Annual Interregional Information

Gary DeShazo
Director, Regional Coordination

Ebrahim Rahimi
Lead Regional Transmission Engineer

2019 Annual Interregional Coordination Meeting (AICM)
February 19, 2019

Introduction and Overview

Draft 2018-2019 Planning Process and transmission project approval recommendations

2018-2019 Transmission Planning Process

January 2018 | April 2018 | March 2019

Phase 1 – Develop detailed study plan

State and federal policy

CEC - Demand forecasts

CPUC - Resource forecasts and common assumptions with procurement processes

Other issues or concerns

Phase 2 - Sequential technical studies

- Reliability analysis
- Renewable (policy-driven) analysis
- Economic analysis

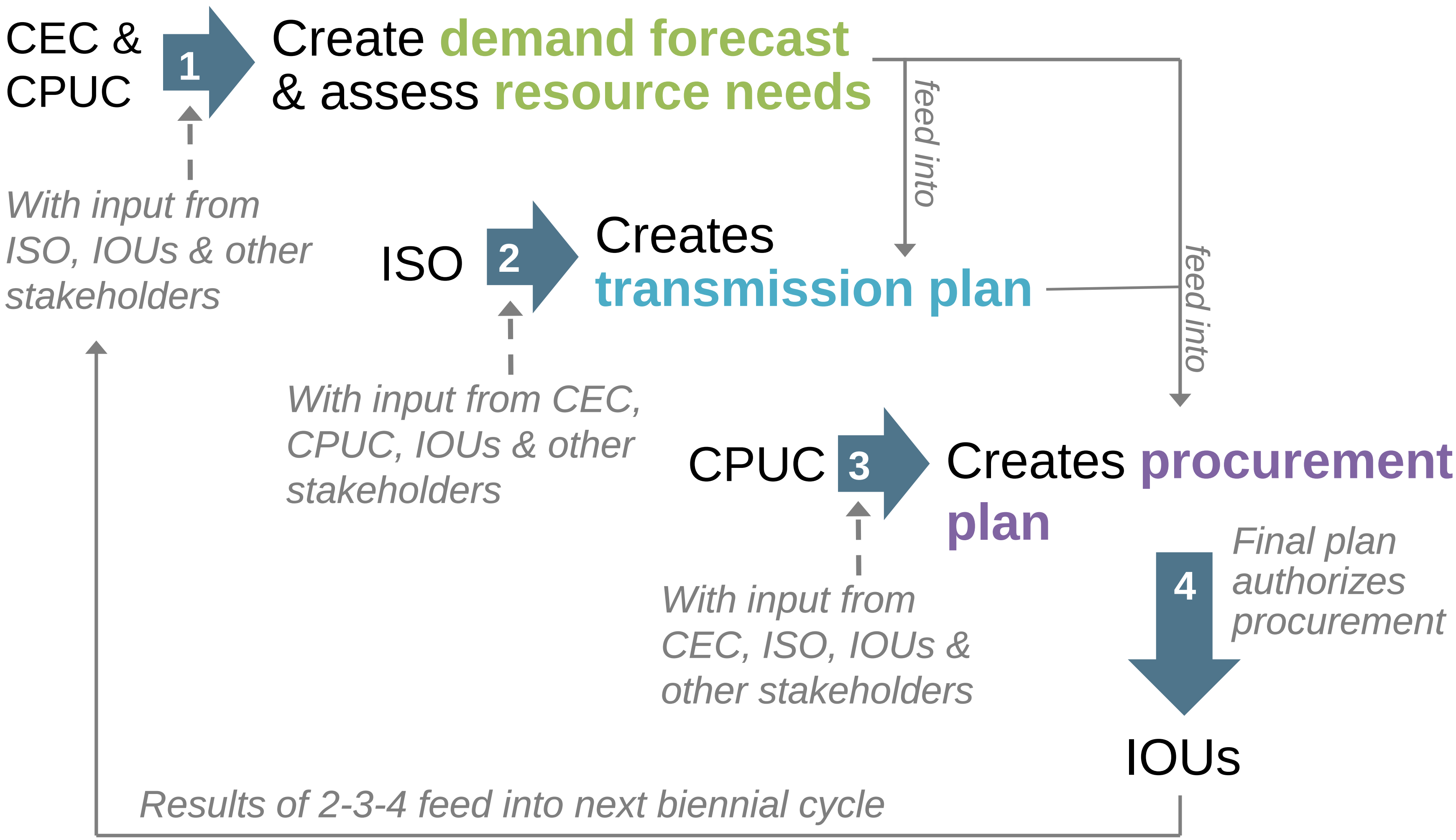
Publish comprehensive transmission plan with recommended projects

Phase 3 Procurement

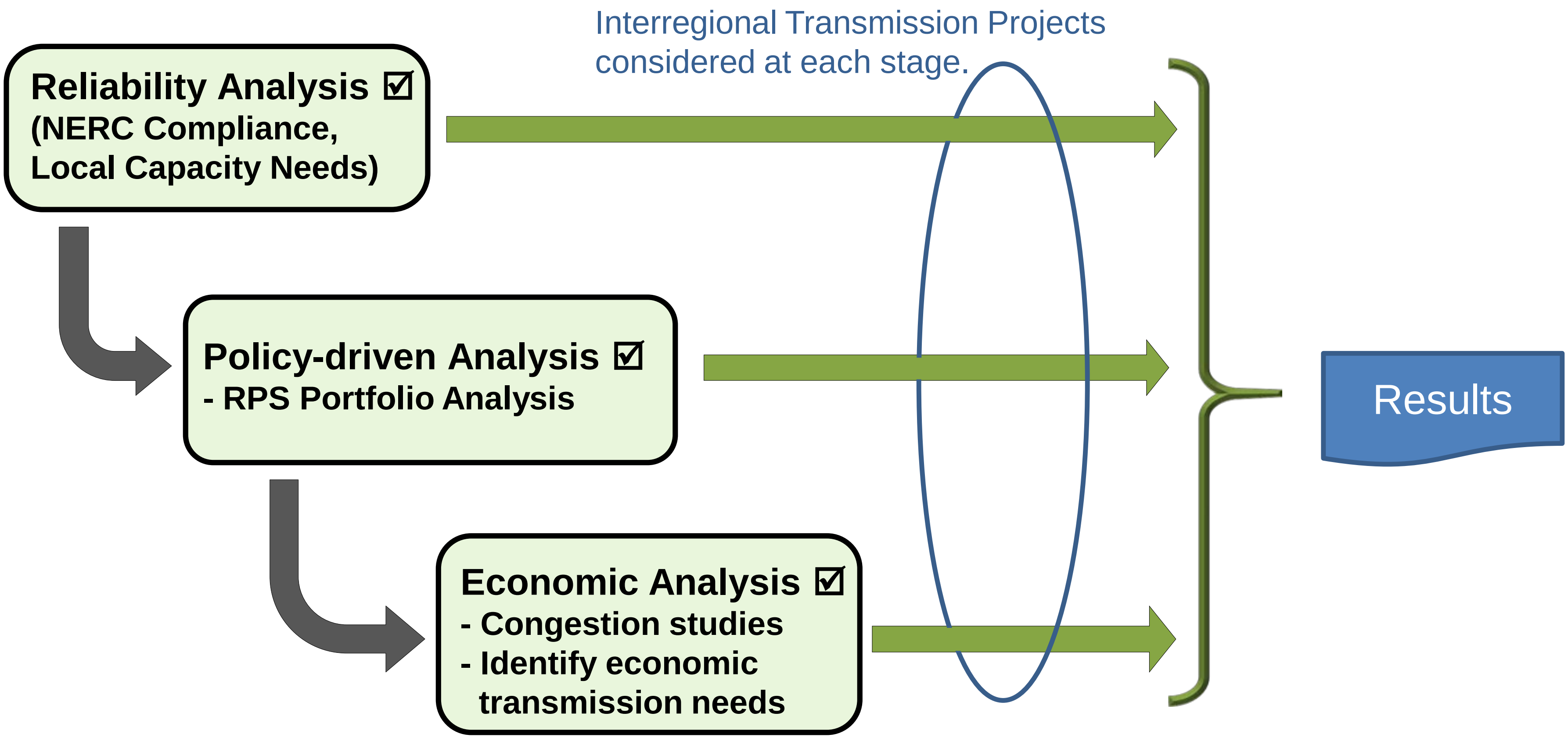
Draft transmission plan presented for stakeholder comment.

ISO Board for approval of transmission plan

Planning and procurement overview



Following our sequential study process has been challenging – but critical to managing study requests:



Stakeholders have submitted proposals into multiple forums, *e.g.* as reliability projects, economic study requests, alternatives to reduce local capacity requirements, and interregional transmission projects

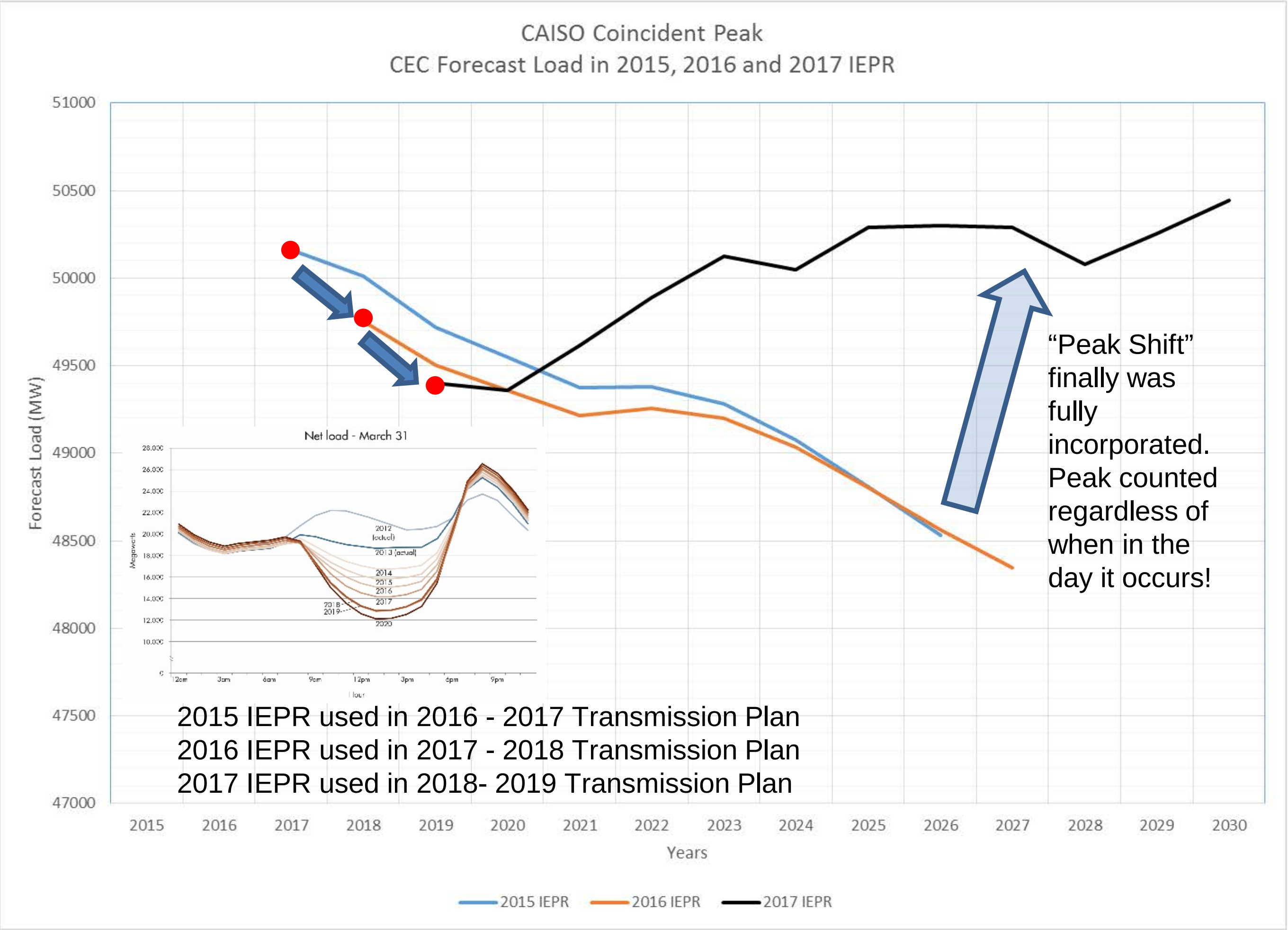
Emphasis in the transmission planning cycle:

- A modest capital program, as:
  - Reliability issues are largely in hand
  - Policy work was informational as we await actionable renewable portfolio policy direction regarding moving beyond 50%
  - Very little economic–driven opportunity, largely due to status of IRP decision-making
- Final resolution of previously approved projects
- Significant interest in development community for transmission lines and storage (battery and pumped hydro) – <u>13</u> proposals for “major” facilities needing detailed economic analysis
- Special study efforts on local capacity areas and gas-fired generation requirements, and on improving transfer capabilities with northwest hydro resources

Consideration of the impacts of behind the meter photovoltaic generation on load shapes – and shifting the time of load peaks to later in the day – continues to evolve:

- In CED 2015 (2016-2026 Forecast), the CEC determined peak loads through downward adjustments to the traditional mid-day peak loads and acknowledged the issue of later-day peaks. In the 2016-2017 planning cycle the ISO conducted is own sensitivities.
- In CEDU 2016 (2017-2027), the CEC provided sensitivities of later day peaks. The ISO used those sensitivities in this 2017-2017 planning cycle to review previously-approved projects, but not as the basis for approving new projects.
- In CED 2017 (2018-2028), the CEC provided hourly load shapes.

CEC forecast includes peak shifts as part of hourly loads



California ISO

New Projects Recommended for Approval (all in PG&E)

Projects	Project cost	Comment
Round Mountain 500 kV Dynamic Voltage Support	$160M-$190M	Reliability – Eligible for Competitive Solicitation
Gates 500 kV Dynamic Voltage Support	$210M-$250M	Reliability – Eligible for Competitive Solicitation
Lakeville 115 kV Bus Upgrade	$10M-$15M	Reliability
Tyler 60 kV Shunt Capacitor	$5.8-$7M	Reliability
Cottonwood 115 kV Bus Sectionalizing Breaker	$8.5M-$10.5M	Reliability
Gold Hill 230/115 kV Transformer Addition Project	$22M	Reliability
Jefferson 230 kV Bus Upgrade	$6M-$11M	Reliability
Christie-Sobrante 115 kV Line Reconductor	$10.5M	Reliability
Moraga-Sobrante 115 kV Line Reconductor	$12M-$18M	Reliability
Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	$0.1M-$0.2M	Reliability
Tesla 230 kV Bus Series Reactor project	$24M-$29M	Reliability
South of Mesa Upgrade	$45M	Reliability
Giffen Line Reconductoring Project	Less than $5M	Economic

Policy-driven analysis was not conducted for approval purposes – only as a sensitivity, as per CPUC direction:

- Per CPUC decision in integrated resource planning proceeding:
  - *50% RPS portfolio (IRP "default" scenario) provided for reliability and economic study purposes*
  - *42 MMT portfolio (IRP "reference" scenario) provided as a policy study "sensitivity", and specifically excluded providing a "policy base case" that would be necessary for any policy-driven transmission to be approved.*
  - *Full capacity deliverability status and energy-only amounts were specified*
- The expectation was that the "preferred" plan coming out of the 2018 IRP effort would form a "base case" for the 2019-2020 planning cycle.

Economic Study Issues:

- Large number of stakeholder proposals for transmission and storage – both pumped hydro and battery
- Proposals came in as:
  - proposed reliability projects
  - economic study requests
  - suggested alternatives to reduce local capacity requirements
  - and/or interregional transmission project proposals

Special study efforts conducted in 2018:

- Risks of early economic retirement of gas fleet (also feeding into IRP process)
- Large scale storage system benefits – found significant production cost benefits, but capacity benefits needed in order to be viable

PLEXOS updates to prior years' efforts

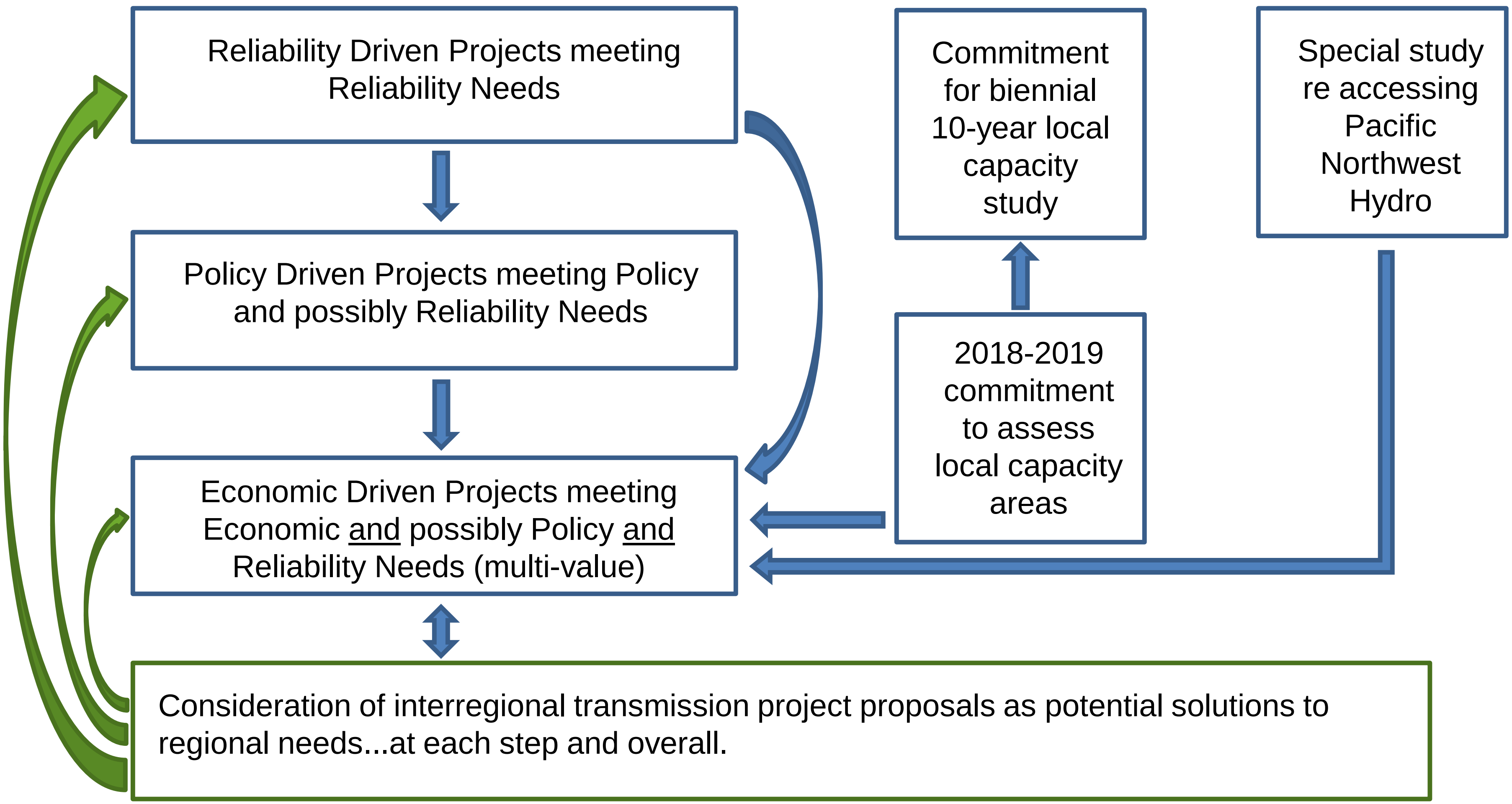
- CPUC/CEC study request re transfers of non-GHG resources with Pacific Northwest
- In-depth study of local capacity resource requirement needs (e.g. profiles of "need") and development of conceptual mitigations for half of the areas and sub-areas (none were found to be economic).

Overview and Key Issues
Economic Assessment

Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analysis or to meet local capacity deficiencies
  - An "economic driven" transmission project may be upsizing a previously identified reliability solution, or replacing that solution with a different project…
- Opportunities were explored to reduce the cost of local capacity requirements – considering capacity costs in particular
- Interregional transmission projects needed to be considered as potential alternatives to regional solutions to regional needs

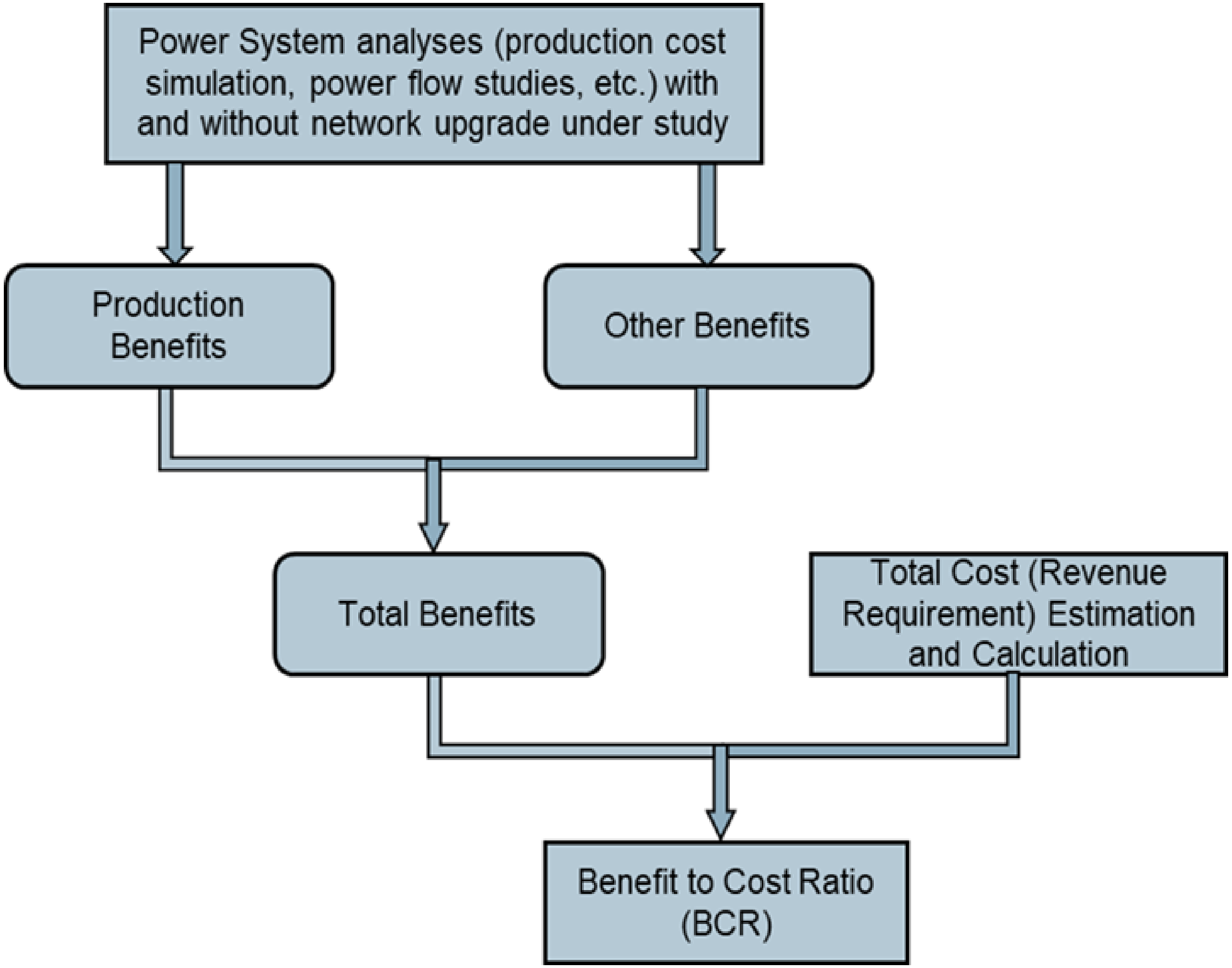
The 2018-2019 economic analysis is heavily coordinated with other study activities:



Two economic focus areas: alternatives to eliminate or reduce local capacity areas and storage as a transmission asset (SATA)

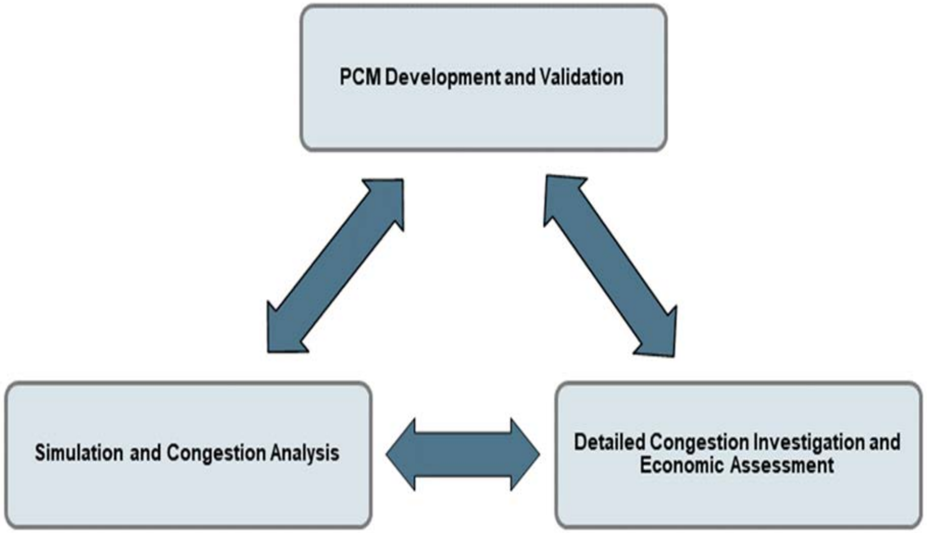
- Local Capacity Requirements
  - Provide profiles to help develop characteristic of potential preferred resources
  - Identify potential alternatives - conventional transmission upgrades and preferred resources - to reduce requirements in at least half of the existing areas and sub-areas
- SATA
  - The SATA initiative has been placed on hold to address certain market issues
  - Some assessment done considering ratepayer benefits
  - Total production cost benefits were also calculated, but for information only
  - Benefits being provided were assessed to see if they were due to the storage functioning as a transmission facility or market provider

Technical approach of economic planning study



Production cost model (PCM) development and validation

- Network model (transmission topology, generator location, and load distribution)
- Transmission operation model (transmission constraints, nomograms, phase shifters, etc.)
- Generator operation model (heat rate, ramp rate, hydro profiles, energy limits, renewable profiles)
- Load model (load profiles, annual & monthly energy & peak demand, DG, DR, & EE load modifiers)
- Market & system operation models, other models as needed (ancillary service requirements, wheeling rate, emission, etc.)



- Production cost simulation software review and enhancement, in coordination with vendors, regions, and WECC work groups, are conducted regularly through the PCM development process

Summary of key database development steps since November stakeholder session

- Changes identified in coordination with the ADS PCM validation process
  - APS load modified based on the updated APS load forecast data
  - BPA load shape modified with the consistent BPA load shape and pumping load profiles
    - Total energy and peak remained the same
  - NW wheeling model modified based on BPA's recommendation with consideration of firm transmission right among NW areas
    - In general, hurdles reduced among NW areas, and between NW and California areas
  - BC Hydro hydro-generator data error fixed, available energy reduced
  - Regions coal generator retirement and replacement, mainly with renewable generators, as recommended by regions

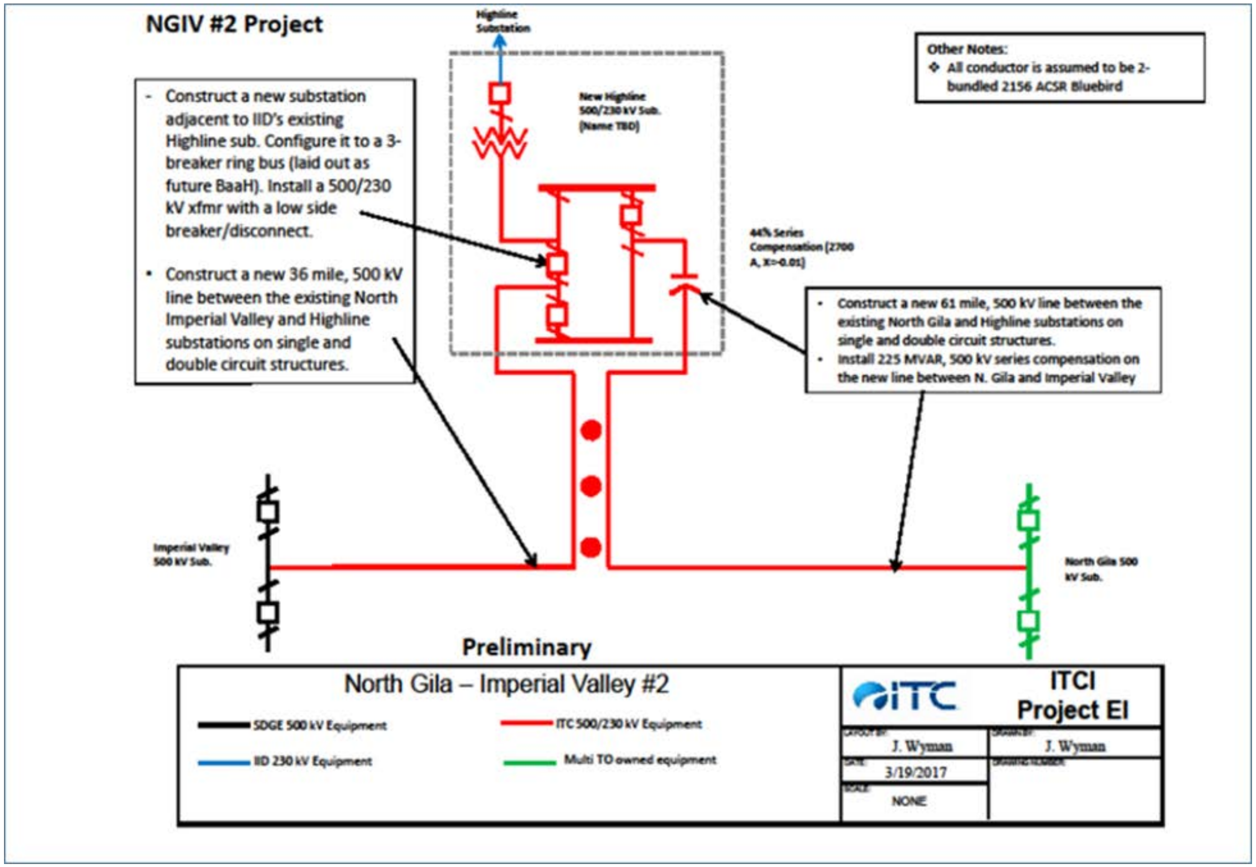
Summary of key database development steps (cont.)

- Ancillary service requirements were updated based on the new renewable and load data, consistent with the assumptions in the ISO's renewable integration study
- Wind profiles were updated for wind generators within ISO footprint
  - New profiles were calibrated to better match capacity factors in historical data
  - ADS PCM has adopted the ISO's wind profiles
- PDCI south to north path rating was modeled as1050 MW based on LADWP's operation limit
- Some SPS models were modified with tripping future renewable generators under contingencies, which helped to reduce congestion and curtailment in the corresponding areas
- Allowed renewable to provide downward load following in the model
  - Helped to reduce renewable curtailment

Future modeling enhancements

- Some potential enhancements discussed in Nov. meeting were not implemented in this planning cycle, mainly
  - Inter-tie derate due to imported A/S
    - Requires major enhancement and redesign of the model and the software
    - Will coordinate with vendors, regions, and WECC work groups in a larger framework for market model enhancement in PCM
  - Hydro generation dispatch to response to the intermittency of renewable
    - Will coordinate with vendors, regions, and WECC work groups for hydro modeling enhancement
- Will provide update of the implementations and applications to stakeholders in the future

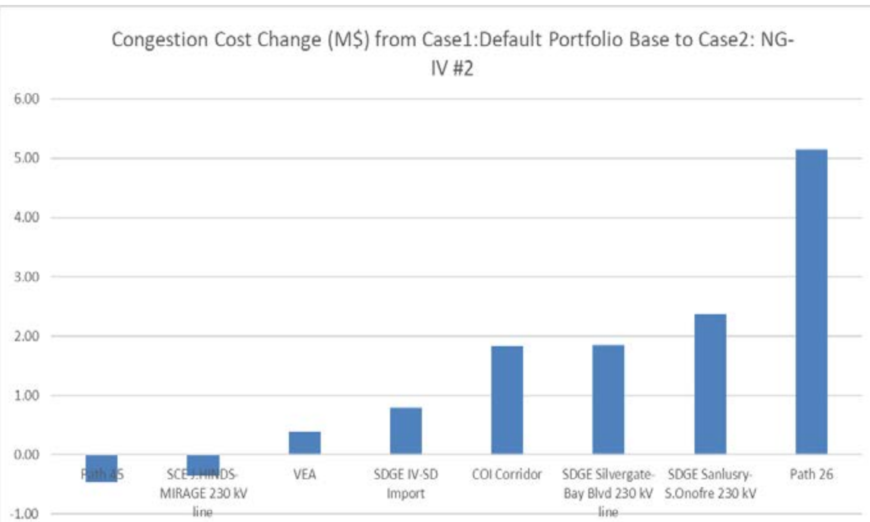
North Gila – Imperial Valley #2 500 kV Project

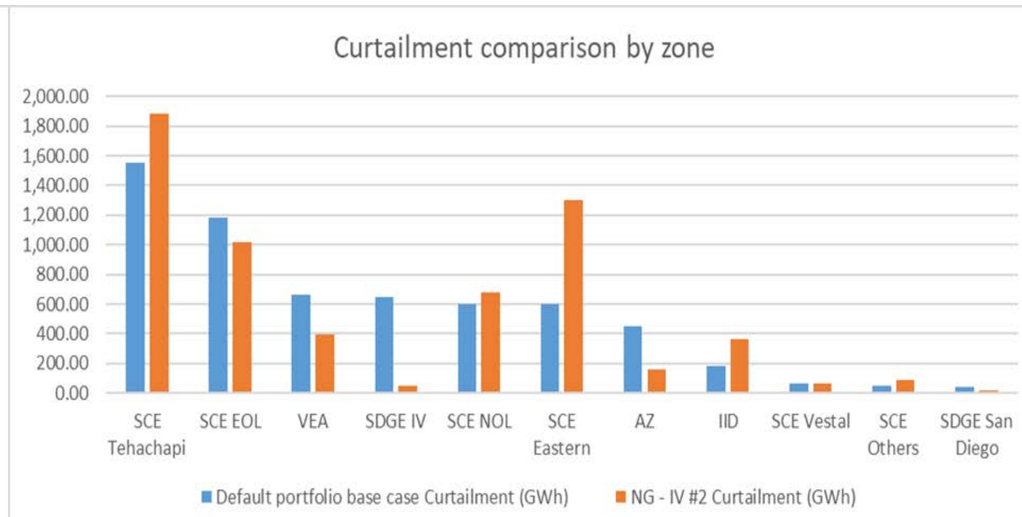


North Gila – Imperial Valley #2 – Production benefit, congestion and curtailment assessment

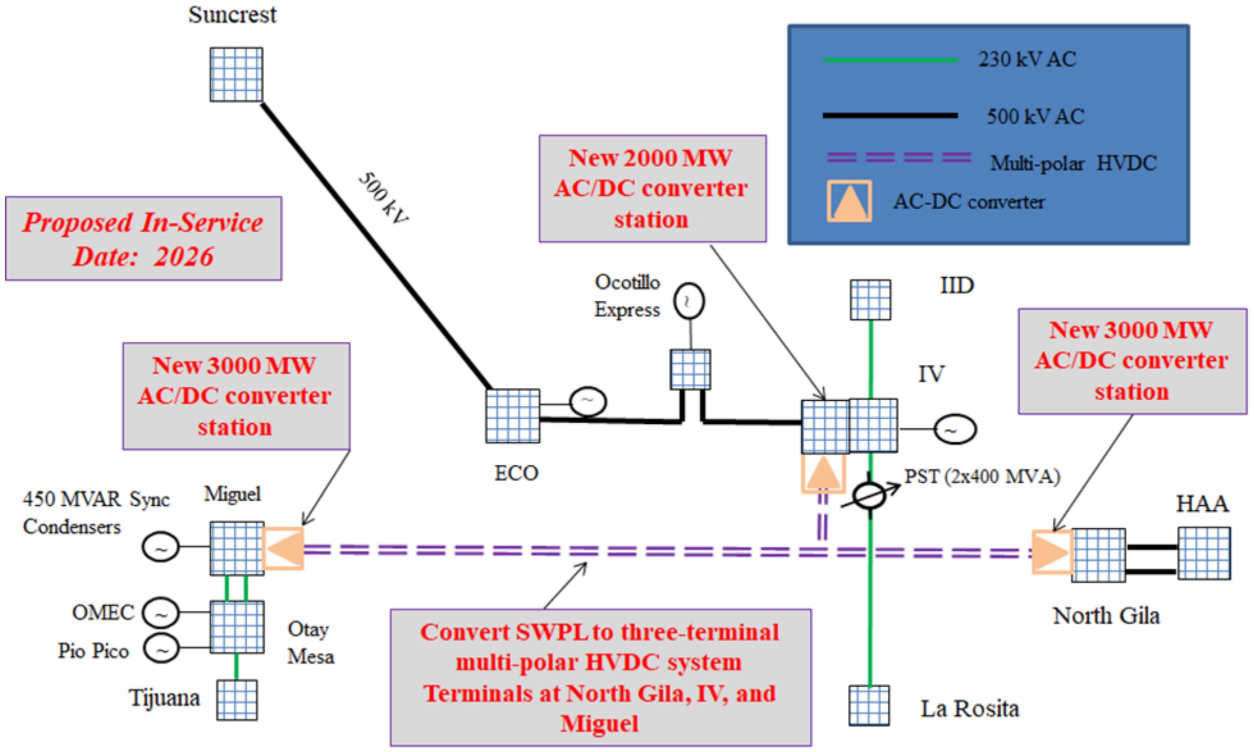
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8485	-27
ISO generator net revenue benefitting ratepayers	2526	2545	19
ISO owned transmission revenue	199	213	14
ISO Net payment	5733	5727	6
WECC Production cost	16875	16886	-11

- The project's estimated capital cost for a single circuit line is $291 million, including loop-in to IID
- With this project modeled, San Diego congestions increased





HVDC Conversion Project

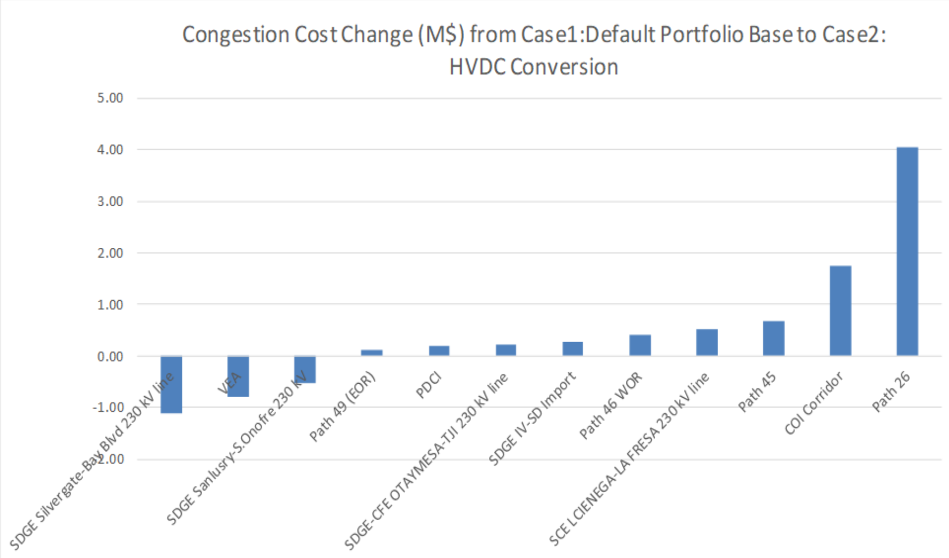


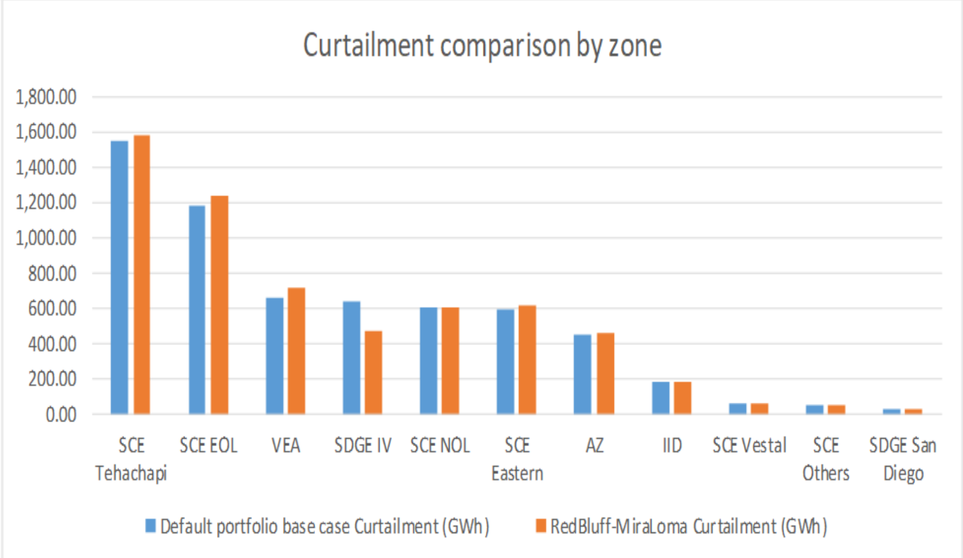
California ISO

HVDC Conversion – Production benefit, congestion and curtailment assessment

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8,464	-7
ISO generator net revenue benefitting ratepayers	2526	2,515	-11
ISO owned transmission revenue	199	204	5
ISO Net payment	5733	5,746	-13
WECC Production cost	16875	16903	-28

- The project’s estimated capital cost is $700 to $900 million





California ISO

Summary of Economic Assessments of Proposed Alternatives for Gas-Fired LCR Reduction in the Southern Area

Congestion or study area	Benefits Consideration	Economic Justification
California Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Mira Loma Dynamic Reactive Support	Local capacity benefits not sufficient	No
Red Bluff – Mira Loma 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Southern California Regional LCR Reduction Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
S-Line Series Reactor	Production cost benefits sufficient, needs further assessment when S-Line Upgrade configuration is finalized	No
HVDC Conversion	Production cost ratepayer benefits and local capacity benefits not sufficient	No
North Gila – Imperial Valley #2 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Lake Elsinore Advanced Pumped Storage (LEAPS) Project (2 options)	Production cost ratepayer benefits and local capacity benefits not sufficient	No
San Vicente Energy Storage Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore Reliability Energy Storage (SRES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore 230 kV Energy Storage (SES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Westside Canal Reliability Center (Westside) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
El Cajon Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No
Border Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No

Interregional Transmission Coordination

From last year's plan to this year's plan a final alignment with the ISO's Order 1000 tariff is in place

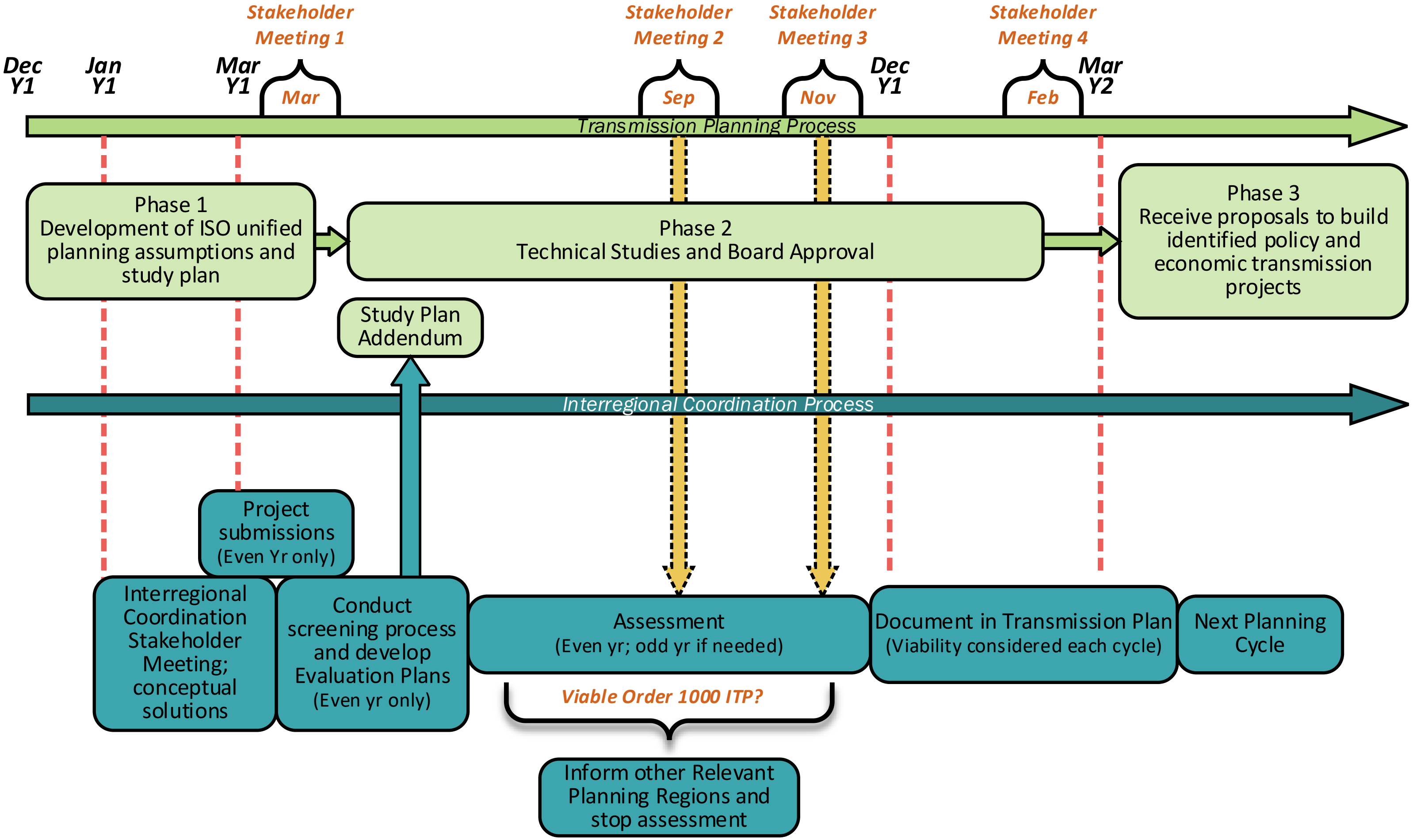
- Previous plans included "special studies" which considered Interregional Transmission Projects in a context beyond what the ISO's tariff requires
- The results of those studies were finalized in last year's plan and provided useful information for California's RPS initiatives
- In this year's plan the ISO has considered and documented its assessment of the proposed ITPs as per the defined processes specified in the ISO tariff
- Chapter 5 has been added to provide transparency on how the ISO considers ITPs in its planning process

Cost allocation is not necessary for one or more planning regions to consider an ITP within it regional process

- The assessment of an ITP in a WPR’s regional process continues until a conclusion on regional need is reached
- If a regional need is not found, no further assessment of the ITP by that Relevant Planning Region is required
- Consideration by at least two Relevant Planning Regions is required for an ITP to be considered for interregional cost allocation purposes
- Otherwise, the ITP will no longer be considered within the context of interregional cost allocation
- One or more planning regions may consider an ITP within its regional process even though it is not on the path of cost allocation
  - Planning region(s) will continue some level of continued cooperation with other planning regions and with WECC
  - Applicable WECC processes will be followed to ensure all regional impacts are considered

The ISO considers an ITP through its transmission planning process, taking up to 2 years to complete

A general representation of the ISO's Order 1000 process



California ISO

Summary of the ISO's consideration of the 2018-2019 ITP submittals

Proposed ITP	Sponsor Identified Need	Cost Allocation	ISO Identified Need in this Planning Cycle
HVDC Conversion	Improve/remove existing reliability limitation; decrease San Diego and greater IV/San Diego LCR requirement	Not Requested	Reliability: None Economic: None - BCR less than 1.0
NG-IV#2	Decrease San Diego and greater IV/San Diego LCR requirement	ISO, WestConnect	Reliability: None Economic: None - BCR less than 1.0
SWIP - North	Economic, policy, reliability, reduce congestion on COI, facilitate access to renewables in PacifiCorp	ISO, NTTG, WestConnect	Reliability: None Economic: None - BCR less than 1.0
Cross-Tie	Strengthen interconnection between PacifiCorp and Nevada; facilitate California's RPS and GHG needs	ISO, NTTG, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express AC/DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions

Frequency Response Assessment and Data Requirements

ISO Frequency Response Studies

- Study goal – determine if the ISO can meet its FRO with the most severe credible contingency – outage of two Palo Verde units
- Previous study results (2014-2015 and 2015-2016 TPP):
  - Total frequency response from WECC was above the interconnection's FRO, but the ISO had insufficient frequency response when the amount of dispatched renewable generation was significant
  - The results of the simulations did not match the actual measurements showing higher response to frequency deviations
  - The study results appeared to be too optimistic, and the actual frequency response deficiency may be higher than the studies showed
- These results were the reason to focus primarily on data collection and model validation in the 2016-2017 and 2017-2018 planning cycles

Study Conclusions

- Starting case- acceptable frequency performance both within WECC and the ISO
- Retirement of frequency-responsive units indicates the ISO may not meet NERC specified FRO requirements
  - Frequency responsive generation capacity in the ISO should be no less than approximately 30% of total resource fleet
  - An expected increase in inverter-based renewable generation will further erode meeting the ISO’s frequency response needs
- Compared to the ISO’s actual system performance during disturbances, the study results seem optimistic as such a more thorough validation of all generator models is needed
- Observation of real system operation show a withdrawal of governor response that was not observed in the simulations

The ISO improved its data collection process as part of the 2018-2019 planning process

- “Generating Modeling” section was added to the Tranmission Planning Process BPM to address data collection needs
- Five categories of participating generators were developed based on size and interconnection voltage
- Data templates available for generator owners to provide their data to the ISO
- Validated modeling data has been requested from all generators for which the ISO is the Planning Coordinator
- Process is underway; additional stages implemented between May 2019 and September 2022
- Generator owners subject to sanction for non-submittal of data

Next Steps

Pacific Northwest – California Transfer Increase Informational Special Study

Background, Objective, Scope :

- CEC and CPUC issued a letter to CAISO* requesting evaluation of options to increase transfer of low carbon electricity between the Pacific Northwest and California

- Study scope:

  1. Increase transfer capacity of AC and DC interties
  2. Increase dynamic transfer limit (DTC) on COI
  3. Implementing sub-hourly scheduling on PDCI
  4. Assigning RA value to firm zero-carbon imports or transfers

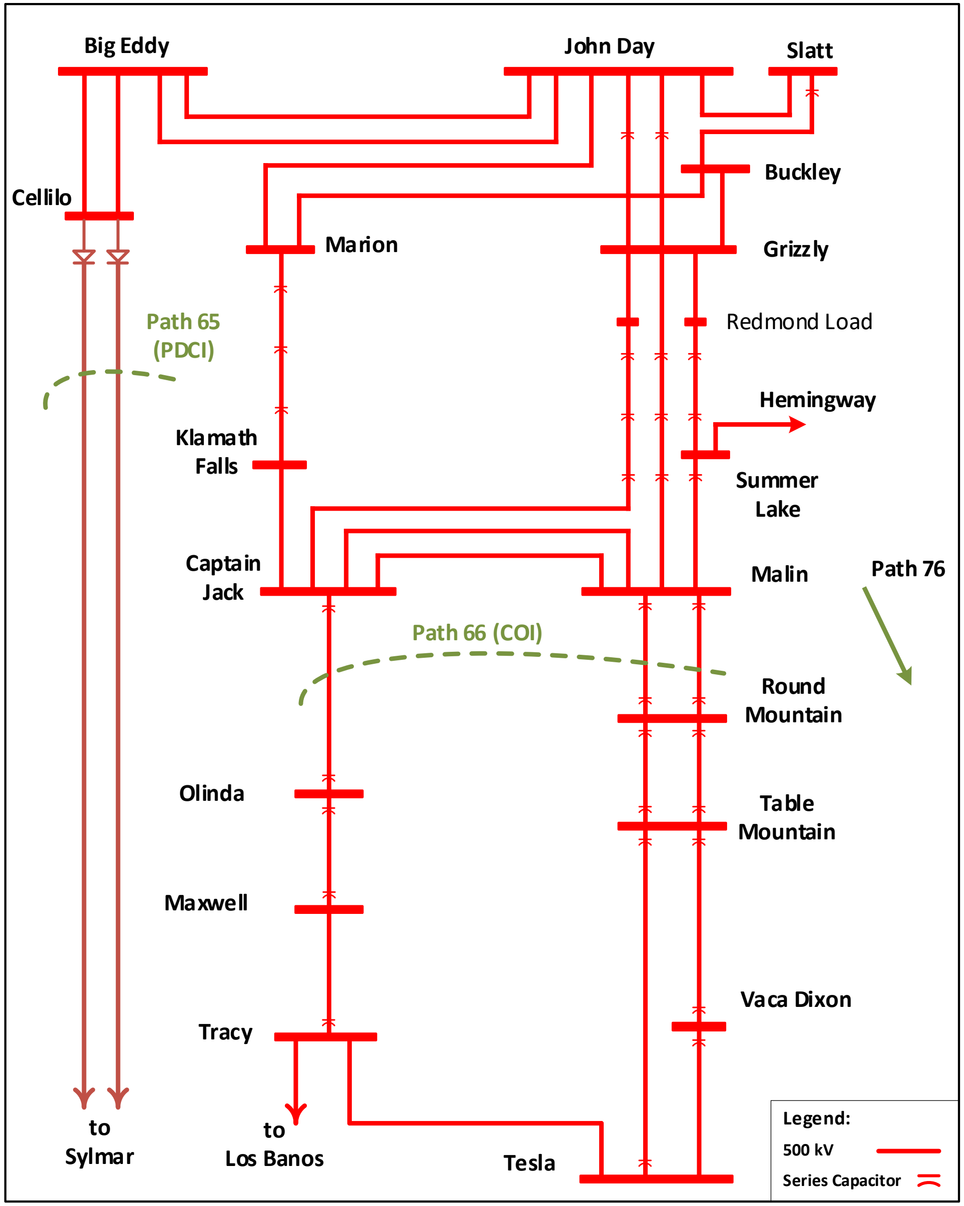
* http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

1. Increase transfer capacity of AC and DC interties

- Near-term Assessment

AC and DC Interties

WECC Path	WECC Path Rating	Operational Limits
PDCI (Path 65)	3,220 MW north to south and 3,100 MW south to north direction	3,210 MW north to south and 1,000 MW south to north direction
COI (Path 66) (California-Oregon Intertie)	4,800 MW north to south and 3,675 MW south to north direction	COI nomogram in the north to south and 3,675 MW in the south to north direction



California ISO

Study Scenarios

Flow Direction	Transfer Objective	Near-term (2023)			Long-term (2028)
		Scenario Description	COI Flow (MW)	PDCI Flow (MW)	Study objective
North to South	Energy Transfer	Late afternoon in the Summer with load almost at peak. Import from PNW to serve load in California.	5,100	3,210	Performed production cost simulation using the WECC ADS case and the updated PNW hydro model received from NWPCC to estimate COI and PDCI congestions under high, medium, and low hydro condition.
	Resource Shaping	Late afternoon in the Spring with load around 60% of peak. Import from PNW to help with the evening ramp in California.	5,100	3,210	
South to North	Resource Shaping	Mid-day in the Spring. Export surplus solar in California to the PNW in anticipation of importing from PNW to help with the evening ramp	3,625	1,500 [1]	
	Energy Transfer	Late afternoon in the Fall. Export solar in Californian to serve load in PNW	2,500-3,600	1000-1500	

[1] PDCI is operationally limited to 1,000 MW in the south to north direction.

COI North to South Path Rating

- Current Path Rating is 4800 MW
- Limiting contingency is N-2 of two 500 kV line of adjacent circuits not on a common tower
  - WECC Regional Criteria used to treat adjacent 500 kV lines (250 feet separation or less) as P7 contingency
  - WECC Path Rating process currently treats as P7
  - NERC TPL-001-4 considers it as an Extreme Event

- Assessment considered treatment as P7 contingency as well as P6 contingency to assess potential COI capability
  - ISO Operations treating the contingency as a conditionally credible contingency

Near-term Assessments Results (North-to-South Flow) Energy Transfer, Summer Evening

- For all N-1 contingencies and the PDCI bipole outage
  - The limiting condition at 5,100 MW is the N-1 contingency of one Round Mountain – Table Mountain 500 kV line overloading the other line

- For N-2 of 500 kV lines in the same corridor but not on the same tower
  - At COI = 5,100 MW, the N-2 outage of Malin – Round Mountain 500 kV #1 & #2 lines causes 10%* overload on Captain Jack – Olinda 500 kV line

- No transient or voltage stability issues

- Potential mitigation measures for N-2 are: reduce COI to 4,800 MW if the contingency is considered credible in operations horizon, additional generation tripping in NW, or load shedding in California.

* http://www.caiso.com/Documents/AppendixC-Draft2018-2019TransmissionPlan.pdf

Near-term Assessments Results (North-to-South Flow) Resource Shaping, Spring Evening

- Similar results as Energy Transfer case for N-1 contingencies and the PDCI bipole outage

- For N-2 of adjacent 500 kV lines:
  - At COI = 5,100 MW, the N-2 outage of Malin – Round Mountain 500 kV #1 & #2 lines causes 18% overload on Captain Jack – Olinda 500 kV line. Voltage at Maxwell 500 kV bus drops to 469 kV.

- No transient or voltage stability issues

- Potential mitigation measures for N-2 are:
  - Reduce COI to 4,800 MW if the contingency is considered credible in operations horizon.
  - Increase generation tripping in the Northwest
  - Load shedding in California
  - Voltage support in California
  - Use FACRI to increase the voltage and reduce the overload if the contingency is not credible.

Near-term Assessments Results (South to North Flow) Resource Shaping, and Spring Evening

- COI flow up to the WECC limit of 3,675 MW S-N is feasible for certain conditions with typical fall and spring off-peak conditions.

- LADWP is the operating agent for the PDCI at the southern terminal. PDCI flow is currently limited to 1000 MW S-N operationally by LADWP to address most, if not all, winter operating conditions.

- PDCI could be dispatched at 1,500 MW or higher in the south to north direction under certain scenarios.
  - Limiting conditions is the simultaneous trip of Adelanto-Toluca and Victorville-Rinaldi 500 kV lines overloading Rinaldi 500/230 kV transformer.
  - Real time data shows that the PDCI south to north flow are becoming more common and recently are hitting the maximum operation limit of 1,000 MW.

Comparison of PDCI and COI flows in 2017 and 2018

August

2017

2018

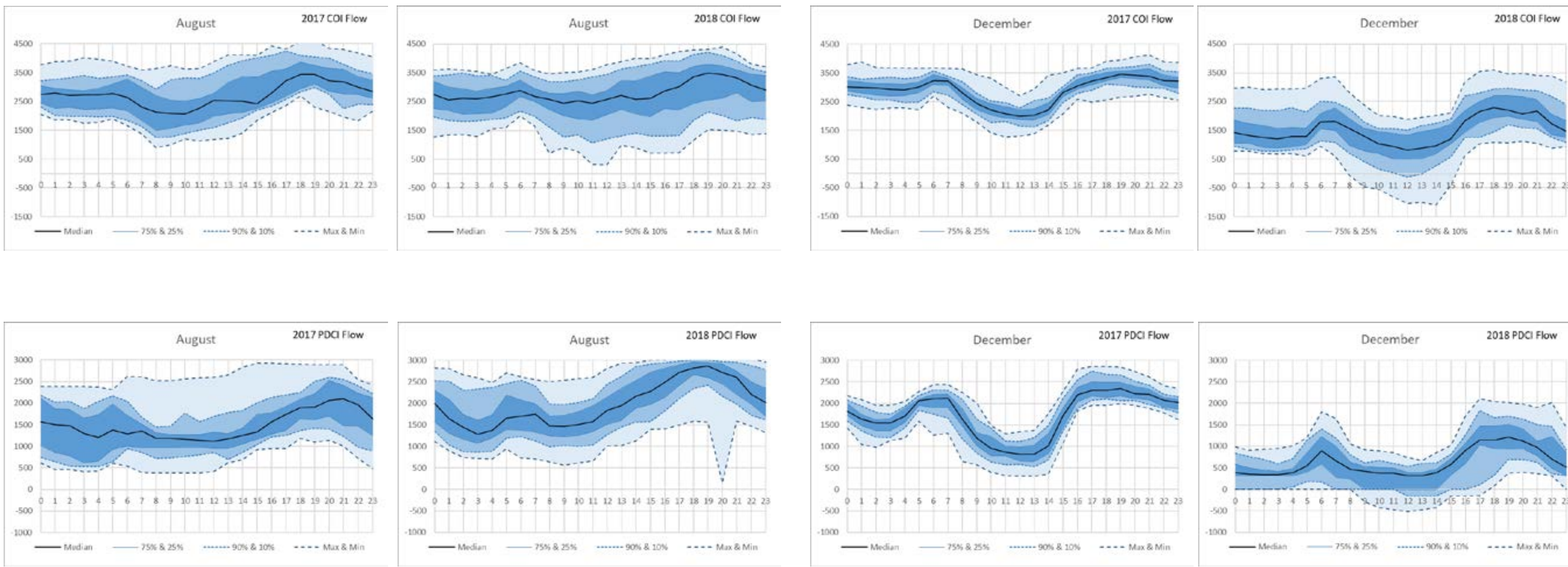
December

2017

2018

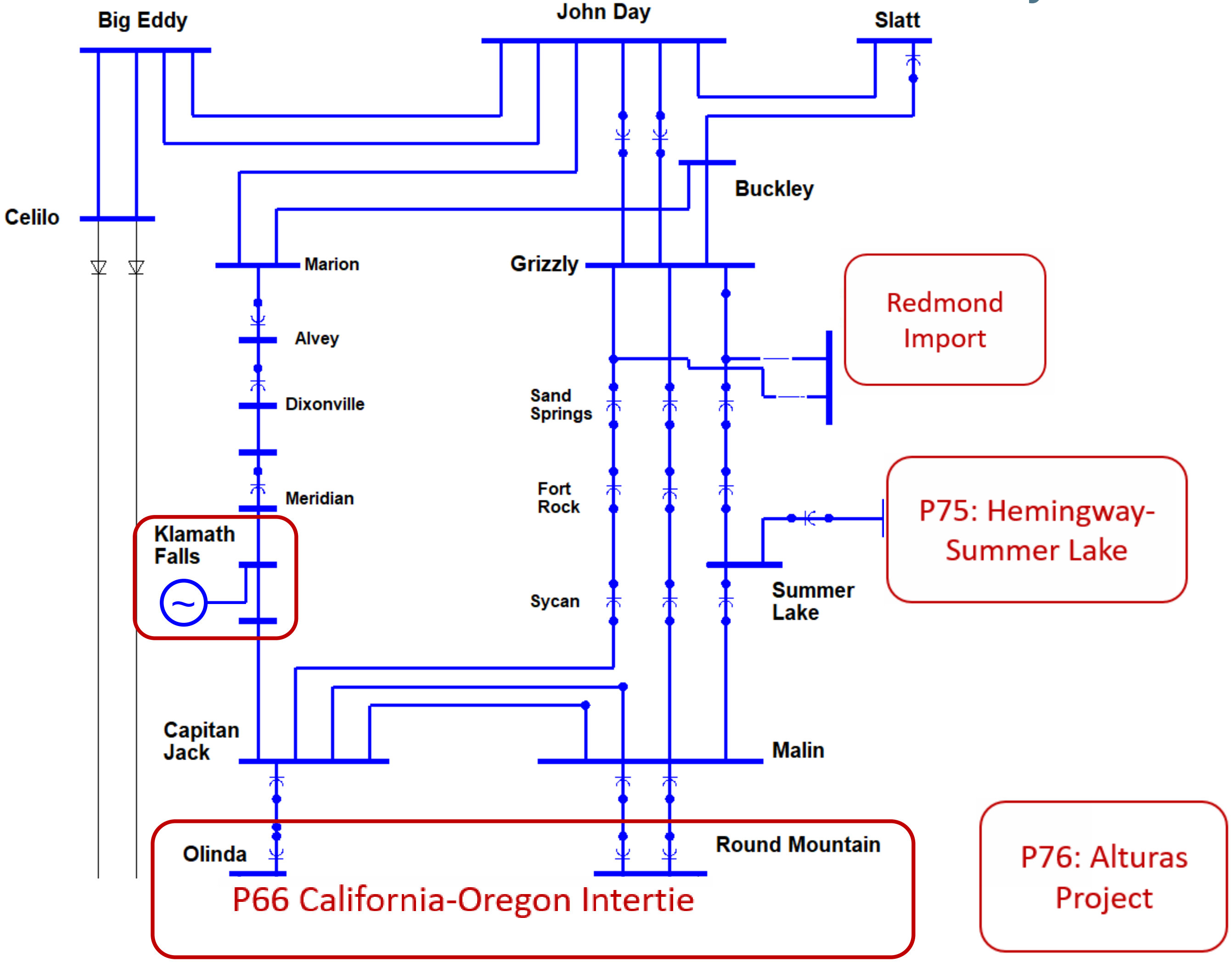
COI

PDCI



Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System

Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System

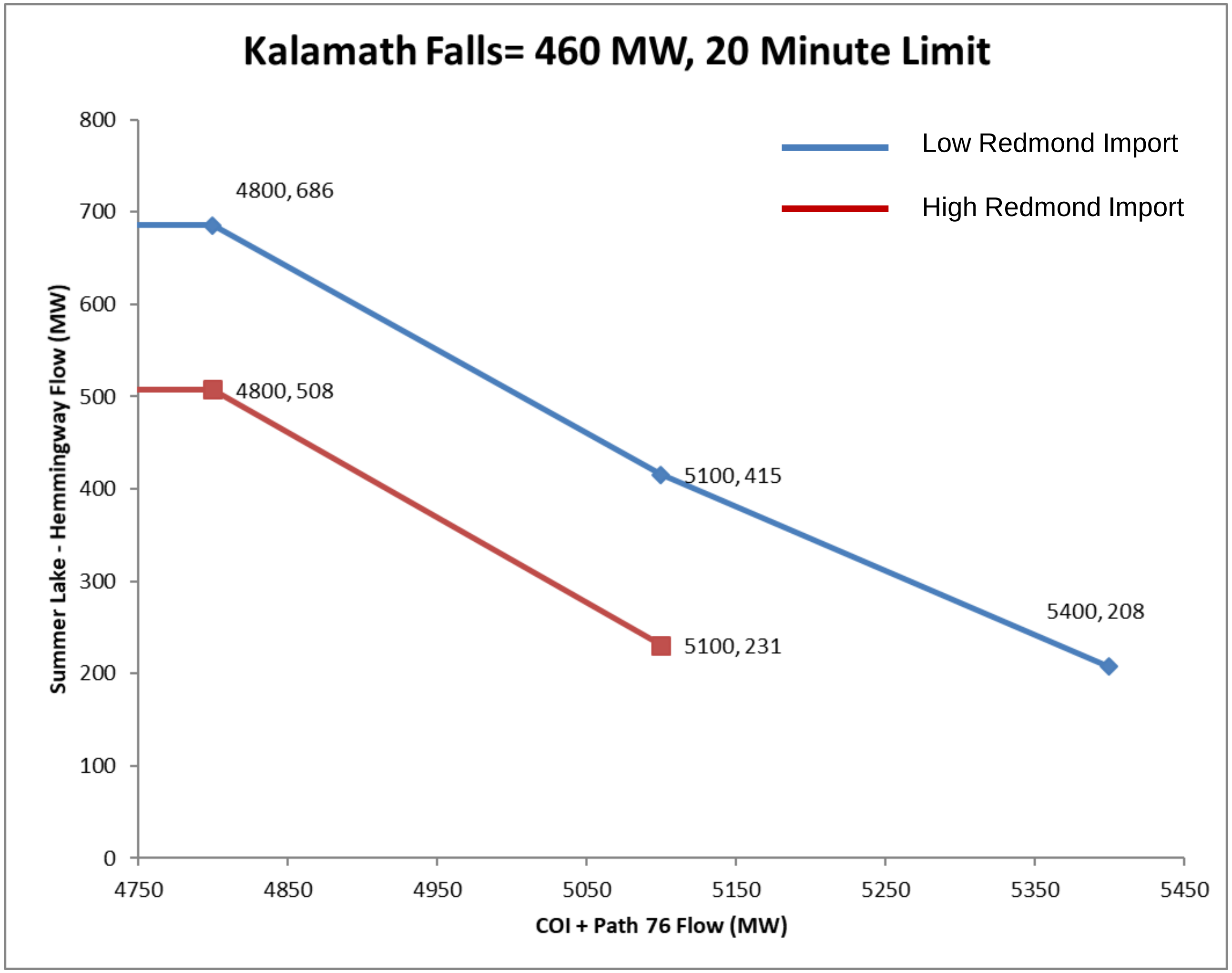


NWACI = P66+P76

NW Net Export = P66+P76+P75

California ISO

Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System



California ISO

1. Increase transfer capacity of AC and DC interties

-Longer-term Assessment - Production Cost Simulation

Pacific Northwest Hydro conditions

- The PCM case starting from ADS PCM, hence the ADS hydro condition is used
- We worked with NWPCC and BPA to developed High, Medium, and Low hydro conditions based on historical data
  - Aggregated monthly energy from hydro generators
  - Aggregated hourly maximum and minimum hydro generation output
  - The aggregated hydro data were allocated to individual units based on analysis on historical data

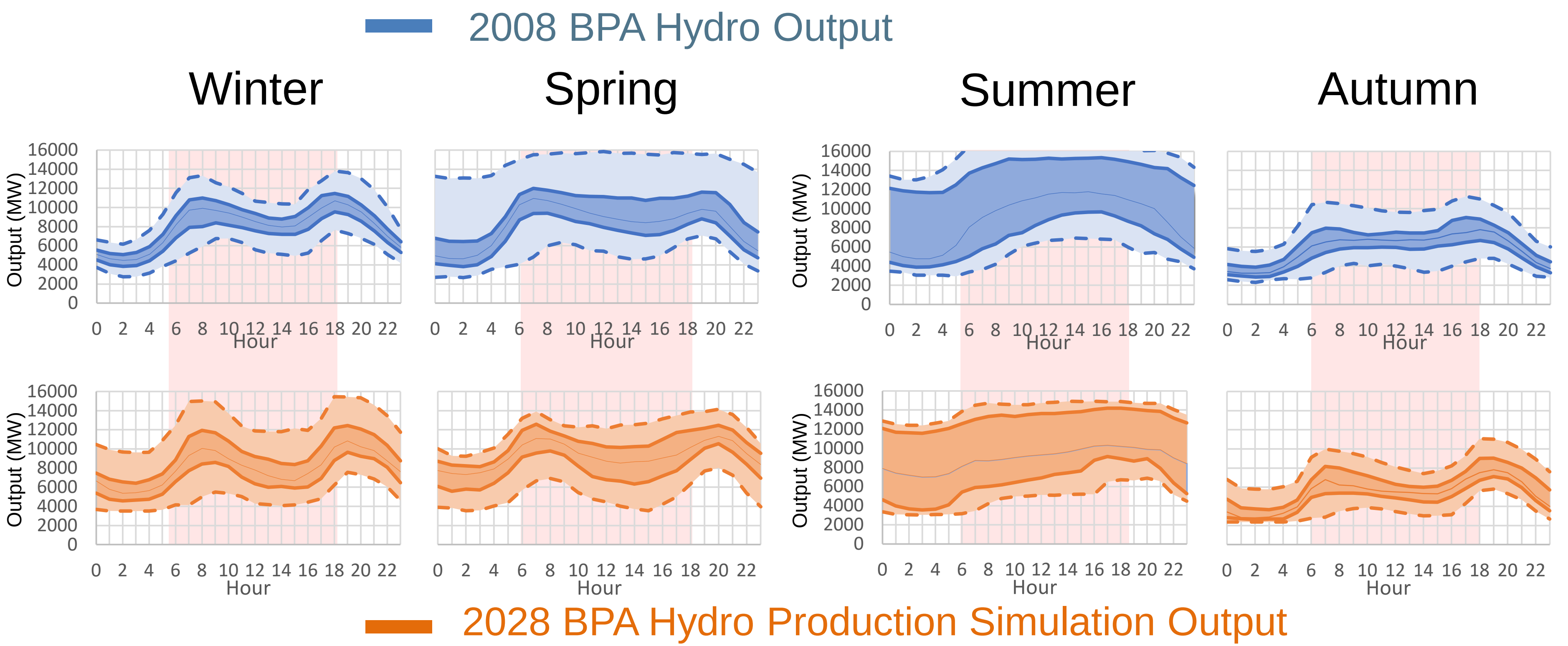
Analysis based on public data

- **California ISO, Northwest Power and Conservation Council and Bonneville Power Authority**. September 6th Portland Stakeholder Workshop. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

- **BPA**. Wind generation & total load in the BPA balancing authority. 2018. Available here: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx

- **US Army Corps of Engineers**. Dataquery 2.0. 2018. Available here: http://www.nwd-wc.usace.army.mil/dd/common/dataquery/www/#

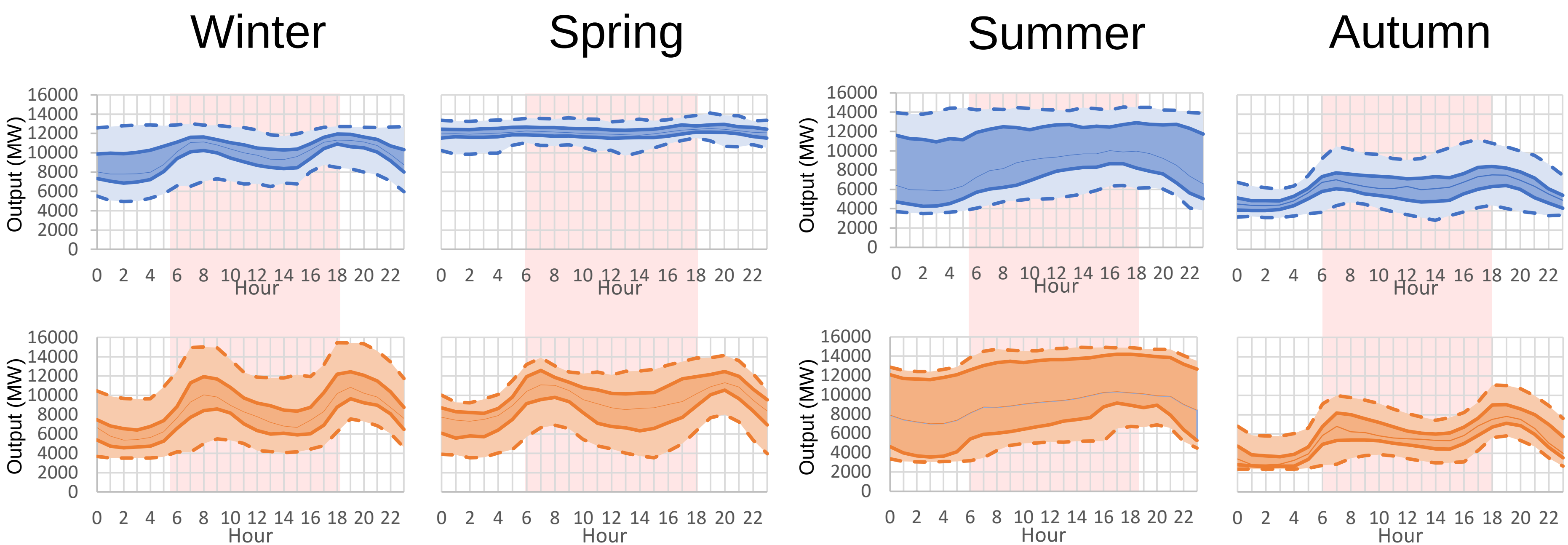
2008 vs 2028 Production Simulation (ADS Case) Seasonal output by hour



September 6th Northwest workshop. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

2017 vs 2028 Production Simulation (ADS Case) Seasonal output by hour

2017 BPA Hydro Output



2028 BPA Hydro Production Simulation Output

Northwest Power and Conservation Council's GENESYS model

- NWPCC's GENESYS model provides a chronological hourly simulation of the Pacific NW power supply (includes ~35GW of installed capacity)
- GENESYS is used for assessing resource adequacy in the Pacific Northwest
- GENESYS considers the non-power requirements of the NW hydro

September 6th Northwest workshop. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

Northwest hydro energy by month

1. High
   - o 95th percentile
   - o 1997
2. Medium
   - o 50th percentile
   - o 1960
3. Low
   - o 5th percentile
   - o 1931

COI congestion with different Hydro conditions (Congestion Hours)

	ISO Planning PCM	Medium	Low	High	ISO Planning PCM with 5100 MW COI rating	Medium with 5100 MW COI rating
COI Congestion Hours	165	387	98	482	132	281
PDCI Congestion Hours (3,100 MW Rating)	0	0	0	0	0	0
PDCI Congestion Hours (1,000 MW Rating)	385	388	Not part of the sensitivity study			

- COI congestion includes congestion of Path 66 (COI) and its downstream lines. COI congestion mainly happened during the hours COI was derated

Summary of Longer-term Assessments Results

- In the North to South flow:
  - COI congestion occurs in all hydro conditions with highest congestion occurring in “high hydro” scenario in 482 hours in a year.
  - No congestion was observed on PDCI in the N-S direction

- In the South to North flow:
  - No congestion on COI was observed in the S-N direction.
  - No congestion on PDCI assuming WECC path rating as limit.
    - There would be congestion on PDCI if the S-N is limited to 1000 MW.
  - Path 26 is congested for more than 1,000 hours in the S-N direction for the medium hydro scenario.

DTC, Sub-hourly PDCI Scheduling, and RA studies

- DTC is a 5-minute scheduling added to normal 15-minute scheduling on COI. DTC limit is currently at 600 MW. BPA's DTC Roadmap [1] details studies and mitigation measures to increase DTC.
- Currently there are no sub-hourly scheduling on PDCI
- A joint BPA/LADWP project was initiated in January 2019 and the current target is to implement the sub-hourly scheduling on PDCI by the end of 2020 timeframe.
- Historically the RA showings on COI and PDCI are less than capacity while Real Time flows are close to capacity.
- There are uncertainty on the amount of available capacity and energy that can be exported to California, increasing or decreasing, in the longer term. The ISO's RA enhancement initiative [2] or the CPUC's IRP [3] and RA proceedings [4] may address some of such uncertainties.

[1] http://www.caiso.com/Documents/AppendixH-Draft2018-2019TransmissionPlan.pdf
[2] http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx
[3] http://www.cpuc.ca.gov/RA/
[4] http://www.cpuc.ca.gov/irp/

Overall Summary, Conclusions, and Next Steps *

- The potential to increase the current WECC Path Rating of the COI from 4800 MW to 5100 MW without any material transmission upgrades has been identified.

- The ISO will continue to monitor and participate in the WECC path rating process review and if the updated process includes the conditionally credible contingency, the ISO will work with the owners of the COI facilities to initiate a WECC path rating process to increase the rating of COI to 5,100 MW.

- The ISO will also continue to monitor the progress of LADWP on the identified further study work of PDCI and BPA on the dynamic transfer capability and implementing sub-hourly scheduling on PDCI.

- Through participation in the WECC ADS process, the ISO will work with other members to ensure latest hydro models are utilized in the production cost simulation model.

- To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. Stakeholders are encouraged to participate in the ISO's RA enhancement initiative that includes a review of the MIC process, and the CPUC's ongoing RA and IRP proceedings.

* Study report: http://www.caiso.com/Documents/AppendixH-Draft2018-2019TransmissionPlan.pdf

Recent COI and PDCI south to north flows