Stakeholder Meeting (Q1 2020)

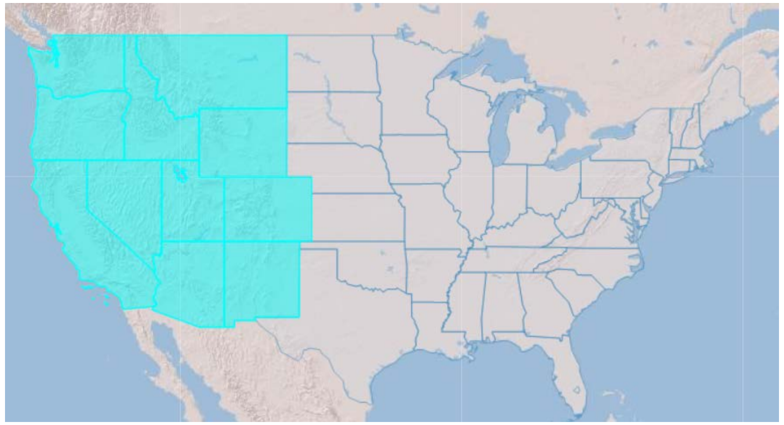
Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies (or the "State-Led Market Study")

Webinar
January 17, 2020
10am – 12 pm MST / 9am – 11am PST

State-Led Market Study made possible through DOE grant

- **The last several years have featured numerous discussions and initiatives related to the formation of coordinated wholesale trading markets in the West**
- **The Utah Governor's Office of Energy Development, in partnership with State Energy Offices of Idaho, Colorado, and Montana, applied for and received a grant from the US DOE to facilitate a 2-year state-led assessment of organized market options**
- **The project is called *Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies***
  - ❖ Or "State-Led Market Study"
- **The project provides Western States with a neutral forum, and neutral analysis, to independently and jointly evaluate the options and impacts associated with new or more centralized wholesale energy markets and potential footprints**
- **Today is the second quarterly stakeholder meeting for the project**
  - ❖ The next meeting will be held in conjunction with WIRAB/CREPC at the Albuquerque Hyatt on the afternoon of Friday, May 1st
  - ❖ A webinar will be held in Q3 2020
  - ❖ A subsequent in-person meeting will occur during the October CREPC/WIRAB meetings

State representatives from 11 Western States are participating in project



Agenda

1. **Introductions - *All***
2. **Project Overview and Progress to Date – *Energy Strategies***
   a) Project Overview & Timeline
   b) Status of Request for Input from Utilities and Market Operators
   c) Stakeholder Engagement Plan Reminder
3. **Review of Technical Work Plan Key Assumptions**
   a) General Assumptions
   b) Modeling of Market Constructs
      i. Trading Costs
      ii. Transmission Availability
   c) *Working* Approach for Benefit Analysis
4. **Public Comment**
5. **Next steps and future meetings – *Utah Office of Energy Development***

Project Overview and Progress to Date

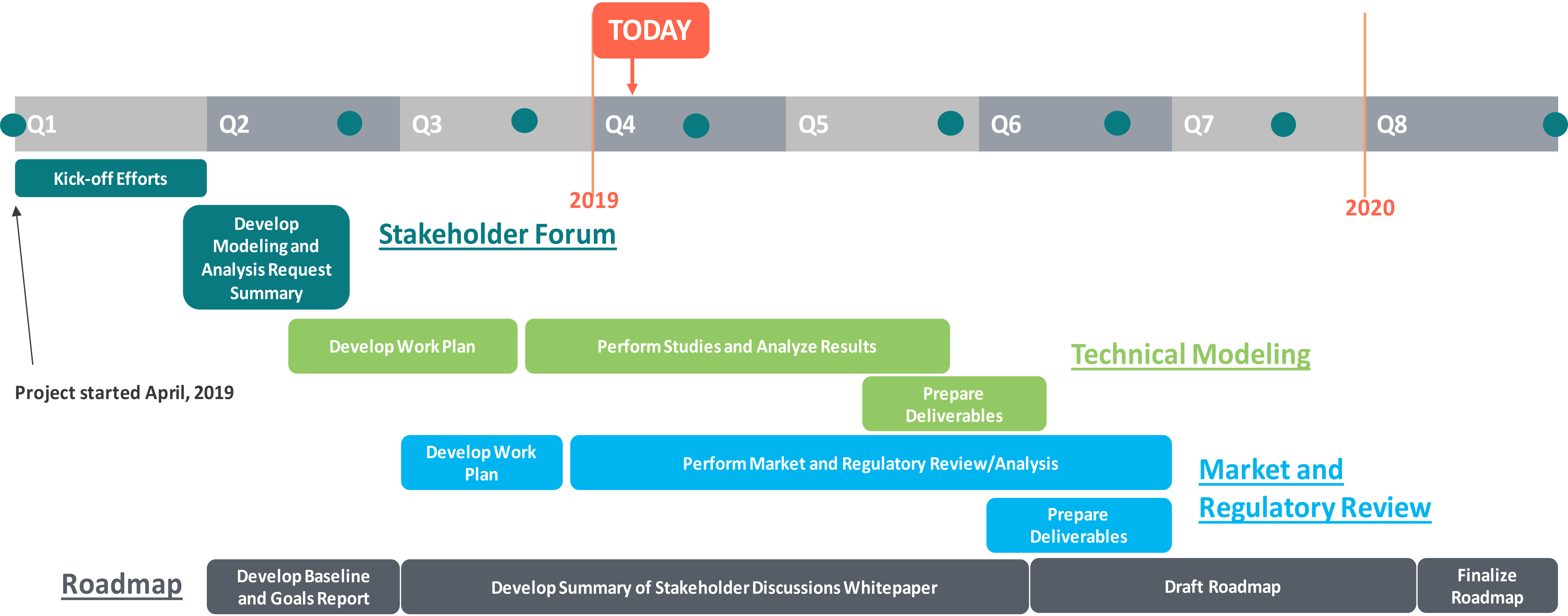
Energy Strategies

Overview of the State-Led Market Study

- **The project uses production cost modeling to evaluate relative operational benefits of alternative market constructs across various footprints**
- **It will also include a market and regulatory review, culminating in a "Market Factor Scorecard" for States to use in evaluating future market proposals in areas which may include energy market offerings, ancillary services, seams issues, transmission planning, transmission cost allocation, public policy considerations, and stakeholder processes**
- **The outcome of this project is a Roadmap that will lay out challenges and provide tools to States to use in evaluating various coordinated market options**

Summary of project timeline

- Two year timeline (eight quarters)
- Stakeholder Forum continues for project duration
- Key deliverables from each work area; body of work feeds into Roadmap



TODAY

Q1 Q2 Q3 Q4 Q5 Q6 Q7 Q8

2019

2020

Kick-off Efforts

Project started April, 2019

Develop Modeling and Analysis Request Summary

Stakeholder Forum

Develop Work Plan

Perform Studies and Analyze Results

Prepare Deliverables

Technical Modeling

Develop Work Plan

Perform Market and Regulatory Review/Analysis

Prepare Deliverables

Market and Regulatory Review

Roadmap

Develop Baseline and Goals Report

Develop Summary of Stakeholder Discussions Whitepaper

Draft Roadmap

Finalize Roadmap

Status of Request for Input from Utilities and Market Operators

- **The Lead Team was interested in seeking targeted feedback from utilities and market operators that have performed similar studies and may have insights, suggestions, or modeling assumptions/techniques to share with the Lead Team to inform this effort**
- **On November 21st, a letter was submitted to utilities and market operators seeking input**
    - ❖ The distribution was primarily gathered from WIRAB/CREPC's list, along with individuals that have joined the distribution list for this study effort
    - ❖ An effort was made to add utility representatives from major utilities that were missing from this list
- **Feedback was requested by December 18th**
    - ❖ EIM Entities requested additional time to respond (through February 1st, though a response may be submitted in mid-January)
    - ❖ CAISO is gathering information and will provide feedback by the end of January on items including:
        - ➢ Suggested CAISO net export levels
        - ➢ Historical EIM Transfer Limits
    - ❖ SPP did not have specific recommendations, but provided the Integrated Transmission Planning Manual and offered to provide information and resources going forward
    - ❖ BPA is reviewing information it can provide and plans to respond by the end of January

Key Areas of Requested Utility and Market Operator Feedback

- **References to most recent resource/transmission planning documents**
- **Input on which units should be modeled as “must-run” in the Status Quo and various market cases**
- **Treatment of transmission contracts and “remote” resources**
- **Suggested data/assumptions for transmission availability and cost**
  - ❖ Day-ahead market assumptions of particular interest
- **Relevant import/export export limits**
  - ❖ CAISO has offered to provide recommended CAISO net export limitations
- **Modeling of GHG requirements/prices**
- **Parameters of Resource Sufficiency testing**
  - ❖ If this test is performed, do utilities/ISOs/RTOs have suggestions on what would it look like? How might information on contracted resources be procured?
- **Suggested sources for natural gas pricing forecasts**

Review of Stakeholder Engagement Plan

- **Objective for today's meeting**
  - ❖Provide stakeholders with information on the Technical Work Plan and key assumptions
  - ❖Take verbal feedback on the study approach, assumptions and key details
  - ❖Invite the opportunity to provide written comments on the study approach presented today
    - ➢ Written comments can be submitted to kfraser@energystrat.com through January 31st
    - ➢ Note that we will review comments, but will not respond specifically to each comment received

- **To receive updates and future meeting announcements, navigate to this link to add your name to the project's stakeholder distribution list: http://bit.ly/2nBP6Gt**

- **When possible, we will distribute meeting materials in advance via this distribution list**

Review of Technical Work Plan

Energy Strategies

Modeling and Analysis Request Summary

- **The previously discussed Modeling and Analysis Request and Guidance Summary document:**
  - ❖Is a whitepaper that ***forms the basis of modeling and regulatory/market analysis*** conducted as part of the Technical Modeling and Market/Regulatory Review activities
  - ❖***Highlights key technical questions posed by the Lead Team that the project will seek to address***
  - ❖Used by Energy Strategies to develop Technical Work Plan
  - ❖Identifies the questions and areas of market development that are not well understood by state agencies and regulators, by identifying them as areas for exploration
- ***Request* document status**
  - ❖Approved by the Lead Team in mid-September 2019, presented to stakeholders in October 2019 (and comments were received and considered in Technical Work Plan development)
  - ❖The *Request* document was used as the basis for the Technical Work Plan detailing "how" the modeling work will be executed
  - ❖Over the coming months, the *Request* document (along with additional Lead Team input) will be used to draft the Market and Analysis Work Plan

Technical Work Plan Status

- **The Technical Work Plan contains more detailed information on how the Contractor will perform the modeling and analysis necessary to address the questions specified in the *Request***
- **Technical Work Plan status**
    - ❖Approved by the Lead Team in December 2019
    - ❖As with the *Request* document, the Technical Work Plan was approved subject to potential modification based on stakeholder feedback either via the formal outreach to utilities/market operators or following this stakeholder meeting
- **Technical Work Plan components**
    - ❖Modeling Tool, Scope & Limitations
    - ❖Core Study Assumptions
    - ❖Market Modeling Approach
    - ❖Benefit Analysis and Study Metrics
    - ❖Study Program
- **Today’s meeting will review several key pieces of the Technical Work Plan**

Study is focused on analyzing three “market constructs”:

EIM/Real-Time Market

- ✓ Centrally optimized real-time dispatch – *Day-ahead unit commitment not optimized across market participants*
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to real-time market
- ✓ Balancing Authority Area (BAA) boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

Day-Ahead Market (DAM)

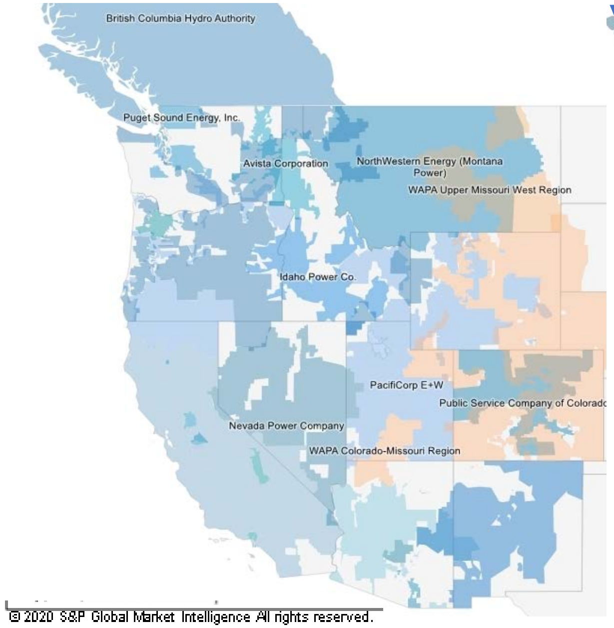
- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to market (other transactions must explicitly pay for transmission)
- ✓ BAA boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

RTO

- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ Joint transmission tariff for participants in a given footprint
- ✓ Transmission used up to reliability limit
- ✓ BAA boundaries and reliability obligations consolidated
- ✓ Joint transmission planning and cost allocation
- ✓ Transmission providers transfer of operational control of transmission

Review of Market Footprints

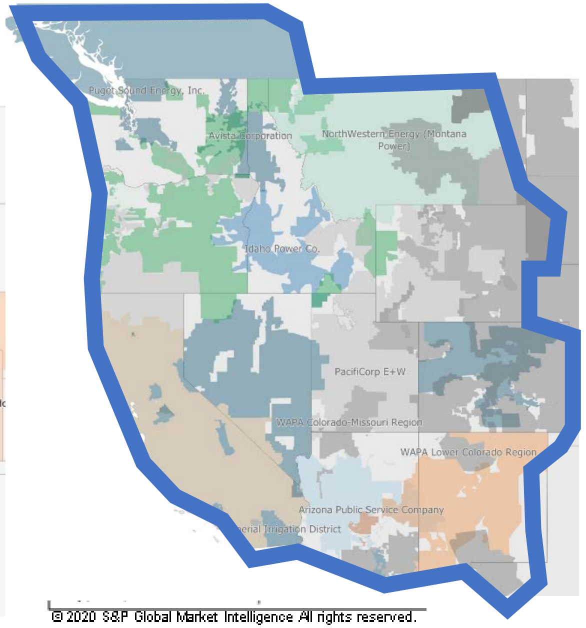
Status Quo



EIM entities that have announced intent to sign EIM Implementation Agreement (or equivalent)*

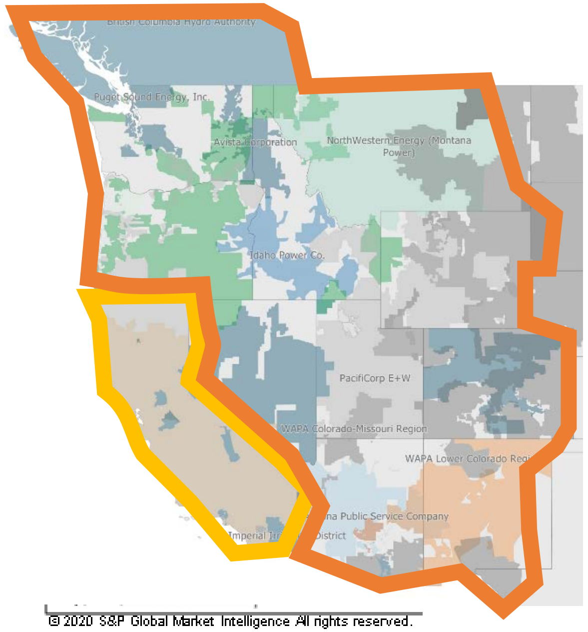
*Announcements that were made before the end of 2019 will be included in the Status Quo footprint.

One Market



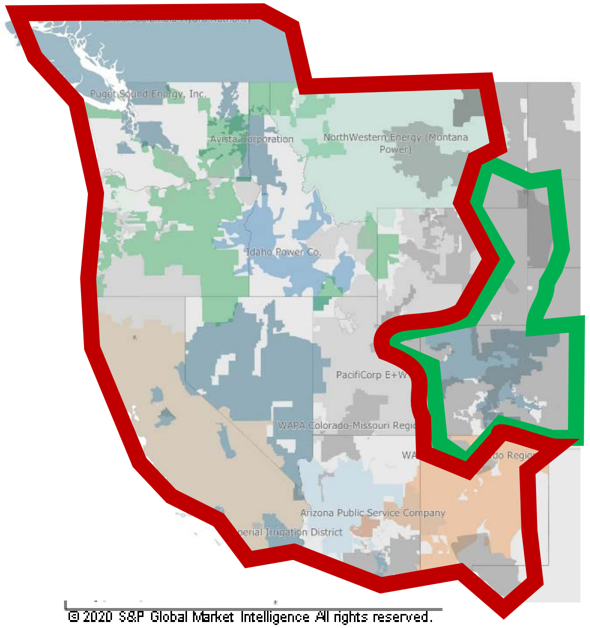
Studied in 2020 and 2030 timeframe

Two Market A



Only studied in 2030 timeframe

Two Market B



Studied in 2020 and 2030 timeframe

Market Footprint Detail by Balancing Authority

Status-Quo (BAs)	One Market	Two Market A	Two Market B
CAISO	All WECC Balancing Areas (excluding AESO)	Footprint A1	Footprint B1
PacifiCorp		CAISO	PSCo
NV Energy		BANC	WACM
Puget Sound Energy		TID	WAUW
Arizona Public Service		LADWP	Footprint B2
Portland General Electric		IID	All remaining WECC Balancing Areas (excluding AESO)
Idaho Power		Footprint A2	
Powerex		All remaining WECC Balancing Areas (excluding AESO)	
SMUD (BANC Phase 1)			
Seattle City and Light			
Salt River Project			
LADWP*			
PNM*			
BANC* (BANC Phase 2)			
WAPA-Sierra Nevada*			
Northwestern Energy*			
TID*			
Avista*			
Tucson Electric Power*			
Tacoma Power*			
BPA*			
PSCO*			
Separate Market for WACM & WAUW*			

***These entities will join (or create) a Real-Time Market in 2021 or later, and thus will be included in the Status Quo for 2030, but not for 2020**

Study Program Detail

Study Year	Type	Market Scenario	Market Footprints			
			Status Quo	One Market	Two Market A (No CA Expansion)	Two Market B (Mountain West & CA Expansion)
2020	Core Studies	Real-time only	◯✓	✓		✓
		Day-ahead				
		RTO		✓		
2030		Real-time only	◯✓			
		Day-ahead	✓	✓	✓	
		RTO		✓	✓	✓
	Sensitivities	Real-time only (EIM)	A			
		Day-ahead				
		RTO		A & B	B	A & B

Key

◯ Benchmark

Sensitivity Key

A - Major Transmission Build
B - Carbon Price
C - TBD

Modeling Framework and Tool

- **The project is using production cost modeling to estimate relative operational benefits associated with organized market configurations**
- **Tool: ABB's GridView™, a production simulation software that simulates grid operations, transmission, and energy markets**
  - Model performs a least-cost security constrained unit commitment and dispatch
  - Nodal representation of the transmission system, including substations, transformers, transmission lines, and transmission interfaces
  - Primary purpose: Generate results estimating the "production cost" or variable power costs required to serve load for a given study year
  - Key "knobs" for market studies: transmission wheeling rates between balancing areas, operating reserve requirements, and market footprints
- **Summary of tool's logic and optimization approach available in Work Plan document**
- **Tool does not perfectly emulate market operations; some examples of limitations include:**
  - Granularity of market intervals
  - Perfect foresight
  - Generic vs. proprietary assumptions
  - Legacy transmission agreements
  - ….among others
- **Despite limitations, the tool reasonably reflects market fundamentals, policies, and technical/operational constraints of the system such that it can produce valuable insight related to energy market development**

Technical Work Plan: General Assumptions

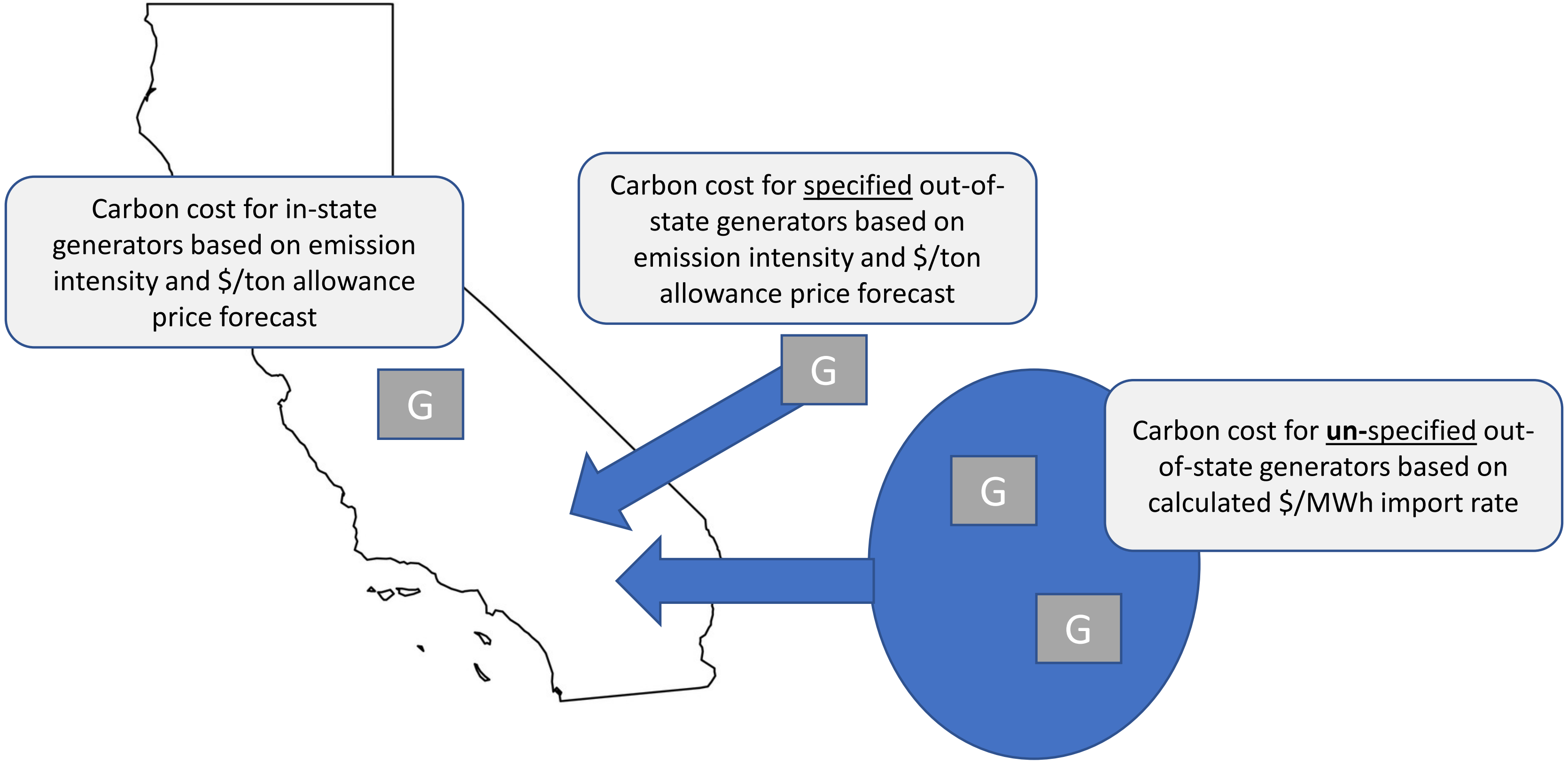
Energy Strategies

General Assumptions: Core Study Assumptions

Assumption Area	Source(s)
Load	✓ WECC: Loads and Resources Data or Anchor Data Set (ADS) ✓ California Energy Commission: 2019 IEPR ✓ Northwest Power and Conservation Council (NWPCC): Data vintage TBD
Generation Supply	✓ 2020 – Based on operating generation as of 12/31/2019 ✓ 2030 – Build off of 2020, but adjust for the following (making use of IRPs, the 2028 WECC ADS, etc.): *Announced/anticipated retirements *New renewable generation required for public policy goals *Forecasted levels of energy storage *Forecasted deployment of other generating resources
Distributed Generation	✓ NREL Regional Energy Deployment System (ReEDS) ✓ CEC IEPR “Mid-Mid” Forecast
Fuel	✓ Gas: CEC 2019 IEPR Forecast (Mid values from NAMGAS Model from October 7, 2019 or more recent, if possible) ✓ Coal: 2018 EIA Annual Energy Outlook
GHG Policies	✓ 2019 IEPR Preliminary Nominal Carbon Price Projections ✓ West-wide carbon price for sensitivity TBD (but based on review of utility IRPs)

General Assumptions: Carbon Modeling

- **California is the only Western state with an enacted carbon policy that impacts day-to-day operations**
  - ❖ Modeling approach is generally consistent with CPUC IRP and CAISO methods



Carbon cost for in-state generators based on emission intensity and $/ton allowance price forecast

Carbon cost for specified out-of-state generators based on emission intensity and $/ton allowance price forecast

Carbon cost for **un-**specified out-of-state generators based on calculated $/MWh import rate

General Assumptions: Transmission Additions

- **2020 studies will assume today's transmission grid based on WECC powerflow cases**
- **2030 studies will require the modeling of incremental transmission upgrades**
- **The study will include regionally significant (e.g., >200 kV) incremental transmission projects that meet one of the following criteria:**
    - ❖ Are currently under physical construction; or
    - ❖ Have been granted a Certificate of Public Convenience and Necessity (CPCN), a Certificate of Environmental Compatibility (COEC), or similar, by the transmission provider's relevant regulatory body(ies); or
    - ❖ Have been approved by an independent system operator board of directors; or
    - ❖ Are planned to be in-service *prior* to 2024 and are included in an approved or acknowledged action plan or near-term plan (as applicable) associated with a utility integrated resource plan
- **While rigid project "inclusion" criteria is ideal because it can be exactly followed to develop forward-looking transmission assumptions, after compiling a list of high-voltage projects and evaluating them in accordance with this method, there may be certain projects that require further consideration**
    - ❖ In these instances, the Lead Team will be consulted to determine if an exception should be made and the exception will be documented

General Assumptions: Ancillary Services & Must-Run Generation

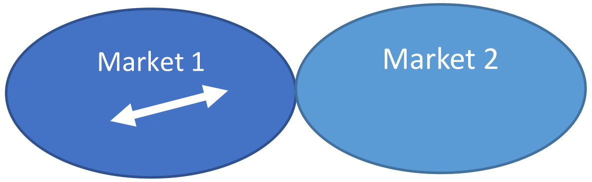
Ancillary Service	Status-Quo	Real-Time Market	Day-Ahead Market	RTO
Spinning Reserves	Carried at Reserve Sharing Group level, with sub-group constraints that are generally consistent with WECC ADS methodology • 25% of obligation must be carried locally for BAs in Northwest • 90% locally in the Southwest			Constraint applied across market footprint
Non-Spinning Reserves	Not modeled (assume there is sufficient quick-start generation to provide this service)			
Regulation & Load Following Will develop hourly shapes that estimate total regulation and load following reserves for a footprint with load and renewable generation variability (based on NREL & ABB methods) for both 2020 and 2030	Carried at the Balancing Authority level, calculated hourly for 2020 and 2030 resource portfolios and loads			Carried by entire market footprint, calculated hourly for 2020 and 2030 resources and loads
Frequency Response Total requirement defined by NERC's 2018 Frequency Response Analysis for the Western Interconnection	Requirement divided to a CAISO requirement, and remaining requirement met be the rest of the West			Total met by the market footprint
Must-Run Generation Must-run status (if received) will be provided by utilities and market-operators	Must-run status maintained			Must-run status may be eliminated, based on utility and market operator feedback

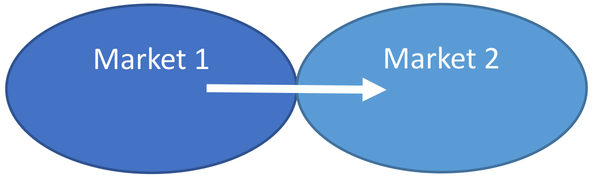
Technical Work Plan: Modeling of Market Construcst

Energy Strategies

Market Modeling: Trading Costs*

Market structure	Intra-market exchange		Export from market footprint	
	Real-time	Day-ahead	Real-time	Day-ahead
Real-time Market	No hurdle rate	Tariff rate	Tariff rate	
Day-ahead Market	Estimated market rate		Tariff rate	
RTO	No hurdle rate		Combined tariff or zonal rate	

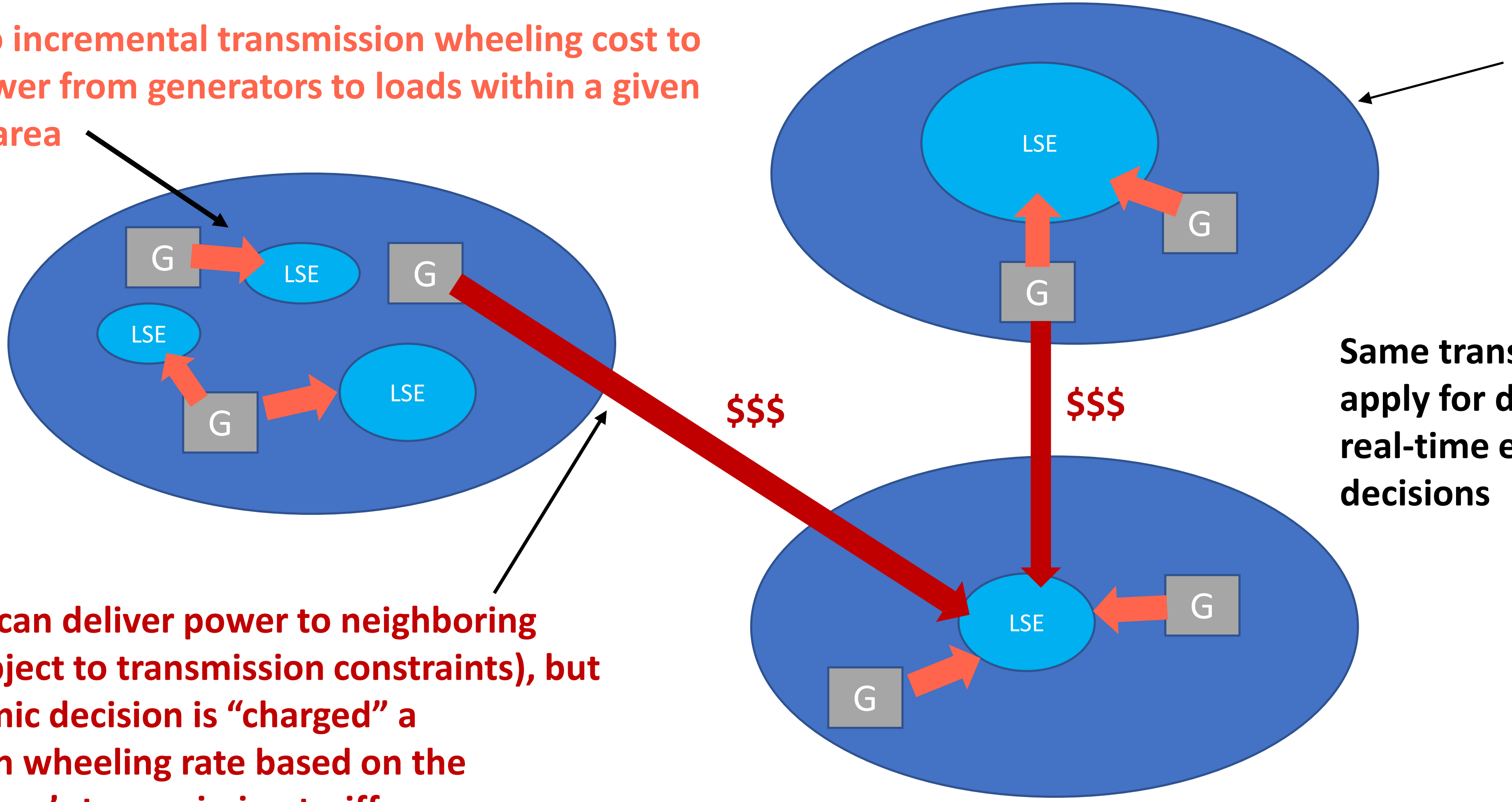




*Note that imputed GHG emissions can also be a trading cost for imports into California and would be additive to these hurdle rate costs. Those costs & modeling conventions were illustrated earlier. Assumed trading friction adders to approximate inefficiency associated with bilateral trading may also apply.

Bilateral Transmission Costs

There is no incremental transmission wheeling cost to deliver power from generators to loads within a given balancing area

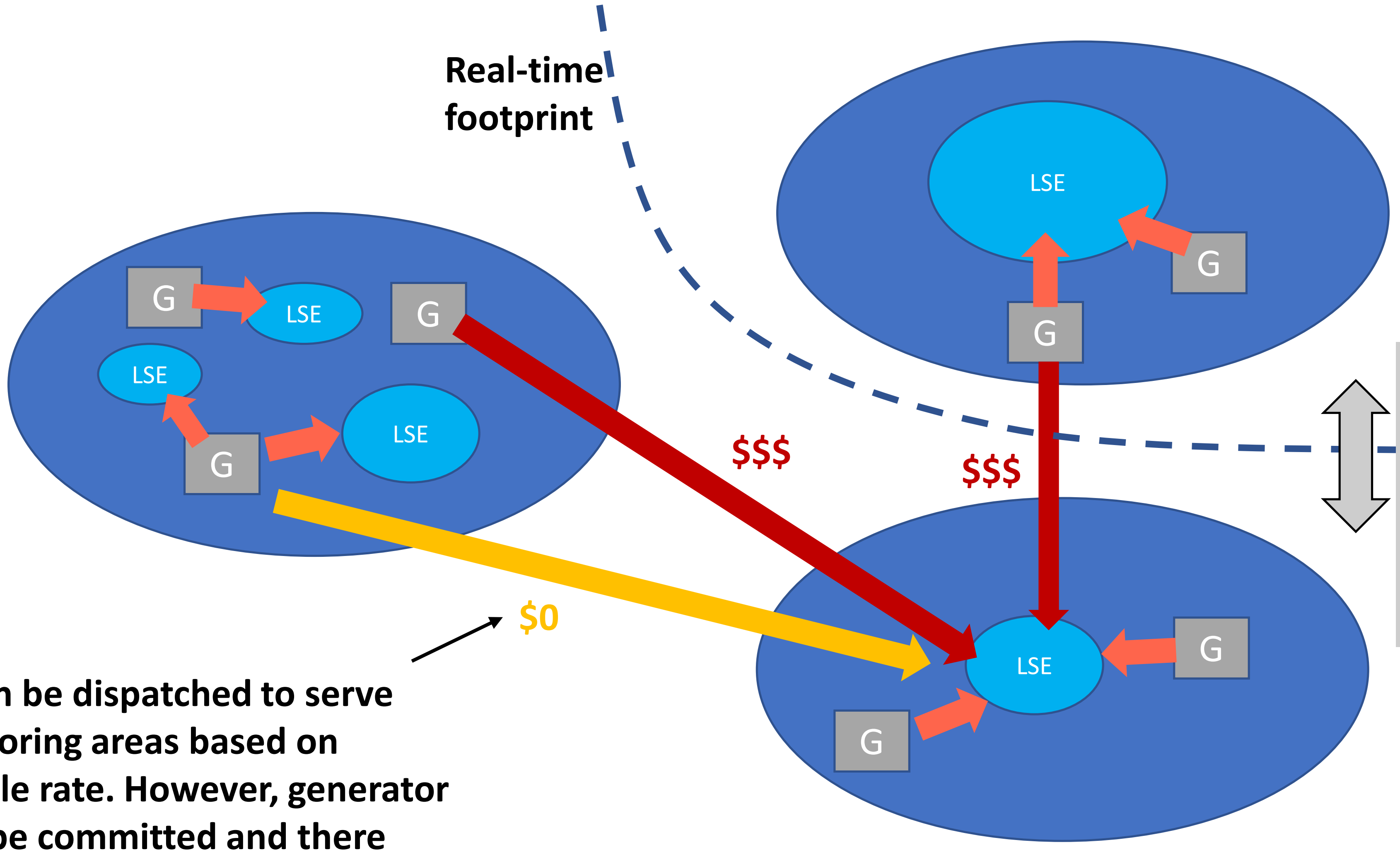


Balancing areas

Same transmission costs apply for day-ahead and real-time economic decisions

Generators can deliver power to neighboring regions (subject to transmission constraints), but that economic decision is “charged” a transmission wheeling rate based on the “sending” area’s transmission tariff

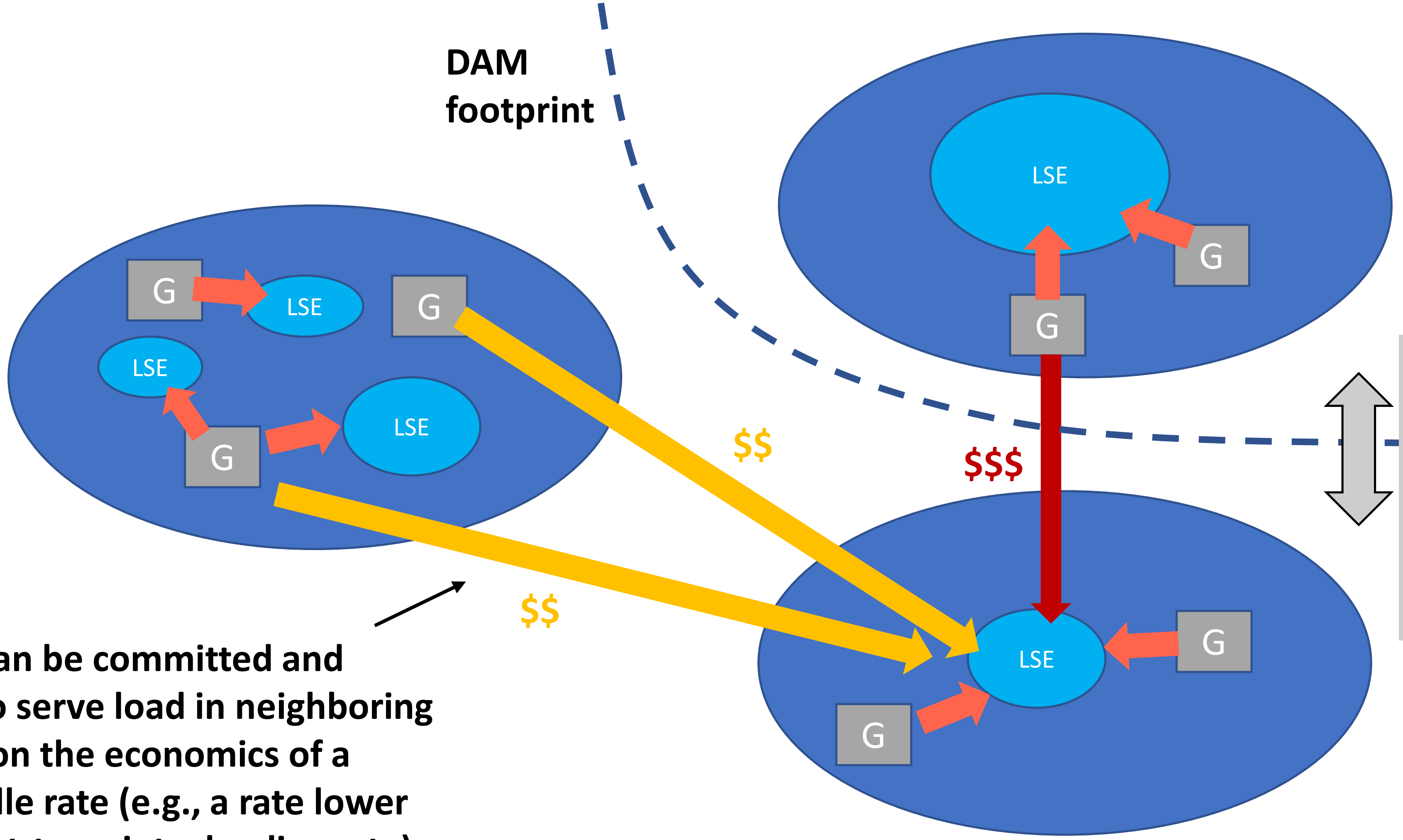
Real-Time Market Transactions: Applicable Only to Generator Dispatch



Dispatch and commitment between non-market areas subject to tariff-based hurdle rate

Generators can be dispatched to serve load in neighboring areas based on $0/MWh hurdle rate. However, generator must already be committed and there must be sufficient real-time market transfer capability.

DAM Transactions: Applicable to Dispatch and Commitment



Dispatch and commitment between non-market areas subject to tariff-based hurdle rate

Generators can be committed and dispatched to serve load in neighboring areas based on the economics of a reduced hurdle rate (e.g., a rate lower than the point-to-point wheeling rate). These transfers are subject to transmission limitations.

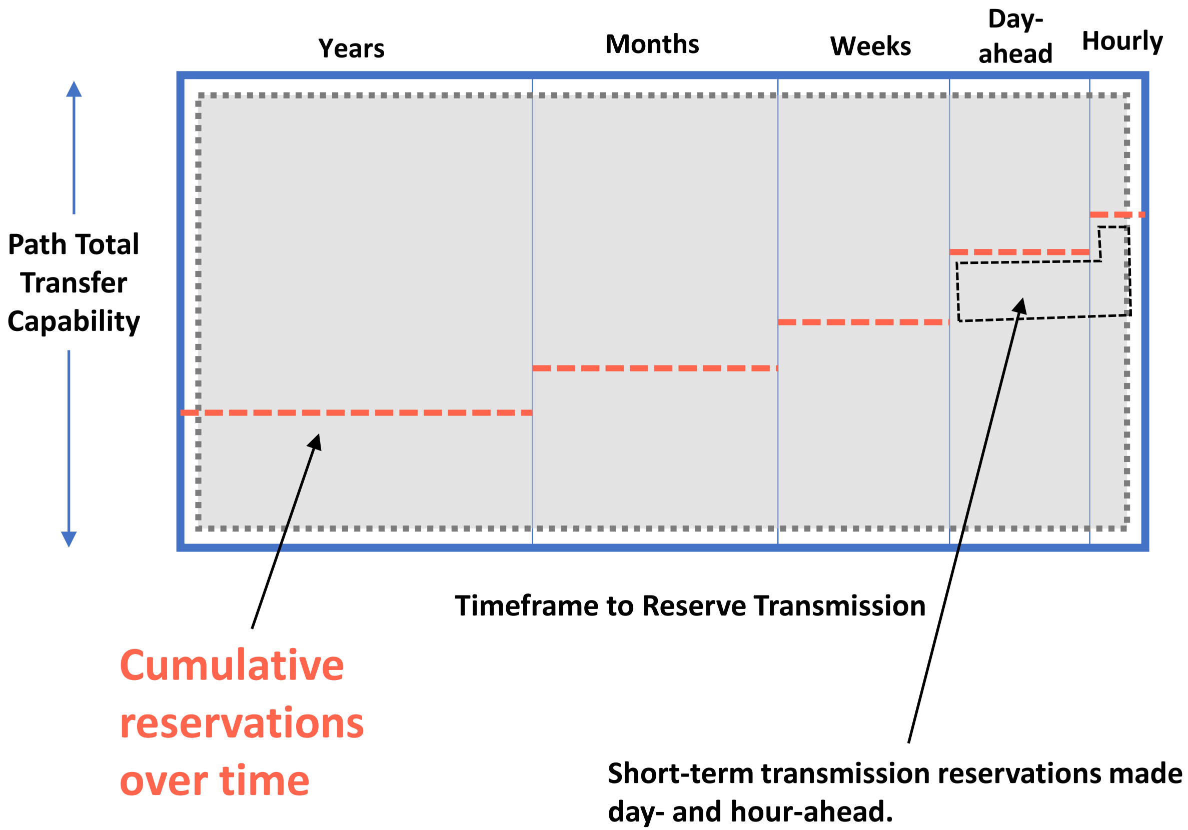
A note on DAM transmission rates:

We will seek to reasonably address transmission revenue challenge by testing a price (e.g., $3/MWh), then adjusting it based on actual flows and analysis of historic transmission revenues

$$ Lost revenues ÷ Available for DAM Transmission used (MWh)

= Estimated market rate for DAM transmission

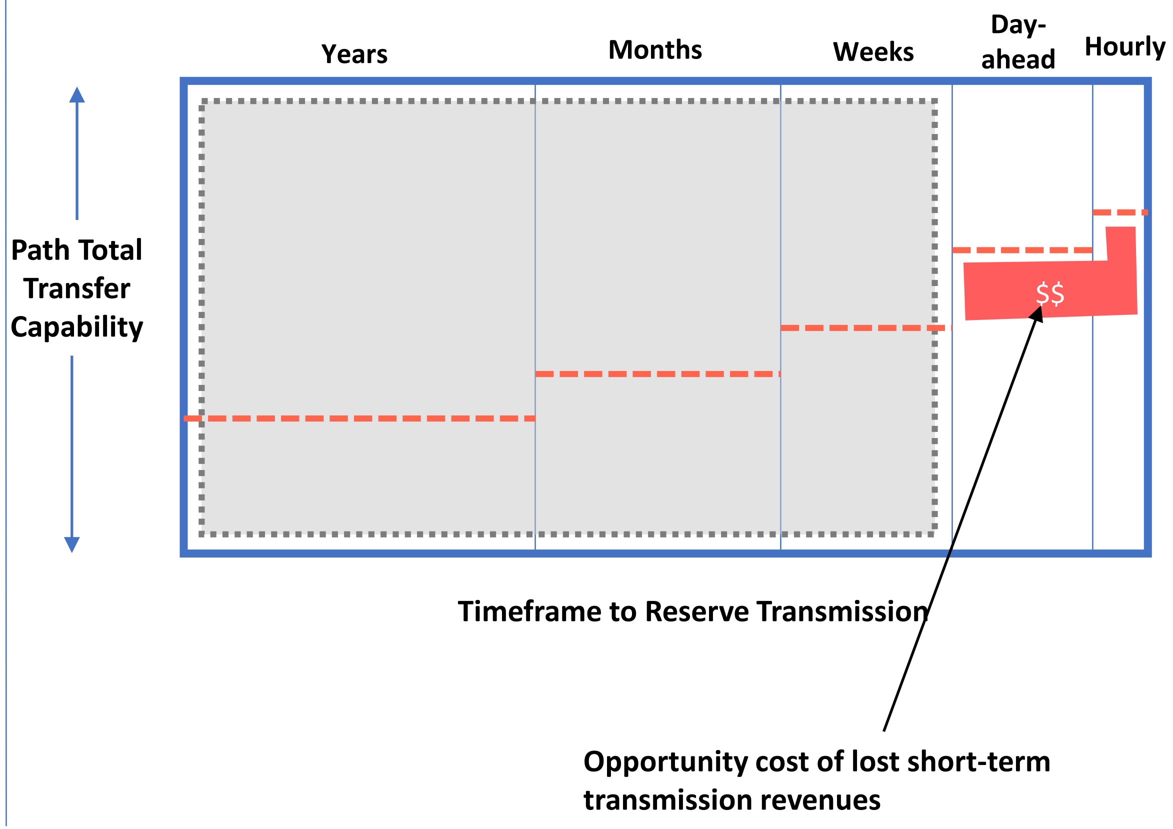
Today's system



Cumulative reservations over time

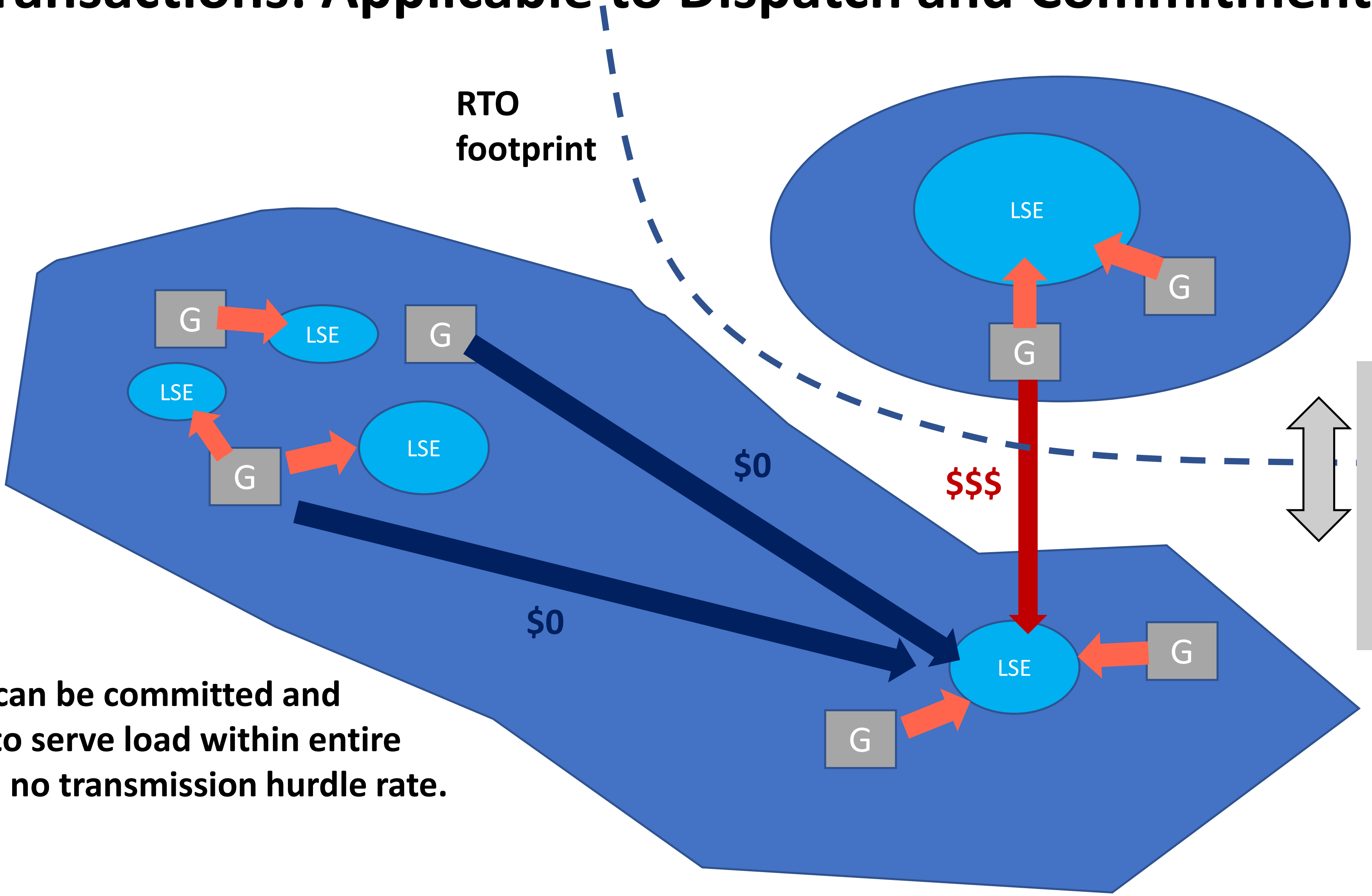
Short-term transmission reservations made day- and hour-ahead.

DAM (generic assumptions)



Opportunity cost of lost short-term transmission revenues

RTO Transactions: Applicable to Dispatch and Commitment



Dispatch and commitment between non-market areas subject to tariff-based hurdle rate

Generators can be committed and dispatched to serve load within entire market with no transmission hurdle rate.

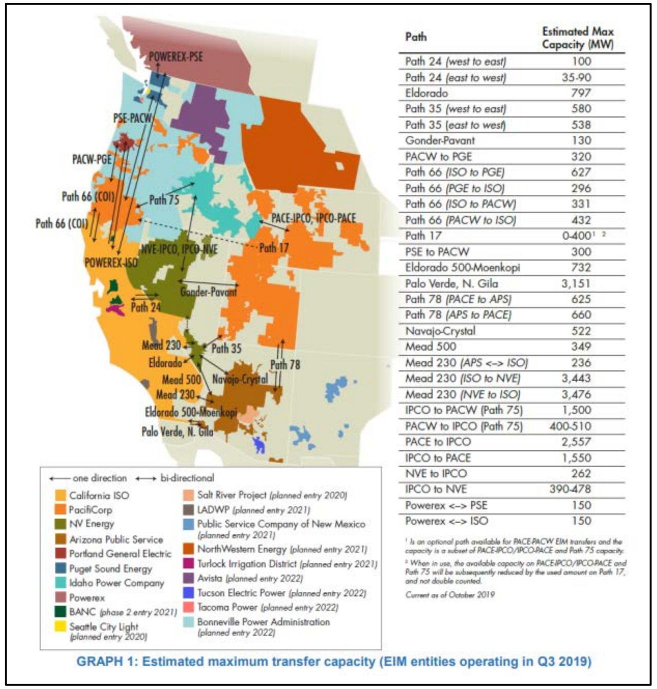
Market Modeling: Transmission Availability

- **In addition to varying transmission costs between market configurations, we also must reasonably adjust the amount of transmission that is available within each market**
- **This transmission capacity assumption is critically important**
  - ❖Consider that the Western EIM has access to only certain amounts of transmission in order to optimize energy dispatch in real-time; if the study were to assume that 100% of transmission was available for the real-time market, we run the risk of over-stating the benefits of real-time energy markets, and understating the benefits of incremental market constructs
- **Do not confuse this with market design: these approaches are going to be simplified relative to methods used to design a fully functioning market**

How Much Transmission Should be Available for Real-Time Markets?

This applies only to real-time interval.

EIM maximum transfer capacity



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400[1] [2]
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <-> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <-> PSE	150
Powerex <-> ISO	150

[1] Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.

[2] When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.

Current as of October 2019

GRAPH 1: Estimated maximum transfer capacity (EIM entities operating in Q3 2019)

Source: Western EIM Benefits Report – 3rd Quarter 2019

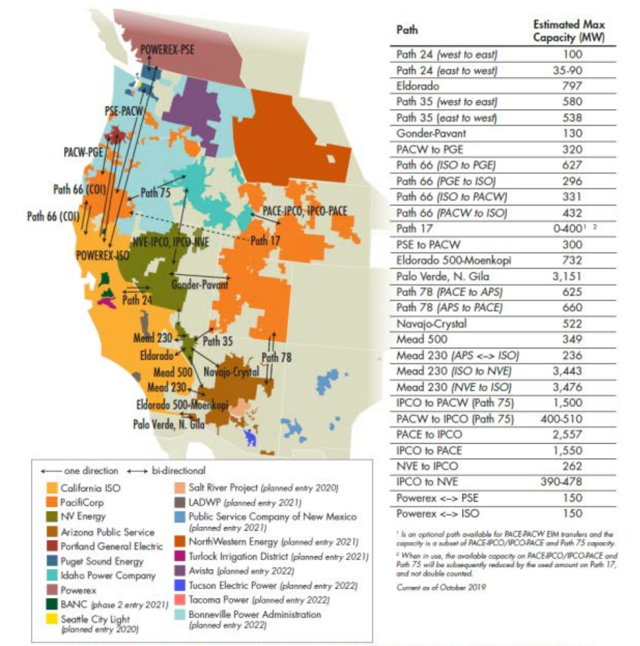
- Western EIM real-time transfer capability based on a historic transfer limits (likely an average or percentile of ETSR limits during 2019, raw data may be provided by CAISO) and forecasts of participation for new entrants (from EIM benefits studies, where available)
- SPP WEIS real-time transfer capability limited to maximum transfer capability between WACM and WAUW balancing areas
- Real-time transmission capability not used in market available for bilateral transactions
- All day-ahead transmission is available for bilateral transactions
- CAISO exports in real-time limited to *TBD*
- CAISO exports in day-ahead limited to *TBD*
- Transmission capability of the system limited by WECC Path Ratings

How Much Transmission Should be Available for DAM?

This applies to both real-time and day-ahead market intervals.

Assume the greater of….

EIM maximum transfer capacity



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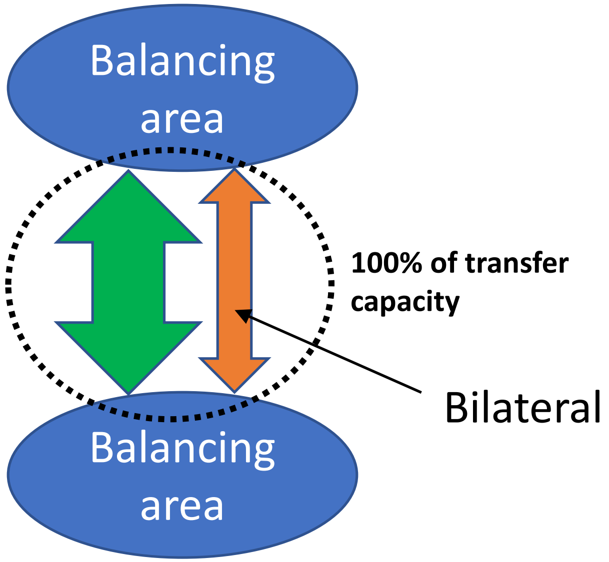
Current as of October 2019

GRAPH 1: Estimated maximum transfer capacity (EIM entities operating in Q3 2019)

Source: Western EIM Benefits Report – 3rd Quarter 2019

vs.

70% of total transfer capacity

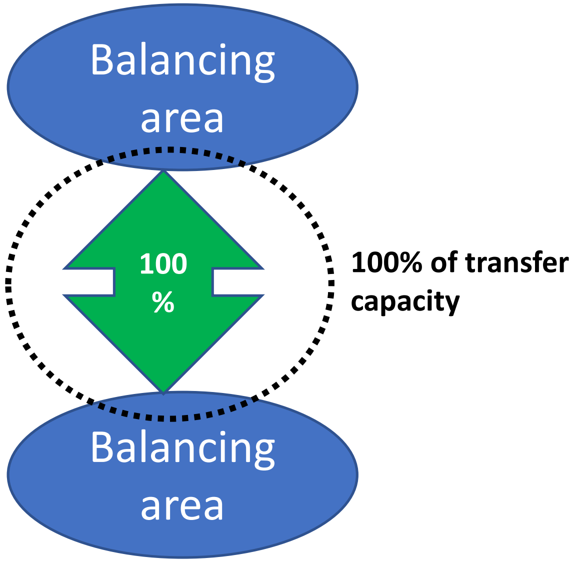


- Day-ahead transfer capability available in market is the *greater* of (a) 70% of total transfer capability between balancing areas *or* (b) historic/anticipated real-time transfer capability (defined above)
- All day-ahead and real-time transmission capacity not used in market is available for bilateral transactions
- CAISO exports in real-time limited to TBD
- CAISO exports in day-ahead limited to TBD
- Transmission capability of the system limited by WECC Path Ratings

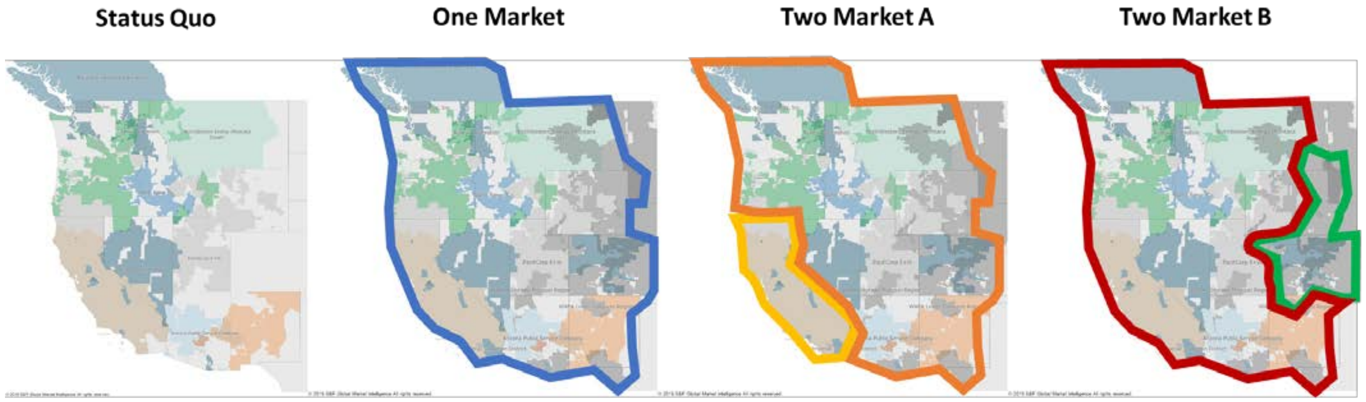
How Much Transmission Should be Available for an RTO?

- **100% of transmission capability available**

100% of total transfer capacity



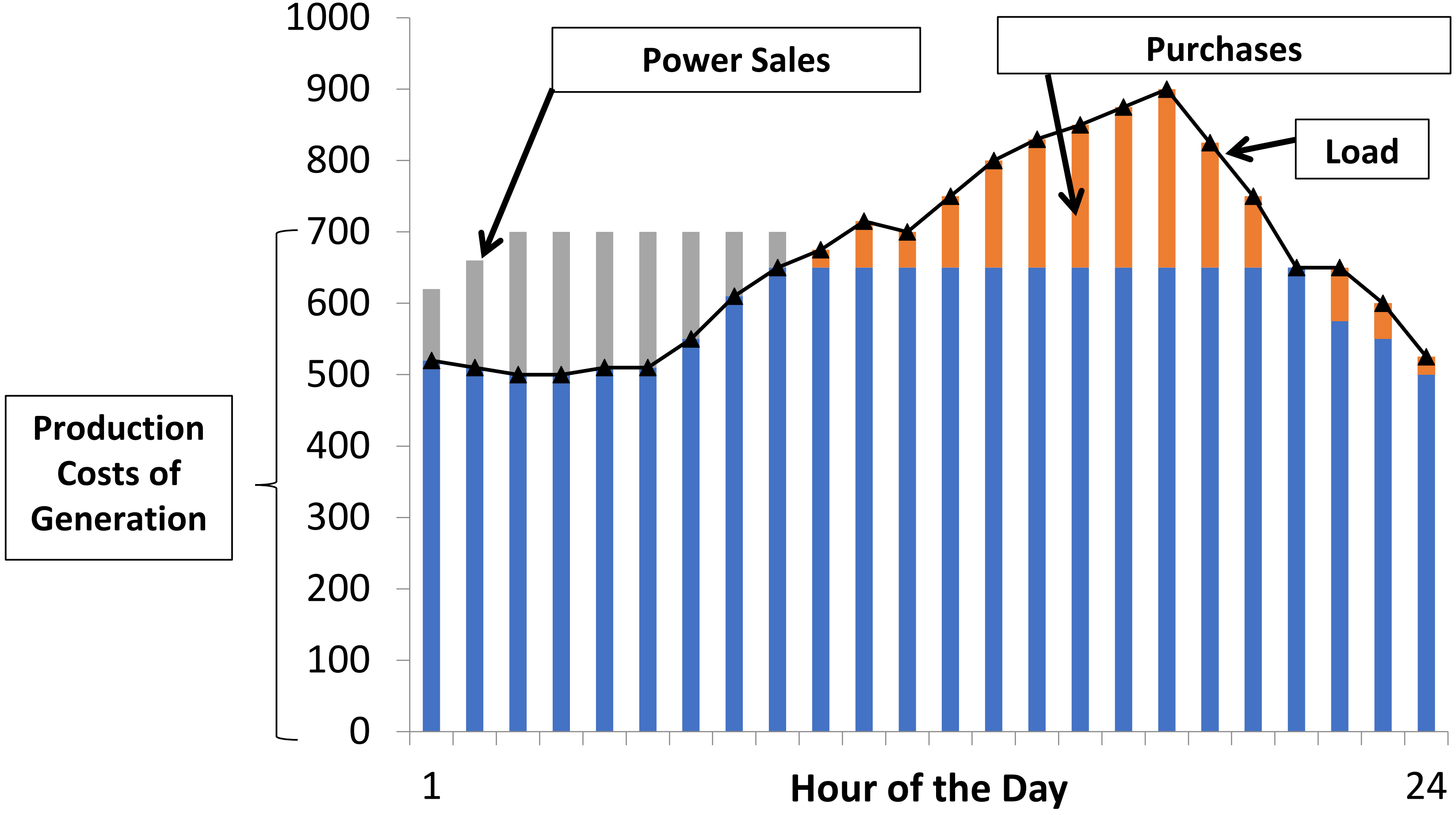
- **All day-ahead and real-time transmission capacity is available for market**
- **No bilateral transmission costs within market footprint (only exports)**
- **CAISO exports in real-time and day-ahead are limited to TBD in Two Market A RTO scenario**
- **CAISO exports in real-time and day-ahead are not limited in One Market and Two Market B RTO scenarios**
- **No intra-market interfaces**
  - ❖ WECC Paths are removed *inside* given market footprint and transmission is used up to maximum reliability limited based on N-1 security constrained economic dispatch)



Technical Work Plan: Working Approach to Benefits Analysis

Energy Strategies

Summary of Adjusted Production Cost (APC) Calculation: Calculated on BA Basis



Production Costs of Generation

+

Cost of Purchases

−

Power Sales Revenues

=

Adjusted Production Cost

Overview of Benefits Approach: Relative Benefits Between Market Configurations (at State-Level)

State-level Calculation Comparing Two Studies

Cost/Benefit Category	States		
	A	B	…
Adjusted Production Cost Savings			
Capacity Benefit			
Start-up/admin costs (estimated)			
Benefit			

$$\text{State A production cost savings benefit} = \text{Production cost savings for BA with load in State A} \times \left(\frac{\text{Load in State A}}{\text{Total BA Load}}\right)$$

Applies only to RTO Configuration

Capacity requirement of many footprints: X

Capacity requirement of consolidated footprint: Y

Capacity benefit (MW): X-Y

Capacity benefit ($): (X-Y)*(Capacity Value)

Study will leverage prior and existing market proposals, and conversations with market providers, to estimate high-level (per MWh or MW) costs for market start-up and administration

Most of the questions deal with the “relative benefits” of a market construct and footprint compared to another

Comments from Stakeholders

Next Steps and Future Meetings

Request for Written Stakeholder Comments & Next Meetings

- **We invite the opportunity for stakeholders to provide written comments on the key aspects of the Technical Work Plan presented today**
- **Process for submitting comments:**
  - ❖Written comments can be submitted to kfraser@energystrat.com through January 31st
  - ❖Note that we will review comments, but will not respond specifically to each comment received
- **Upcoming meetings**
  - ❖The next Stakeholder Meeting will take place in Albuquerque on the afternoon of Friday, May 1st (following the CREPC/WIRAB meetings)
    - ➢ This meeting will also be available via webinar
  - ❖In July/August 2020, the Q3 2020 stakeholder meeting will take place via webinar
    - ➢ Date will be announced during the May 1st meeting
  - ❖In October, the Q4 2020 stakeholder meeting will take place in conjunction with CREPC/WIRAB meeting in San Diego and there will also be a call-in/webinar option