MARKETS+

Development Update

August 17, 2022

Southwest Power Pool
WESTERN ENERGY SERVICES

WELCOME AND OVERVIEW

BRUCE REW, SPP

TODAY'S AGENDA – REVIEW PORTLAND MEETING

Welcome and Overview
Congestion Rents
Base Schedules
Settlements
Functional Roles and Responsibilities
Unit Commitment and Resource Sufficiency
Market Transmission Service Revenue Recovery
Governance
GHG Tracking and Accounting
Service Offering and Next Steps/Schedule

CONGESTION RENTS

MICHA BAILEY, SPP

CONGESTION RENTS

DA Congestion Rents
- **Sum up all Generators**
- **Sum up all Loads**
- **Net out losses**

Allocation of DA Congestion Rents

GENERAL CONSENSUS ON THE ALLOCATION OF CONGESTION RENT

- Allocation, no market functions
  - No Simultaneous Feasibility Testing (SFT) in allocation
  - SFT occurs in Transmission Service process
- Allocation cap
  - Network = 103% * (Average last three years of peak load)
  - PTP = MWs on PTP reservation
- No uplift calculations
  - What is collected, allocate back
- All positions will be options not obligations
  - Counter flow positions will have a value of $0

ADDITIONAL CONSIDERATIONS

- All Day-Ahead Congestion Rents will be allocated back out to agreed upon TSRs
- Allocation equation:
  - [Sum of MP's TSR MWs * (Source MCC minus Sink MCC)]/ Sum of Total [TSR MWs * (Source MCC minus Sink MCC)]
- Timing of TSR submittal
  - Monthly vs Daily

ASSUMPTIONS

Settled the DAMKT Congestion Rent collected for chosen intervals in two separate scenarios

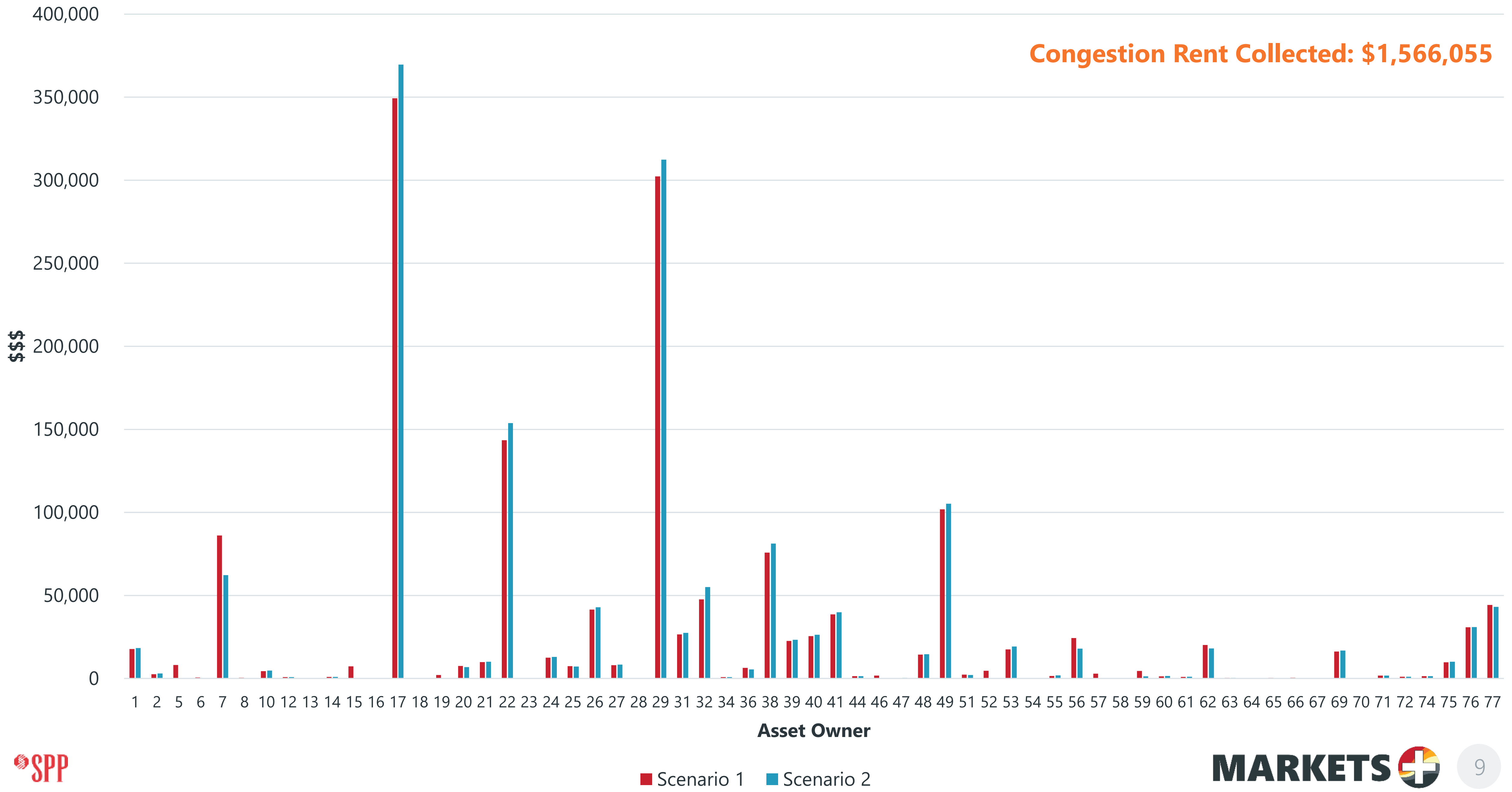
Scenario 1: All TSRs

- Allocation based on all TSRs for each Asset Owner
- NITS service pro-rated to nomination cap based on HPL

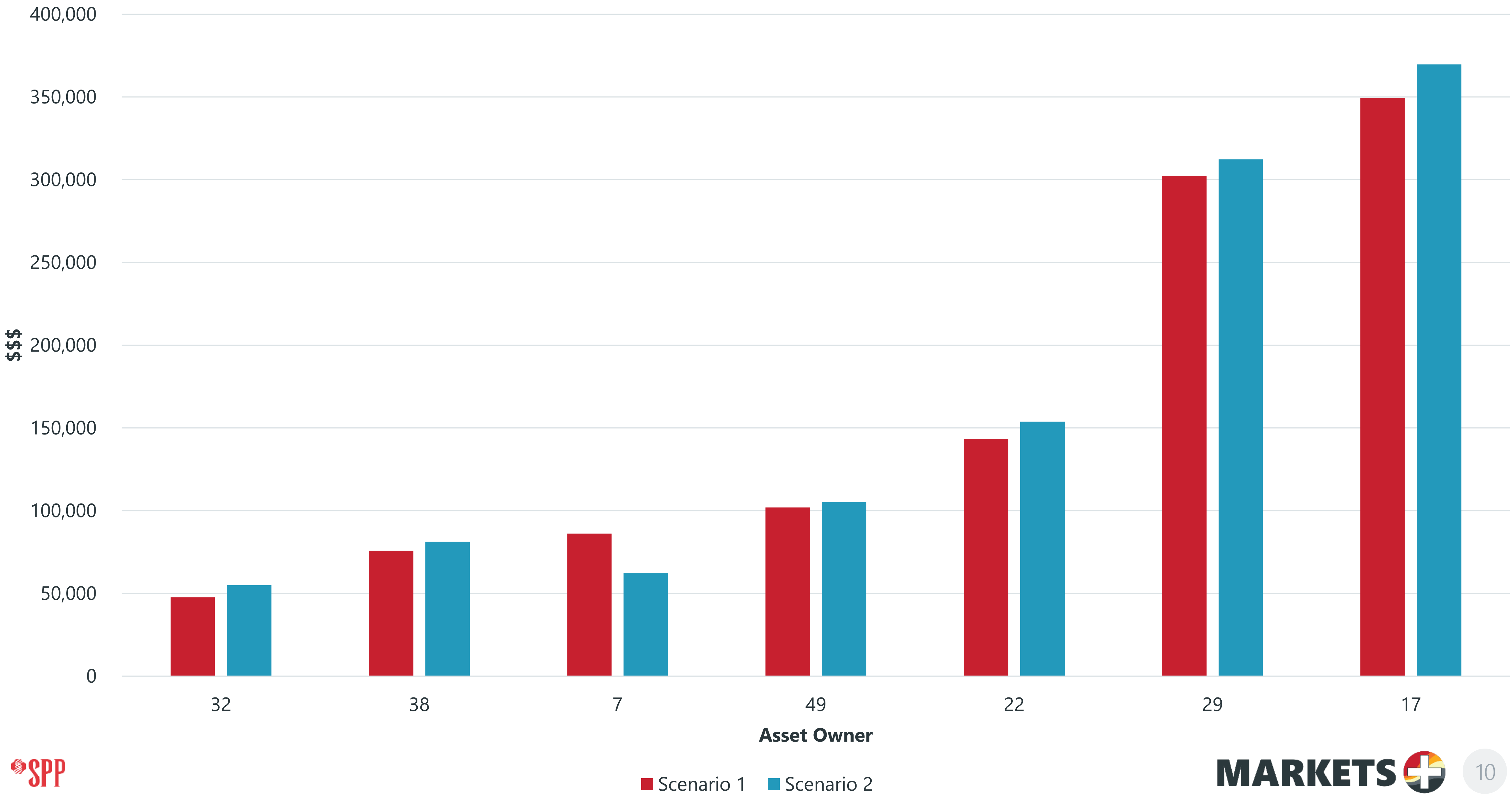
Scenario 2: Pick your Source/Sink Pair

- Allocation based on TSRs for each Asset Owner corresponding DAMKT resource bids for that hour
- NITS service pro-rated to nomination cap based on HPL

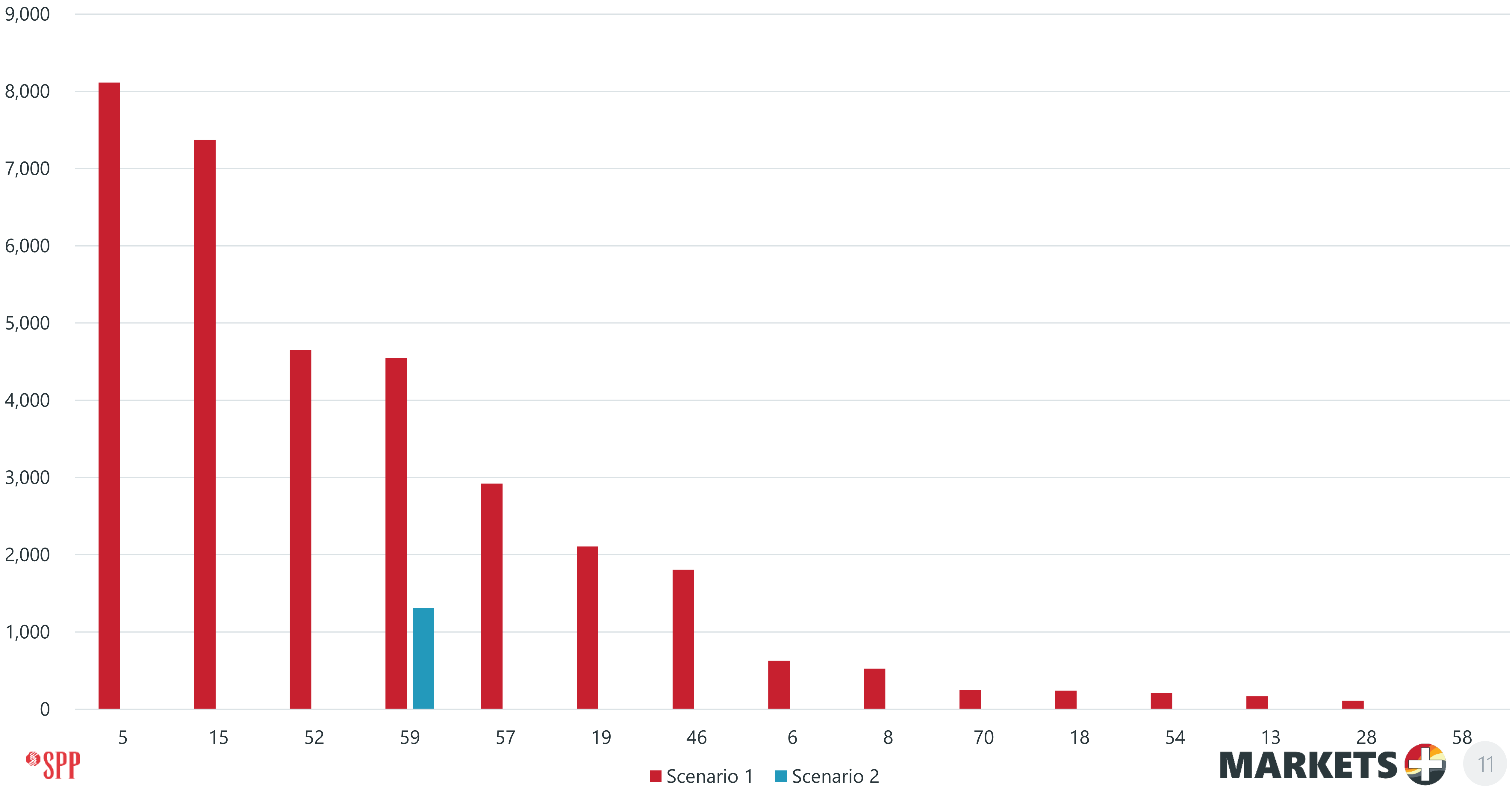
Congestion Rent Allocation Interval 1



Congestion Rent Allocation Interval 1: A Closer Look



Congestion Rent Allocation Interval 1: A Closer Look



QUESTIONS/DISCUSSION

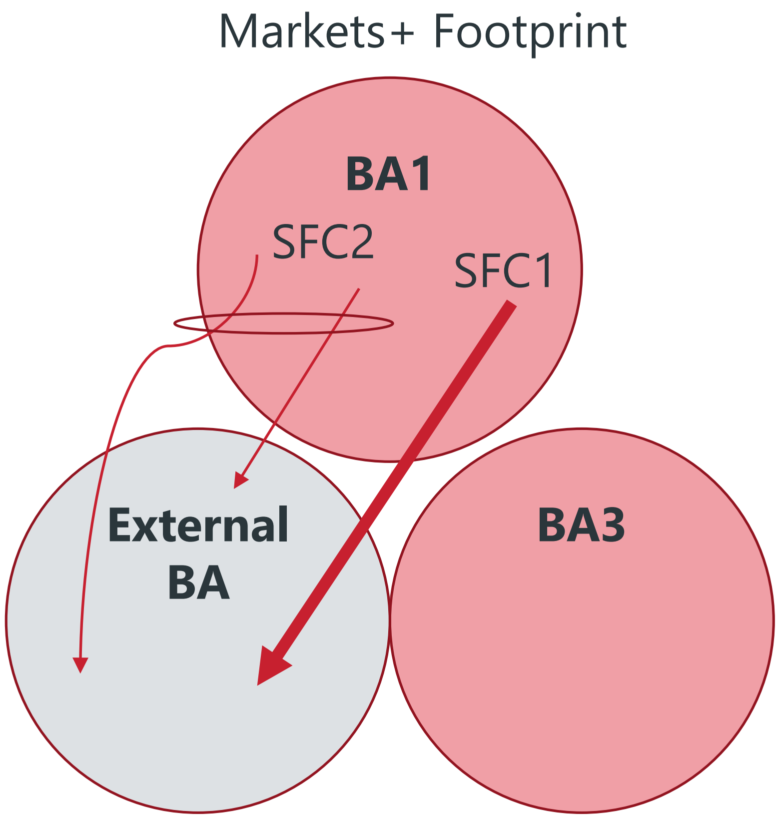
BASE SCHEDULES

DANIEL BAKER, SPP

MARKETS+ TRANSMISSION AVAILABILITY

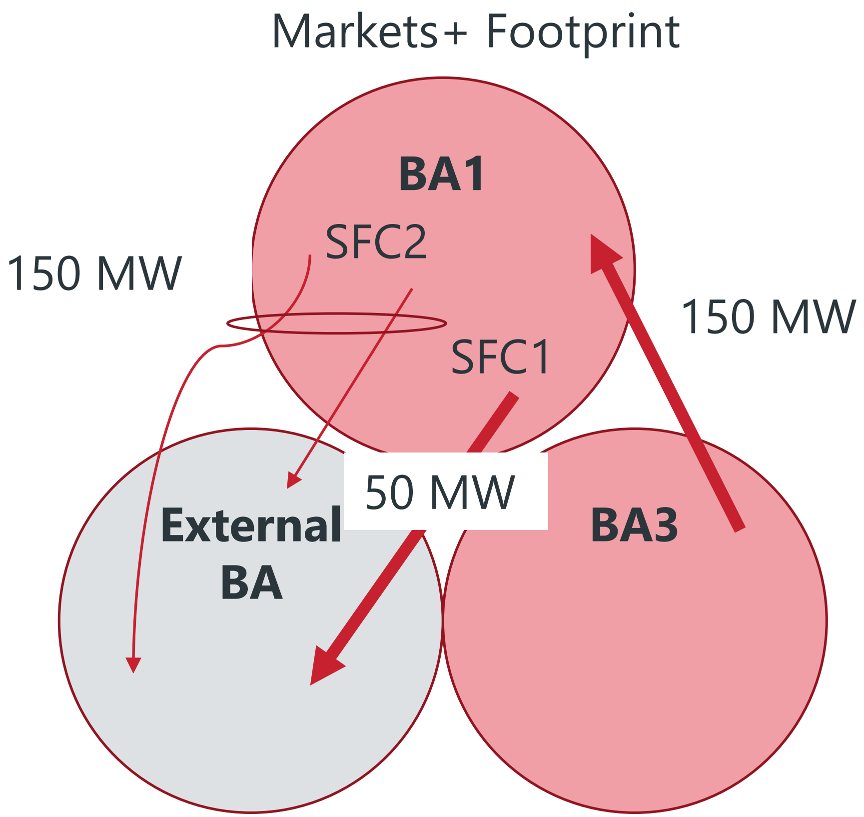
- All-in transmission concept
- Will respect transmission rights not associated with a Markets+ participant
  - Service Flow Constraints
- Transmission Schedules
  - BA Base Tags
  - BA Base Schedules
    - Market SCED does not consider in solution
    - Market SCUC will use these to ensure BA sufficiency
  - Markets+ Base Schedules
    - External BA to Markets+ BA transfers (imports, exports, wheels)
  - Capacity Tags
    - Could represent reserves or other capacity set-asides

PRE-DAMKT ACTIVITY



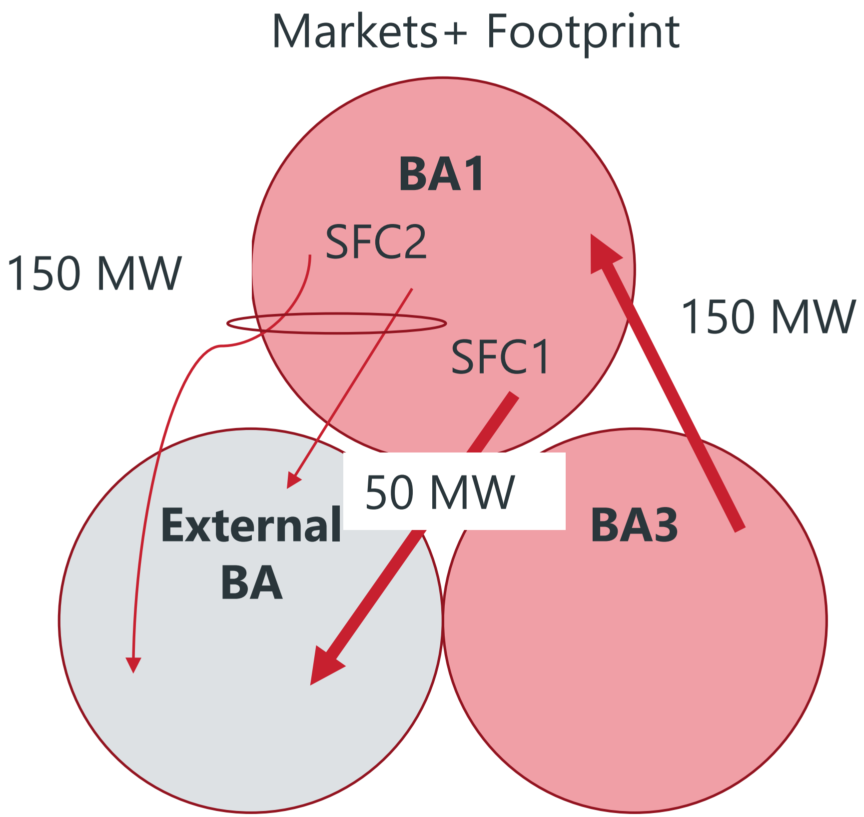
- BA1 has 200 MW allocation on SFC1
- BA1 Tags 200 MW exports prior to DAMKT
- SFC1 is set to 200 MW to limit Market Flow to within participant rights
- SFC can represent one or group of transmission elements (path)
- SFC functions much like a N-1 Flowgate

DAMKT ACTIVITY



- Markets+ clears the transaction and dispatches more economic generation in BA3 to serve the NSI
- Market flow nominates 50 MW from BA1 to External BA
- During the DAMKT solve, transmission sales are suspended to ensure consistency

OPERATING DAY ACTIVITY



- SPP Updates Dynamic Tag between BA3 to BA1 with 150 MW representing intra-BA Dispatc
- New schedules in real-time have no position in DAMKT and are exposed to real time prices

TRANSMISSION INFORMATION

- Balancing Authorities/Transmission Operators will provide hourly information prior to the market run:
  - Net Scheduled Interchange
  - Markets+ Base schedule information
  - Transmission set-asides (non-capacity tag reserves etc)
- SPP will be the scheduling agent for Markets+
  - Update Dynamic Schedule for Markets+ flow between participating BAs

TRANSMISSION USAGE

- TSPs within this Markets+ Footprint will maintain their OATT and administer their OASIS.
- TSPs will continue to sell Transmission Service as they do today
- Markets+ will utilize available transmission to meet the regional load obligation economically and reliably.
- Markets+ Dispatch will utilize Market Transmission Service to account for market flow on transmission within the Markets+ footprint

MARKETS+ IMPORT TAG TRANSACTION

- Markets+ import tags only describe those tags that come into the Markets+ footprint from an external entity (ex. CAISO). Can sink in any Markets+ BA
- Import tags are identified to the market system by the first scheduling entity that is a Markets+ BA.
- The interface point at the Markets+ border is used to determine the LMP to settle the import tag.
- The Markets+ system does not recognize or use generation that originates outside of Markets+ for systems or settlements.
- The Markets+ system does not deliver external generation to a specific load inside of the footprint. The load is served by market dispatch
- The Markets+ systems use the “Sink” on the tag as a reference to determine the Market Participant for settlements.

MARKETS+ EXPORT TAG TRANSACTION

- Markets+ export tags only describe those tags that leave the Markets+ footprint from an internal entity. Can source from any Markets+ BA.
- Markets+ export tags are identified to the system by the last scheduling entity that is a Markets+ BA.
- The interface point at the Markets+ border is used to determine the LMP to settle the export tag.
- The Markets+ system does not recognize or use loads that receive generation from Markets+ for systems or settlements (Markets+ will not settle with external parties).
- The Markets+ systems use the "Source" on the tag as a reference to determine the Market Participant for settlement.
- The export tag does not directly impact the commitment or dispatch of an individual generator/resource.

MARKETS+ WHEEL THROUGH TRANSACTION

- Markets+ wheel through tags originate and terminate external to the Markets+ footprint but cross boundaries between BAs and TSPs inside Markets+
- Markets+ systems do not use external sources or sinks on wheel through tags
- The interface point for the entry of the tag and the exit of the tag (Markets+ footprint) are used to determine the LMP difference as needed for settlements

MARKET TRANSMISSION SERVICE

- Used to compensate TSP for usage of the transmission system to facilitate market flow via dynamic tags
- Markets+ use of MTS in the DA will be compensated at the MTS rate
- Markets+ Dispatch utilizes the lowest priority transmission service in real time to make use of all available transmission capacity
- Not a replacement for point to point or network integrated transmission service
- Can not be used for off system sales or purchases

QUESTIONS/DISCUSSION

SETTLEMENTS

MICHA BAILEY, SPP

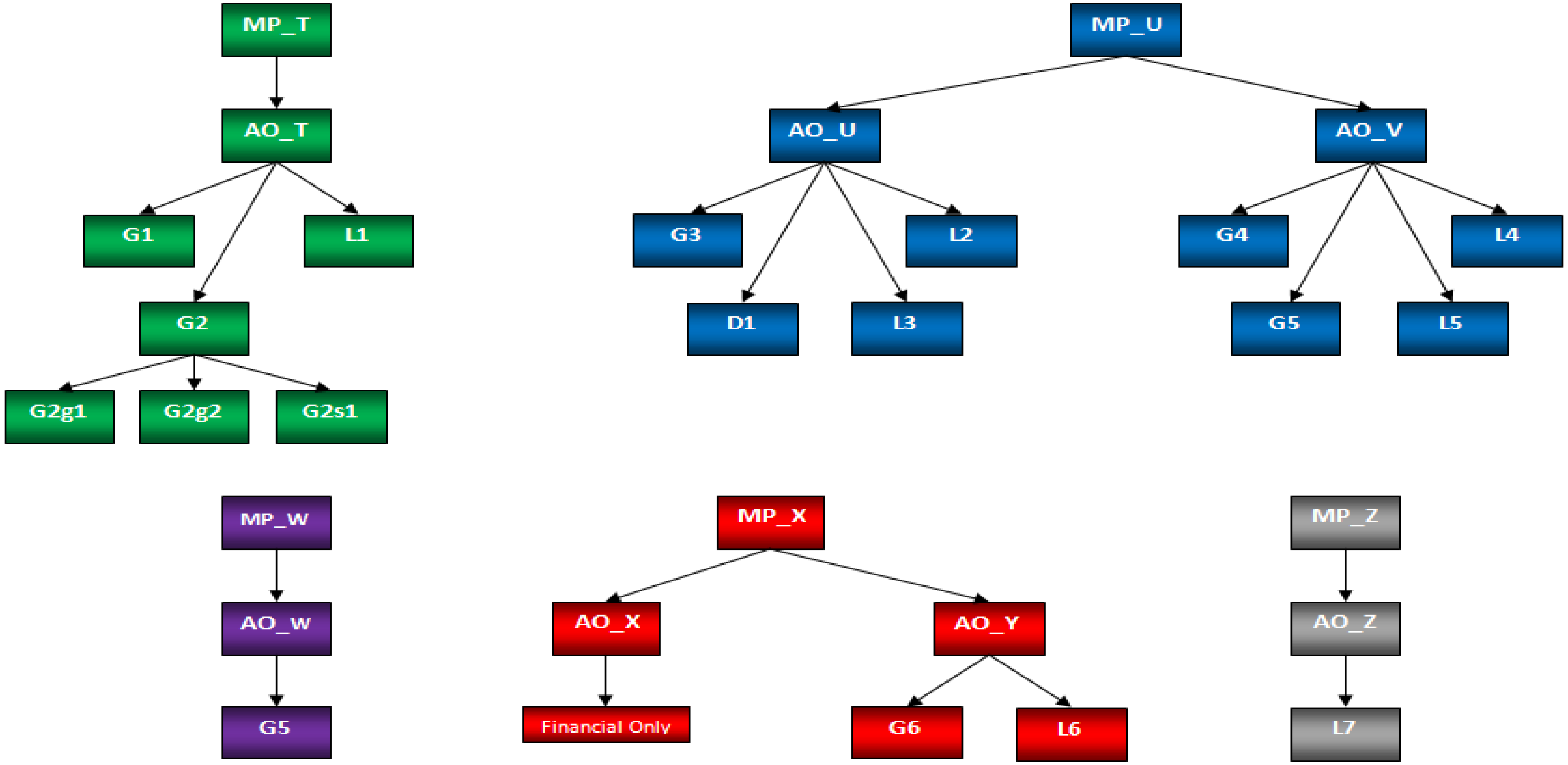
SETTLEMENTS

General Overview	Timelines
	Meter Data Submission
	Reporting
	SPP Settlement Management System
Settlement Design	Day Ahead vs. Real Time
	Determinants/Charge Types
	Distribution Methods
	Revenue Neutrality Uplift (RNU)
	Make Whole Payment/Out of Merit
	Recovery of Market Transmission Service Use Costs

MODELING – MPS ARE FINANCIALLY RESPONSIBLE

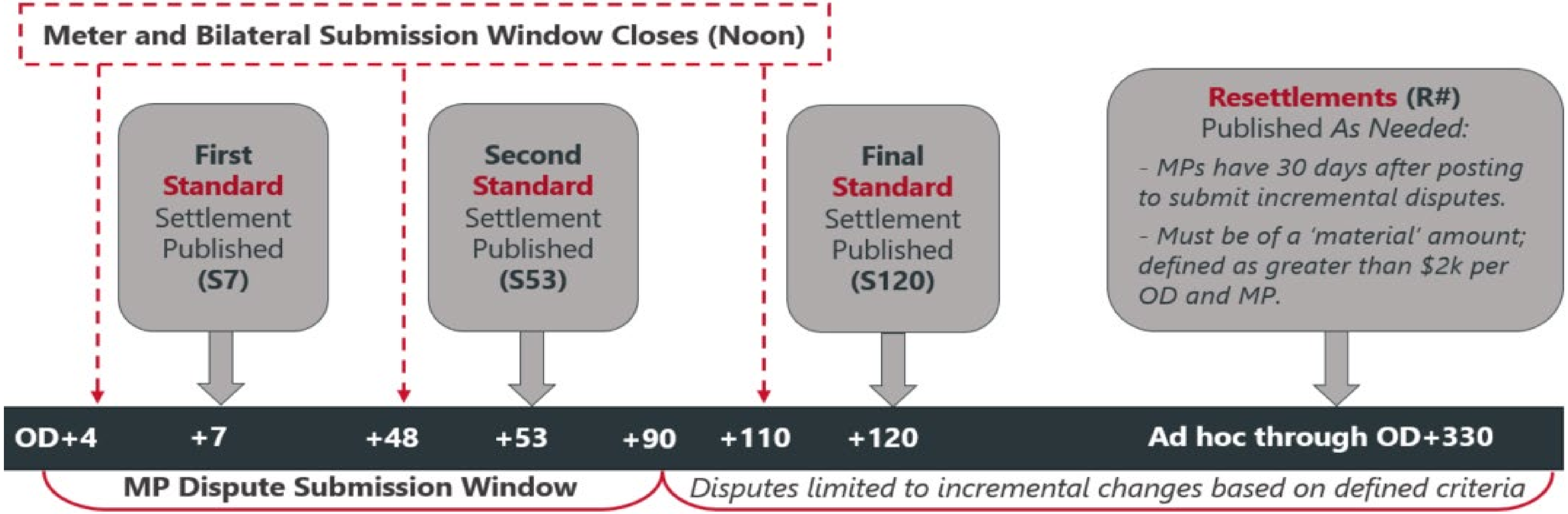
Commercial Model:

Financial Entities & Relationships



Legend:	AO = Asset Owner
	MP = Market Participant
	G = Generator
	L = Load
	D = Demand Response

TIMELINES



- Three standard daily postings: S7, S53, S120
- Meter data due OD+4 (S7), OD+48 (S53), OD+110 (S120)
- Invoices post weekly on Thursday and include all settlement postings for the prior Wednesday through current Tuesday

REPORTING - PRIVATE

- Determinant Report (Daily)
  - Most granular, includes all determinants and charge types
- Statement (Daily)
  - Roll-up at the Asset Owner and Market Participant Level
- Invoice (Weekly)
  - Only for Market Participants since they are financially responsible
- FERC Reports
  - In our current market, SPP creates these reports in the format FERC has requested as a convenience for the Members. They can download these reports and submit them to FERC.

REPORTING - PUBLIC

Historical

- SPP Market-wide rates
- Uplift (MWP, OOME, Products)

Calendar

- Excel File Download

SETTLEMENT MANAGEMENT SYSTEM

- Maintained in-house, no vendors
  - Minimizes implementation time, provides flexibility, and cuts costs
- Adaptable and scalable
  - One system for different Settlement types (market, transmission)
- Shadow Calculation
  - Use a separate in-house program
  - Runs for all postings
  - Shadows 100% of the calculations for all entities

DAY-AHEAD VS REAL-TIME AND DISTRIBUTION METHODS (COST CAUSATION)

- Day-Ahead (Depends on which DA Market option is selected)
  - Financially Binding
  - Hourly Settlements
- Real-Time
  - Difference between Real-Time and Day-Ahead
  - 5-Minute Settlements

Load Ratio Share

Market Activity

Deviation

APPLY BA OR MARKET-WIDE?

DISCUSS WHO IS INCLUDED IN UPLIFT

- Revenue Neutrality Uplift (RNU)
- Make Whole Payment (MWP)
- Out Of Merit Energy (OOME)

RECOVERY OF MARKET TRANSMISSION SERVICE USE COSTS

- Costs for Qualified Recovery (QR) amounts for Transmission use
- This would remove a need for a separate Transmission Settlement instance, consolidating all settlement into a singular timeline
- Calculate an hourly recovery (fixed cost) that is used to charge MPs for their share of market activity
- MW activity – Participation in the market

QR / 8760 = Hourly Recovery Cost

MP MW / Total Footprint MW* = MP MW %

Recovery Cost * MP MW % = MP Charge

Transmission Provider's QR
____
Total QR Recovered

- Collection

*Suggestion to exclude Interchange Transactions from total footprint MS (Only Gen and Load)

- Distribution

NEXT STEP DISCUSSION

- Before going much further, market design concepts must be complete in order to decide how to settle
- Settlements should settle the market based on how the market solved
- No matter what the design of the market is, when to Settle (Timelines) should be the same
- Are there special scenarios that need to be considered?

QUESTIONS/DISCUSSION

FUNCTIONAL ROLES AND RESPONSIBILITIES

DANIEL BAKER, SPP

FUNCTIONAL ROLES AND RESPONSIBILITIES IN MARKETS+

- RELIABILITY COORDINATOR (RC)
- BALANCING AUTHORITY (BA)
- TRANSMISSION OPERATOR (TOP)
- TRANSMISSION SERVICE PROVIDER (TSP)
- TRANSMISSION OWNER (TO)
- GENERATOR OWNER/OPERATOR (GO/GOP)
- PURCHASING-SELLING ENTITY (PSE)
- LOAD SERVING ENTITY (LSE)
- MARKET OPERATOR (MO)

TAKEAWAYS FROM PORTLAND MEETING

- Functional responsibilities do not change with implementation of Markets+
- Market Operator function will be introduced, but will not have compliance obligation
- Functional roles will flex to include coordination between Market Operator and reliability functions (BA, TSP, TOP, RC)
- Close coordination between MO, BA and TSP functions will be required
  - "A day in the life of" scenarios will be created as market protocols are developed

QUESTIONS/DISCUSSION

RESOURCE SUFFICIENCY AND UNIT COMMITMENT

JIM GONZALEZ, SPP

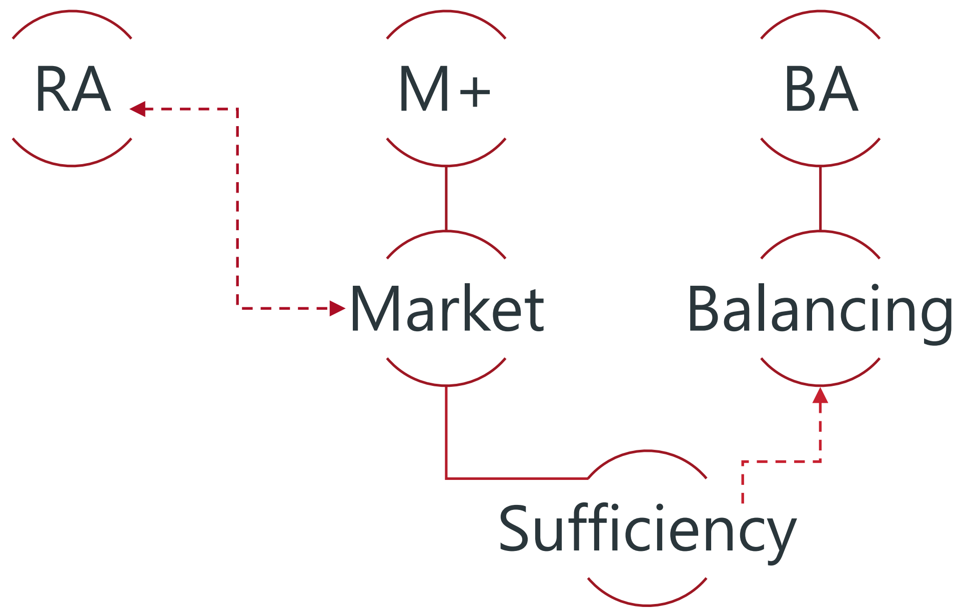
TOPICS FOR DISCUSSION

- Resource Sufficiency
- Optimal Physical Unit Commitment
- Centralized Unit Commitment & Multiple BAs

RESOURCE SUFFICIENCY

WHY IS SUFFICIENCY IMPORTANT FOR MARKETS+?

- BA separate from Market
- RA separate from Market
- Multiple BAs
- RA may vary in footprint
- Centralized Unit Commitment and Dispatch



HOW DOES MARKETS+ ENSURE RESOURCE SUFFICIENCY?

RA Program + Market Design Features = Resource Sufficiency

- Markets+ is not a Resource Adequacy Program
  - Markets+ participation will require TBD minimum threshold RA standard
- Markets+ will need design features to incent participants to “bring” RA capacity to Day-Ahead Market
  - Must Offer
  - Scarcity Pricing / Pricing when system is “stressed”

*** Markets+ Sufficiency will only be as good as the RA standard/program ***

*** Markets+ is a tool, not the rule ***

Southwest Power Pool WESTERN ENERGY SERVICES

SPP

SPP PROPOSAL TO ENSURE RESOURCE SUFFICIENCY

- Participants must participate in comprehensive RA program (e.g., WPP's WRAP) or meet equivalent standard
- Participants must make RA capacity available to Markets+
  - Day-Ahead Market and Real-Time Balancing Market
  - Question?: Should requirement be by individual resources or equivalent total capacity
- Scarcity Pricing model should distinguish between insufficient and sufficient BAs
- Markets+ unit commitment processes heavily coordinated with BAs, especially in times of system stress.
  - BAs will have more tools in the toolbox than market operator

UNIT COMMITMENT

PHYSICAL AND OPTIMAL

PRIMARY UNIT COMMITMENT OBJECTIVES

- Maintain Reliable Operations of the Bulk Electric System
  - Participating Balancing Authorities individually sufficient
  - Generation deliverable to load
- Minimize total production cost
  - Maximize participation in the Day-Ahead Market
    - Resources and Load
  - Make decisions early enough to have the largest set of available Resources

PHYSICAL

OPTIMAL

TWO OPTIONS FOR PRIMARY UNIT COMMITMENT

- SPP RTO Method
  - DAMKT
    - Limited must Offer
    - Voluntary Market
    - Behavior-driven
- Alternative Method
  - DAMKT split into parallel paths
    - Physical Commitment
      - Forecast-driven
    - Financial Market
      - Voluntary
      - Purely Financial

EQUALLY RELIABLE

RA Program

RTO Method

ALT Method

Resource Sufficiency

THOUGHTS ON RTO METHOD

- RA Program ensures sufficient capacity
- DAMKT Primary Unit Commit Tool
  - Voluntary, financial market with physical output
  - Full set of generation is not offered in DAMKT
- Settlements design incents behavior to reflect RT
  - In theory, little divergence between DA and RT
  - In practice, unit commitment always different
- DA RUC important, first test of DAMKT results
- Incremental RUCs ensure reliability and adjust for changes

THOUGHTS ON ALTERNATIVE METHOD

- RA Program ensures sufficient capacity
- DA RUC primary commitment tool
  - More efficient commitment
  - Isolated from voluntary, financial market
- Incremental Cost of Capacity to bridge DAMKT to expected RT conditions is paid by the DAMKT rather than the RTMKT
  - Allocation of cost is more granular between DA RUC and DAMKT
  - RTMKT pays cost of RUC commitments for RT Need (uncertainty)

SPP PROPOSAL

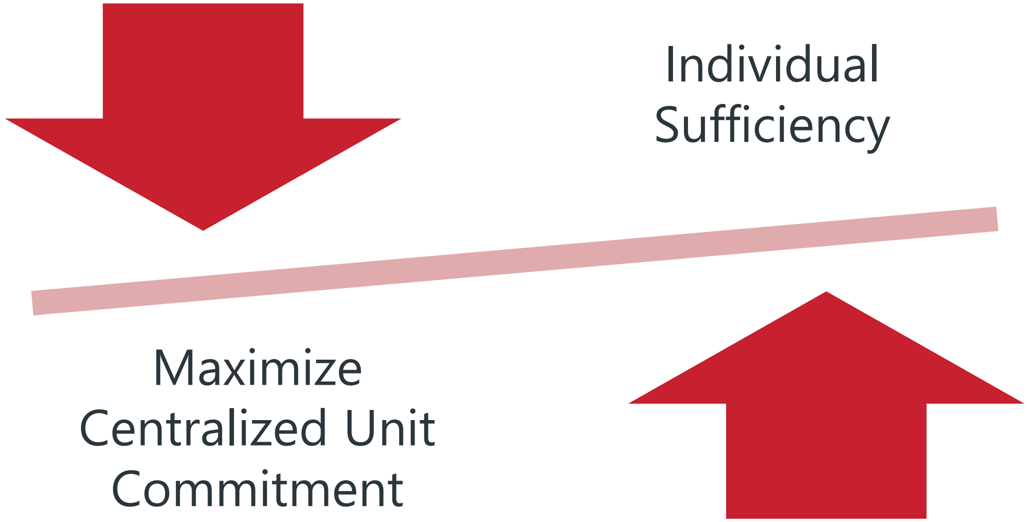
- Further investigate Alternative Method during next phase of Markets+ design
  - Potential benefits of more optimal physical commitment while retaining voluntary, financial market worth additional effort of new market design construct
  - Can quickly transition to RTO Model if additional cost and effort exceed expected benefit.

CENTRALIZED UNIT COMMITMENT

MULTIPLE BALANCING AUTHORITIES

MARKETS+ MODEL

- Markets+ does not include BA consolidation
  - Existing BAs will continue to exist and maintain NERC requirements
- Markets+ will have centralized unit commitment and dispatch



QUESTIONS/DISCUSSION

MARKET TRANSMISSION SERVICE REVENUE RECOVERY

STEVE DAVIS, SPP

TADT DASHBOARD

Revenue Recovery Amount

Revenue Recovery mechanism (load vs. market based)

Revenue distribution methodology

All transmission in, out by exception

TSP data collection and analysis

Working draft of design document

TSP and Planning functions retained, OATT rights respected

Base Schedule support

Flow-based operations DA and RT

Ongoing Discussions/work

Future Discussion

Nearing Comment Phase

Ready for comment

Ready for Offering

TRANSMISSION USAGE ASSUMPTIONS

- Transmission systems will continue to be operated by existing TO/TSP as they are today
- Market will leverage transmission in a flow-based manner to maximize use of the system
- Short-term P2P revenue will decrease as entities leverage the market in lieu of real-time bilateral trading
- A transmission use charge needs to be established to allow recovery of revenue lost due to changes in market activity – **Market Transmission Service**

MARKET TRANSMISSION SERVICE REVENUE RECOVERY DETERMINATION

- From 8/3 meeting –
  - Concerns about over-collection were raised if 100% of Short Term Firm and Non Firm revenues are used
    - 50% of STF and NF was proposed:

Transmission Data*	Total	Total less BPA
STF	$88,091,387	$59,339,042
NF	$60,442,798	$42,742,574
Sum of STF+NF	$148,534,185	$102,081,615
50% of STF+NF	$74,267,092	$51,040,807
NEL (MWh)	289,022,118	192,853,044
MTS charge @ 50% based on NEL	$.26	$.26

*Transmission data will need to be collected from all M+ participants to determine final rate

MTS (QUALIFIED) REVENUE RECOVERY DETERMINATION PROPOSAL

- Calculate ratio of STF+NF vs. total ATRR (e.g. 10%)
- Determine Recovery Scaling Factor to apply to ratio (50% is current example)
- Apply ratio to future year to account for changes in ATRR

Example MTS calculation:

Year 1
ATRR=$120M
STF+NF=$12M or 10% of ATRR
Recovery scaling factor is .5
.5*(10% of $120M)=$6M

Year 2
ATRR=$130M
10% recovery ratio is maintained from initial baseline
Recovery scaling factor is .5
.5*(10% of $130M)=$6.5M

MTS (QUALIFIED) REVENUE RECOVERY DETERMINATION PROPOSAL

- Apply Recovery Scaling Factor (50% is current example) to average of previous three years' STF+NF for initial baseline.
- Establish Transmission Working Group under Markets+ governance framework to monitor revenue recovery calculation for subsequent years
  - Work with TSPs to ensure collection amount is commensurate with loss of STF and NF revenue, adjust as necessary.
- Market information will be available after first year to use for calculations

MTS (QUALIFIED) REVENUE RECOVERY PROPOSAL

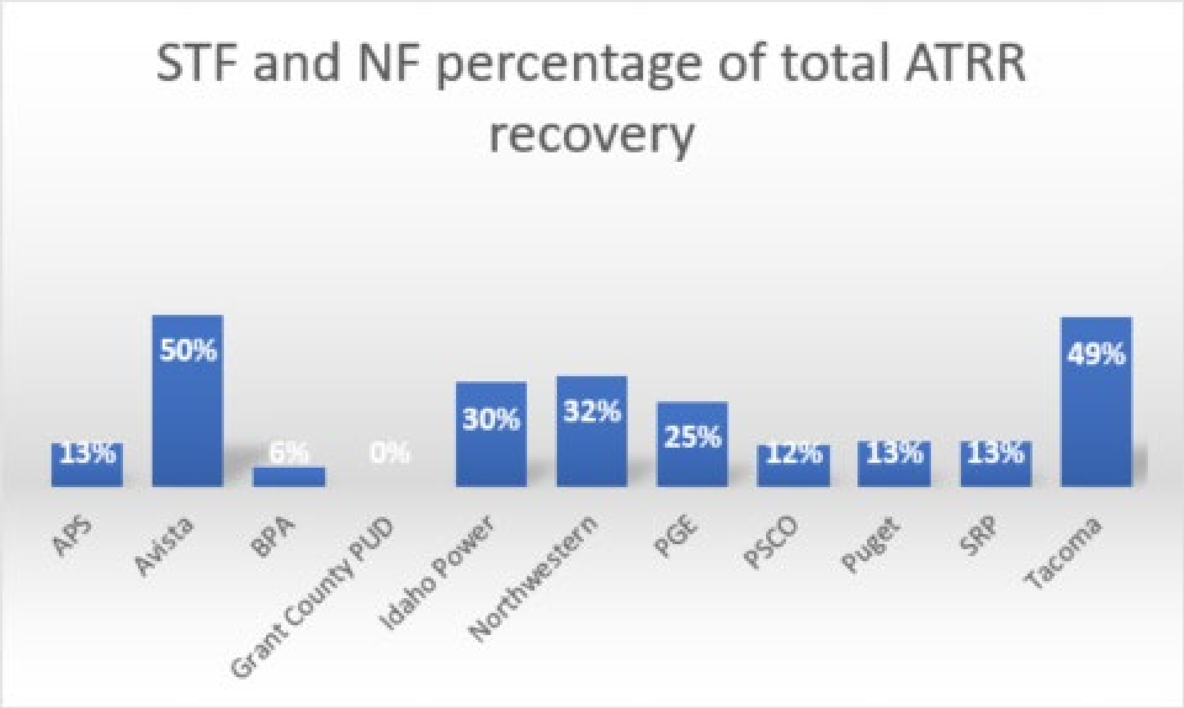
- Recovery mechanism
  - Market-based solution
- Apply a charge to the market for the use of the transmission system
- Based on revenue recovery amount established for MTS and applied to all MW settled by market
- Compensation provided from the market via MTS billing determinant
- Does not affect overall marginal energy costs in the solution

MTS (QUALIFIED) REVENUE RECOVERY PROPOSAL

- Annual recovery amount is static (e.g. $74,267,092)
- Market will be billed monthly to recover MTS revenue and applied to next market settlement statement
- Amount per MW will vary based on overall market use
- Ensures accurate collection of established recovery amount without need for annual true up
- Any changes to Recovery Scaling Factor or TSP percentage of ATRR will be applied to future year calculation

MARKET TRANSMISSION SERVICE (QUALIFIED)REVENUE DISTRIBUTION PROPOSAL

- Distribution method
  - Based on established Revenue Recovery for MTS



$$\frac{\text{Transmission Provider's MTS RR}}{\text{Total MTS Revenue Recovery}}$$

SPP

MARKETS+

NEXT STEPS

- Provide informal comments to draft design document
  - Will provide new draft August 26th for the informal comment period that includes updates from Portland meeting
  - Comments due by September 16th

- Upcoming TADT Meetings
  - September 7th 10:00 am – 12:00 pm Mountain
  - September 21st 10:00 am – 12:00 pm Mountain

QUESTIONS/DISCUSSION

GOVERNANCE

KARA FORNSTROM, SPP

GOVERNANCE BREAKOUT SESSION TOPICS

SPP Perspectives on Comments
SPP Board of Directors
Markets+ Independent Panel
Markets+ Market Stakeholders
Markets+ Participant Executive Committee
Types of Sector Voting

SPP BOARD OF DIRECTORS (SPP BOD)

- Ultimate Oversight
- Significant recognition to the MIP
- Shall review:
  - Material Impact
  - M+ budgets, debt and staffing
  - MIP Appeals

Should SPP Director on MIP recuse on Appeal Vote?

Will Markets+ get Sufficient Attention from SPP BOD?

Can SPP BOD change MIP Authority?

When is Materiality Determined?

How determine Materiality?

MARKETS+ INDEPENDENT PANEL (MIP)

- Comprised of five persons (One is SPP Director)
- Recent and relevant senior level management expertise and experience: electric industry, markets, utility regulation
- Section 205 Rights
- Appeals to SPP BOD
- Four year terms, no term limits

SPP Director on MIP should be Non-voting

Terms
Support 4 year terms
Term should be shorter
Establish term limit

SPP Director on MIP should have Western Experience

SPP Director should not Automatically be MIP Chair

Appeals
Require good cause?
Broaden who can Appeal
Further describe Process

MARKETS+ MARKET STAKEHOLDER (MMS)

- Executed Stakeholder Agreement
- Does not contribute generation or load
- Voting rights: MIP Selection Forum
  - Eligible for voting seat on MIP NC & WGs
- Annual fee of $5,000

“Cost Prohibitive”
“Unpopular”
“Eliminate Fee”
“Reduce Fee”
“Caused Significant Opposition”

Establish Waiver Process?

Exit Fee?

Will fee negatively impact robustness of non-participant involvement?

Fee seems Arbitrary & Intended to Narrow Stakeholder Participation

Requiring a Fee is Not Necessary to Ensure Stakeholder Engagement

MARKETS+ PARTICIPANTS EXECUTIVE COMMITTEE (MPEC)

- Each Markets+ Participant will appoint a representative
- Authority:
  - Make recommendations to the MIP
  - Establish Working Groups and Task Forces

All Stakeholders should be Represented on the MPEC

Support Participant Only Composition

Concerns about MPEC Chair appointing WG Representatives

How will MPEC provide Recommendation to the MIP? Advisory? Non-binding?

If only Participants on the MPEC, create Advisory Group for Stakeholders?

MPEC VOTING OPTIONS TO CONSIDER

NIPPC Proposal: Three equally weighted sectors: (Unicameral)

- *Investor-owned utilities*: All Participants within this sector are "public utilities" under the Federal Power Act, are regulated by a state regulatory commission, and have a fiduciary responsibility to investors to earn a rate of return on ratebased assets.
- *Public power*: Participants in this sector would include publicly-owned utilities, electric cooperatives, power marketing administrations, and perhaps Powerex (as a subsidiary of BC Hydro – a Canadian Crown Corporation).
  - Given the significance of BPA, WAPA, and Powerex as wholesale marketers within the same sector as retail utilities, the sector may want to reserve a portion of the vote (for example, 30-50%) to those three entities or, alternatively, weight votes within the sector by load responsibility.
- *Independent*: Independent power producers, marketers, transmission developers, and end-users. This sector is purposefully a "catch-all" for Participants who aren't utilities or publicly owned marketers. The presence of end-users within the sectors reflects uncertainty about the extent to which those entities will elect to become Participants while still reserving them a sector for purposes of MPEC voting.

Other Weighted Voting Option (Unicameral)

Upon execution of a Participants Agreement, a Participant shall be assigned to one of two Membership sectors for the sole purpose of voting on matters before the Markets+ Participants Executive Committee: Balancing Authority Participants (BAP) or Other Participants.

Each sector votes separately with the result for that sector being a percent of approving votes to the total number of Participants voting. The BAP sector represents 50% of the vote and the Other Participants sector represents 50% of the vote.

An action is approved if the average of these two percentages is at least 66%.

MPEC VOTING STRUCTURE

17 of 21 Commenters provided input

Prefers the Three Sector option (7)

- Not equally weighted
- Include a re-opener provision to reevaluate market participation

Prefers the BA/Non-BA sector voting structure (5)

Should MMS have Voting Rights?

Overview of SPP Membership Sectors

Sector	Definition
Alternative Power	Entities that advocate for the development of alternative power resources including wind, solar, and battery.
Cooperatives	Member-owned and operated. Primarily provide electricity to residential customers.
Federal Power Marketing Agency	Any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy.
Independent Power Producer	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.
Independent Transmission Companies	Entities that build, own, and operate transmission facilities, but do not generate electricity.
Investor Owned Utilities	For-profit corporations owned by either public or private shareholders and typically regulated by state commissions.
Large Retail	Non-residential end-use customers with individual or aggregated loads of one MW or more
Marketers	Business entities engaged in buying and selling electricity. Power marketers do not usually own generating or transmission facilities.
Municipals	Owned and operated by the local government or another state body to provide electricity to the public.
Public Interest	Includes consumer advocates, environmental groups, citizen participation, and other entities that are largely representative of end-use customer interests
Small Retail	Residential customers and other customers with individual or aggregated loads of less than one MW
State Agencies	Agencies of a state that provide electricity to municipalities and/or end-use customers.

MIP Nominating Committee

- Ten sector-based representatives (based on first written comment responses):
  - MIP representative, who shall serve as chair
  - Independent power producers
  - Markets+ State Committee member
  - Public interest organizations
  - Cooperatives
  - Municipal utilities
  - Federal agency
  - Investor-owned utilities
  - Competitive marketers
  - Trade groups
- Election process mirrors SPP BOD process
- Approval: Each MMP and MMS votes at MIP Selection Forum

Add Consumer Advocate? Or retail/small commercial customer sector?

How Many is Too Many?

Eliminate Trade Group Sector?

Primarily Meet Privately?

Add Large Customer Sector?

Add PUDs to Municipals? Own sector?

TYPES OF SECTOR VOTING – SPP EXAMPLES

Members Committee

- 24 Representatives
- 6 IOUS, 5 Coops, 2 Munis, 2 State Power Agencies, 1 FPMA, 2 Alternative Power/Public Interest, 1 Independent Transmission, 1 Large Retail Customer and 1 Small Retail Customer

Corporate Governance Committee

- 11 Representatives
- SPP President, BOD Chair, 1 IOU, 1 Coop, 1 Muni, 1 IPP/marketer, 1 State Power Agency, 1 Alternative Power/Public Interest, 1 Independent Transmission, 1 Large/small retail Customer and 1 FPMA

Strategic Planning Committee

- 5 Transmission Owners
- 5 Transmission Users
- 3-4 Directors

Human Resources and Finance Committees

- 6-9 Members
- Equal Representation
- 2-3 Transmission Owners
- 2-3 Transmission Users
- 2-3 Directors

SPP Bylaws Section 3.1: "appointments shall be made with due consideration of the various types (sectors) and expertise of Members and their geographic locations."

TYPES OF SECTOR VOTING – RTO/ISO COMPARISON

	CAISO	MISO	PJM	SPP
Senior Committee	None	Advisory Committee	Members Committee	MOPC and Members Committee
Voting Stakeholders	None	MISO Members	PJM Members	SPP Members
Non-Voting Stakeholders	Stakeholders	Non-members	Non-members	Non-members
Senior Committee Voting Approach	None	10 Weighted Sectors (66%)	5 Weighted Sectors (66%)	MOPC: Each Rep. Members: 2 Weighted Sectors (66%)
*Governance Structure and Practices in the FERC Jurisdictional ISOs/RTOs (Feb. 2021) Prepared for NESCOE				

QUESTIONS/DISCUSSION

GHG TRACKING AND ACCOUNTING

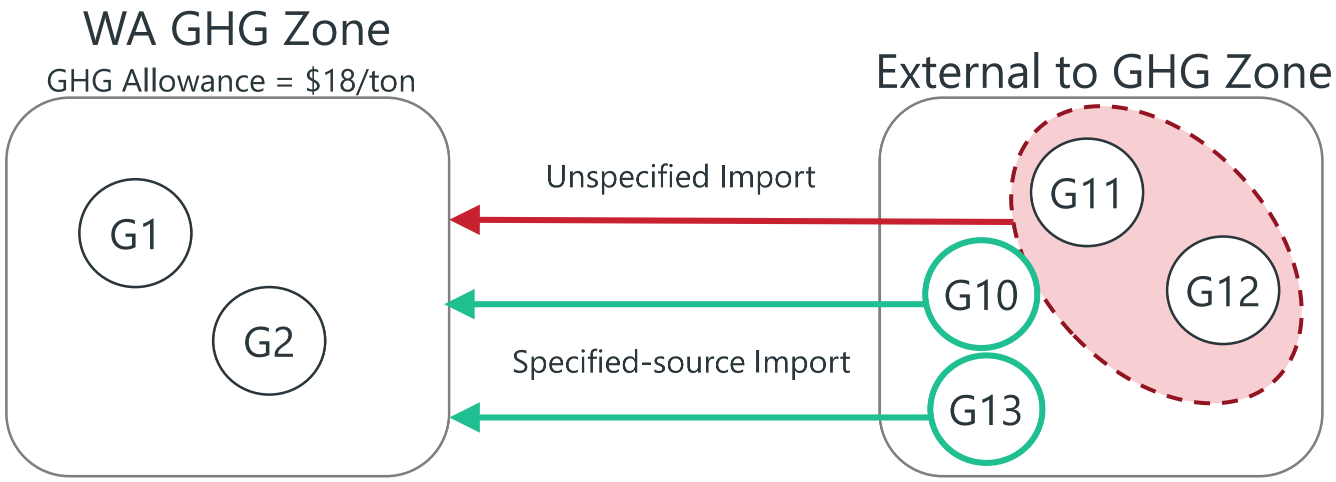
YASSER BAHBAZ, SPP

DESIGN OBJECTIVES

- Minimize total production costs with GHG costs considered
- Provide a framework for any capacity to be dispatched to the zone
- Properly account for MWs serving the zone, both from specified and unspecified sources
- Implement a solution that meets the intent of GHG policies
- Ensure that GHG costs associated with imports into the GHG zone only apply to load in that zone.

3 TYPES OF RESOURCES FOR A GHG ZONE

- The 3 types are defined in the following slide from the GHG May 2022 Workshop
  - ✓ *GHG Internal Resources*
  - ✓ *Specified-source Imports*
  - ✓ *Unspecified Imports*
- GHG zone imports allow resources outside the zone to participate in supplying the GHG zone. These MWs are accounted for and allocated.



GHG ZONES

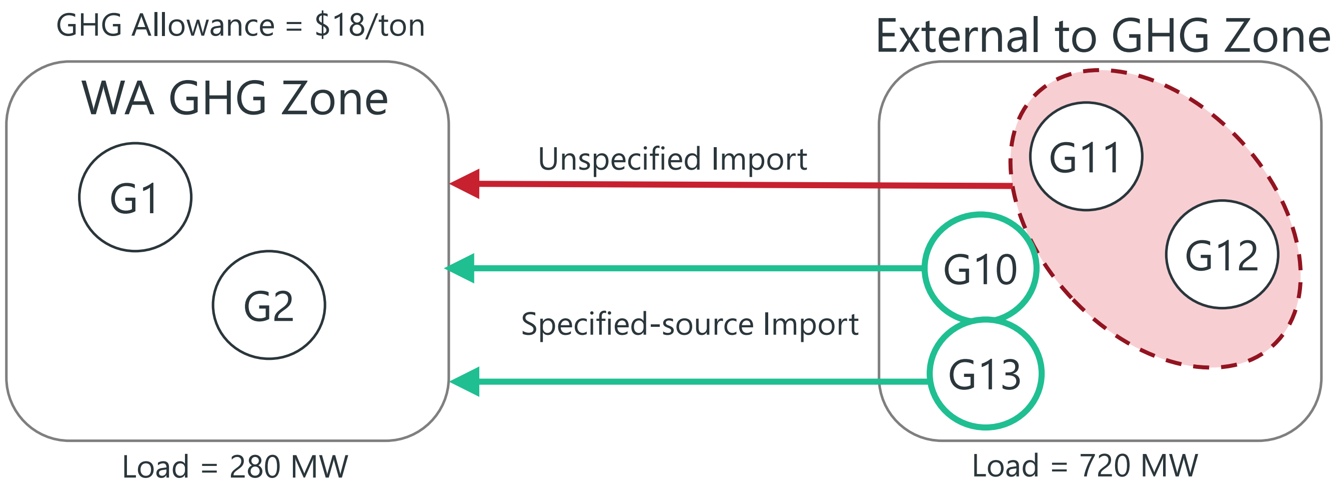
- All GHG zone Dispatched MW
  - Is subject to GHG costs
  - Satisfies GHG zone load first.
- GHG rate is specified by
  - resources for GHG zone resources
  - source for Specified-source imports
  - A pre-determined rate for unspecified-source imports
- GHG costs are *<u>not</u>* included directly in the resource offered $/MWh
- MWs serving load in the zone from external or internal resource/fleet are accounted for

GHG PRICE INDEPENDENT OF ENERGY LMP

- GHG cost is the marginal cost of additional load moving to the GHG zone
- GHG costs associated with imports into the zone are not included in the LMPs
- GHG loads and injection MWs assigned to serve the GHG zone are subject to the GHG price
  - GHG zone load pays, and all injections are assigned GHG payments
  - GHG payments are made to Internal Resources and to Resources associated with Specified-source Imports
  - To be determined on who receives GHG payments for Unspecified-source import MWs

EXAMPLE SYSTEM

ID	GHG Type	Max MW	$/MWh	WA GHG ton/MWh
G1	Internal	200	36.8	0.4 ($7.2/MWh)
G2	Internal	150	2	0
G10	Specified Source	50	37	0.35 ($6.3/MWh)
G11	Unspecified	600	36	0.5 ($9/MWh)
G12	Unspecified	200	3	
G13	Specified Source	15	25	0



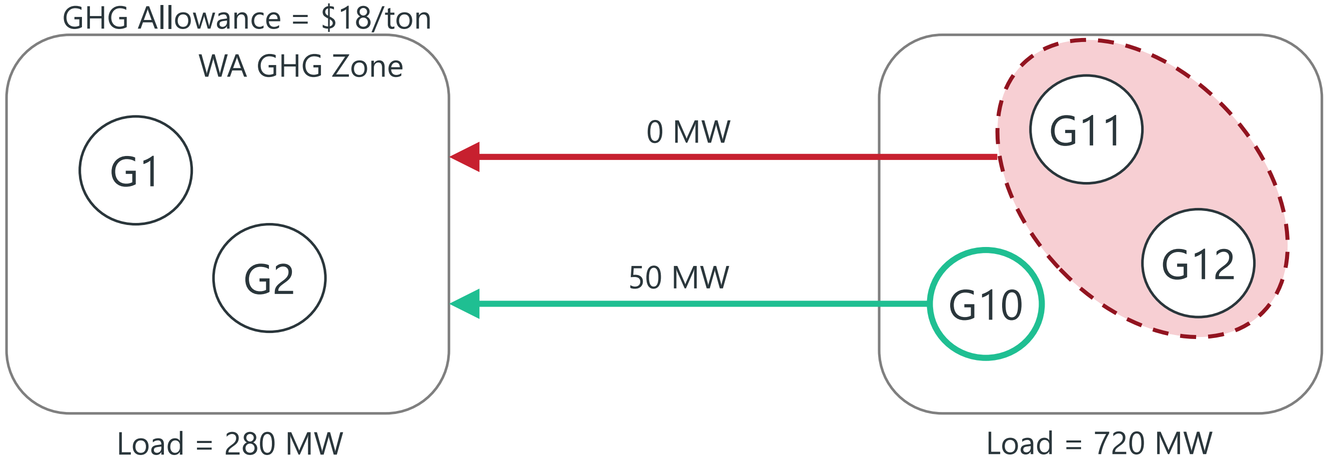
Would these MWs have served load outside the zone if there weren't GHG zone load? Or are they just re-designated for WA?

IMPORTS HELP MEET GHG ZONE LOAD

ID	Max MW	$/MWh	GHG ton/MWh	Dispatch MW	WA Assign MW
G1	200	36.8	0.4 (=$7.2/MWh)	80	80
G2	150	2	0	150	150
G10	50	37	0.35(=$6.3/MWh)	50	50
G11	600	36	0.5 (=$9/MWh)	520	0
G12	200	3		200	
G13	0	0	0	0	0
				1000	280

WA Load Requirement:
G1 80MW + G2 150MW + G10 50MW ≥ 280MW

Shadow price = $8/MWh
incremental WA requirement:
G1 increment up
- G11 increment down



System Power Balance:
Total generation = 1000 MW

Shadow price = $36/MWh
Incremental sys load requirement:
G11 increment up

POSSIBLE SOLUTIONS TO MW RE-DESIGNATION

- To minimize or eliminate the "MW Re-Designation", also associated with Specified imports, the following approaches should be investigated further
  - *Implement a GHG Baseline (two-pass solution) approach in the optimization solution*
    - Optimal but must address conditions causing linear programming-based solution limitations
  - *Add transmission deliverability requirements*
  - *Consider resources designation in the resource sufficiency process when determining Specified-source Imports*

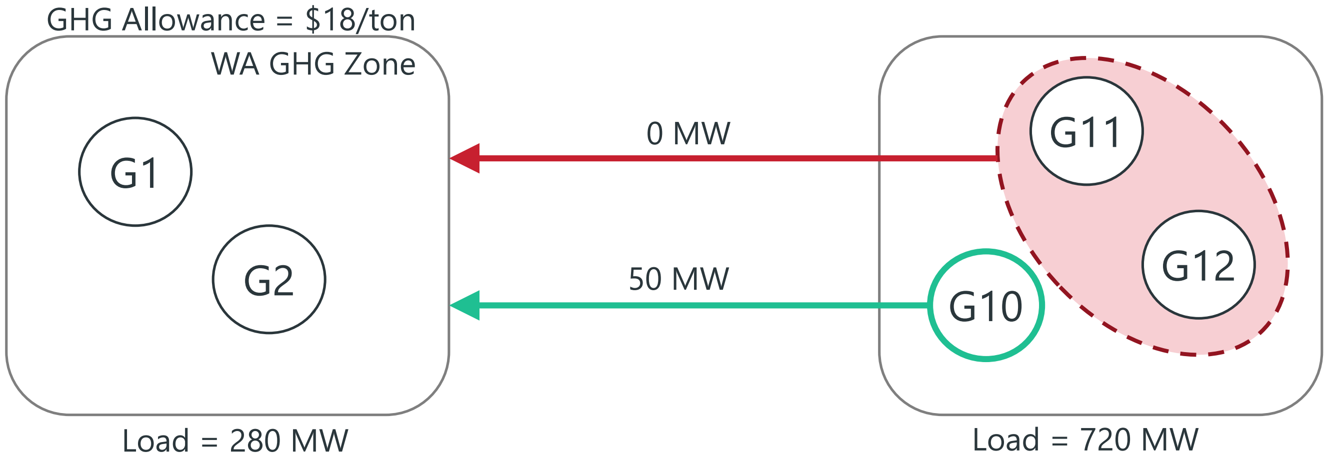
EXAMPLE WITH BASELINE APPROACH: IMPORTS HELP MEET GHG ZONE LOAD

ID	Max MW	Baseline MW	$/MWh	GHG ton/MWh	Dispatch MW	WA Assign MW
G1	200	130	36.8	0.4 ($7.2/MWh)	80	80
G2	150	150	2	0	150	150
G10	50	0	37	0.35($6.3/MWh)	50	50
G11	600	520	36	0.5 ($9/MWh)	520	0
G12	200	200	3	0	200	
					1000	280

*G13 offline

WA Load Requirement:
G1 80MW + G2 150MW
+ G10 50MW ≥ 280MW

Shadow price = $8/MWh
incremental WA requirement:
G1 increment up
- G11 increment down



System Power Balance:
Total generation = 1000 MW

Shadow price = $36/MWh
Incremental sys load requirement:
G11 increment up

EXAMPLE: SETTLEMENTS

Equal at all Locations since no congestion or losses

Dispatch MW * LMP

WA GHG price applies to any resource which may participate

WA Assign MW * WA GHG Price

Energy $ + WA GHG $

Energy Dispatch Cost + WA Assign MW * WA GHG Rate * WA GHG Price per ton

ID	Dispatch MW	LMP $/MWh	Energy $	WA Assign MW	WA GHG ($/MWh)	WA GHG $	Total Payment ($)	Total Costs ($)
G1	80	36	2,880	80	8	640	3,520	3,520
G2	150	36	5,400	150	8	1,200	6,600	300
G10	50	36	1,800	50	8	400	2,200	2,165
G11	520	36	18,720	0	8	0	18,720	18,720
G12	200	36	7,200	0	8	0	7,200	600
WA Ld	-280	36	-10,080	-280	8	-2,240	-12,320	N/A
Rest Ld	-720	36	-25,920	0	N/A	0	-25,920	N/A

Resource Energy + GHG payments ≥ Energy + GHG costs

TAKE AWAYS

- Designing and implementing a comprehensive market solution for GHG can be supported by SPP market staff and SPP market and settlements systems
- A proper comprehensive solution should allocate costs associated with GHG zone import to load in the GHG zone
- The stakeholder process will be key to reaching a solution that meets the GHG policies' intent and is supported by the participants

NEXT STEPS

- Continue to evaluate solutions to address the MW Re-Designation concerns and involve participants in understanding the pros and cons of each approach
- Discuss the proper entity(ies) responsible for collecting the GHG costs allocated to resources

QUESTIONS/DISCUSSION

SERVICE OFFERING NEXT STEPS AND SCHEDULE

BRUCE REW, SPP

SERVICE OFFERING

MARKETS+ DRAFT SERVICE OFFERING

Governance

- Balanced Approach and Participation
- Organizational Structure: MIP, MPEC, MSC, Working Groups, Task Forces, MIP Nominating Cmte and Forum

Market Design

- Responsibilities: Participants and Operator
- Key Features: Products; Timeline/Processes; Resource Registration Types; Price Formation; Centralized Unit Commitment; Centralized Unit Dispatch; Robust Physical Sufficiency; Flow-based Market Operations; Virtuals; In-line, Impact-based Mitigation; Marginal Losses; GHG Pricing/Settlement
- Compatability with Existing Constructs: Scheduling Activities; Coordinated Congestion Management; Congestion Hedge; GHG Tracking; Resource Adequacy; RSG; Division of Responsibilities

Transmission

- ATRR: Eligible for Recovery and Recovery Mechanism
- Transmission Revenue Distribution Methodology
- Base Schedule Methodology
- Flow-Based Operation

MARKETS+ DRAFT SERVICE OFFERING

Market Settlements

- Net Settlement
- Uplifts
- Timelines
- Dispute Process

Market Monitor

- Model
- Market Power Mitigation

Other Sections

- Resource Adequacy
- Potential Future Market Enhancements
- Stakeholder Relations
- Implementation: Development and Launch Timeline

NEXT STEPS SCHEDULE

SCHEDULE

• August 26:	Revised Design Document Issued
• Early Sept:	Governance Straw Proposal Version 3.0 Issued
• Mid Sept:	Webinar – Governance Proposal Version 3.0
• September 15:	Written Comments Due on Revised Design Document
• September 28:	Webinar – Draft Service Offering
• November 7-8:	In-Person Meeting in Phoenix

2022 MARKETS+ GOAL AND SCHEDULE

- Draft Service Offering – September 30
  - Written Comment Period - October
- Final Service Offering – November 18
  - Will Not Include: Market Protocols and Tariff Language
- Commitment to Investigate – Q1 2023
  - Financially Binding to Scope Implementation
- Stakeholder Process to Develop Market Protocols and Tariff Language
- Participant Agreement Execution – Fund Implementation

MARKETS+

Southwest Power Pool
WESTERN ENERGY SERVICES