Informational Study:
Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California

Ebrahim Rahimi
Lead Engineer, Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting
November 26, 2018

Background and Objective:

- 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
- The request included an assessment of the role the AC and DC interties can play in displacing generation whose reliability is tied to Aliso Canyon
- An informational special study was included in the 2018-2019 transmission planning cycle

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

Study Plan

- Draft Study Plan posted on April 12, 2018
- Stakeholder call on Draft Study Plan on April 18
- Stakeholder comments submitted by April 25
- Final Study Scope posted on May 23

http://www.caiso.com/Documents/FinalStudyScopeforTransfersbetweenPacificNorthwestandCalifornia.pdf

California ISO

2018-2019 Transmission Planning Process

Study Scope for

Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California Informational Study

May 23, 2018

Final

ISO Market and Infrastructure Development Division May 23, 2018

Study Scope:

- To evaluate the impact of the following on Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California:

  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

1. Increase transfer capacity of AC and DC interties

Near-term and Long-term Assessments

- Near-term assessment (year 2023)
  - To assess the potential to maximize the utilization of existing transmission system
    - Identify minor upgrades that may be required

- Longer-term assessment (year 2028)
  - To use production simulation to assess the potential benefits of increased transfer capabilities
    - If production simulation results determine that higher capacity on AC and DC interties are beneficial beyond existing path ratings, snapshots to test alternatives to increase the capability will be developed
  - Effective hydro modeling is critical to the study

1. Increase transfer capacity of AC and DC interties

- Near-term Assessment

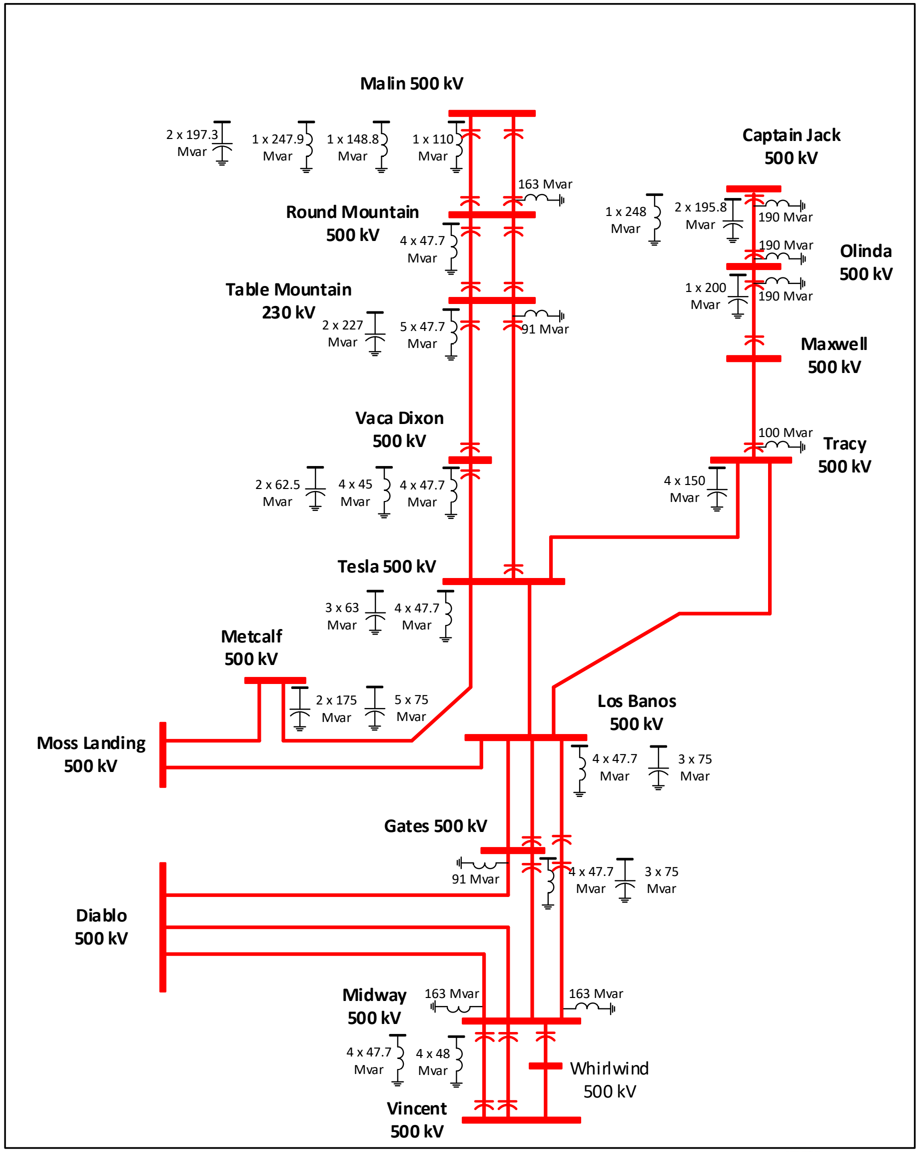
Increase transfer capacity of AC and DC interties in Near-term

- In the North to South direction the objective is to test COI flow at 5,100 MW under favorable conditions in the following scenarios:
  - Energy transfer in Summer late afternoon
  - Resource shaping in Spring late afternoon
- In the South to North direction the objective is to test PDCI flow at 1,500 MW or higher. PDCI is currently operationally limited to around 1000 MW in the S-N direction.
  - Energy transfer in Fall late afternoon
  - Resource shaping in Spring mid-day

Near-term Study Scenarios (North to South Flow)

Case Name	2023HS_ET_N-S_R2.sav	2023SOP_RS_N-S_R2.sav
Case Description	High import from PNW to CA to serve energy in California	High import from PNW to CA for Resource Shaping in early evening in Spring
Year/Season	2023, Late Summer	2023, Spring, early evening
Initial WECC Case	23HS2a1	23HW1a1
COI (66)	5,105 MW (N-S)	5,100 MW (N-S)
PDCI (65)	3,210 MW (N-S)	3,210 MW (N-S)
Path 15	1,520 MW (N-S)	500 MW (N-S)
Path 26	3,490 MW (N-S)	1,540 MW (N-S)
Path 46	7,360 MW (E-W)	4,190 MW (E-W)
Path 76	0 MW	0 MW
IPP (27)	1,720 MW (E-W)	640 MW (E-W)
NW-BC (Path 3)	2,160 MW (N-S)	2,510 MW (N-S)
ISO Load	~ 95% of peak load	~ 60% of peak load
ISO Solar	~ 0	~ 0
ISO Wind	~ 60%	~ 60%
Total ISO Import	13,260 MW	8,900 MW
Northern California Hydro	2,440 MW (60%)	1,700 MW (42%)

500 kV Transmission System



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 N-2 of adjacent circuits not on same tower as an Extreme Event
- Assessment considers 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
  - Meets all the reliability standards
    - The limiting condition 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
  - 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 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.

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

- For all N-1 contingencies and the PDCI bipole outage
  - No thermal overload issues
    - The limiting condition is the N-1 contingency of one Round Mountain – Table Mountain 500 kV line overloading the other line
  - No voltage issues following switching of shunts.
  - No voltage stability issues
  - No transient stability issues

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

- For N-2 of 500 kV lines in the same corridor but not on the same tower
  - Malin – Round Mountain #1 and #2
    - Causes 18% overload on Captain Jack – Olinda 500 kV line.
    - Voltage at Maxwell 500 kV bus drops to 469 kV
- Potential Mitigation
  - 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 Study Scenarios (South to North Flow)

Case Name	2023falloffpk_etr_pdci1000sn_v2.sav	2023falloffpk_etr_pdci1500sn_v2.sav	2023sop_rs_pdci1500sn_v2.sav
Case Description	Fall offpeak energy transfer from California to the Pacific Northwest with PDCI flow at 1,000 MW (S-N) and with COI at 3,627 MW (S-N)	Fall offpeak energy transfer from California to the Pacific Northwest with PDCI flow at 1,500 MW (S-N) and with COI at 2,543 MW (S-N)	Spring off-peak energy shaping with PDCI at 1500 MW (S-N direction) and COI at 2,725 MW (S-N)
Year/Season	2023, late fall	2023, late fall	Early spring 2023, around noon
Initial WECC Case	23HW1a1	23HW1a1	23HW1a1
COI (66)	3,627 MW (S-N)	2,543 MW (S-N)	2,725 MW (S-N)
PDCI (65)	1,000 MW (S-N)	1,500 MW (S-N)	1,500 MW (S-N)
Path 15	3,972 MW (S-N)	2,296 MW (S-N)	1,403 MW (S-N)
Path 26	661 MW (S-N)	239 MW (S-N)	1,120 MW (N-S)
Path 46	7,276 MW (E-W)	7,435 MW (E-W)	5,088 MW (E-W)
Path 76	114 MW (N-S)	114 MW (N-S)	115 MW (N-S)
IPP (27)	1,575 MW (E-W)	1,575 MW (E-W)	1,575 MW (E-W)
NW-BC (Path 3)	1,408 MW (S-N)	1,405 MW (S-N)	1,400 MW (S-N)
ISO Load	~ 61% of peak load	~ 61% of peak load	~60% of peak load
ISO Solar	80%	80%	100%
ISO Wind	~ 69% (SoCal), 3% (PG&E)	~ 69% (SoCal), 3% (PG&E)	~ 69% (SoCal), 3% (PG&E)
Total ISO Import	-238 MW (export)	-260 MW (export)	-2,927 MW (export)
Northern California Hydro	1,513 MW (37%)	1,513 MW (37%)	1,513 MW (37%)

Near-term Assessments Results (South-to-North Flow)

- For the overlapping contingencies (N-1-1) or N-2 (WECC Common Corridor) of 500 kV lines in the same corridor but not on the same tower
  - The transmission contingency of Adelanto-Toluca and Victorville-Rinaldi 500 kV lines
    - No overloading concerns
    - No voltage or transient stability concerns

- For the extreme contingency of N-2-1 of Rinaldi-Tarzana 230kV #1 and 2 lines, followed by Northridge-Tarzana 230kV line
  - Thermal loading concerns on various 138kV lines internally within LADWP's BAA
  - These are existing local area reliability concerns due to having no dispatch of local generation

- For 500kV bulk contingencies treated as either P6 or P7 of 500 kV lines in the same corridor but not on the same tower in northern California
  - Various 230kV line constraints were observed
  - Olinda 500/230kV transformer loading for the 1000 MW PDCI S-N study case

Near-term Assessments Results (South-to-North Flows)

- Potential Mitigation
  - Dispatch local generation post first contingency to prepare for the next contingency for the extreme outage loading concerns
  - For local congestion concerns, there are existing RAS schemes to mitigate (i.e., inserting line series reactor on 230kV line)
  - For other local congestion concerns in northern California, either include generation curtailments to either existing or new RAS schemes to trip generation (as a P7 contingency) or implement system readjustment after first contingency (as a P6 contingency).
  - Further details of study results will be included in the draft Transmission Plan report.

Near-term Assessments Results (South-to-North Flow) Sensitivity Studies

- Three South-North sensitivity studies were also assessed as follows:
  1. 1500 MW PDCI S-N resource shaping, spring off-peak, solar generation at 100% installed capacity, additional loads include 600 MW Castaic pump loads

  2. The above sensitivity study case, but with PDCI flow at 1,050 MW S-N

  3. 1500 MW PDCI S-N resource shaping, spring off-peak, solar generation at 100% installed capacity, high hydro generation in the Northwest, no Klamath Falls generation; this case had an earlier assumption of having local generation dispatch in LADWP's LA Basin.

Near-term Assessments Results (South-to-North Flows) Sensitivity Studies - continued

- For the overlapping contingencies (N-1-1) or N-2 (WECC Common Corridor) of 500 kV lines in the same corridor but not on the same tower
  - The transmission contingency of Adelanto-Toluca and Victorville-Rinaldi 500 kV lines
    - Loading concerns for the Rinaldi 500/230kV Bank H for sensitivity study case 1 above
    - Loading concern for the Century – Victorville 287kV line for sensitivity study case 1
- For the extreme contingency of N-2-1 of Rinaldi-Tarzana 230kV #1 and 2 lines, followed by Northridge-Tarzana 230kV line
  - Thermal loading concerns on various 138kV lines internally within LADWP's BAA
  - These are existing local area reliability concerns due to having no dispatch of local generation
- For 500kV bulk contingencies treated as either P6 or P7 of 500 kV lines in the same corridor but not on the same tower in northern California
  - Various 230kV line congestion occurs
  - Olinda 500/230kV transformer loading concern for sensitivity study cases 2 and 3
  - Round Mountain 500/230kV transformer overloading concern for sensitivity study case 2

Near-term Assessments Results (South-to-North Flows) Sensitivity Studies - continued

- Potential Mitigations for reliability concerns associated with changes to the PDCI flows:
  A. The following conceptual mitigation options could help maintaining PDCI schedules and imports into LADWP under critical contingencies:
     1. Install two 230kV phase shifters with 540 MVA, 0 to -40◦ phase angles on the Sylmar-Gould 230kV line at Sylmar end (notes: there are variations on locations for the phase shifters), OR
     2. Install RAS to trip pump loads (this mitigation option is **not** favored by LADWP)

  B. The following conceptual operating mitigations are provided here for information only. ***It is noted that LADWP System Operations retains jurisdictional responsibility for proposing and implementing operating actions. These options may involve curtailing schedules or loads under critical contingencies.***
     1. Potential operating actions to curtail pump loads after the first contingency, ***OR***
     2. Potential operating actions to reduce PDCI S-N flow to 1,000 MW after the first contingency, ***OR***
     3. Potential operating actions for implementing system operating limit for VIC-LA path

Near-term Assessments Results (South-to-North Flows) Sensitivity Studies - continued

- Potential mitigations for existing reliability or congestion concerns (these are not caused by changes in PDCI flows)
  - Dispatch local generation post first contingency to prepare for the next contingency for the extreme outage loading concerns to address existing local reliability concerns for LADWP's 138kV lines due to having no dispatch of local resources (notes: this is an existing local area reliability concern).
  - For local congestion concerns in northern California, there are existing RAS schemes to mitigate (i.e., inserting line series reactor on 230kV line, opening 500/230kV circuit breakers at Round Mountain)
  - For other local congestion concerns in northern California, either include generation curtailments to either existing or new RAS schemes to trip generation (P7 contingencies) or implement congestion management protocol for overlapping P6 contingencies.
  - Details of study results will be included in the draft Transmission Plan report.

Summary of Near-term Assessments Results

- In the North to South flow:
  - With N-2 of 500 kV lines in adjacent circuits, COI limit will remain 4,800 MW
  - If the outage of two 500 kV adjacent lines where to be considered conditionally credible contingencies (as P6), COI limit could potentially increase to 5,100 MW under favorable condition.
  - Further studies are required for COI limit beyond 5,100 MW

- In the South to North flow:
  - 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.
  - PDCI flow is currently limited to 1000 MW S-N operationally by LADWP to address most, if not all, winter operating conditions. LADWP is operating agent for the PDCI at the southern terminal.
  - However, under certain fall and spring off-peak light load scenarios, PDCI S-N flow could be operated higher (i.e., 1,500 MW) under normal condition. Under critical contingency conditions, the PDCI S-N flow would need to be reduced to its 1,000 MW limit.
  - Potential transmission upgrades, such as phase shifting transformers, could be an option for providing imports for LADWP via Sylmar path while maintaining PDCI S-N flow at 1,500 MW. This is exploratory at this time and would need further assessment for engineering and operational feasibility.

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

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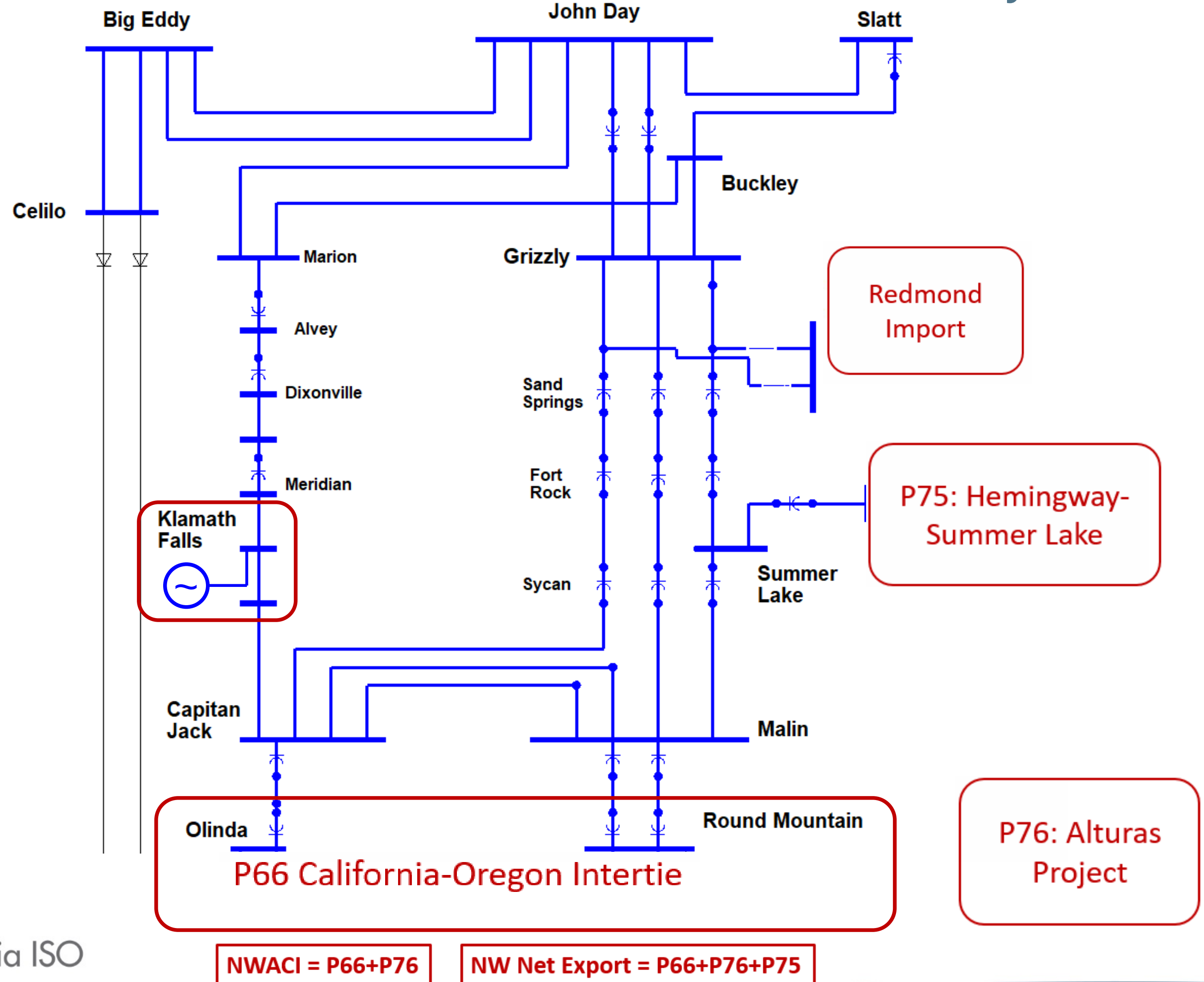
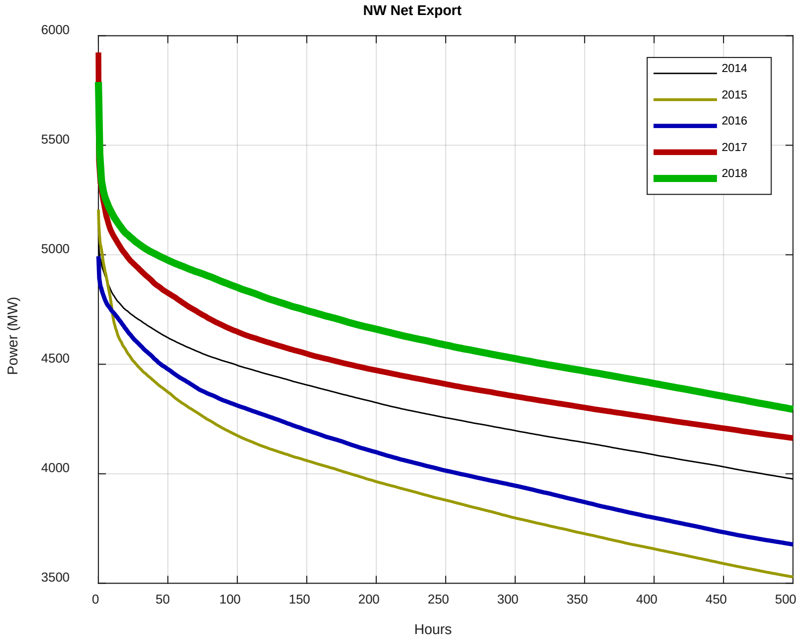
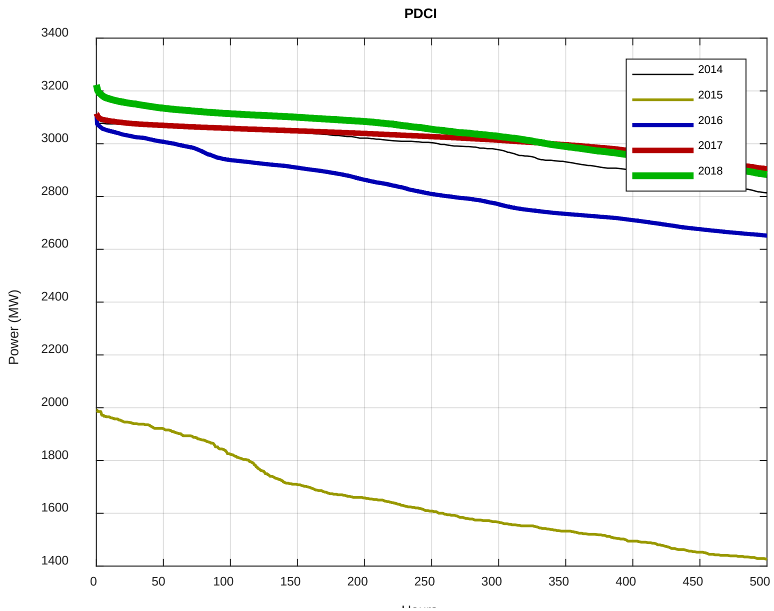


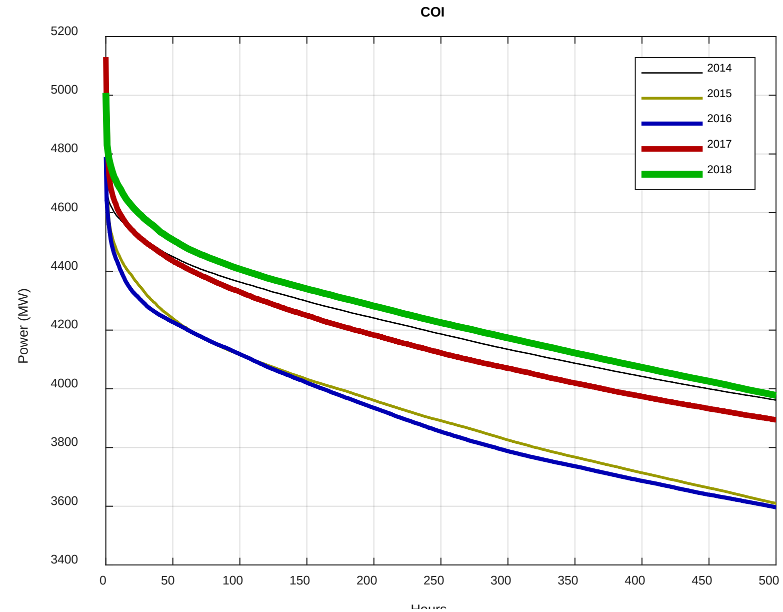
Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System



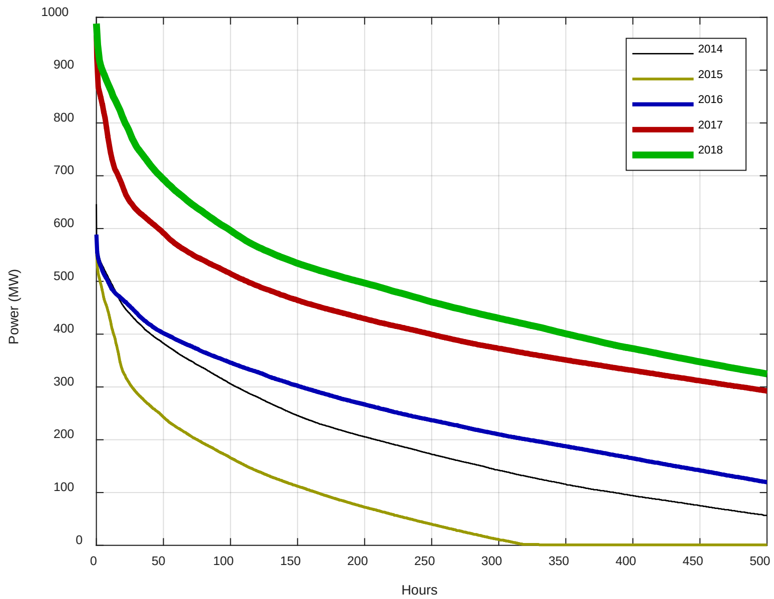
- NW exports on Southern Interties have increased in past two years
- NE Net Export = Path 66 COI + Path 76 Alturas Project + Path 75 Summer Lake
- The increase is primarily due to higher West to East flows on P75 Summer Lake-Hemingway (see next slides)

Data is from June 1 to October 1 each year

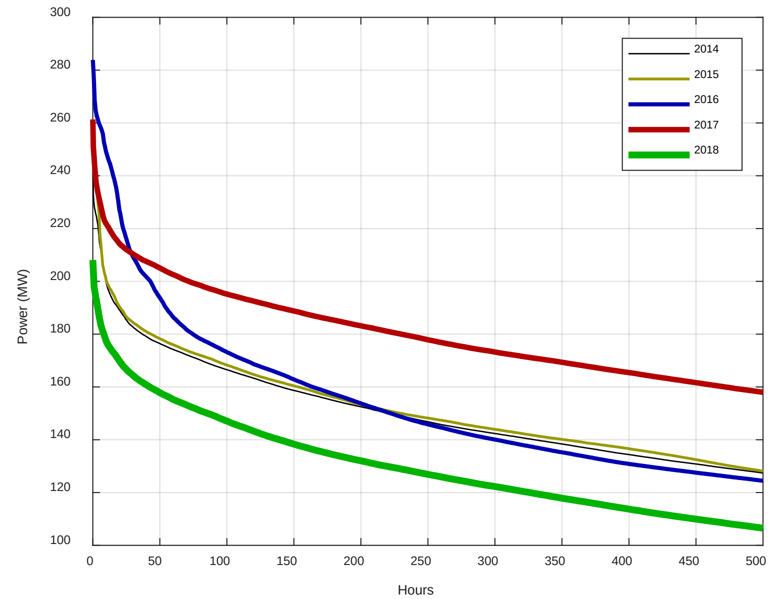




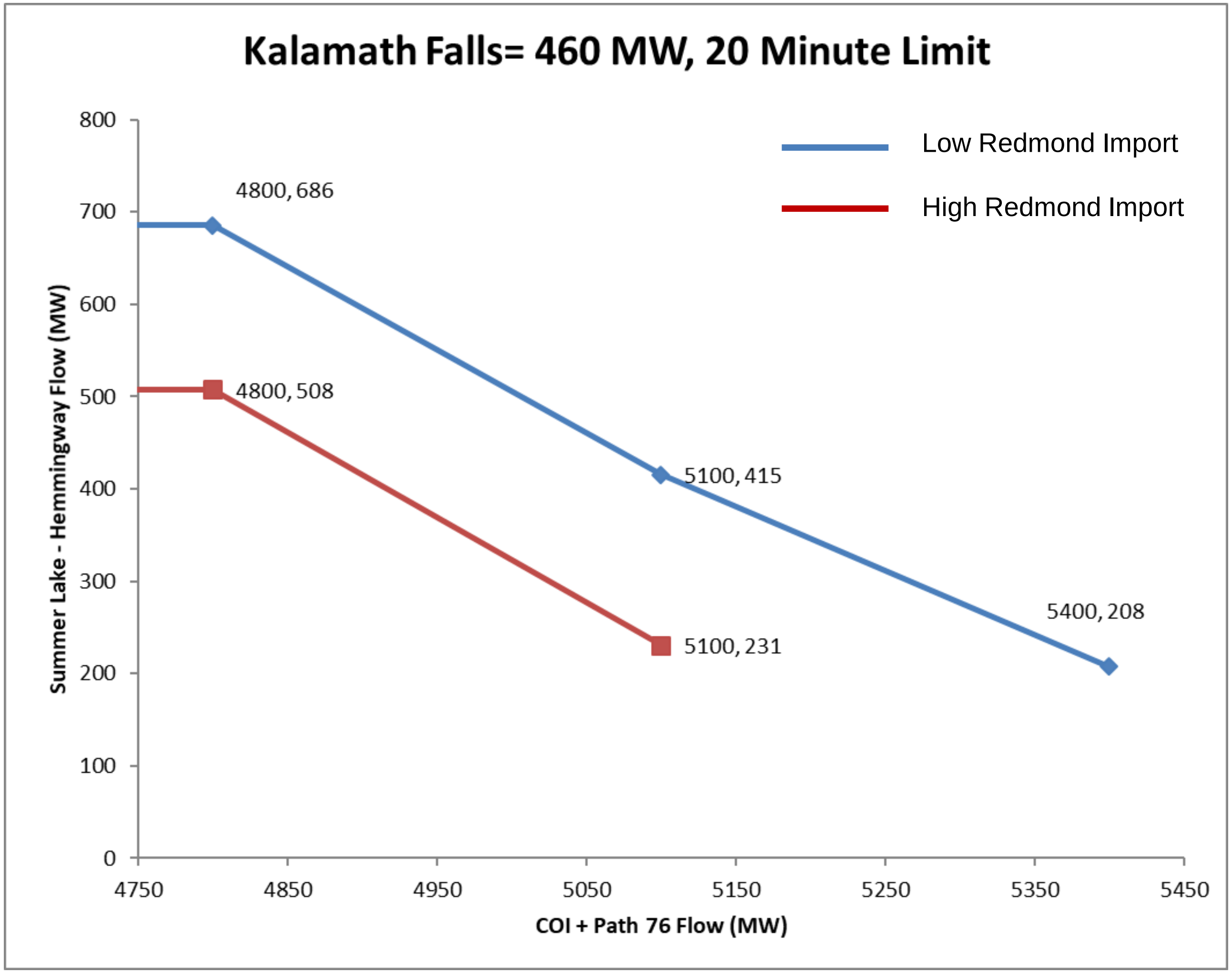
Path 75: Summer Lake to Hemingway (W-E)



Path 76: Alturas Project



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



Near-term Assessments Results
Next Steps for Studies Conducted by BPA on PNW System

- Finalize thermal and voltage stability analysis for “N-S “Energy Transfer Cases”
- Finalize thermal and voltage stability analysis for “N-S “Resource Shaping Cases”
- Finalize South to North studies
- N-2 contingency studies
- Transient stability assessment

1. Increase transfer capacity of AC and DC interties

-Longer-term Assessment - Production Cost Simulation

Increase transfer capacity of AC and DC interties Longer-Term Assessment

- Hydro Assumptions in Production Simulation Model
  - WECC Anchor Data Set (ADS) will be used for the production simulation analysis
    - ABB GridView software
  - Hydro assumptions in ADS are based on historical hydro output from 2008/2009
  - Outreach with the Planning Regions and the hydro owners to review modeling and make updates as required
    - The ISO will receive information on typical, high, and low hydro scenarios from NWPCC and BPA
    - GridView study with updated hydro assumptions will provide an insight to potential benefits of higher intertie capacity in the long term

Pacific Northwest Hydro conditions

- The PCM case starting from ADS PCM, hence the ADS hydro condition is used
- We work 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

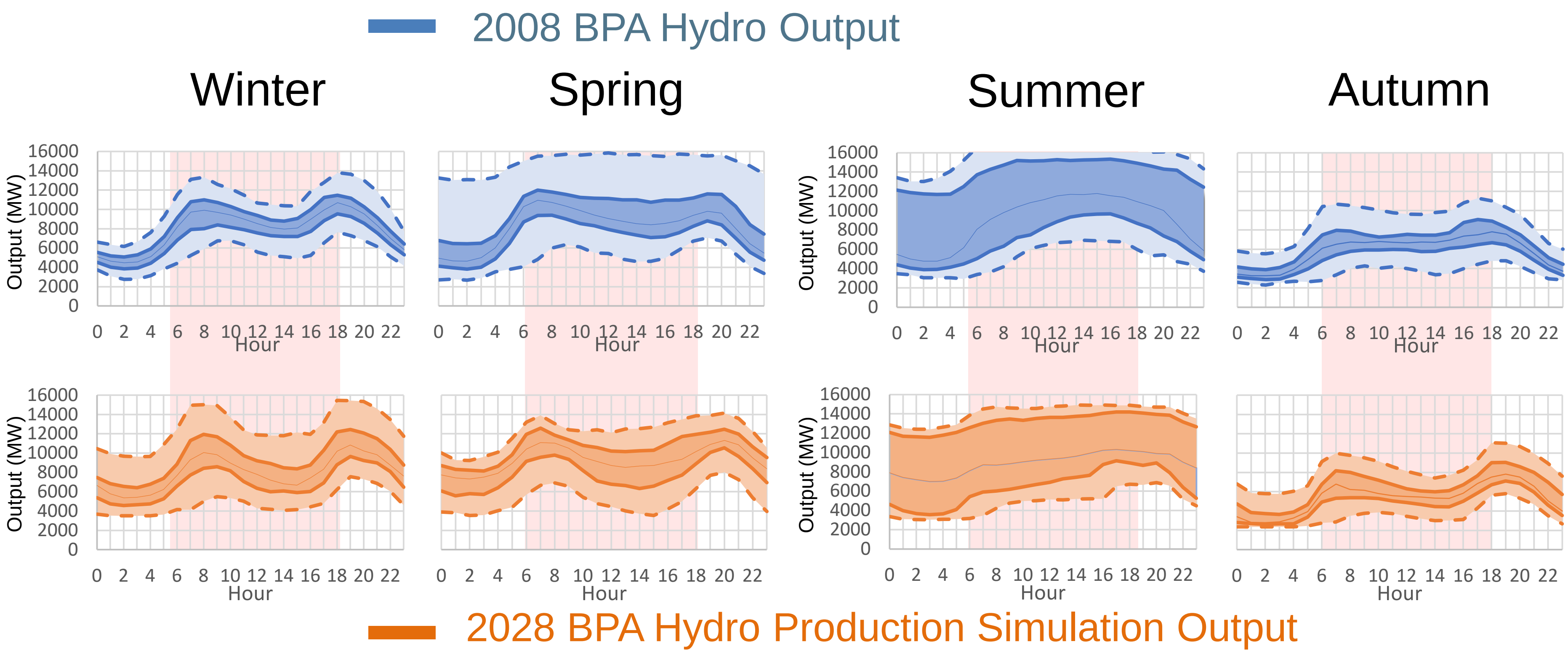
Analysis based on public data

- **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/#

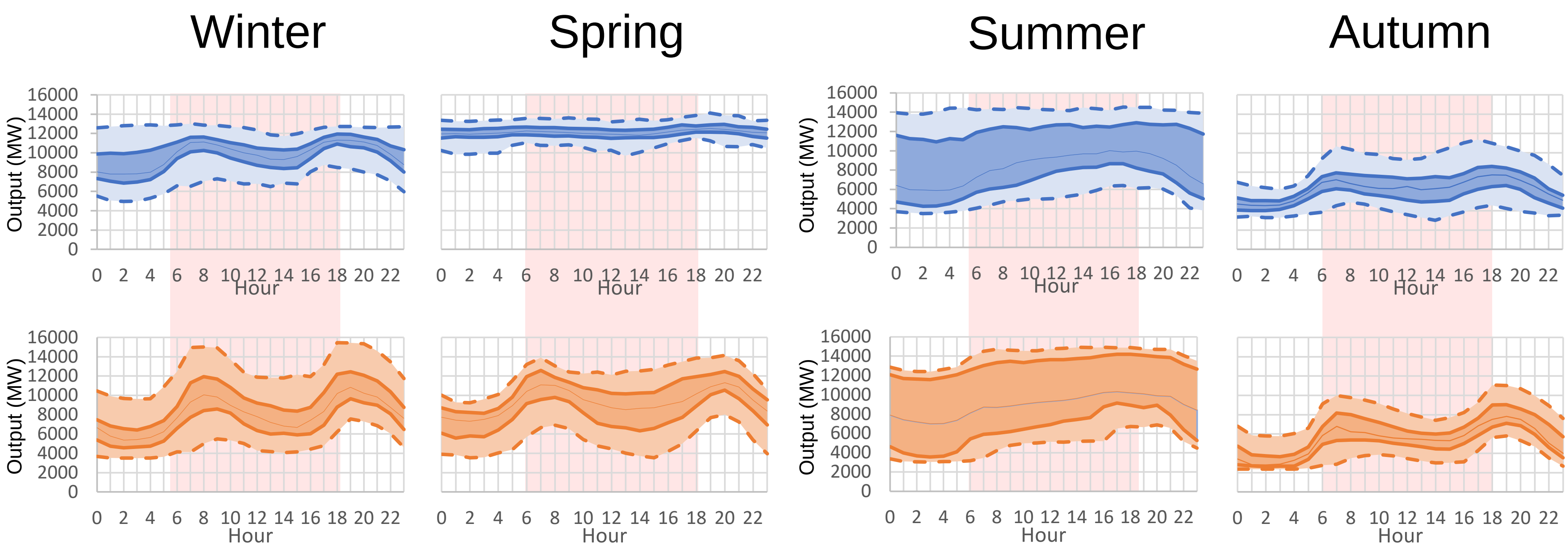
2008 vs 2028 Production Simulation
Seasonal output by hour



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 Seasonal output by hour

2017 BPA Hydro Output



2028 BPA Hydro Production Simulation Output

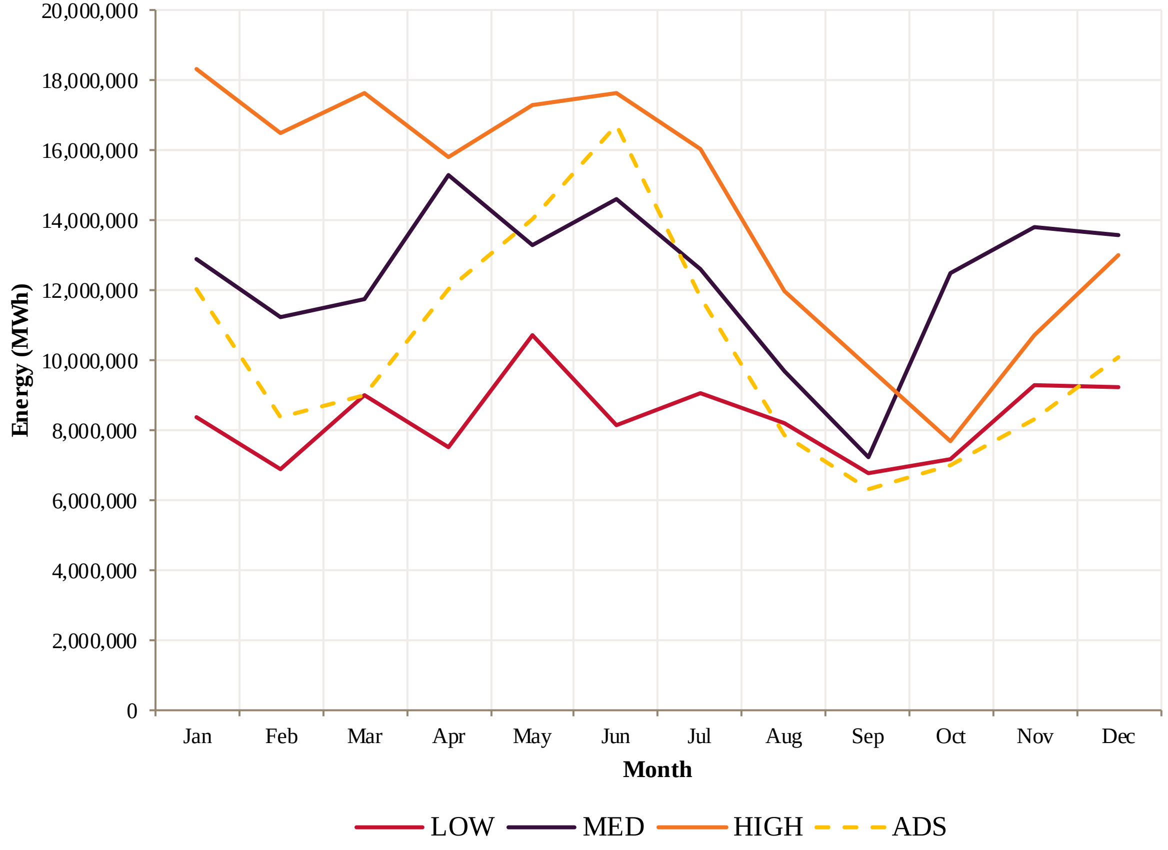
Northwest Power and Conservation Council's GENESYS model

- 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

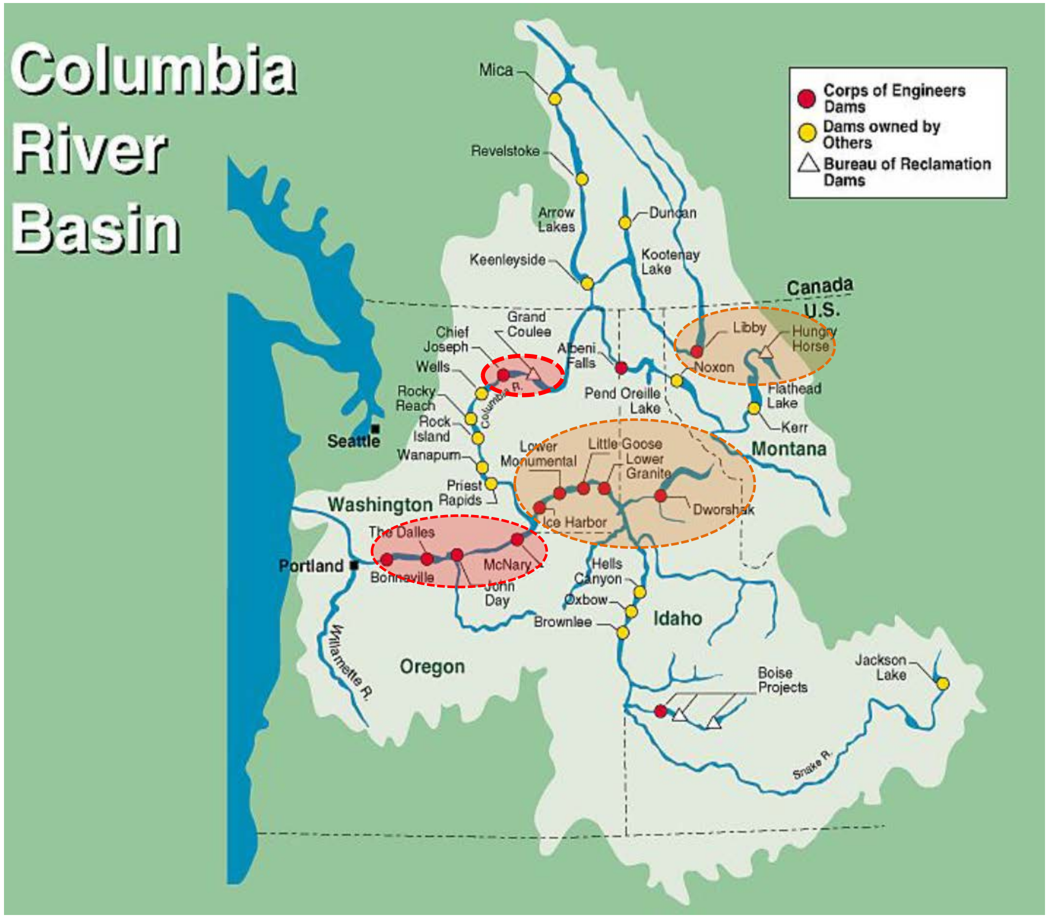
1. High
   - o 95th percentile
   - o 1997
2. Medium
   - o 50th percentile
   - o 1960
3. Low
   - o 5th percentile
   - o 1931

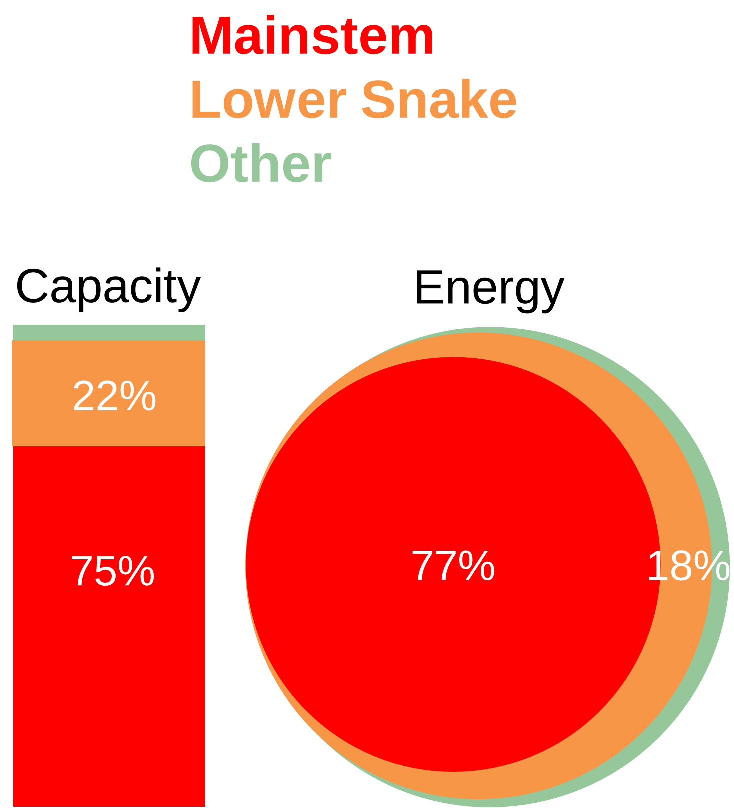


Updating ADS hydro modeling parameters

- Rated capacity for **each NW hydro unit** was used to assign
  - o Monthly energy for each year
  - o Monthly max output for each year
  - o Monthly min output for each year
  - o Monthly daily average operating range for each year
- **Exceptions**
  - o Federal Columbia River Power System Mainstem
    - Grand Coulee, Chief Joseph, McNary, Bonneville, John Day and The Dalles.

Federal Columbia River Power System

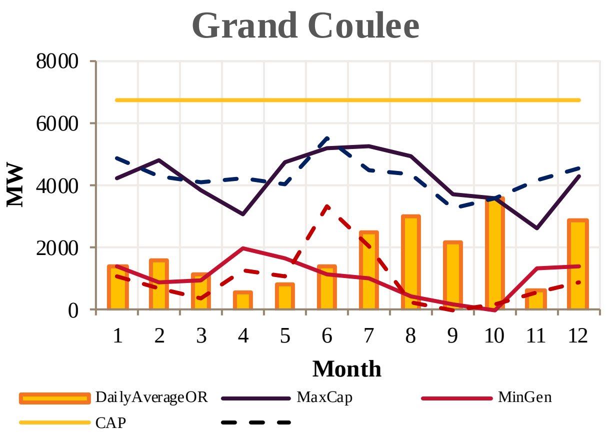


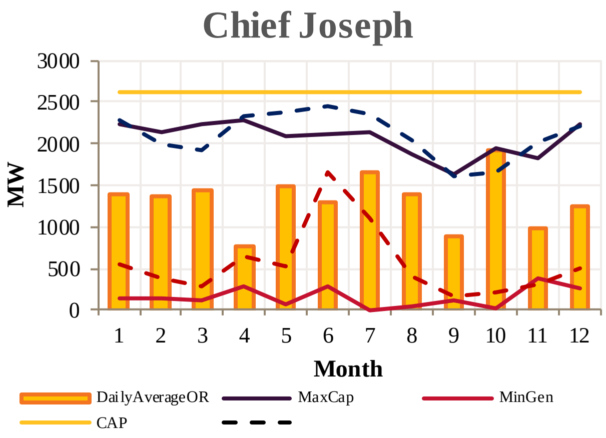


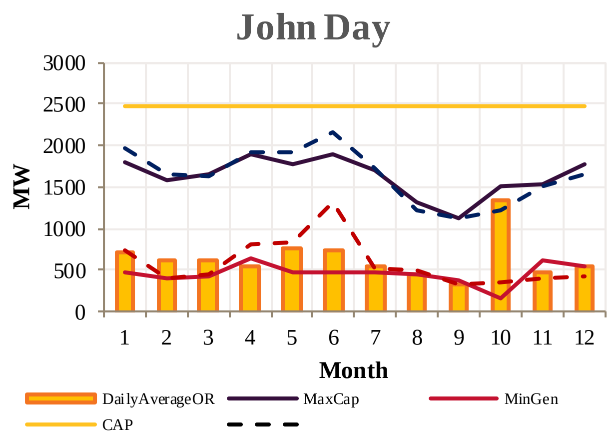
Data source (right): BPA. Asset Category Overview 2017-2030 Hydro Asset Strategy. 2016. Underlying data available here: https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2016IPRDocuments/2016-IPR-CIR-Hydro-Draft-Asset-Strategy.pdf

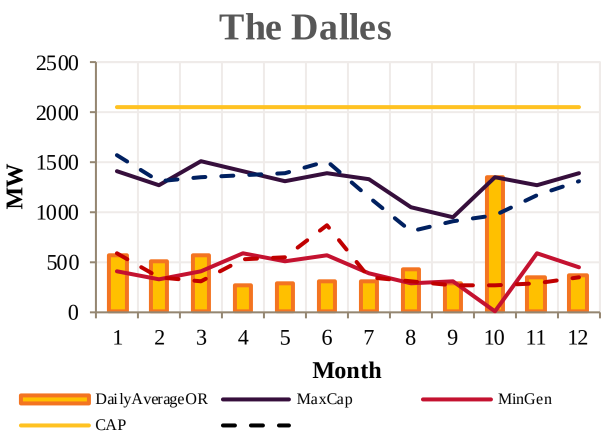
Figure source (left): BPA. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

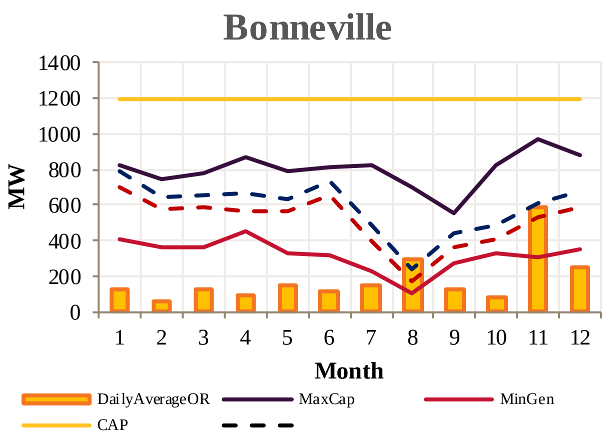
Mainstem modeling parameters - medium

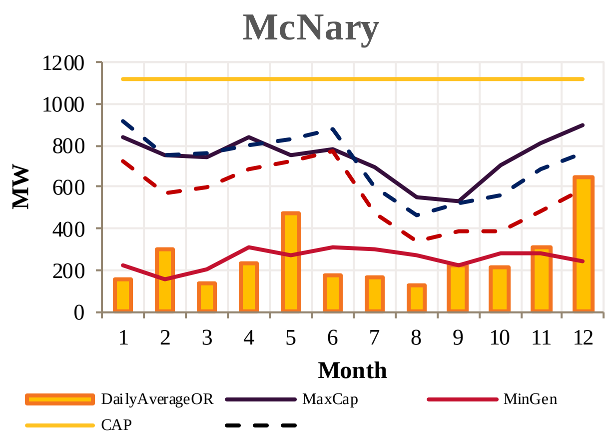




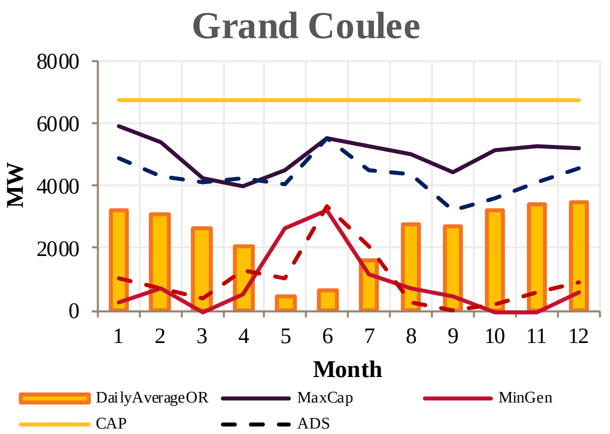


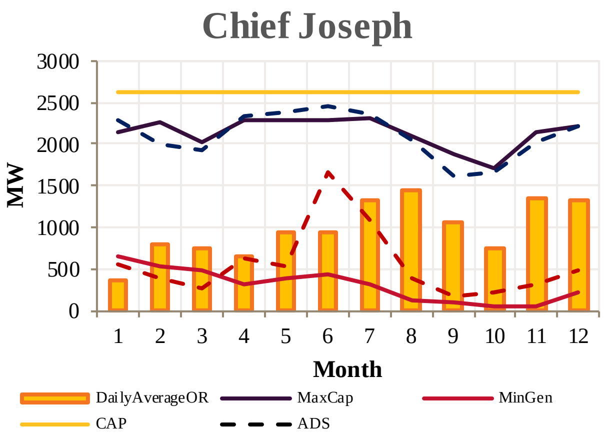


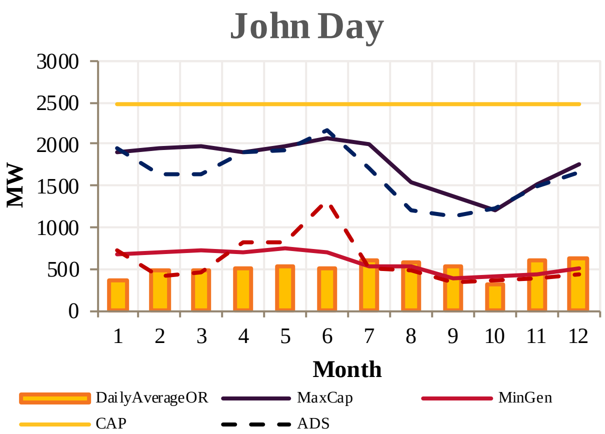


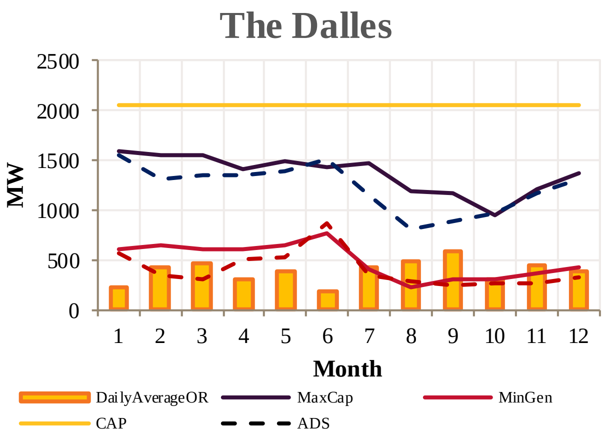


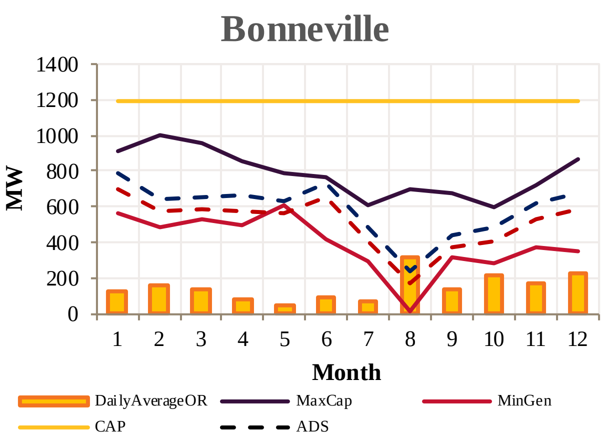
Mainstem modeling parameters - high

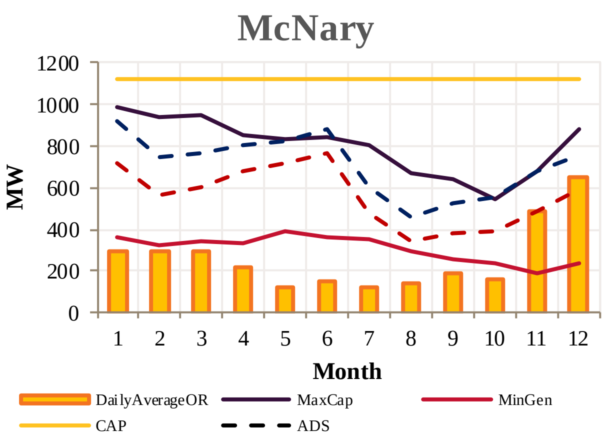




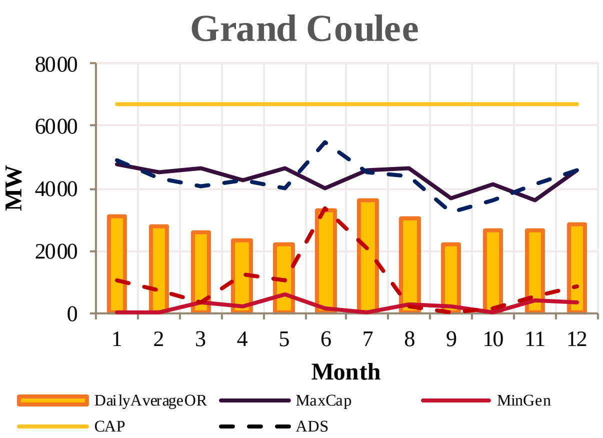


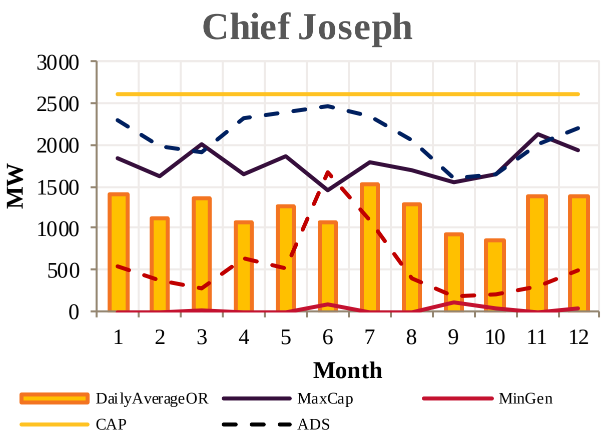


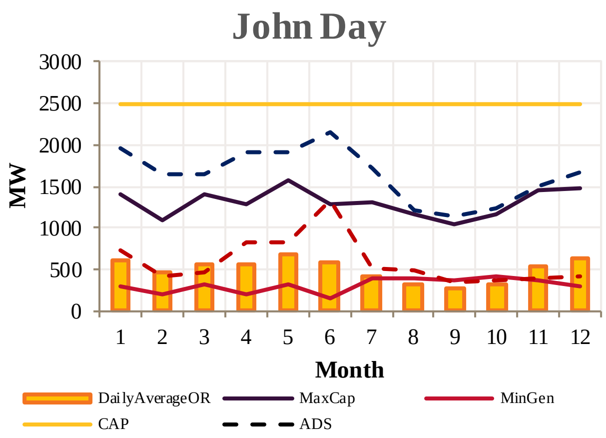


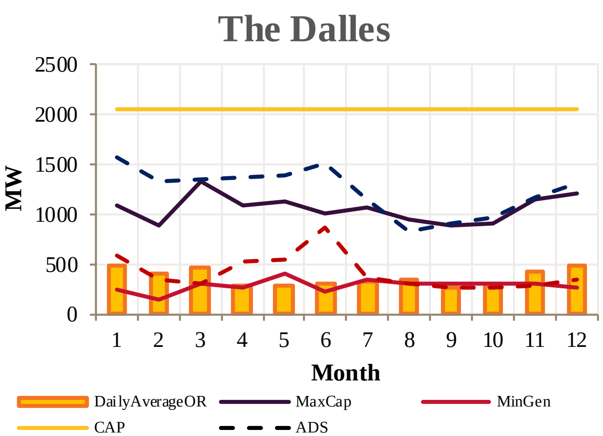


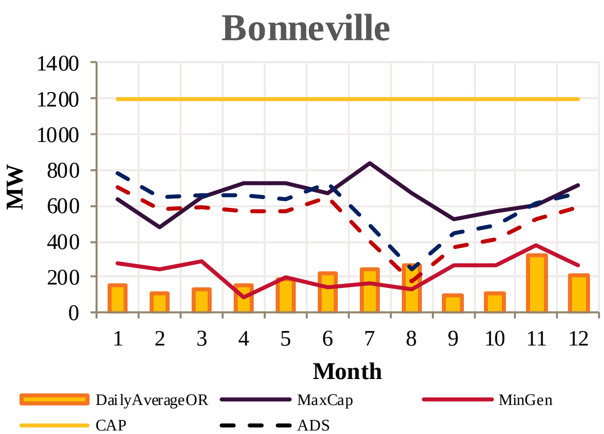
Mainstem modeling parameters - low

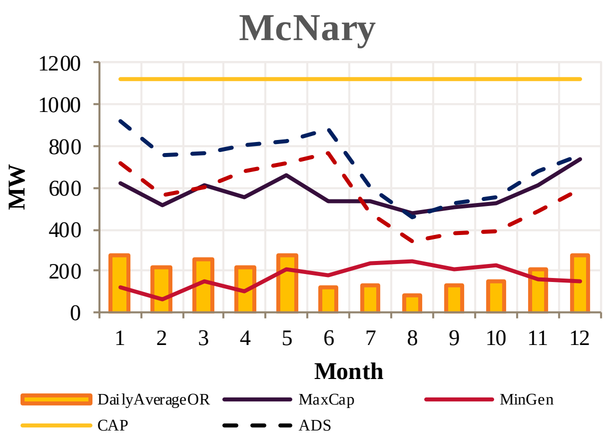












COI congestion with different Hydro conditions (Congestion Hours)

Path	ADS	NWPCC Med	NWPCC Low	NWPCC High
COI	175	349	49	1,597

- COI congestion includes congestion of Path 66 (COI) and its downstream lines
- In the base case studies, COI path rating is 4800 MW, and COI scheduled outage and derate are modeled
  - COI congestion mainly happened during the hours COI was derated
- A sensitivity with assuming 5100 MW of COI path rating was conducted using the NWPCC Med Hydro condition
  - In 265 hours COI was congested, comparing to 349 hours in the base case study

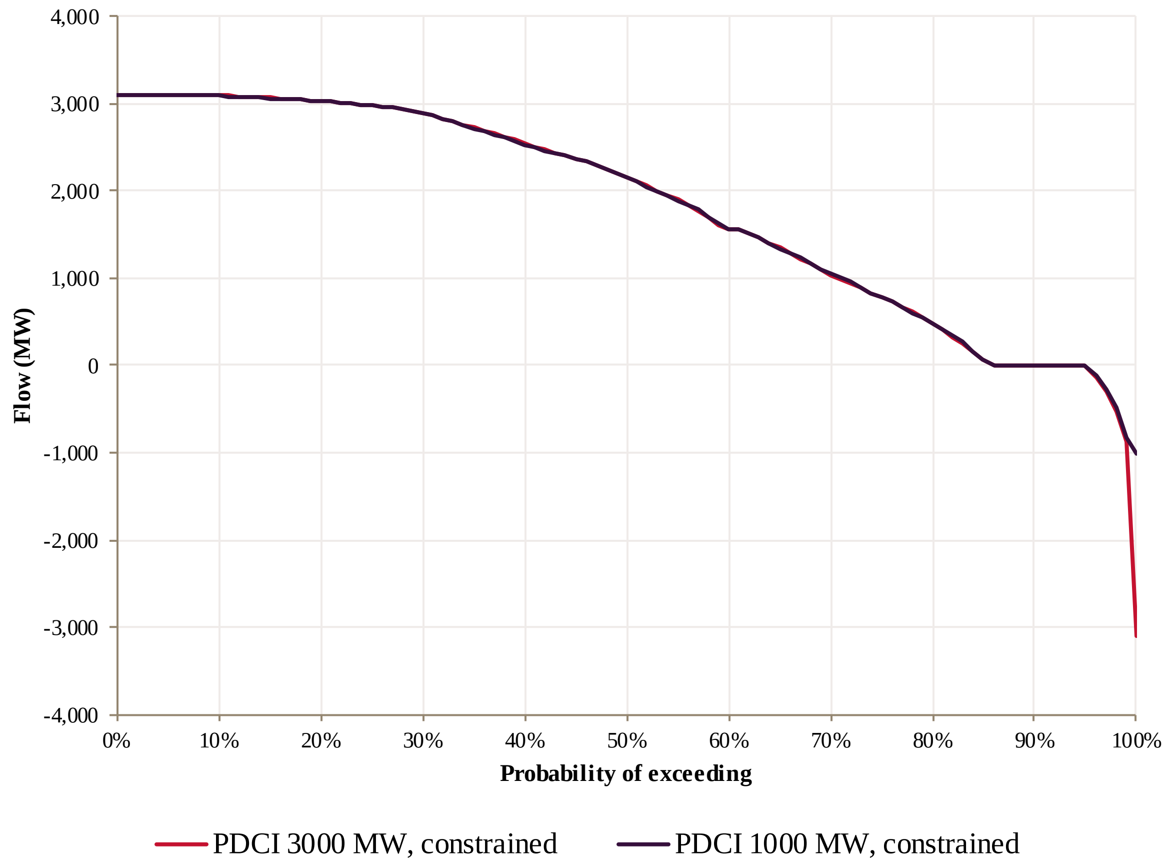
Sensitivity of 1000 MW PDCI South to North limit

PDCI Limit	PAC NW Hydro	SCE curtailment (TWh)	Path 26 Congestion Cost ($M)	Path 26 Congestion Hours	PDCI Congestion Cost ($M)	PDCI Congestion Hours
3000	ADS	6.48	41.2	1284	0	0
1000	ADS	6.52	42.6	1289	1.02	102
3000	Med	6.62	35.5	1155	0	0
1000	Med	6.64	38.2	1139	0.665	67

- 1000 MW of PDCI South to North rating assumption is based on LADWP's operation limit
- Path 26 and PDCI congestions were in from South to North direction in simulation results

California ISO

PDCI Flow Duration Curves
South to North limit sensitivity



Consideration of other sensitivities

- Adjust hydro dispatch model to allow NW hydro to respond the change of COI flow
- CAISO export limit
- Several hydro model parameters may impact the hydro response for a given the hydro condition
  – Hydro dispatch cost (current NW hydro have -$50 ~ -$75/MW dispatch cost)
  – Hydro daily operating range
  – Hydro banking water capability

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 1,597 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 1,100 hours in the S-N direction for the medium hydro scenario.

2. Increase dynamic transfer limit (DTC) on COI

Current NWACI DTC and Limitations to Increase DTC

- The Dynamic Transfer Capability (DTC) on the Northwest AC Intertie (NWACI) has increased from 400 MW to 600 MW effective 7/1/2018 *.

- Limitations to Increase DTC beyond 600 MW:
  - Excessive voltage fluctuations and reactive switching
  - RAS Arming
  - Voltage Stability

* https://www.bpa.gov/transmission/Doing%20Business/bp/Redlines/Redline-DTC-Operating-Scheduling-Reqs-BP-V08.pdf

Excessive voltage fluctuations and reactive switching

- Active power flow variations can cause excessive voltage variations VAR switching.

- At 600 MW DTC limits, loads along COI lines may experience voltage change but at higher DTC other areas might be impacted.

- Voltage variability is the limiting DTC factor about 80% of time today.

RAS Arming

- The RAS arming requirements change rapidly with changing system conditions.

- If dispatchers are unable to keep with manual RAS arming, the system can end up in an insecure state.

- RAS arming requirements are very steep between 2,500 and 3,600 MW of COI flow.

- If a generator that is armed for RAS changes its power output because of EIM dispatch, the adjustments to over-all arming amount and its allocation among COI RAS participants are required for the system reliability.

Voltage Stability

- A fast ramp up of the COI power may result in a sub-optimal system state such that it may become voltage unstable for a critical contingency.

- This limitation applies to dynamic transfers when the flows are within 400 MW of the COI voltage stability limit. Voltage stability study was done by BPA Planning with all lines in service and COI limit of 4,800 MW.

- Voltage stability is the limiting DTC factor about 20% of time, mainly under outage conditions.

Potential Solutions to Increase DTC

Limitations	Solutions
Excessive voltage variability and reactive switching	Real-Time Allocation of COI DTC; COI DTC Nomogram; Apply DTC limits to actuals; Coordinated Voltage Control; State Awareness and Analytics Tools
Voltage stability	Synchrophasor RAS
RAS arming	Automate arming of COI and PDCI RAS
	System Performance Studies
	System Performance Monitoring, Baselining and Analytics

Potentially no DTC limit in the long term

- Coordinated voltage control and other measures will address excessive voltage fluctuation issues.

- BPA is in process of automating arming of COI and PDCI RAS. The automation will remove the RAS Arming limitation.

- Synchrophasor RAS will remove the voltage stability limit. BPA's plan is to seek approval of SP RAS as Wide-Area Protection Scheme. Once the RAS is approved, BPA will remove voltage stability limitation.

- Upon implementation of the required measures and completing detailed studies, the objective is to remove the DTC limit.

3. Implementing sub-hourly scheduling on PDCI

Implementing Sub-hourly scheduling on PDCI

- AGC and EMS modifications at BPA end are required to enable 15-minute and 5-minute scheduling on PDCI.

- Automation of PDCI RAS arming is required, the current project is in progress with expected completion date in 2020

- Voltage variability: BPA performed initial system impact studies of PDCI dynamic transfers on the Pacific Northwest system:
  - The studies indicated increased switching of power factor correction capacitors at BPA and LADWP substations, further analysis of switching device duty is required
  - System impact studies of simultaneous COI and PDCI 5-minute scheduling are planned in 2019

Study Plan for sub-hourly schedule

- BPA will perform studies in 2019 to determine AGC and other EMS modifications required.
- A joint BPA/LADWP studies will be performed in order to fully assess what will need to be modified to automate the control of the DC from AGC systems.
- The joint study is expected to be completed in two years.
- The next steps will be decided based on the outcome of the studies

4. Assigning RA value to firm zero-carbon imports

RA Review in CEC/CPUC letter:

- "…Assigning some resource adequacy (RA) value to hydro generation imports that could be shaped through unused storage capacity potentially available in the Northwest…"

- "… Assigning some RA value to firm zero-carbon imports or transfers. Develop a bounding case that assumes maximal utilization of existing infrastructure investments supporting Energy Imbalance Market operations of participating entities in the Northwest, as well as the integration of synchro-phasor data into control room operations. This case will inform further study and explore the maximum annual expected Northwest hydro import capability of the California ISO grid to estimate an upper bound on avoided GHG emissions assuming that RA/RPS counting criteria are not limiting…"

RA procurement process

- As part of MIC process, the ISO calculates MIC on all branch groups(BG) based on the historical hour-ahead scheduled import on the BGs.

- The calculation is done annually, using the historical data over the two prior years

- From all the hours in each year, in which CAISO load was higher than 90% of peak load in that year, the highest two scheduled imports will be selected (total of 4 data points for each BG).

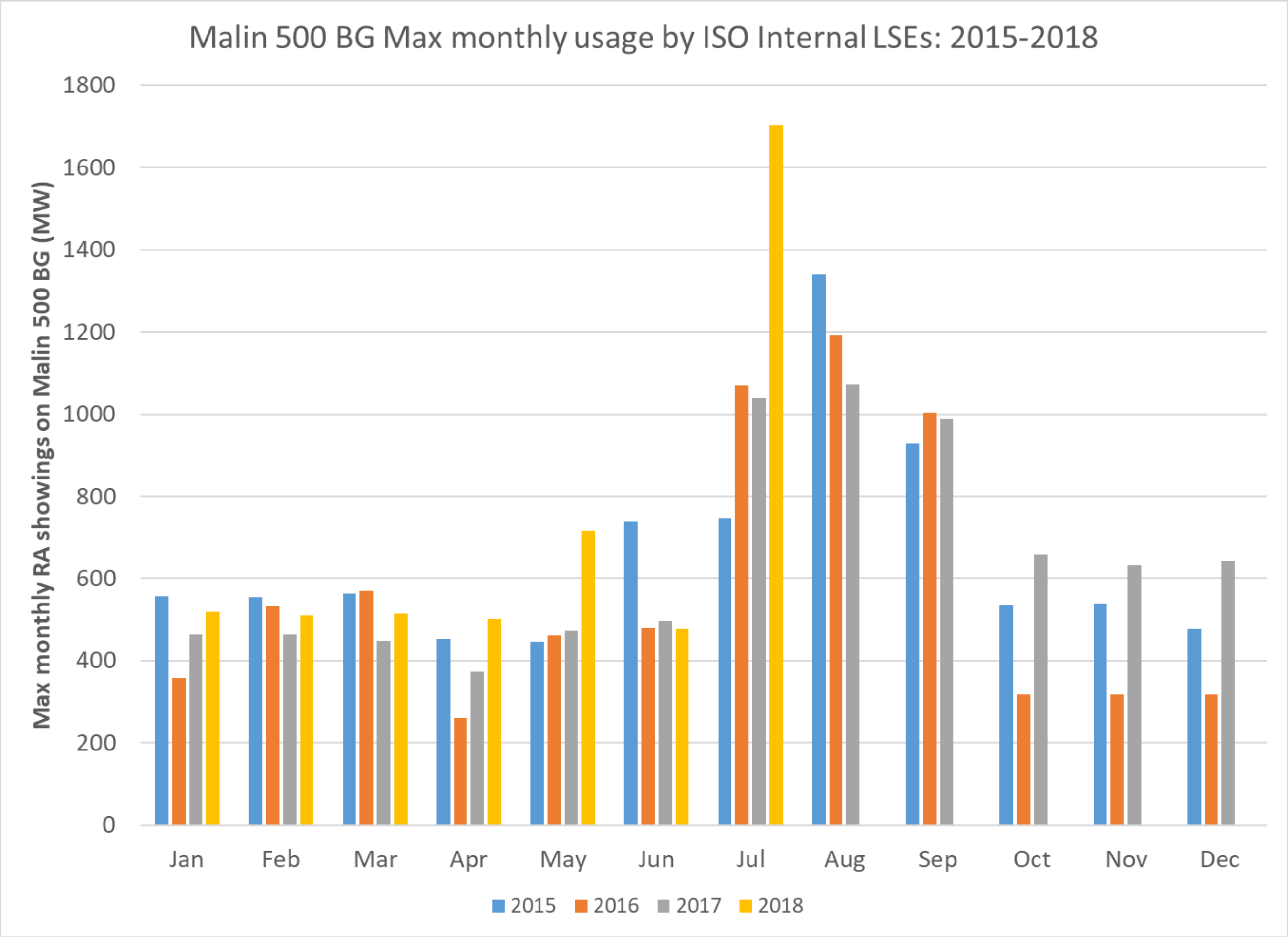
- The average of the above four data points determines the MIC for any BG.

Historical MIC allocation on Malin 500 BG

- Malin 500 BG consists of the Malin-Round Mountain #1 and #2 500 kV lines which are part of COI.
- Malin 500 maximum capacity is 3,200 MW which is 2/3 of COI's WECC path rating of 4,800 MW
- Following the above process, the allocated MIC to Malin 500 BG in the last few years:

Year	Max limit on Malin 500 BG MIC (MW) (2/3 of COI limit)	Allocated MIC on Malin 500 BG (MW)	ETCs and TORs on Malin 500 BG held by entities outside the ISO (MW)	Available RA for Internal ISO LSEs (MW)
2015	2,983	2,913	880	2,033
2016	3,133	3,032	880	2,152
2017	3,127	3,008	900	2,108
2018	3,200	3,008	1,200	1,808

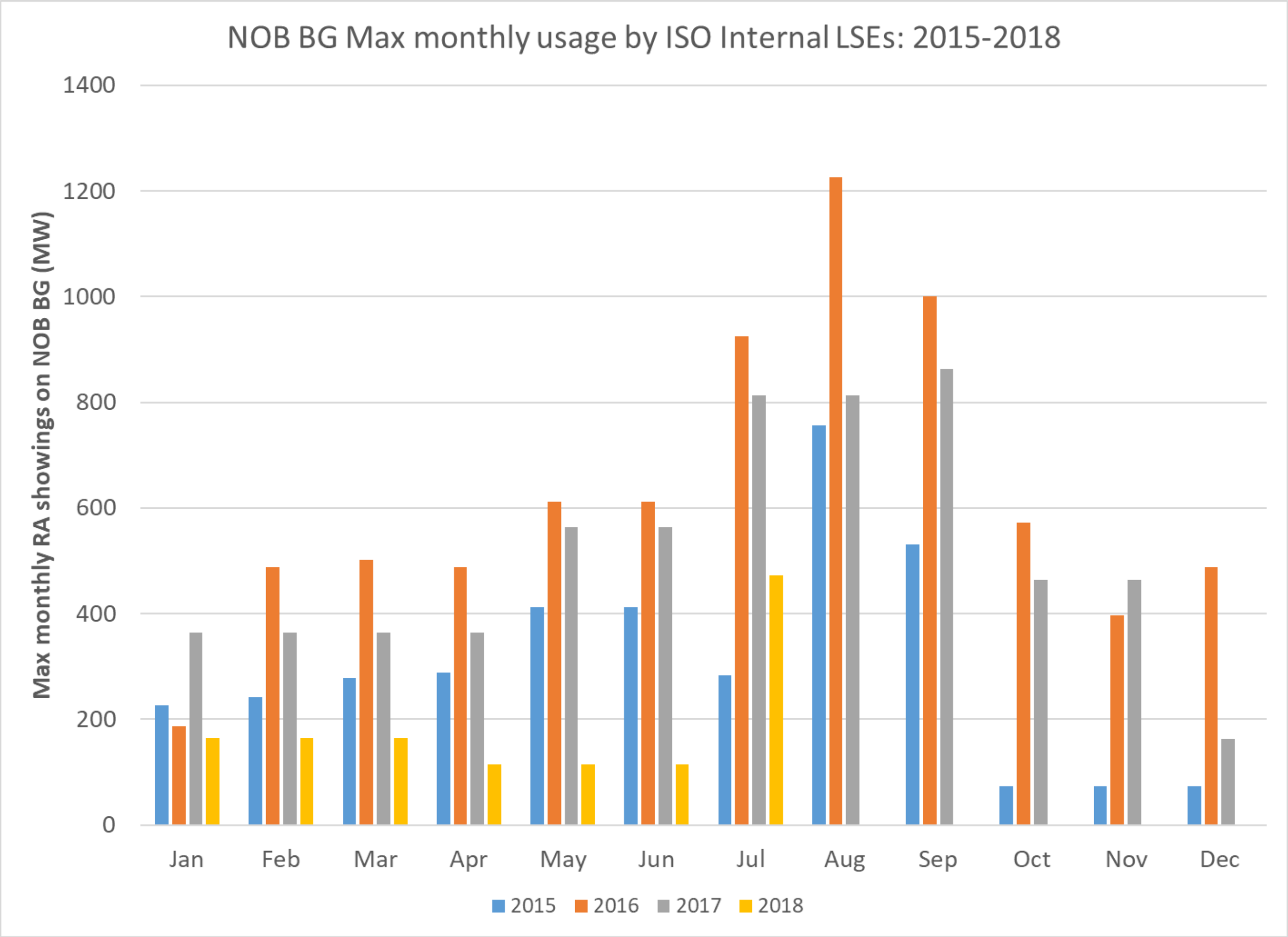
Historical RA showings on Malin 500



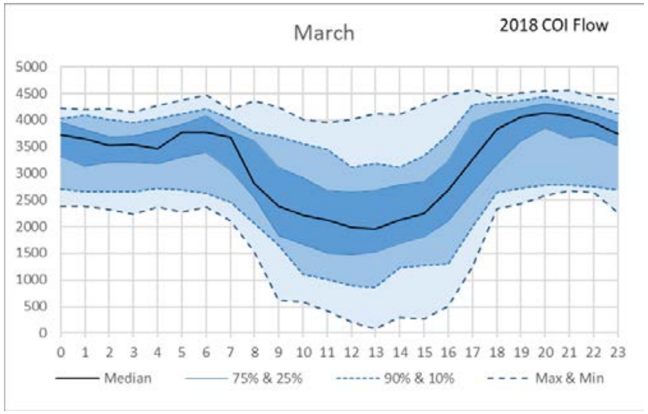
Historical MIC allocation on NOB BG (PDCI)

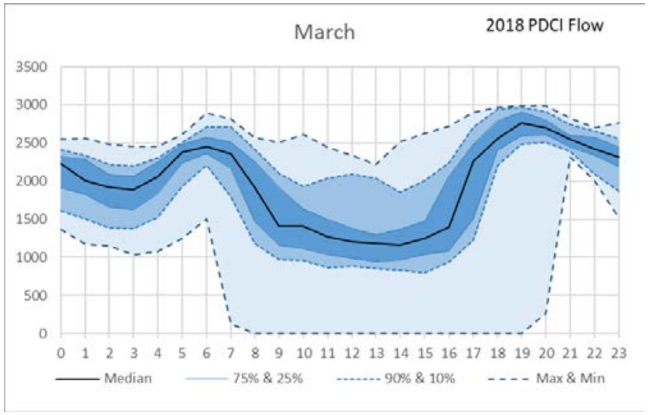
Year	Max limit on NOB BG MIC (MW)	Allocated MIC on NOB BG (MW)	ETCs and TORs on NOB BG held by entities outside the ISO (MW)	Available RA on NOB BG for Internal ISO LSEs (MW)
2015	1,564	1,544	0	1,544
2016	1,564	1,544	0	1,544
2017	1,294	1,283	0	1,283
2018	1,294	1,270	0	1,270

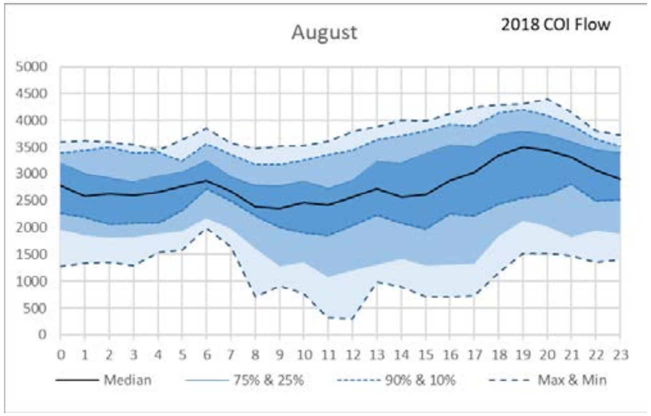
Historical RA showings on NOB BG (PDCI)

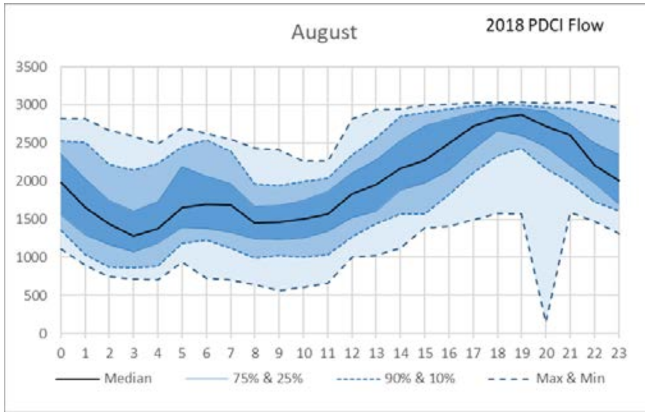


COI and PDCI Flows – March and August 2018









Potential barriers for higher RA showings

- As per CPUC/ISO requirements, commitment of firm capacity is required 45 days ahead of the operating month in order to be counted towards RA.
  - Challenges to forecast hydro that far in advance.

- Potential priorities of PNW entities to serve local loads.

- Currently the FERC-approved ISO RA Import allocation process is one year at a time. Some LSEs prefer to sign multi-year contracts.

- In general, firming up capacity and energy going through number of Balancing Authority Areas may results in additional cost compared to internal California resources.

Summary of RA Analysis

- The RA showings are less than available MIC for most of the year,
- The hour-ahead import schedules which are the basis for MIC are close to path rating.
- In real time, and in recent years, COI and PDCI flows have similar trends as California's net load.
- From Carbon/GHG perspective, there seems to be little to no impact if hydro import from PNW has RA assigned to it or not, as hour-ahead scheduling data shows that potentially low-carbon energy is already coming into California.

Next Steps

- January 31, 2019 post draft Transmission Plan
  - Finalize and document the detailed analysis
- February 7, 2019 stakeholder meeting on draft Transmission Plan