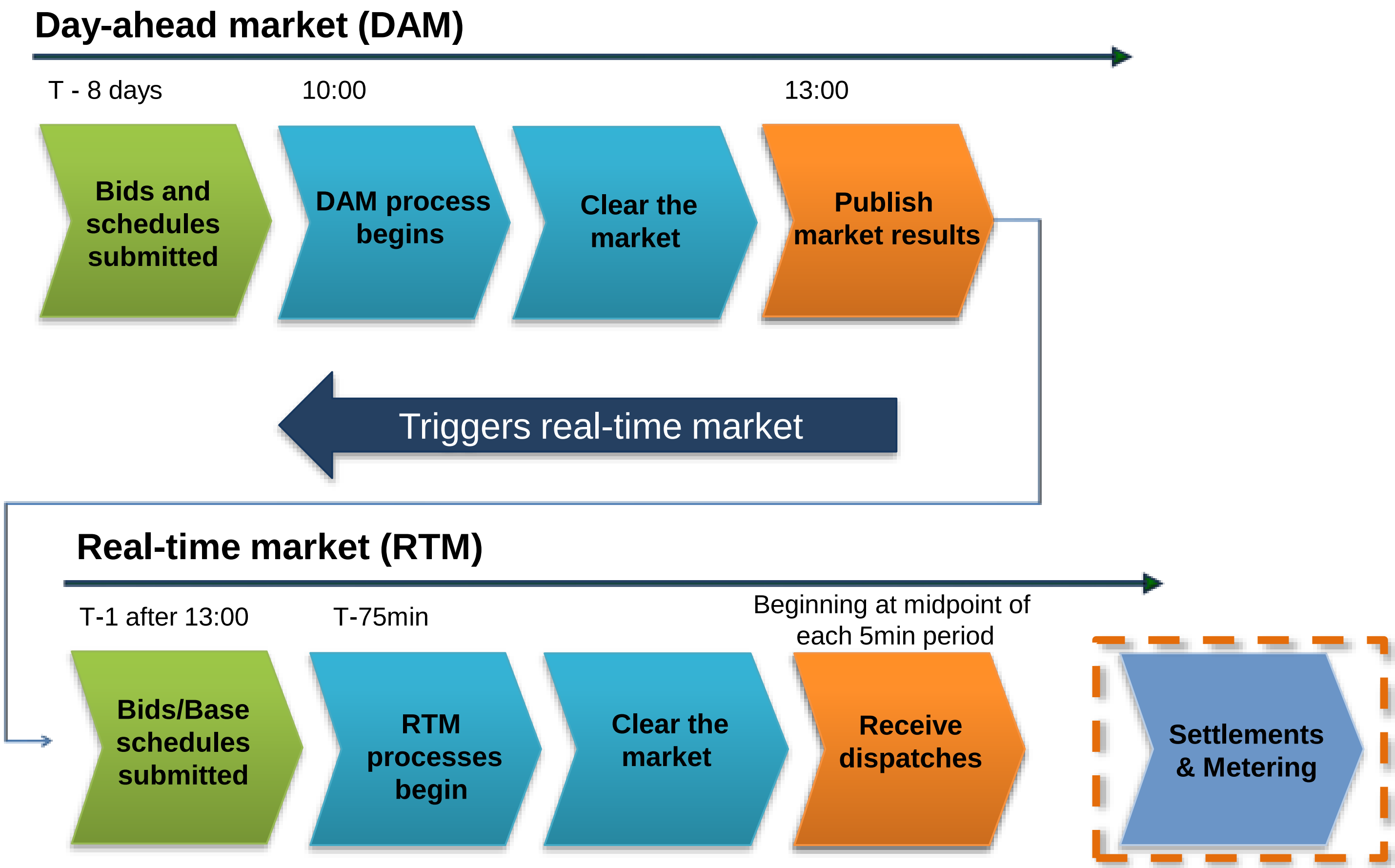
SETTLEMENTS

Section Objectives: Settlements

By the end of this section, you will be able to:

- Identify day-ahead settlement concepts
- Identify timelines for key metering and settlements activities
- Describe the process for determining bid cost recovery
- Explain the purpose of the Inter-SC trades and grid management charges

Market process timelines: post market

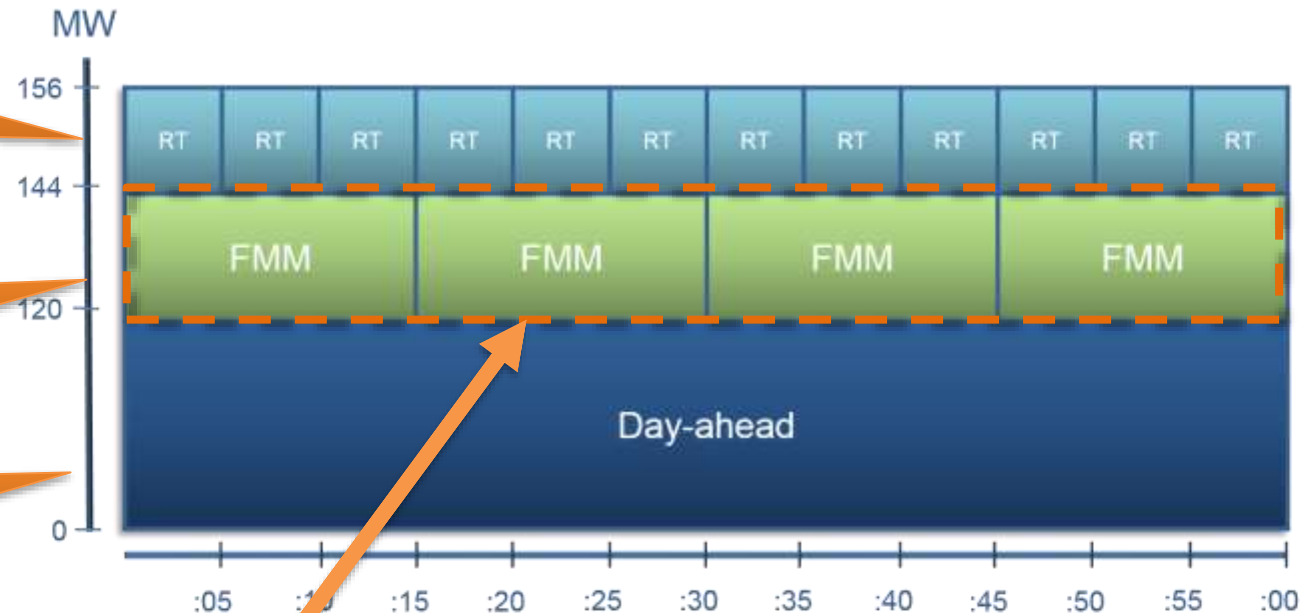


Energy settlements are broken down by applicable markets

Additional real-time award

Incremental award in the FMM

Initial day-ahead award



Convergence bids are liquidated in real-time using the simple average of the 4 FMM LMPs

What is the ISO's role in settlements?

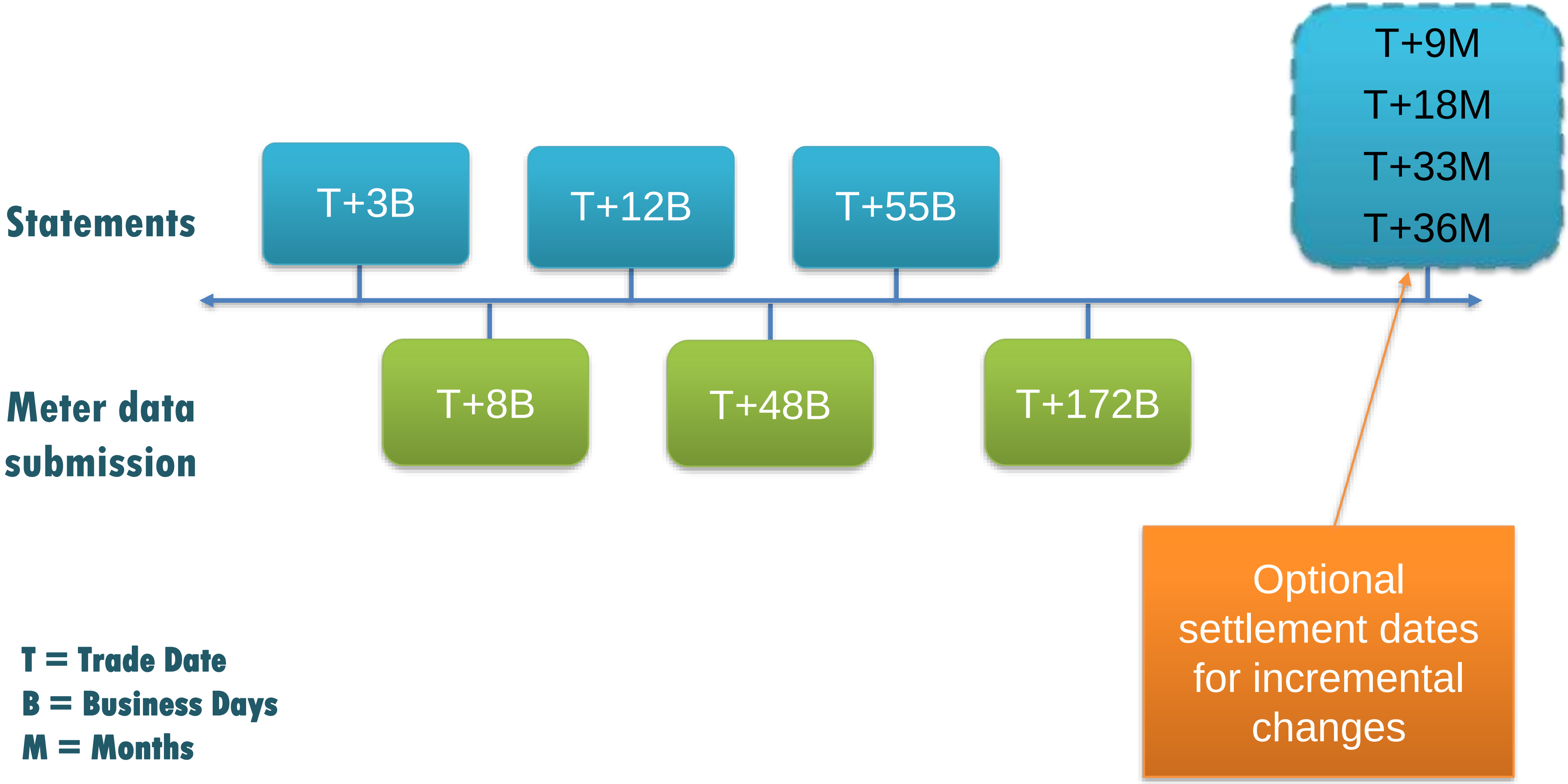
Charges and payments for market and transmission-related activities between market participants are processed through the ISO

Formulas are associated with each **charge code (CC)** to determine how transactions will be settled

Settlement statements break down what is to be charged or paid for each charge code

Invoice charges to be remitted or payment advices of what will be paid out are produced based on the statements

Timelines are critical to settling the market efficiently



T = Trade Date
B = Business Days
M = Months

Settling **day-ahead** market transactions

Physical

- Financially binding regardless of real-time performance
- **Physical supply awards** are ***paid*** the DA LMP for all schedules, at the price node where the transaction is scheduled or bid – CC 6011
- **Physical demand awards** are ***charged*** the DA LMP where the DLAP is scheduled – CC 6011
- **Import and export awards** are ***paid or charged***, respectively, at their scheduling point – CC 6011

Virtual

- Settled in the day-ahead market and liquidated in the real-time market
- **Virtual supply awards** are ***paid*** the DA LMP at the location where the transaction is bid – CC 6013
- **Virtual demand awards** are ***charged*** at the location where the transaction is bid – CC 6013

More about settling the **day-ahead** market

- **Ancillary service awards** are ***paid*** the MW value that is awarded at the ancillary services marginal price (ASMP), which is a resource-specific price

- **Residual unit commitment capacity awards** are ***paid*** the resource-specific RUC price, if applicable

Key Points: **Ancillary Services**

- SCs get this settlement when receive an ancillary service capacity award in the day-ahead market
- If a resource is does not provide awarded ancillary service capacity, they are subject to no-pay
- When a resource is awarded for an ancillary service, they need to submit an energy bid in real-time.
- Spin, non-spin, regulation ancillary services are all settled similarly, with the exception that regulation also considers mileage.

Ancillary Services - Spinning obligation example

- Assume*:

Spin procured for ISO BA	500 MW
Total cost of spin for ISO BA	$1000
SC's spin obligation quantity	125 MW
SC's self provided spin	25 MW

*no reg up substitution in this example

- Settlement

Spinning Reserve Rate	*	Net Spinning Reserve Obligation	=	Spinning Reserve Obligation Amount
$1000/500 MW		125 MW – 25 MW		Settlement (CC 6194)

3

Key Points: **Residual Unit Commitment**

- SCs get this settlement when receive an award for RUC capacity.
- If a resource is does not provide awarded RUC capacity, they are subject to no-pay
- When a resource is awarded for an ancillary service, they need to submit an energy bid in real-time.
- There may also be RUC payment associated with bid cost recovery

Questions?

BID COST RECOVERY AND MITIGATION

Key Points: **Bid Cost Recovery**

- An SC would receive bid cost recovery if their eligible bid costs exceeded their revenues over a trade day
- There are mitigation measures in place to ensure that bid cost recovery payments are justified
- Day-ahead and real-time bid cost recovery are settled separately
- RUC is a day-ahead product but it is netted against real-time bid cost recovery.

Bid cost recovery is a financial mechanism to ensure that SCs are able to recover eligible bid costs

- start-up costs
- minimum load costs
- transition costs for multi-stage generators
- energy costs

A “shortfall” is when eligible bid costs exceed eligible revenues over a trading day

Costs	Revenues
• Start up cost • Minimum load cost • Energy costs (MW x bid) • AS costs (MW x bid)	• Minimum load (MLE x LMP) • Energy award (MW x LMP) • AS award (MW x ASMP)

Costs vs. revenues over one hour

Costs

Name	Hour	Cost	Comment
Start Up	HE 5	$1,000	From master file
Minimum Load	HE 5	$4,000	From master file
Energy	HE 5	$2,500	IFM MW x IFM bid (50 MW x $50)
Ancillary Services	HE 5	$ 100	IFM MW x IFM bid (10 MW x $10)
Total Costs	**HE 5**	**$7,600**	

Revenues

Name	Hour	Rev.	Comment
Minimum Load (50 MW)	HE 5	$3,000	ML x LMP (50 MW x $60)
Energy	HE 5	$3,000	Awarded MW x LMP (50 MW x $60)
Ancillary Services	HE 5	$ 150	Awarded MW x LMP (10 MW x $15)
Total Revenues	**HE 5**	**$6,150**	

Is there a shortfall?

What else do we need to know to determine if this resource is eligible for BCR?

4

Costs vs. revenues over the whole day (DA and RT)

Eligible for BCR?

Costs

Hour Ending	1…4	5	6	7	8…24	
Start Up	$ 0	$1,000			$ 0	
Minimum Load	$ 0	$4,000	$4,000	$4,000	$ 0	
Energy	$ 0	$2,500	$2,500	$2,500	$ 0	
Ancillary Svc	$ 0	$100	$100	$100	$0	
Daily Costs	**$ 0**	**$7,600**	**$6,600**	**$6,600**	**$ 0**	**$20,800**

Revenues

Hour Ending	1…4	5	6	7	8…24	
Minimum Load	$ 0	$3,000	$3,500	$4,000	$ 0	
Energy	$ 0	$3,000	$3,500	$4,000	$ 0	
Ancillary Svc	$ 0	$150	$200	$200	$0	
Daily Revenues	**$ 0**	**$6,150**	**$7,200**	**$8,200**	**$ 0**	**$21,550**

Shortfall

A “commitment period” is when a resource is online and synchronized to the grid and available for dispatch

- Self-commitment period – the portion of a commitment period when a resource submits an energy self-schedule or AS self-provision
  - Not eligible to recover the following costs:

Start up costs	Minimum load costs	Transition Costs

- CAISO commitment period – not a self-commitment period.
  - Eligible for recovery of all bid costs.

Interties and bid cost recovery

Imports

- Eligible for day-ahead BCR
- Recovery of energy costs only
- Eligible for real-time BCR if submitting bids using the 15 minute dispatch option

Exports

- Not eligible for BCR

BCR mitigation measures

- A resource must be eligible for bid cost recovery
- DA Metered Energy Adjustment Factor (MEAF)
  - Scale down cost based on actual delivered energy to total expected energy
- Persistent Deviation Metric
  - Mitigate cost when resource persistently deviates from the CAISO dispatch

BID COST RECOVERY ALLOCATION

Key Points – Bid Cost Recovery Allocation

- Day-ahead bid cost recovery is allocated to IFM load uplift obligation and/or positive net virtual demand. If there are unallocated costs remaining, they are allocated to measured demand.
- RUC bid cost recovery is allocated to net negative demand deviations and/or positive net virtual supply. If there are unallocated costs remaining, they are allocated to metered demand.
- Real-time bid cost recovery is allocated to measured demand (includes exports).

Tier 1: First, costs are allocated to SCs with an IFM load uplift obligation and positive net virtual demand

- An SC with an IFM load uplift obligation has:

Supply less than demand

- An SC with net virtual demand has:
  - *only considered if ISO has positive net virtual demand*

Tier 2: Any remaining unallocated costs are allocated to <u>measured</u> demand

CAISO measured demand includes exports

Questions?

INTER-SC TRADES

Inter-SC Trades

An optional settlement service provided to facilitate trades of bilaterally procured energy between SCs

Both supply and demand schedule or bid their energy in the day-ahead market

Allows participants to “flip the money” and potentially reverse the “double settlement” from the market

Example - Inter-SC trade (IST) for energy

Generator A **Load B**

Agreement	20.60 MW per hour, per day $40 per MW for one day
Contract Payment	Load B pays Generator A $19,776 for supply needed to meet their need for that day

After both submit their schedules, they use an IST to swap monies from “double settlement”. Let’s look at the results…

Results of the day-ahead market

	Load B	Gen A
Bi-lateral contract	($19,776)	$19,776
CAISO Market	($20,305)	$20,750
Net amount	**($40,081)**	**$40,526**

Money exchanged outside of the market

Market settlements

Net amount without IST

	Load B	Gen A
Bi-lateral contract	($19,776)	$19,776
CAISO Market	($20,305)	$20,750
IST	$20,750	($20,750)
Net amount	**($19,331)**	**$19,776**

Both Gen A and Load B submit matching IST trade info to the ISO

Net amount settled through the IST process

Inter-SC trades for **energy**

Types

PHY
physical resource

APN
trading hub or default LAP

CPT
PHY not supported by energy schedule

Markets

Day-ahead settled hourly based on corresponding pnode/apnode DA LMPs

(CC 6301)

Real-time settled hourly based on the average of 4 FMM intervals on corresponding pnode/apnode LMPs

(CC 6371)

Inter-SC trades for **AST and UTC**

Ancillary Services (AST)	IFM load uplift obligation (UTC)
For spin, non-spin and regulation	For trading IFM Load uplift obligation
Submit as early as midnight on the trading day until T-45	Submit as early as midnight on the trading day until T-45
No separate charge type **(CC 6194, 6294, 6594, 6694)**	No separate charge type **(CC 6636)**

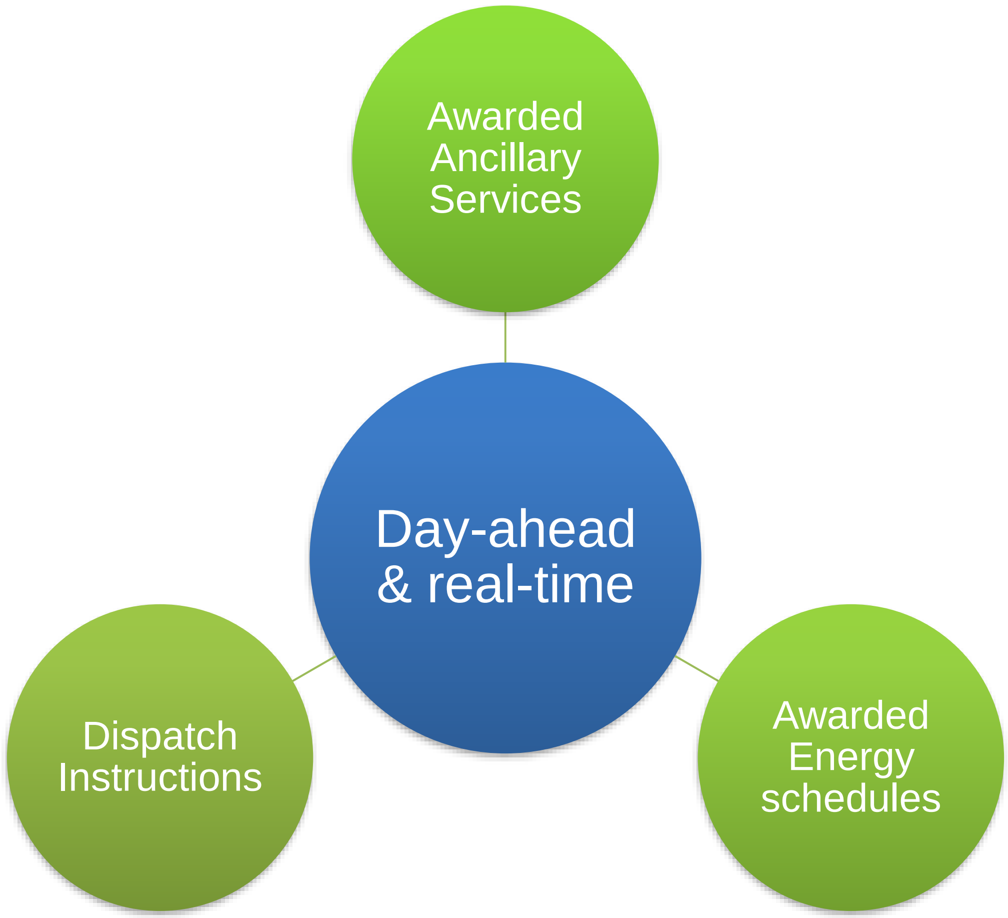
Questions?

GRID MANAGEMENT CHARGES AND ADMINISTRATIVE FEES

What is the grid management charge (GMC) and how is it applied?

Market Services Charge recovers costs for implementing and running the markets

- ✓ Imports
- ✓ Exports
- ✓ Generation
- ✓ Load



System Operations Charge recovers costs for running the grid in real-time

Based on gross absolute value of actual real-time energy flow

- Forward scheduled Energy
- Instructed Imbalance Energy
- Uninstructed Imbalance Energy

✓ Generation

✓ Load

✓ Imports

✓ Exports

GMC: Congestion revenue rights (CRR) services

Designed to recover costs the ISO incurs for running the CRR markets

Applied to a CRR holder's total MW holdings of CRRs that are applicable to each hour

GMC administrative and transaction fees

Bid segment fee

- $.005 applied to all submitted bid segments
- Physical bids and virtual bids

SCID fee

- $1,000 per SCID that have settlements activity within a trade month
- Calculated monthly

Forecasting service fee

- $.10 per MWh based on actual metered energy for eligible intermittent resources*
- Calculated monthly

* Does not apply to external EIRs that use their own forecast. All other EIRs are subject to this charge.

Grid management charges and administrative fees

Charges	Charge code	Rate	Units
Market services	4560	$0.1065	MWh
System operations	4561	$0.2797	MWh
CRR services	4562	$0.0100	MWh
EIM transaction charges - Market services charge - System operations	4564	 $0.0841 $0.1091	MWh
Fees			
Bid segment fee	4515	$0.0050	Per bid segment
Inter-SC trade fee	4512	$1.00	Per Inter-SC trade
CRR bid fee	4516	$1.00	# of nominations & bids
TOR charges fee	4563	$0.2400	Minimum of supply or demand TOR MWh
Monthly SCID fee	4575	$1,000	Per month
Miscellaneous fees			
Forecasting service fee	701	$0.1000	MWh

BAA charges

EIM charges

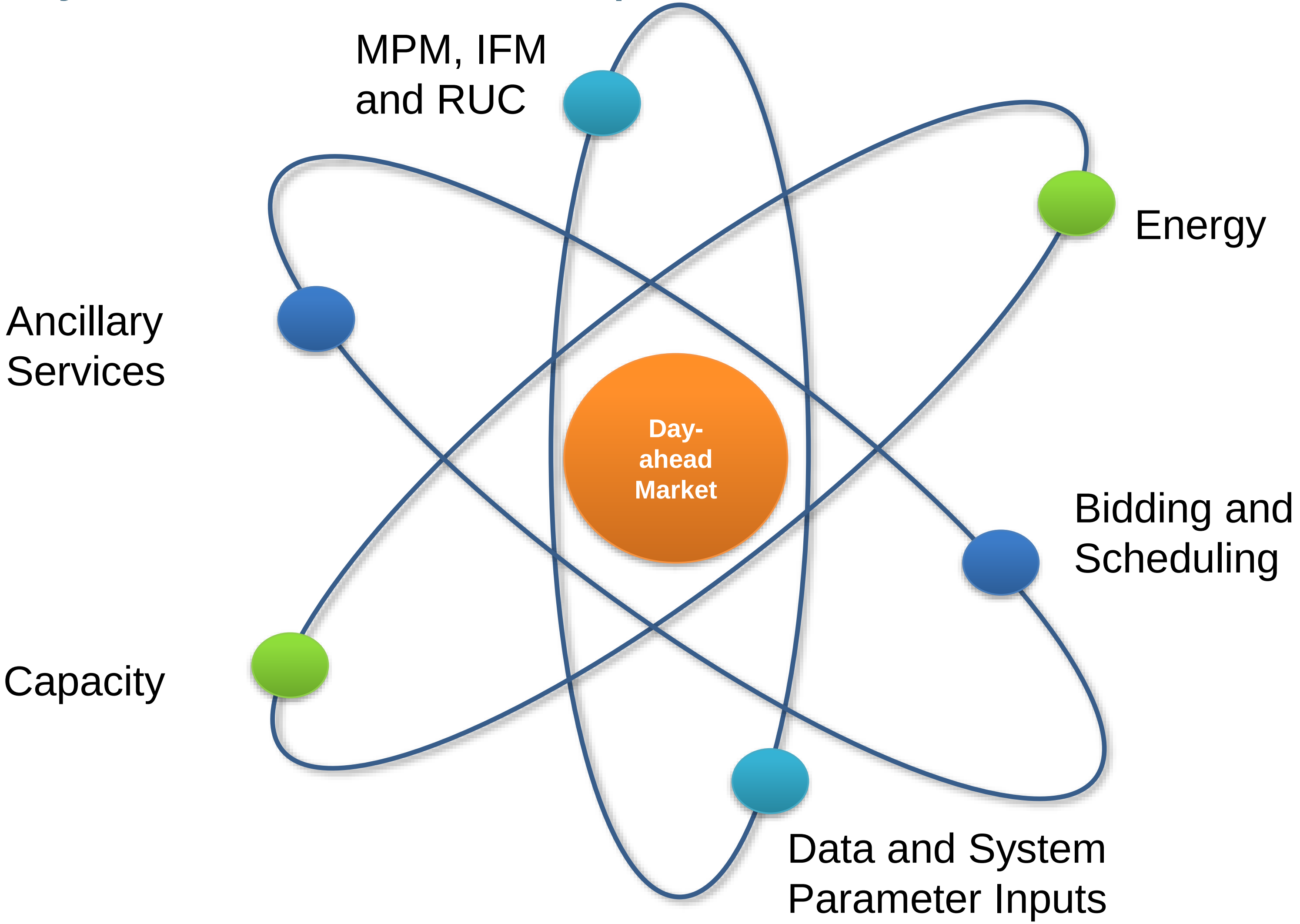
Apply to all transactions

Automatically apply to ISO BAA; elective for EIM

Effective 5/1/19

Questions?

Day-ahead market recap



WRAP UP

Current initiatives that look to modify existing day-ahead market

- **Extended Day-Ahead Market**
  - Develop rules to enable EIM entities to participate in day-ahead market
- **Day-Ahead Market Enhancements**
  - Co-optimizing supply based on both cleared demand and demand forecast
  - Day-ahead imbalance reserve product
- **System Market Power**
  - Review results of ISO's analysis of ISO balancing authority area's structural competitiveness
  - Determine if measures are appropriate to address system-level market power
- **FERC Order 831 – Import Bidding & Market Parameters**
  - Cost verification for import bids above $1,000/MWh
  - ISO market constraint relaxation prices

California ISO

Thank you for your participation!

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