CAISO 2017/18 Transmission Planning Meeting Sep 21/22, 2017: Stakeholder Comments

Submitted by	Company	Date Submitted
Sandeep Arora (sarora@lspower.com) (925) 201 5252	LS Power Development, LLC	10/06/17

LS Power appreciates the opportunity to provide comments on the material presented at Sep 21, 22 meeting for CAISO's 2017/18 Transmission Plan. The following comments are related to the Economic Planning – Production Cost Model Development & Interregional Transmission project evaluation portions of CAISO's Sep 22, 2017 presentation.

Economic Planning – Production Cost Model Development:

Comments previously submitted by LS Power (at the Study Plan stage of the 2017/18 Transmission Plan[1] and Study Findings stage[2] of the 2016/17 Transmission Plan) noted certain deficiencies in CAISO's economic study models that result in significantly under-estimated Day Ahead Intertie Congestion on major CAISO Intertie paths. In particular, congestion on the Malin & Nevada-Oregon Border (NOB) paths has been reported in CAISO's Department of Market Monitoring (DMM) annual reports for the last four years in the range of $49 million to $149 million per year. In contrast, CAISO's economic studies as a part of the previous transmission plans show congestion costs on CAISO's California-Oregon Intertie (COI) and Pacific DC Intertie (PDCI) paths at less than $1 million per year. As previously noted in LS Power's comments, there are several reasons for this discrepancy -- but there are ways this discrepancy can be minimized if certain modelling enhancements are made to CAISO's economic study model. While CAISO has made some modelling enhancements in the 2016/17 TPP, there are several additional ones that still need to be made in order to more accurately capture intertie scheduling constraint congestion.

LS Power recently worked with The Brattle Group ("Brattle") to model some of the enhancements it had previously proposed to CAISO as an attempt to analyze their ability to represent actual

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[1] LS Power comments on CAISO's Study Plan for 2017/18 TPP: http://www.caiso.com/Documents/LSPower_EconomicStudyRequest_Draft2017-2018StudyPlan.pdf

[2] LS Power comments on CAISO's Economic Study presentation for 2016/17 TPP: http://www.caiso.com/Documents/LSPowerComments_2016_2017TransmissionPlanningProcess_Nov16_2016Meeting.pdf

Intertie Congestion, especially on the Malin & NOB intertie scheduling constraints. A brief summary of this work is provided below and a Brattle slide deck report documenting this work is also being submitted along with these comments.

The Brattle Group Study – September 2017:

LS Power recently contracted with Brattle to conduct an economic planning study. The purpose of the study was to implement modeling enhancements to CAISO's 2016/17 production cost model and to perform production cost simulation studies to estimate the likely impact of these enhancements on congestion on the Malin & NOB intertie scheduling constraints.

<u>Benchmarking the Study:</u>

The Brattle work started from the CAISO's 2016/17 planning model database[3] which was used for the economic planning studies in the 2016/17 TPP cycle. The Brattle analysis converted that case from the native GridView data format for use in the Power System Optimizer (PSO), another commercially available production cost simulation model. PSO was used because it has the capability to simulate contract-path transactions and congestion on scheduling constraints, which apparently is not possible with the GridView model. The PSO simulation tool has been previously used for CAISO-sponsored studies, including the SB350 study.

As a first task, after converting the database to PSO, Brattle benchmarked this case against the CAISO's 2016/17 TPP economic planning study results. The outcomes of this benchmarking exercise are shown in the Brattle slide deck report which is being submitted with these comments. Although perfect benchmarking was not achieved, the amount of congestion noted using the PSO replication of the GridView case was lower than what was reported for a number of limiting constraints in CAISO's economic study. The differences relate to the fact that the models have different unit commitment algorithms (GridView uses a heuristic algorithm while PSO uses mixed-integer optimization) and how hurdle rates between balancing areas are imposed (GridView imposes hurdle rates on physical flows while PSO imposes hurdle rates on contract path transactions). However, the physical COI congestion in the Brattle benchmarking case was very close to what CAISO had identified in its TPP GridView case.

<u>Modelling Enhancements:</u>

After completing the benchmark simulation, Brattle analysis modelled the following enhancements: (a) added Intertie scheduling constraints to create a more accurate representation of WECC-wide scheduling and congestion, and (b) updated hurdle rates to better reflect the trading frictions that exist in bilateral scheduling, using assumptions from the SB350 study. In addition, Brattle simulations included a case with preliminary assumptions about existing contract paths and reduced hurdle rates for hydro resources from BC Hydro's system to

[3] Downloaded from CAISO's Market Participant Portal. This case is a 2026 system representation.

reflect the reality that PowerEx (a) likely has long-term transmission reservations to reach the CAISO's Malin and NOB scheduling points, and (b) faces very low CO_2 costs for at least a portion of its hydro imports into California based on its Asset Controlling Supplier emissions rate filed with the California Air Resources Board[4].

As a result of these enhancements, the simulated flows on Malin and NOB paths increased and were noted to be comparable to historical flows in some periods of similar net load and hydro conditions. The simulated 2026 power flows were lower than historical flows during the daytime hours due to the incremental solar generation that is projected to be online by 2026. However, the predicted flows and associated congestion on intertie scheduling constraints, such as Malin & NOB, remained high during the evening and night hours when solar generation is offline suggesting that solar buildout in California doesn't help reduce this congestion.

<u>Study Findings:</u>

The key findings of this modelling effort include:

(1) The simulation of intertie scheduling constraints shows ~$10 million in annual congestion on the Malin and NOB intertie scheduling constraints, which is over 10 times more congestion than what has been found in CAISO studies for COI and the PDCI for the last several TPP cycles but still lower than historical congestion.
(2) With the reduced PowerEx import hurdles, the simulated congestion on Malin and NOB increases to $14 million, or more than 15 times higher than in the 2016/17 TPP studies.
(3) The Brattle simulations show approximately 2,000-2,300 binding hours on Malin and NOB. While this result is still lower than the historical 2,800-4,700 hours, it is significantly greater than the 120 hours on COI and the PDCI predicted in the 2016/17 TPP.
(4) In addition to the Intertie scheduling congestion, the Brattle case also shows approximately $1 million in of physical congestion on COI, similar to what CAISO found.
(5) Additional modelling enhancements, as recommended in the Brattle slide deck report, should be implemented which will likely bring the congestion in Brattle simulations much closer to the historical $49 mm to $149 mm congestion.

<u>Conclusion:</u>

The Brattle study concluded that implementing select modelling enhancements that reflect contract path scheduling and intertie scheduling constraints significantly improves the realism of simulated congestion of these paths, partially resolving the large discrepancy between recorded historical congestion and congestion predicted by TPP studies. The study also showed that the increasing magnitude of California's installed solar capacity is not a major driver in terms of reducing ITC congestion on paths such as Malin & NOB since this congestion typically occurs during periods of no/low Solar output in California. Not all potential enhancements were

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[4] Current and historical ACS rates for BPA, Powerex, and Tacoma Power are available at: https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm

modelled in this Brattle study, but if they were, they would be expected to further reduce the discrepancy between simulated congestion in economic planning models and the actual congestion that is occurring in the CAISO market. The Brattle slide deck makes specific recommendations on what additional enhancements should be considered to simulate realistic levels of congestion on Malin & NOB.

Next Steps:

LS Power recommends that CAISO adopt these modeling enhancements for its 2017/18 TPP Economic Studies. Further, CAISO should simulate some sensitivities, such as various Hydro output assumptions for the Pacific Northwest and California, which can have substantial implications on power flows and disproportionately affect congestion over the Malin and NOB import paths, but were not explored in this study.

Interregional Transmission Project Evaluation:

LS Power has the following comments on this section of CAISO's presentation:

Robinson Summit to Harry Allen transmission capacity:

As part of its Interregional project submittal, LS Power had proposed that approximately 1000 MW of new transmission capacity will be dedicated for CAISO use after SWIP North project is built. This transmission capacity will be from Midpoint to Eldorado[5] 500 kV substations, approximately 575 miles. Pursuant to a Transmission Use and Capacity Exchange Agreement (TUA)[6] with NV Energy, once SWIP North is built there would be an exchange of capacity between Great Basin, a LS Power affiliate, and NV Energy. NV Energy would get a share of the capacity between Midpoint and Robinson Summit 500 kV and Great Basin would get a share of capacity between Robinson Summit and Harry Allen 500 kV (ON Line), without either party having to pay any amount for this capacity exchange to the other. As a result of this capacity exchange, LS Power would have bidirectional transmission capacity on the entire path from Midpoint to Harry Allen, estimated at approximately 1000 MW (subject to the terms of the TUA). This was recognized as a footnote in CAISO's presentation and we recommend that this assumption continue to be used for any future work to be done in this area. Given this, SWIP N project should not need to procure 1000 MW of transmission capacity between Robinson Summit & Harry Allen substation. Any additional transmission capacity on Robinson Summit to Harry Allen, as required to count WY wind resources as fully deliverable, can potentially be procured through NV Energy OATT.

Coal Shutdown can potentially create new Available Transmission Capacity on the existing system from WY to Midpoint:

As coal power plants east of Midpoint substation in Idaho retire, transmission capacity will likely

[5] The Harry Allen to Eldorado segment is on schedule to be in service in 2020.

[6] https://elibrary.ferc.gov/idmws/docket_search.asp [enter docket #ER16-1372]

become available on the existing transmission lines that connect wind locations in Wyoming to Midpoint in Idaho. Table 1 below shows potential coal retirements as shown for Preferred Portfolio of PacifiCorp's 2017 Integrated Resource Plan. These coal retirements can potentially make more existing transmission capacity available thereby allowing wind resources in WY to deliver to Midpoint. We recommend that CAISO analyze this further and not draw ATC availability conclusions by only looking at transmission availability on OATI OASIS.

Table 1: Potential Retirement of Coal Generation

Unit	Pmax (MW)	Dispatch level in NTTG 2016/17 base case	Potential Retirement Year[7]
Colstrip 1	330	retired	2022
Colstrip 2	330	retired	2022
Naughton 3	350	retired	2018
Bridger 1	578	531	2028
Bridger 2	578	500	2032
Dave Johnston 1	106	106	2027
Dave Johnston 2	106	106	2027
Dave Johnston 3	220	220	2027
Dave Johnston 4	330	330	2027
Naughton 1	163	122	2029
Naughton 2	201	0	2029

<u>Cost estimate for new transmission from Wyoming to Midpoint, ID</u>

CAISO studies suggest that new transmission will be needed to bring wind resources from WY into Midpoint. CAISO used the plan of service and cost estimate for Gateway West, a transmission project proposed by PacifiCorp. This cost estimate was taken from the RETI 2.0 Project Western Outreach report. However, the full build out of Gateway West should not be required to enable deliveries of wind from WY to Midpoint in light of (i) Gateway West is designed to serve PacifiCorp load (including OR and WA) as opposed to delivering to CA, (ii) the coal retirements referenced above and (iii) favorable wind resources are under development in western WY which will significantly reduce the transmission to Midpoint. The required build out should be further studied by CAISO including an examination of opportunities to re-conductor lines as opposed to building new lines. Including the full build out of Gateway West artificially inflates the cost of the SWIP N option and will skew the results.

<u>Other attributes to be analyzed:</u>

Similar to comments made in previous section on economic studies, CAISO should implement

[7] Retirement year as proposed in the Preferred Portfolio of PacifiCorp's 2017 Integrated Resource Plan. No definitive decision on retirement date has yet been announced or approved.

modelling enhancements to its production cost model for ITP evaluation as well such that intertie scheduling congestion is correctly captured on CAISO's ITC interfaces. CAISO's ATC analysis shows that ~300 MW ATC is available south of Central OR towards COI. As the Brattle study shows, if modelling enhancements are implemented in CAISO economic study models, the intertie congestion that routinely gets recorded to CAISO's Malin & NOB paths does get captured in the studies. Given this historical congestion on this path, an additional value of SWIP North project is that it will make 1000 MW of new scheduling capability at Midpoint for Hydro and other energy schedules from Pacific Northwest that typically get curtailed due to congestion issues on Malin & NOB. These will now have an alternate path to get to California from Central OR to Central ID (as shown on Page 37 of CAISO's Sep 22, 2017 TPP presentation).

<u>Reliability impacts of projects</u> - When analyzing reliability impacts of ITP projects, in addition to the metrics CAISO developed, consideration should also be given to the following metrics for ITP comparison:

(1) Is the line outage of an ITP itself posing any reliability risks to the Bulk Electric System? Will a SPS be required that would trip several generators for loss of the ITP line? If so, what is the impact of the SPS on grid reliability and are there any operational & market implications from this SPS in terms of the need for CAISO to procure additional operating reserves to protect against loss of the ITP line?
(2) Does the ITP project bring any benefits to the WECC system as a whole? For instance is the ITP project a network line (vs a long gen tie line) that could help further reinforce the WECC network and protect against a potential blackout that could be caused by WECC NE-SE separation[8]?

<u>EIM benefits</u> – When comparing ITP projects CAISO should also look into whether projects are helping increase EIM benefits. If an ITP is helping increase EIM transfer capability between multiple EIM regions, this should be a huge benefit to all regions and should be noted accordingly for ITP comparison purposes. For the RETI 2.0 Project Western Outreach report[9] this attribute of ITP projects was accounted for. The report said that "*A number of the projects would enhance the efficiency of the existing (or expanded) EIM as well as a future regional energy market. The SWIP North project is an excellent example of this. The project would increase transfer capability between NV Energy and PacifiCorp, which is currently limited to 430 MW (see Figure 10)*". CAISO's analysis similarly should account for this benefit of ITPs as well.

LS Power thanks CAISO staff for the opportunity to submit these comments.

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[8] See WECC procedure related to NE-SE separation at: https://www.wecc.biz/Reliability/WECC-1%20RAS%20Operating%20Procedure%208.22.2016.pdf

[9] See pages 68, 69 of RETI 2.0 Western Outreach Project Report, which is at: *http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf*

APPENDIX A:

THE BRATTLE GROUP ITC CONGESTION STUDY

SEPTEMBER, 2017

Modelling Enhancements for CAISO Transmission Planning

The Feasibility and Value of Incorporating Intertie Scheduling Constraints into CAISO's Planning Model

PREPARED FOR

LS Power

PREPARED BY

Judy Chang
Hannes Pfeifenberger
Kai Van Horn
Michael Hagerty
John Imon Pedtke
Jesse Cohen

October 6, 2017

THE Brattle GROUP

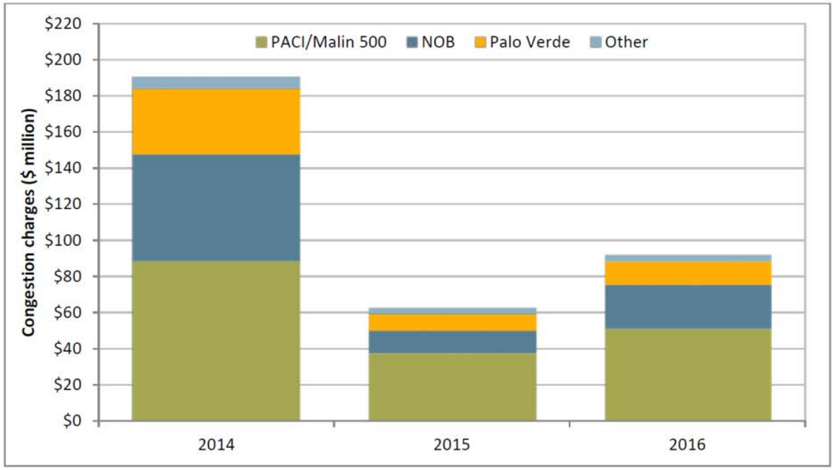
Content

Intertie Scheduling Constraint Overview

Intertie scheduling constraints (ITCs) represent limitations on transfers between CAISO and neighboring Balancing Authorities

- ITCs are contractual limitations on power flow over the transmission system rather than the physical limitations of the transmission lines
- ITC limits are based on the magnitude of CAISO's transmission rights over the interties with neighboring balancing authorities
- Historically, ITC congestion accounts for a significant amount of CAISO market congestion
  - Northwest ITCs account for ~75% of historical ITC congestion, nearly all of which occurs on NOB and Malin

Actual DA Market Import Congestion on Interties



Source: CAISO 2016 Annual Report on Market Issues and Performance, p. 180

Historical Import Congestion on Intertie Scheduling Constraints

Import Region	Intertie Constraint	Import Congestion Charges ($million)					
		2011	2012	2013	2014	2015	2016
Northwest	PACI/Malin 500	$48.9	$84.7	$34.0	$88.7	$37.7	$51.1
	NOB	$25.5	$59.2	$27.8	$58.9	$12.4	$24.3
	Rest of Northwest	$7.3	$3.7	$2.6	$2.9	$0.2	$0.4
	Northwest Total	**$81.6**	**$147.6**	**$64.5**	**$150.5**	**$50.3**	**$75.9**
Southwest	Palo Verde	$25.9	$19.2	$26.4	$36.6	$9.3	$12.9
	Mead	$8.3	$15.2	$2.2	$1.2	$1.3	$1.0
	Rest of Southwest	$3.9	$8.5	$7.4	$4.4	$5.6	$2.0
	Southwest Total	**$38.1**	**$43.0**	**$36.0**	**$42.2**	**$16.1**	**$16.0**
	Other	$0.8	$2.3	$0.2	$0.1	$0.0	$0.9
	Intertie Constraint Total	**$120.6**	**$192.9**	**$100.7**	**$192.8**	**$66.4**	**$92.8**

Source: CAISO 2013-2016 Annual Reports on Market Issues and Performance

Study Purpose

The purpose of this study and report is to:

- Demonstrate that modeling the CAISO system with considerations for Intertie Scheduling Constraints (ITCs) would better reflect actual market conditions than the traditional approach of only modeling physical constraints
- Demonstrate the potential for incorporating ITCs into CAISO transmission planning process by applying such methods/tools to the ISO’s 2016/2017 TPP dataset
- Capture scheduling congestion on the order of magnitude of observed levels of day-ahead congestion, particularly on the northern ITCs of NOB and Malin
- Identify additional updates/modifications to the transmission planning assumptions that could result in a more accurate representation of ITC congestion

Limitations of Modelling Congestion in CAISO TPP Studies

The CAISO TPP simulations understate congestion and its impact on wholesale power prices in CAISO, particularly for scheduling constraints at the interfaces with neighboring systems

- GridView does not currently have the capability to model contract paths and associated scheduling constraints in a way that captures the realities of bilateral transactions (e.g., using point-to-point transmission service)
- The ISO's current modeling database does not capture certain hydro import advantages that have a significant impact on import flows and congestion
  - The 2016/2017 TPP database captures BPA's ability to export to CA at a significantly lower carbon hurdle (based on its ACS emissions rate) than generic imports, but does not include similar assumptions for Powerex and Tacoma Power imports, both of which have excess hydro power available for exports to CA at a low CO2 import cost
  - This understates simulated imports from these entities and associated intertie congestion
- The 2016/2017 TPP database uses normal hydro, average transmission outages, and weather-normalized loads
  - Because congestion tends to increase disproportionately during abnormal hydro, outage, or load conditions (e.g., above-average NW hydro and below-average CA hydro), the normalized assumptions do not yield simulation results that reflect the average of likely future outcomes

Study Approach

We incorporated hourly contract path limits on CAISO imports to the assumptions in the ISO's 2016-2017 TPP database

- We used a commercially available production cost simulation model: Power System Optimizer (PSO), the same model used in the SB350 study
- The hourly limits are based on historical 2016 ITC limits posted on CAISO's OASIS website

For this analysis, we simulated two cases for the proof of concept:

- **Case A: 2016/2017 TPP case using PSO (no ITCs incorporated)**
  - Model input assumptions consistent with CAISO 2016/2017 TPP database
  - Provide a baseline against which we can compare the results of modeling the ITCs
- **Case B: Case A *with* ITCs simulated (with updated hurdle rates and with/without enhanced Powerex hydro scheduling assumptions)**
  - Represent ITCs that account for majority of imports/congestions in DA market
  - Modify hurdle rates and hydro assumptions to better capture bilateral trading friction in WECC and import flow from Pacific Northwest into California
  - Illustrate potential modelling assumption enhancements, such as capturing lower CO2 import rates for excess hydro, that can improve representation of scheduling congestion

For the rest of this report, we compare the results from Case A and Case B to illustrate a simulation of the 2026 CAISO system with consistent levels of CAISO congestion and power flow as history.

Major Constraints Between Pacific Northwest and California

A small number of constraints account for the majority of physical and intertie scheduling congestion between the Pacific Northwest and California.

Some of the constraints are physical and others are contractual. Thus, the system planning simulations should reflect both of these types of constraints.

- **CAISO 2016/17 TPP**: represents only the physical constraints (the first two in table below)
- **Brattle Case B**: represents both physical and ITCs constraints

Constraint	Type	Limits (Import/Export from CA)	Description
COI/PACI *California-Oregon Intertie / Pacific AC Intertie*	Physical	4,800 MW / 3,675 MW	Constrains physical flows on the 500-kV line connecting Captain Jack to Olinda and the two 500-kV lines connecting Malin to Round Mountain
PDCI *Pacific DC Intertie*	Physical	3,220 MW / 3,100 MW	Constrains physical flows on DC line connecting Celilo in BPA and Sylmar in LADWP
Malin (into CAISO) *MALIN500*	ITC	3,200 MW / 2,450 MW	Represents CAISO's transmission rights on the COI
NOB (into CAISO) *Nevada-Oregon Border*	ITC	1,591 MW / 1,520 MW	Represents CAISO's transmission rights on the PDCI

Source: CAISO 2016/2017 TPP database; CAISO Oasis

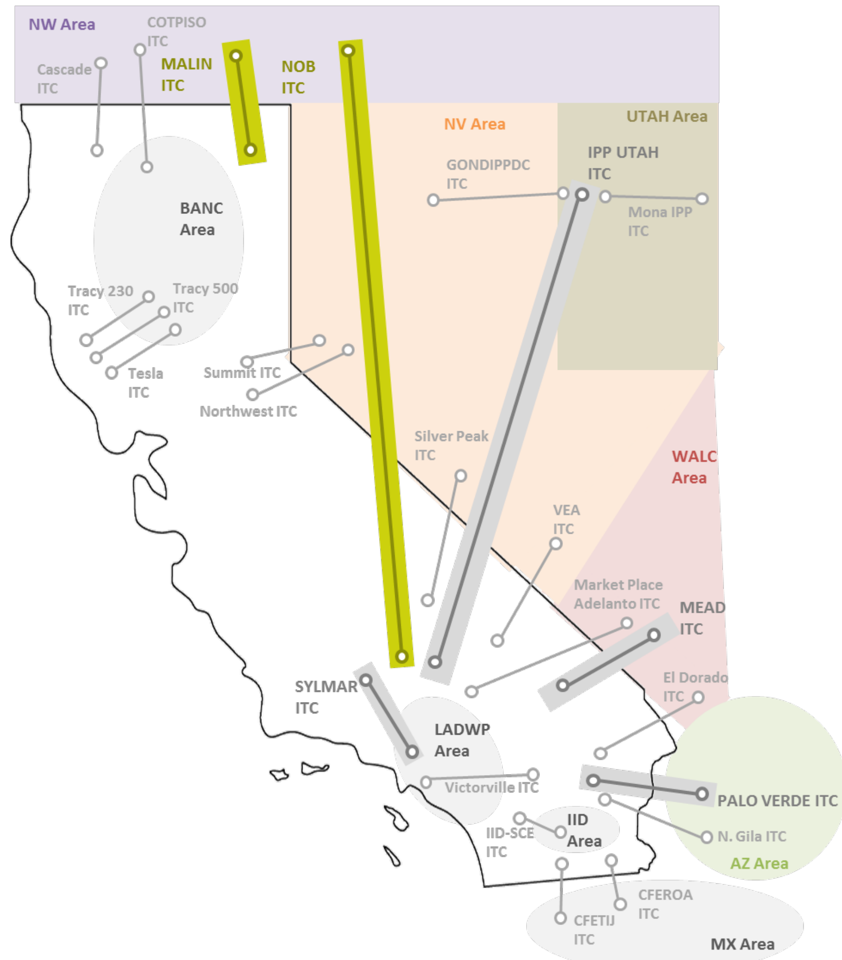
Note: The reported limits in the table represent the default limits on each constraint; hourly limits vary with outage conditions

Modeled CAISO Intertie Scheduling Constraints

In Case B, we model the six ITCs that capture the majority of CAISO import flow and congestion:

- Northwest Interface ITCs:
  - MALIN
  - NOB
- Southwest Interface ITCs:
  - PALO VERDE
  - MEAD
  - IPPUTAH
  - SYLMAR

CAISO Intertie Constraints



Summary of Key Results

Case A reasonably replicates the CAISO's 2016/2017 TPP model

- We find a similar distribution of congestion hours in the Brattle Case A and the CAISO TPP model
- CAISO's 2016/2017 Transmission Plan reports $44 million in physical congestion and 3,200 binding hours, while Brattle Case A finds $15 million in physical congestion and 2,200 binding hours
- Lower congestion in Brattle Case A is conservative in the sense that it does not simulate more congestion than the CAISO TPP model (differences likely attributable to underlying optimization model)

Case B finds 15x more import congestion on the CAISO's northern interface than the CAISO's 2016/2017 TPP model

- Scheduling congestion on both Malin and NOB is $10-$14 million in Case B, compared to <$1 million in congestion on physical import constraints (COI and PDCI) in 2016-17 TPP between Pacific Northwest and California
- The Case B results also show the additional $1 million in physical congestion on the COI and PDCI limits (consistent with CAISO 2016-17 TPP simulation results)
- The magnitude of scheduling congestion on Malin and NOB in Case B more closely aligns with historical congestion on these constraints
- Enhancing NW hydro and CO_2 cost assumptions for hydro imports into CA better align simulations with historical flows, increasing Case B congestion on Malin and NOB by about $4 million (from $10 million to $14 million annually)

Case A Simulation Metrics

Case A

Case A vs. 2016/2017 TPP Results

Congestion on Constraints Reported in CAISO 2016/2017 Transmission Plan

Transmission Constraint	2016/2017 TPP Congestion Charges (M$)	2016/2017 TPP Duration (hr)	Case A Congestion Charges (M$)	Case A Duration (hr)
BOB SS (VEA) - MEAD S 230 kV line	$23.72	600	$7.41	437
PG&E LCR	$9.73	684	$2.83	403
Path 26	$5.03	320	$1.78	650
PG&E /TID Exchequer	$1.68	651	$0.02	12
J. HINDS-MIRAGE 230 kV line #1	$1.09	187	$0.44	120
COI	$0.84	120	$1.11	363
Path 45	$0.63	655	$0.20	27
SCE LCR	$0.49	34	$0.00	0
Path 15/CC	$0.44	32	$1.64	90
Reported CAISO 2016-17 Total:	**$43.65**	**3,283**	**$15.44**	**2,102**

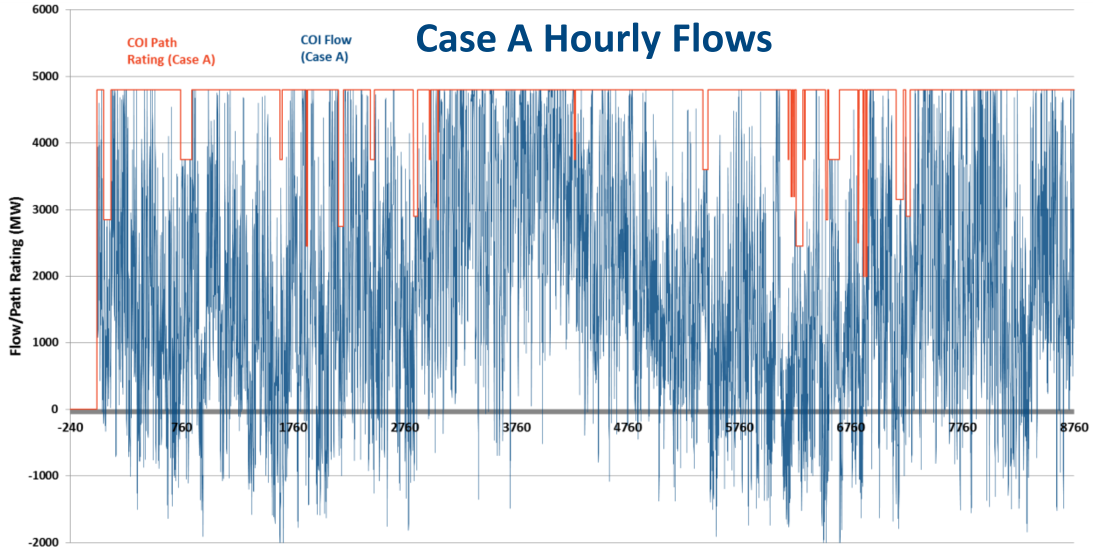
Source: CAISO 2016/2017 Board Approved Transmission Plan, pp. 179
Note: We exclude from the table constraints that show < $0.1 million in congestion in both Case A and the 2016/2017 Transmission Plan

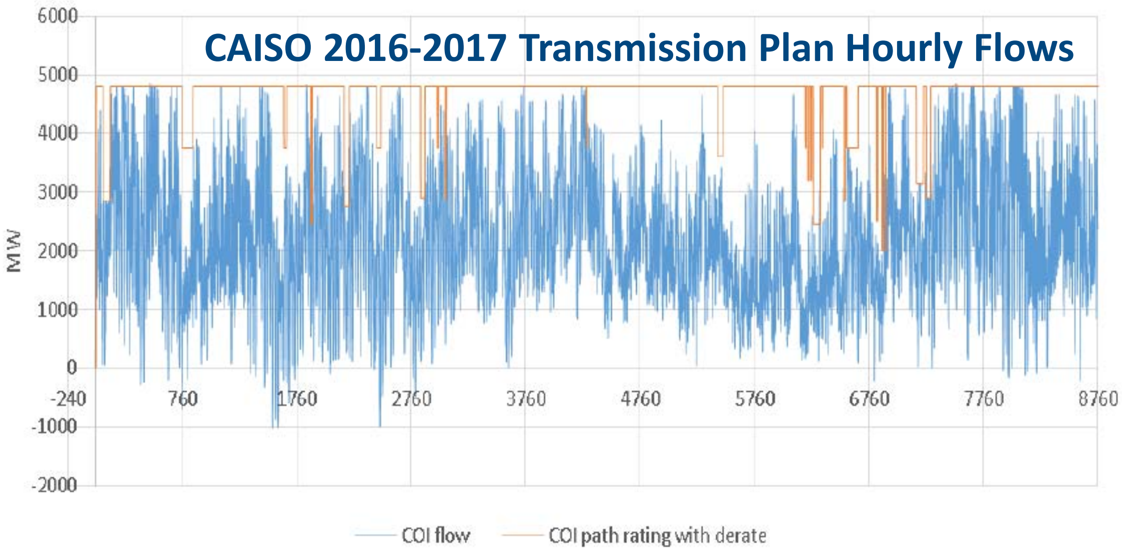
Case A congestion amounts to $15.4 million over 2,102 hours on the set of constraints reported in the CAISO's 2016/2017 Transmission Plan

- COI congestion in Case A is similar to that in CAISO's TPP model at ~$1 million
- Pattern of congestion across constraints in Case A is similar to the CAISO's TPP model
- More than 50% of the difference in congestion is attributable to two constraints:
  - BOB SS-MEAD line constraint (286 MW line in Nevada) and PG&E LCR constraints
- Remaining differences in congestion in the simulations likely due to differences in underlying modeling frameworks (such as using physical vs. contractual wheeling rates and heuristic vs. mixed integer programming optimization unit commitment in GridView vs. in PSO)
- We are unable to compare congestion on constraints that are not in the CAISO-reported list

Case A

Comparison of COI Path Flow and Ratings





Source: CAISO 2016/2017 Board Approved Transmission Plan, pp. 191

- COI flows are similar between Case A and CAISO's 2016/2017 TPP , but greater hourly variations in Case A compared to the CAISO's 2016/2017 TPP model
- We have not analyzed the drivers of the difference in flows (Will need more detailed results from the TPP model to be able to compare)
- Potential drivers of differences:
  - Realized operation of phase shifters, in particular the Path 76 phase shifter at Alturas
  - Regional commitment patterns due to underlying unit commitment approach

Case B Results

Overview of Case B

Brattle Case B simulates the ITC limitations, enhances the use of hurdle rates over contract paths and hydro scheduling assumptions to demonstrate that congestion over ITCs can be simulated with a more accurately representation of WECC system

Case B1: ITC Implementation

- Add to Case A intertie scheduling constraints based on 2016 limits and relax CAISO net-export constraint
  - Assume that explicitly representing the contractual limits between CAISO and its neighbors via the ITCs supersedes need to enforce net-export constraint
- Also updated hurdle rates to those used in SB350 Study (increases hurdle rates by \$2-\$9/MWh)
  - SB350 hurdle rates based on 2016 short-term, off-peak wheeling charges and also capture other trading friction and scheduling fees not captured in the 2016/2017 TPP database hurdle rates

Case B2: Illustrative Enhanced Hydro Scheduling and Hurdle Rate Assumptions

- Simulate BC Hydro's scheduling against weighted average of CAISO and BC net load (15% CAISO, 85% BC)
  - Represents incentives for BC hydro to capture higher prices in CA during CAISO peak net load
- Add zero-hurdle contract path from BC Hydro to Malin/NOB based on historical levels of Powerex transactions at these interties
  - Implemented rough proxy for Powerex long-term transmission contracts (assumed ~1000 MW to Malin and NOB)
- Add low CO_2 charges for hydro imports to CA from BC Hydro (similar to treatment of hydro imports from BPA)
  - Amount of hydro imports varies monthly; based on quantity of modeled hydro in excess of modeled load in BC
  - Reduced CO_2 charges for a limited quantity of imports from \$14.74/MWh to Powerex rate of \$0.66/MWh
- In the absence of publicly-available data, Case B2 only utilized informed placeholder assumptions for known market conditions that demonstrate importance of these inputs and, if refined, could more accurately capture scheduling congestion

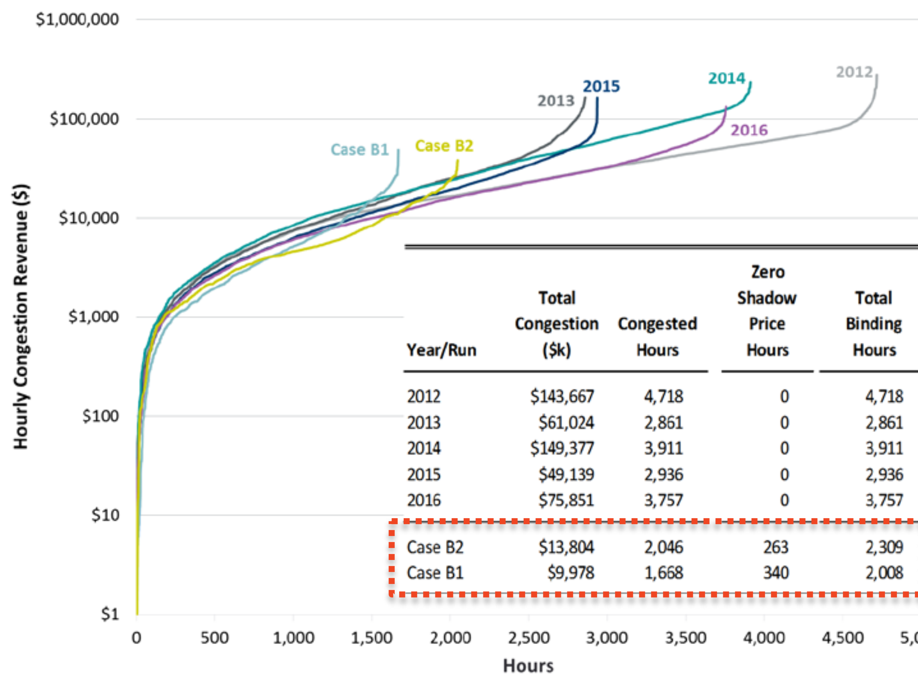
Case B

Modeled vs. Historical Congestion over the Interties

Case B's hours of congestion and congestion costs over Malin+NOB are still below historical levels, but are more consistent with the observed historical congestion levels than the current CAISO simulation results

- Case B2 finds 15x more congestion at Malin+NOB than ISO finds on COI and PDCI
  - CAISO simulations show less than $1 million in physical congestion on COI and PDCI in 2016/17 Transmission Plan
  - We find similar physical congestion on COI, as well as an additional $10-$14 million in congestion on the Malin and NOB intertie scheduling constraints
- Case B2 results in 2,309 total binding hours on Malin+NOB, compared to 2,800-4,700 hours historically
  - CAISO simulations show only 120 congested hours on COI, none on PDCI

Cases B1 and B2 and Historical Congestion on Malin and NOB Interties



Year/Run	Total Congestion ($k)	Congested Hours	Zero Shadow Price Hours	Total Binding Hours
2012	$143,667	4,718	0	4,718
2013	$61,024	2,861	0	2,861
2014	$149,377	3,911	0	3,911
2015	$49,139	2,936	0	2,936
2016	$75,851	3,757	0	3,757
Case B2	$13,804	2,046	263	2,309
Case B1	$9,978	1,668	340	2,008

Source: Historical data downloaded from CAISO OASIS; Cases B1 and B2 based on PSO simulations

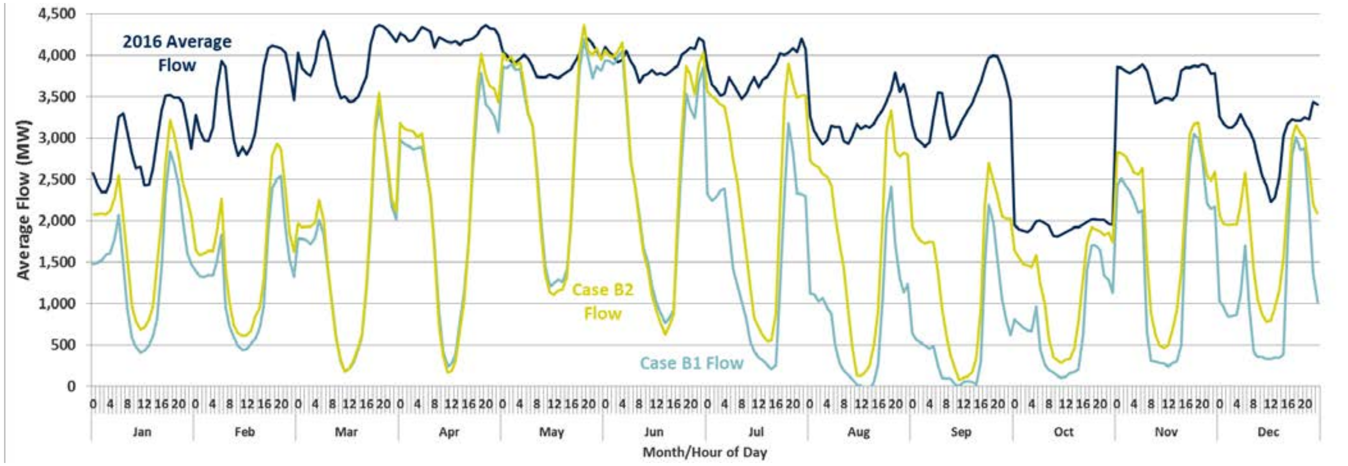
Case B

Modeled vs Historical Flows over the Interties

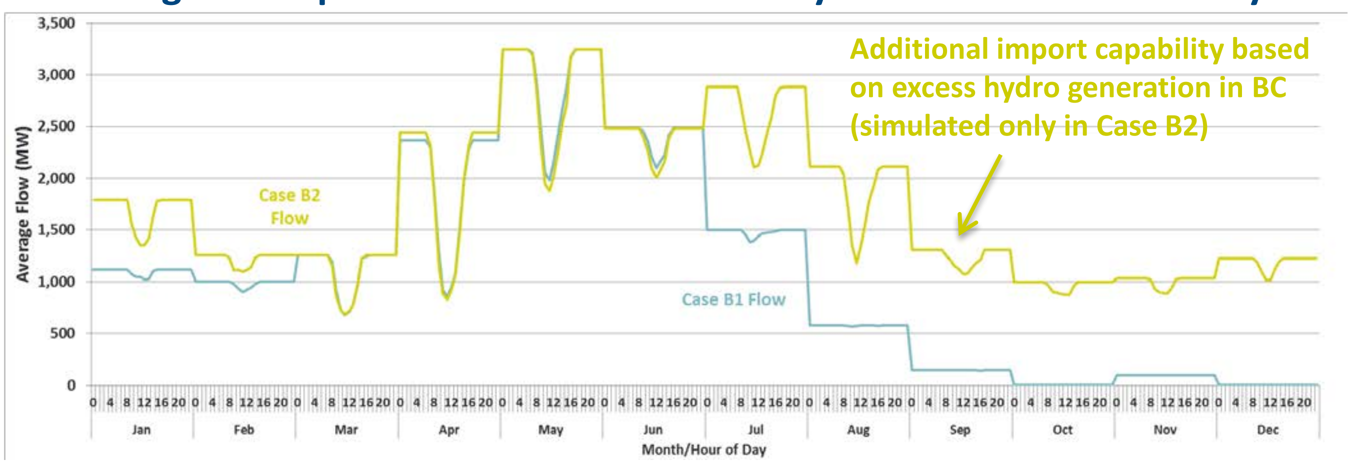
Case B flows over Malin+NOB intertie are not as high as historical levels, but are similar in high-hydro months:

- Case B1 and B2 flows are lower than historical in the daytime partly due to higher solar generation in 2026 than in historical years
- Allowing BC Hydro/Powerex to import at the reduced CO_2 emissions rate in Case B2 increases the flows over NOB and Malin, more consistent with historical flows
- Case B2 simulations show the importance of capturing assumptions about hydro scheduling and CO_2 costs to align modeled system with actual system experience

Average Flow on Malin+NOB ITCs by Month and Hour-of-Day



Average CA Imports at the Low CO2 Rate by Month and Hour-of-Day



Source: Historical data downloaded from CAISO OASIS

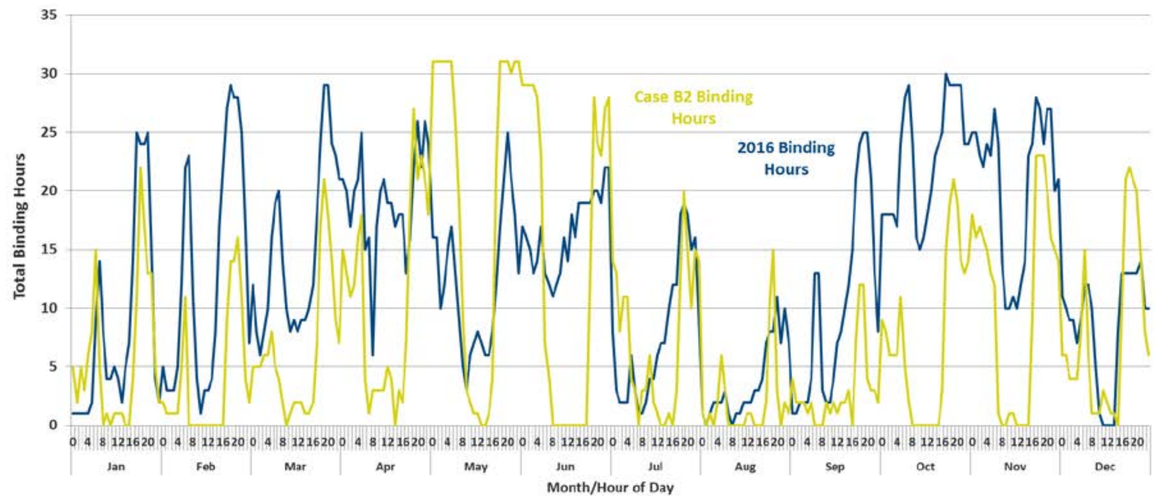
Case B

Modeled vs Historical ITC Congestion over Time

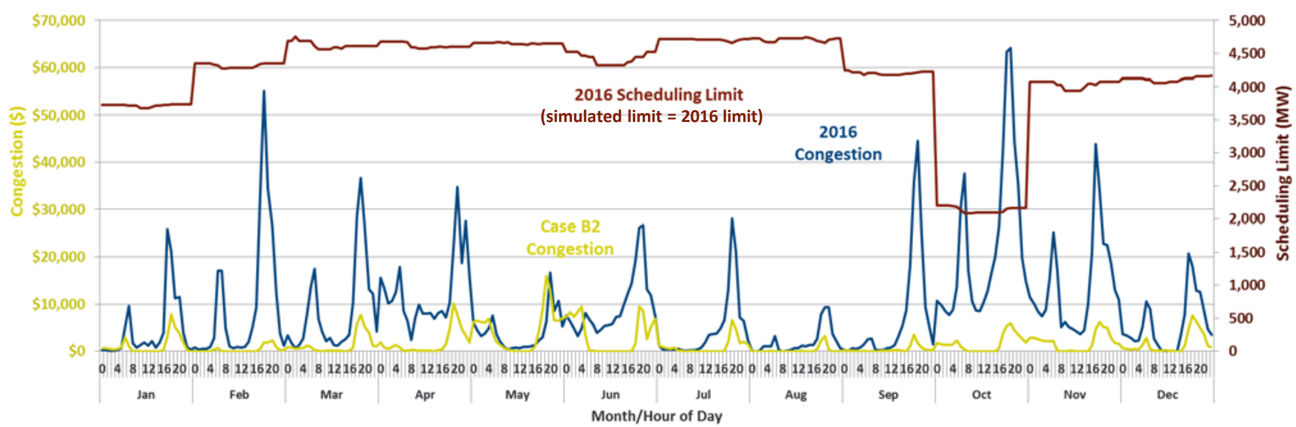
Case B's congestion pattern over Malin+NOB track historical levels

- The number of binding hours is closely aligned between modeled Case B and historical levels
- But the congestion costs are lower in Case B compared to historical levels
- The periods of highest modeled congestion coincide with the high hydro periods

Modeled vs. Historical Malin+NOB Binding Hours by Month and Hour-of-Day



Modeled vs. Historical Malin+NOB Congestion Cost by Month and Hour-of-Day



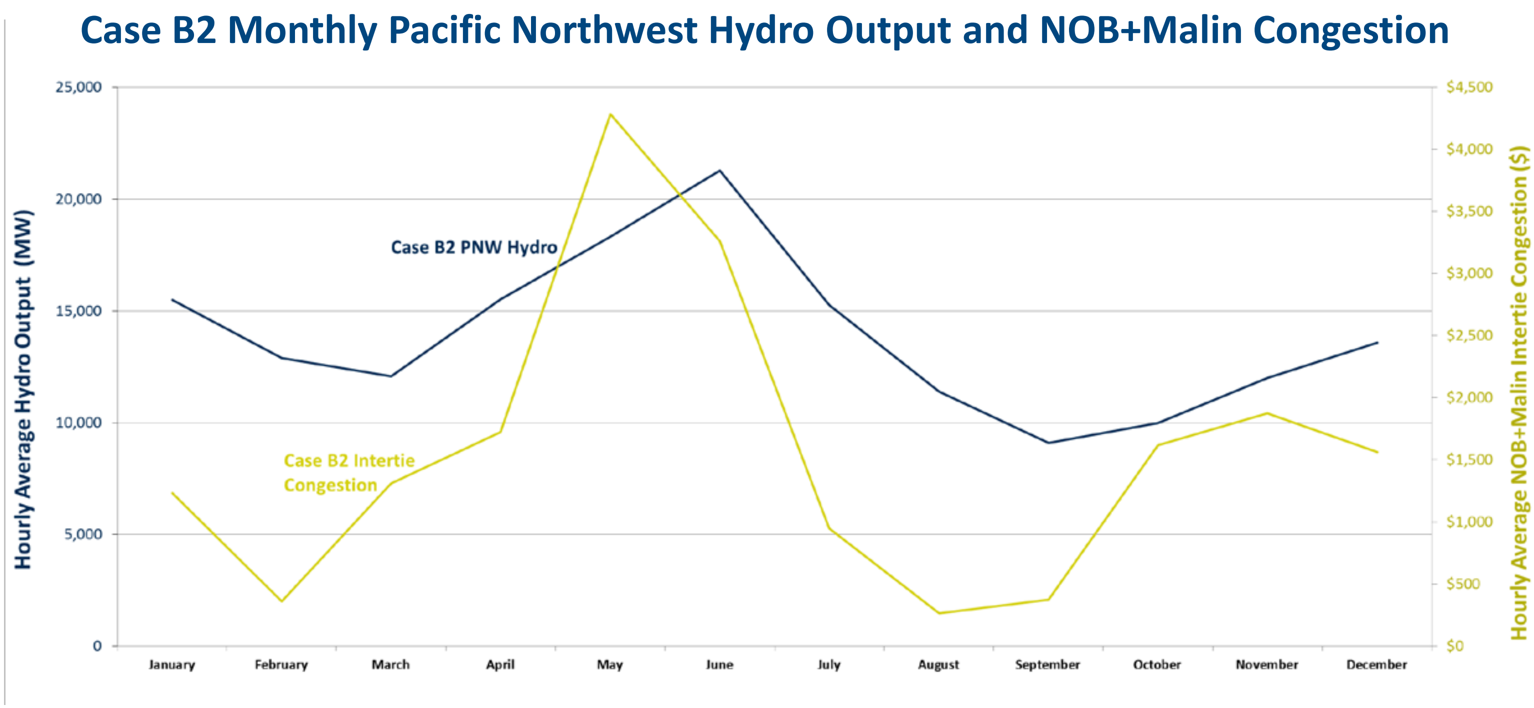
Source: Historical data downloaded from CAISO OASIS

Case B

Modeled Hydro and ITC Congestion

Hydro conditions in the Pacific Northwest are a significant driver of scheduling congestion over the NOB and Malin ITCs

- Highest congestion periods over Malin and NOB occur in the spring when hydro output from the Pacific Northwest is peaking
- Periods of lower Malin and NOB congestion coincide with lower hydro output from the Pacific Northwest



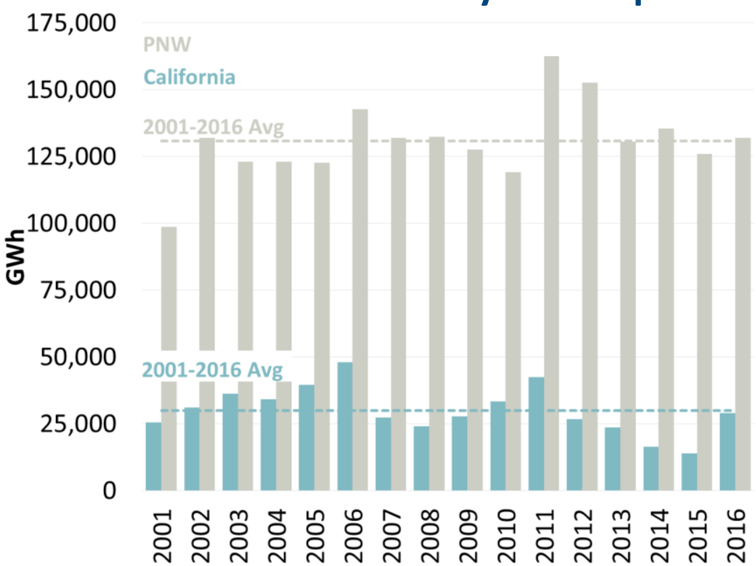
Case B

Historical Hydro Patterns

Over the past five years California and Pacific Northwest hydro have moved in different directions (for example, in 2012, CA had a low hydro year, but the Pacific Northwest experienced a high hydro year)

- The simulated 2026 year uses "average" (2009) hydro levels for both CA and the Pacific Northwest. Thus, other hydro conditions are not captured in the simulation
- However, actually hydro conditions observed historically since 2011 (high NW and/or low CA hydro) contribute significantly to high flows and congestion over Malin and NOB intertie constraints

Historical Annual Hydro Output



Source: EIA 906/920/923 filings and Brattle Analysis

Historical CA and PNW Hydro

	Hydro Output (GWh)		Percent Change from 2001-2016 Avg Output		Hydro with Respect to Avg	
	CA	PNW	CA	PNW	CA	PNW
2012	26,837	152,740	-10.5%	16.8%	Low	Very High
2013	23,755	130,580	-20.8%	-0.2%	Very Low	Avg
2014	16,409	135,494	-45.3%	3.6%	Very Low	High
2015	13,861	125,952	-53.8%	-3.7%	Very Low	Low
2016	28,945	131,986	-3.5%	0.9%	Low	Avg

Source: EIA 906/920/923 filings and Brattle Analysis

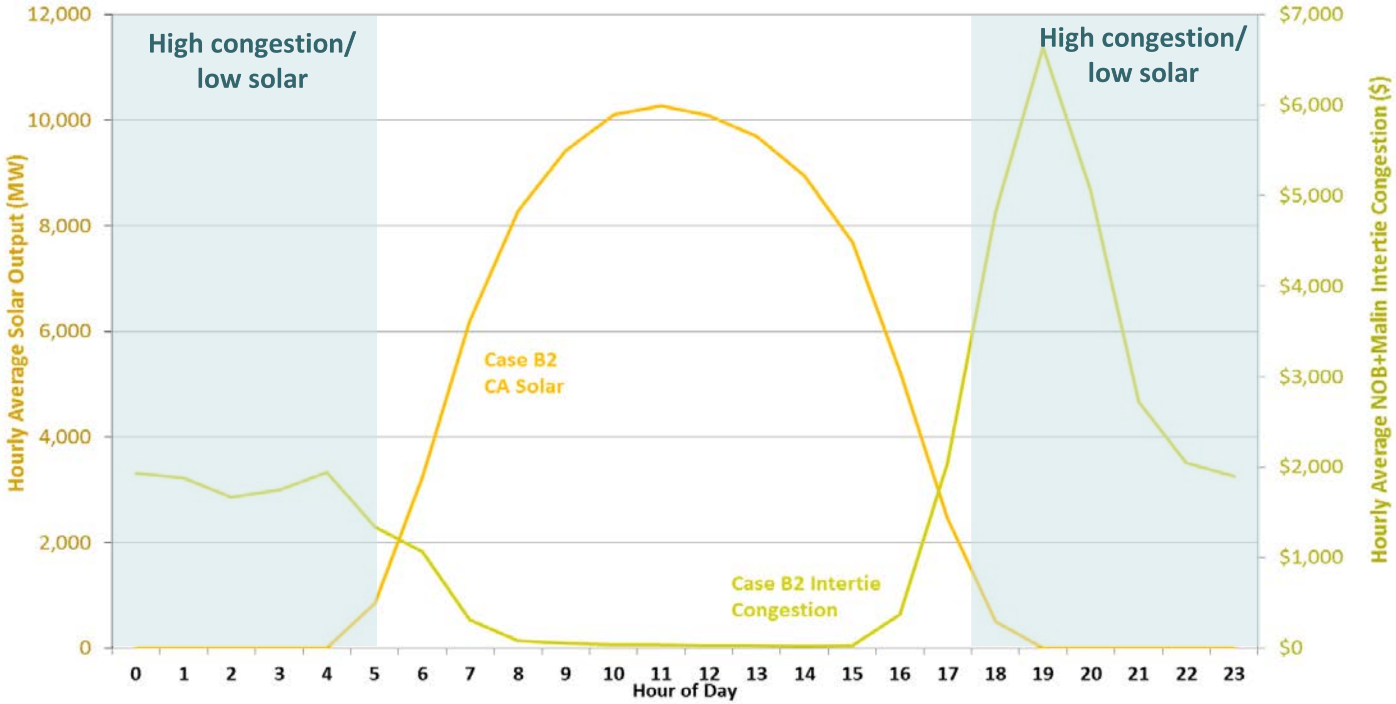
Case B

Impact of Solar on Congestion over Malin and NOB ITC

The magnitude of California's installed solar generation is not a major driver of congestion over the Northern ITCs

- The majority of Malin and NOB ITC congestion in Case B2 occurs during periods of low/no solar output in California (when net load peaks and during the night)
- Increasing solar capacity in the California will have a limited impact on reducing import congestion on Malin and NOB ITCs

Case B2 Hourly Average California Solar Output and NOB+Malin Congestion



Conclusions and Recommendations

Conclusions and Recommendations

We demonstrate the capability to represent realistic levels of CAISO intertie scheduling congestion in transmission planning models

- We find \$10-\$14 million in congestion on the Malin and NOB ITCs, which is over 15x higher than the NW import congestion in CAISO's 2016/2017 TPP simulations

We show that enhancing Northwest hydro modeling assumptions can improve the representation of system conditions on Malin and NOB

- Illustrative simulations with lower-carbon charges for imports from Powerex better align modeled and historical flow and increase modeled Malin and NOB ITC congestion by \$4 million (from \$10 million to \$14 million)
- Additional enhancements to hydro and hurdle assumptions could represent the system more realistically, and potentially increase the \$14 million in Malin+NOB simulated congestion in our Case B2 to more closely align simulation results with the historical congestion ranges of \$49-\$149 million for these ITCs

We recommend CAISO explore incorporating intertie scheduling constraints and an enhanced NW hydro representation into its simulation of the 2017/2018 TPP Economic Studies to more accurately assess benefits of the future CAISO transmission system

Additional Factors Not Yet Simulated

Other factors that could align simulation results with historical system conditions:

- Model additional hydro condition scenarios (e.g., high/low hydro from Pacific Northwest)
  - Every year since 2011 deviated significantly from "average" hydro conditions, driving more power flows from the north into California
  - Modeling CA and Pacific Northwest hydro as "average" will understate the actual flows into CA
- Capture low CO_2 costs for all Asset Controlling Supplier (ACS) improves the accuracy of the simulations
  - Imposing full carbon charges on CA imports from all BAAs except BPA dampens flows into CA
  - Should model Powerex and Tacoma hydro sales flowing into CA at low carbon charges
  - The potential high impact of improving this assumptions is demonstrated in Case B2
- Model scenarios with more extreme load conditions
  - Model currently uses weather-normalized load for all areas. This is an unlikely "average" case
  - More extreme load conditions in the Pacific Northwest and CA would reflect greater volatility in power flows and congestion
  - Simulating only weather normalized load levels likely understates flows and congestion levels
- Model scenarios with more severe transmission outage conditions
  - Some historical years, such as 2014, had extended high-impact transmission outages that are not reflected in the "average year" outage data used in transmission planning,
  - Such above-average outage conditions will reoccur in the future and tend to have a disproportionately high impact on congestion which is not captured in simulations

Modeled vs. Real-World Bilateral Friction

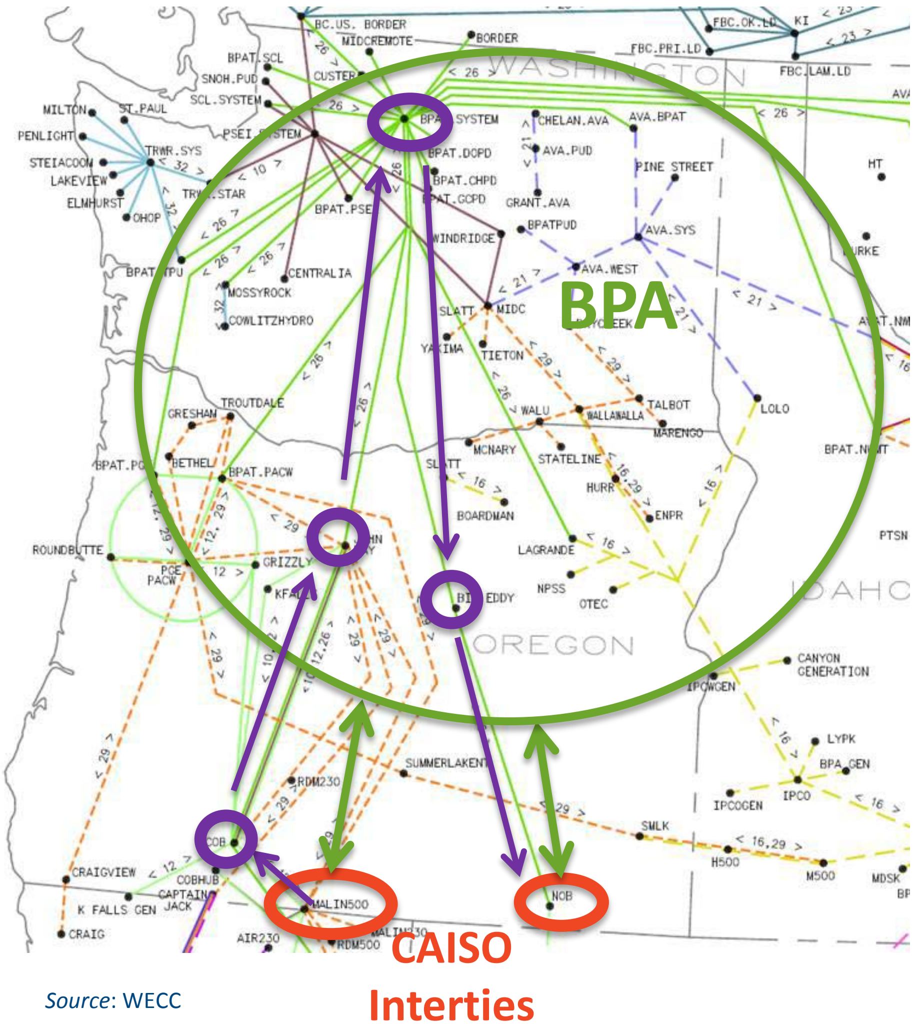
Conventional modeling of contract paths typically assumes each balancing area is a single scheduling point (the green BPA bubble in the figure)

- Provides unlimited capability and flexibility for scheduling transactions within each BA to reach interconnections with other BAs
- The bilateral frictions encountered when moving power from one point to another are not fully captured
  - e.g., going from Malin to NOB in the figure requires just two transactions in the simulations—into and out of the BPA bubble

In reality, BAs are composed of multiple scheduling points (see map of WECC scheduling points in the figure) with limited ATC

- Transfers between scheduling points through a BA may require several transactions
  - e.g., the purple bubbles and arrows in the figure
- Even when modeling limitations on BA-to-BA transactions (as represented by the ITCs), this still understates the frictions and more limited flexibility encountered by bilateral transactions within/between BAs

Modeled vs Real-World Bilateral Scheduling



Source: WECC

Power System Optimizer (PSO)

PSO is a state-of-the-art nodal production cost simulation model developed by Polaris Systems Optimization, Inc.

- Similar to GridView, Promod, GE-MAPS, Plexos, Dayzer
- Simulates security-constrained commitment and economic dispatch of generation interconnected to transmission system
- Detailed transmission representation (path ratings, thermal constraints, contract path limits, contingency constraints, etc.)
- Contract path layer (captures realities of point-to-point scheduling)
- Highly flexible reserve modelling (spin, regulation, load following, user-configurable timing and parameters)
- Configurable "decisions cycles" simulate availability of information and timeframes of operations and (e.g., day-ahead, hour-ahead, real-time)
- Detailed energy storage representation (MW capacity, MWh capacity, ramp rates, efficiency)

Author Bio

Judy W. Chang
Principal, Director
Judy.Chang@brattle.com
617.864.7900 office
617.234.5630 direct

Note:

The views expressed in this presentation are strictly those of the presenter and do not necessarily state or reflect the views of *The Brattle Group, Inc*.

Ms. Judy Chang is an energy economist and policy expert with a background in electrical engineering and 20 years of experience in advising energy companies and project developers with regulatory and financial issues. Ms. Chang has submitted expert testimonies to the U.S. Federal Energy Regulatory Commission, U.S. state and Canadian provincial regulatory authorities on topics related to transmission access, power market designs and associated contract issues. She also has authored numerous reports and articles detailing the economic issues associated with system planning, including comparing the costs and benefits of transmission. In addition, she assists clients in comprehensive organizational strategic planning, asset valuation, finance, and regulatory policies.

Ms. Chang has presented at a variety of industry conferences and has advised international and multilateral agencies on the valuation of renewable energy investments. She holds a BSc. In Electrical Engineering from University of California, Davis, and Masters in Public Policy from Harvard Kennedy School, is a member of the Board of Directors of The Brattle Group, and the founding Director of New England Women in Energy and the Environment.

Author Bio

Johannes P. Pfeifenberger
Principal, Cambridge
Hannes.Pfeifenberger@brattle.com
617.864.7900 office
617.234.5624 direct

Johannes (Hannes) Pfeifenberger is an economist with a background in power engineering and over 20 years of experience in the areas of public utility economics and finance. He has published widely, assisted clients and stakeholder groups in the formulation of business and regulatory strategy, and submitted expert testimony to the U.S. Congress, courts, state and federal regulatory agencies, and in arbitration proceedings.

Hannes has extensive experience in the economic analyses of wholesale power markets and transmission systems. His recent experience includes reviews of RTO capacity market and resource adequacy designs, testimony in contract disputes, and the analysis of transmission benefits, cost allocation, and rate design. He has performed market assessments, market design reviews, asset valuations, and cost-benefit studies for investor-owned utilities, independent system operators, transmission companies, regulatory agencies, public power companies, and generators across North America.

Hannes received an M.A. in Economics and Finance from Brandeis University and an M.S. in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

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